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NEWS RELEASE

MEREN ANNOUNCES 2025 FOURTH QUARTER AND FULL-YEAR RESULTS, ITS YEAR-END 2025 STATEMENT OF RESERVES AND FIRST QUARTERLY DIVIDEND OF 2026

February 24, 2026 (MER–TSX, MER–Nasdaq-Stockholm, MRNFF–OTCQX) – Meren Energy Inc. ("Meren" or the "Company") today published its financial and operating results for the three months and the year ended December 31, 2025, and posted its 2025 statement of reserves on SEDAR+ (www.sedarplus.ca) as part of its Annual Information Form. Meren is also pleased to declare its first quarterly distribution in 2026 of approximately $25.1 million under its base dividend policy.

Meren President and CEO, Oliver Quinn commented: *"2025 was a strong year of delivery for Meren. We closed the transformational Prime consolidation, delivered strong shareholder returns, and strengthened the balance sheet through disciplined deleveraging. These actions have reshaped the company into a simpler, more resilient business that can deliver value through the cycle. As we enter 2026, our priority is consistent execution with a focus on converting our high-quality organic growth opportunities into long term value drivers and returns, whilst maintaining capital discipline and a healthy balance sheet."*

Highlights*

- During 2025, closed the transformative Prime amalgamation to take full control of Prime's assets, doubling Meren's reserves and production;
- Distributed approximately $100 million to the Company's shareholders under the base dividend policy and repurchased 5.9 million shares at a cost of approximately $8 million;
- Achieved average daily W.I.[1] and entitlement[2] production of 30,800 boepd and 35,100 boepd, respectively, for 2025, in line with the revised full-year management guidance;
- Sold three cargos in Q4 2025 at an average sales price of $64.4/bbl and twelve cargos in 2025 at an average sales price of $72.2/bbl, both of which were higher than average Dated Brent for the same periods;
- In 2025 reduced the RBL by $420.0 million, reducing interest expenses and ending 2025 with a debt balance of $330.0 million;
- End of 2025 cash balance of $174.7 million resulting in a net debt position of $155.3 million with a Net Debt/ EBITDAX[3] of 0.4x as at December 31, 2025, with RBL facility headroom of $138.4 million.
- During 2025:
    - EBITDAX[3] of $440.7 million;
    - Cashflow from operations[3,4] before working capital adjustment of $261.8 million; and
    - Cash capital investments of $100.2 million.
- Reported net loss of $31.6 million ($0.05/share) for full-year 2025, primarily from a non-cash impairment of $105.3 million for the Agbami cash generating unit ("CGU") reflecting a more conservative oil price and cost outlook compared to prior assumptions;
- Following continued strong operating performance and after consideration of organic investment requirements and balance sheet resilience, the Board has declared the first quarterly dividend in 2026 of approximately $25.1 million; and

* All dollar amounts in this press release are U.S. Dollars unless otherwise indicated.

- On February 2, 2026, the Company announced that Roger Tucker had stepped down from the role of President and CEO and as a director of Meren, and that Oliver Quinn had been appointed as his successor and joined the Board as director.
- **Meren's year-end 2025 reserves[5]:**
  - YE'25 reserves determination has delivered after-tax 1P NPV(10) and 2P NPV(10) valuations of $588 million (YE'24: $1,248 million) and $1,499 million (YE'24: $2,128 million) respectively[6].
  - YE'25 W.I. and net entitlement[7] 1P reserves of 48.8 MMboe (YE'24: 59.8 MMboe) and 62.5 MMboe (YE'24: 70.8 MMboe), respectively.
  - YE'25 W.I. and net entitlement 2P reserves of 87.7 MMboe (YE'24: 101.6 MMboe) and 107.4 MMboe (YE'24: 116.4 MMboe), respectively.
  - YE'25 aggregate W.I. 2P reserves and 2C contingent resources of 140.2 MMboe (YE'24: 129.6 MMboe).

2025 Fourth Quarter Results Highlights

		Three months ended		Twelve months ended	
Meren Highlights [i,ii]	Unit	December 31, 2025	December 31, 2024	December 31, 2025	December 31, 2024
Net (loss) / income	$'m	(90.8)	6.2	(31.6)	(279.1)
Net (loss)/ income per share – basic [iii]	$/ share	(0.13)	0.02	(0.05)	(0.62)
Net debt position [iv]	$'m	155.3	289.1	155.3	289.1
WI production [iv]	boepd	28,100	34,400	30,800	34,000
Entitlement production [iv]	boepd	31,500	39,000	35,100	38,800
Cash flow from operations [v,vi]	$'m	18.7	n/a	261.8	n/a
EBITDAX [v]	$'m	72.7	n/a	440.7	n/a
Capital investments [v]	$'m	19.8	n/a	100.2	n/a

Notes:

i. The financial information in this table was selected from the Company's audited consolidated financial statements for the year ended December 31, 2025. The Company's consolidated financial statements, notes to the financial statements, management's discussion and analysis for the year ended December 31, 2025 and 2024 and the 2025 Report to Shareholders and Annual Information Form have been filed on SEDAR+ (www.sedarplus.ca) and are available on the Company's website (www.mereninc.com).

ii. The table includes non-GAAP measures. Definitions and reconciliations to these non-GAAP measures are provided on pages 14-17 of the 2025 Shareholder Report.

iii. Based on the weighted average number of shares outstanding for the three months and year ended December 31, 2025, of 675,685,556 and 624,464,015 respectively, which accounts for the newly issued shares to BTG Oil & Gas on March 19, 2025.

iv. Net debt position and production numbers as presented for the comparative periods includes 100 percent of Meren Coöperatief U.A. (previously known as Prime Oil & Gas Coöperatief U.A) to be comparable with net debt position and production numbers for the three months and year ended December 31, 2025.

v. Highlights are reported for the year 2025 only, on a constructed financial information basis, see pages 10-12 of the 2025 Shareholder Report for further information.

vi. Cash flow from operations before working capital and interest payments.

In 2025, the Company recorded revenue, mainly related to oil sales, following the amalgamation with Meren Coöperatief U.A. (previously known as Prime Oil & Gas Coöperatief U.A) ("Meren Coop"). In 2024 and 2023, the Company held a 50% investment in Meren Coop, accounted for as a Joint Venture and therefore no revenue was recognized in these years.

In 2025, the Company recorded a net loss attributable to common shareholders of $31.6 million (2024: net loss of $279.1 million).

As at December 31, 2025, the Company determined that there was an indicator of impairment of $105.3 million in respect of its oil and gas properties related to the Agbami field cash generating unit ("CGU"), reflecting a more conservative oil price and cost outlook compared to prior assumptions. This assessment was driven by recent oil price volatility and updated cost forecasts.

A significant portion of the revised cost outlook relates to planned long-term life-extension activities required to enable the Agbami FPSO to continue operating reliably and safely through the end of the current license period. These activities are also expected to enhance the flexibility of the Agbami FPSO to support future infill drilling and potential nearby tie-in opportunities, consistent with the Company's long-term organic growth strategy. Such potential upside relates to contingent resources which are not included in the recoverable amount of the CGU for impairment testing purposes. The impairment does not reflect any adverse change in reservoir performance, reserves classification or the operational integrity of the Agbami field.

Please refer to the 2025 Shareholder Report for further details on the 2025 and comparative 2024 periods.

Year-End 2025 Statement of Reserves

The Company has posted its 2025 statement of reserves on SEDAR+ (www.sedarplus.ca) as part of its Annual Information Form. This disclosure is based on an independent reserves evaluation, effective January 1, 2026, prepared by RISC (UK) Limited ("RISC") for Meren in accordance with Canadian National Instrument 51-101 – Standards for Oil and Gas Activities ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook").

Meren's main assets are an indirect 8% interest in Petroleum Mining License ("PML") 52 and an indirect 16% interest in PMLs 2, 3, 4; these are deep-water Nigeria concessions. PML 52 is operated by affiliates of Chevron Corporation and contains the producing Agbami field. PML 2, PML 3 and PML 4 are operated by affiliates of TotalEnergies SE and contain the producing Akpo and Egina fields.

The year-end 2025 reserves and reconciliation of changes in W.I. reserves are summarized in the following tables:

Summary of Oil and Gas Reserves (Forecast Prices and Costs)

Reserve Category	Light and Medium Oil Gross (MMstb)	Light and Medium Oil Net (MMstb)	Natural Gas Gross (Bscf)	Natural Gas Net (Bscf)	Oil Equivalent Gross (MMboe)	Oil Equivalent Net (MMboe)
Proved						
Developed Producing	20.2	29.1	52.0	52.0	28.8	37.8
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	18.3	23.1	10.0	10.0	20.0	24.8
Total Proved	**38.4**	**52.2**	**62.0**	**62.0**	**48.8**	**62.5**
Probable	30.7	36.6	49.7	49.7	39.0	44.9
Total Proved plus Probable	**69.1**	**88.8**	**111.7**	**111.7**	**87.7**	**107.4**
Possible	23.7	25.4	51.9	51.9	32.4	34.0
Total Proved plus Probable plus Possible	**92.8**	**114.2**	**163.6**	**163.6**	**120.1**	**141.4**

Notes:

i. The figures in the table may not add up precisely due to rounding.
ii. Units are MMstb (million stock tank barrels) and Bscf (billion standard cubic feet).
iii. Oil equivalent values are based on volumes Barrel of Oil Equivalent (BOE): 6 Mcf = 1 BOE. BOEs may be misleading particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
iv. Gross Company Reserves are the total project sales volumes multiplied by Meren's working interest.
v. Net oil Reserves are Meren's net entitlement calculated using economic limit testing.
vi. Gross and net Reserves for sales gas are equal as the gas terms are set out in the Gas Sales and Purchase Agreement, rather than the PSA, and the net Reserves are based on Meren's working interest.

Gross	Light and Medium Oil (MMstb)			Conventional Natural Gas (Bscf)		
	Proved	**Probable**	**Proved + Probable**	**Proved**	**Probable**	**Proved + Probable**
Effective date: 31 December 2025	**44.8**	**34.1**	**78.9**	**89.8**	**46.0**	**135.8**
Extensions and Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0
Resource Transfers	-0.9	-0.5	-1.4	-1.9	-1.2	-3.1
Technical Revisions	2.5	-2.9	-0.4	-6.2	4.9	-1.3
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0
Production	8.0	0.0	8.0	19.7	0.0	19.7
Effective date: 1 January 2026	**38.4**	**30.7**	**69.1**	**62.0**	**49.7**	**111.7**

Notes:

i. The figures in the table may not add up precisely due to rounding.
ii. Gross Company Reserves are the total project sales volumes multiplied by Meren’s working interest.

Outlook

Nigeria

Nigeria’s macroeconomic and sector-specific reforms are beginning to show tangible results, with improved fiscal clarity, stronger government engagement, and targeted incentives aimed at sustaining investment in the oil and gas sector. The Federal Government has reaffirmed its support for upstream development through regulatory stability and commercial incentives, contributing to renewed capital commitment across offshore oil and gas projects. This improved investment climate is evidenced by recent final investment decisions on major developments such as Bonga North, Ubeta Gas Project, and HI Offshore Gas Project, which collectively signal growing confidence in Nigeria as a destination for long-term energy investment.

In collaboration with its JV Parties, the Company is continuing to advance the restart of the Akpo/Egina 2026 drilling campaign following the break in the 2025 program. Work is underway to secure a deepwater rig with the drilling of the Akpo Far East near-field prospect, the first planned well in the campaign. This will be followed by the drilling of further infill development wells in the Akpo and Egina fields in late 2026 and into early 2027. Notably, the pause in the drilling program has created a valuable opportunity for the interpretation of 4D seismic data focused on the maturation of infill well candidates.

The Akpo Far East prospect presents a strategically-positioned fast-cycle tie-back opportunity that will utilise the existing Akpo facilities. The prospect lies about 5 km east of the currently producing Akpo field and the planned drilling approach will assess all prospective resource volumes identified within the prospect. To support this, efforts are ongoing to complete all the work required to spud the Akpo Far East exploratory well in 2026.

Work is actively progressing on the remaining subsurface and development opportunities within the PML 2/3/4 license area. Preowei Field subsurface review and development validation activities continued in Q4 2025 with study results expected in H1 2026 to guide the timing and scope of an FID. The planned appraisal activity by TotalEnergies in the Egina South area in OPL 257, currently expected in 2026, may further de-risk adjacent resources and, if successful, indicate potential additional value for Meren through proximity to existing infrastructure.

In early 2026, Meren and its JV Parties in PML 2/3 successfully executed an amendment to the gas sales agreement that includes a revised index for gas pricing, locking in a long-term gas price that is more reflective of the current LNG economics compared to 2018 when the contract was initially signed. The amendment also includes a mechanism for the sellers to recover the historical difference between the interim gas price adjustment and the new index, starting from 2020 when the previous index ceased to be published. This historical amount will be recovered through an upward adjustment to the netback pricing that includes the handling fee for the gas sold, which will improve future gas revenue for the Company.

In Agbami, the FPSO unit life extension studies to ensure long term asset integrity and to enhance operation performance of the facility, are expected to conclude in 2026. Also, the ongoing 4D seismic interpretation and rig contracting activities for the Agbami infill drilling program remain on schedule. The Agbami infill drilling campaign is expected to commence in Q1 2027, following the planned arrival of the rig in Q4 2026 with the Ikija appraisal well being matured to initiate the campaign as the first well.

Namibia Orange Basin Development and Exploration, Blocks 2912 and 2913B

The Venus Field in Block 2913B remains the most advanced deepwater discovery in the Orange Basin and is expected to anchor Namibia's first large-scale offshore oil development. The project is being progressed by TotalEnergies (Operator, 50.5%) together with QatarEnergy (30.0%), NAMCOR (10.0%) and Impact Oil & Gas (9.5%). Through its shareholding in Impact, Meren holds an effective 3.8 percent indirect interest in the Venus development. Under Impact's carried-interest arrangement with TotalEnergies, Meren's exposure to all development and exploration costs on Blocks 2912 and 2913B remains fully funded through to first commercial production, without any financial cap.

The Environmental and Social Impact Assessment (ESIA) for the proposed Venus development has been completed and published, and the associated Environmental Clearance Certificate (ECC) application has been submitted to the relevant Namibian authorities. Completion of the ESIA represents a key regulatory milestone, further de-risking the project. FEED work is proceeding on the base-case concept of up to 40 subsea wells tied back to a single FPSO with a nameplate capacity of approximately 160,000 barrels per day of oil, with reinjection of associated gas offshore. Contractor bids have been received and are within expectation. The project schedule remains consistent with the current planning framework with FID targeted for 2026 and first oil in 2030, subject to the completion of negotiations between the operator and the government on enhanced fiscal terms for the project, which is expected to be the first producing oil field and the first deepwater development in Namibia.

The Venus development is regarded by the Namibian government as a strategic national project with the potential to establish Namibia as a new deepwater oil producer. Appraisal and exploration activities continue across the broader Orange Basin and additional prospects are being evaluated using newly acquired 3D seismic data on Blocks 2912 and 2913B.

Namibia's oil and gas sector remains active and supportive, with strong investment from international operators, rollout of a Local Content Policy, and infrastructure upgrades at the Walvis Bay and Lüderitz ports. Execution and infrastructure challenges, including marine services capacity, environmental approvals, and gas monetization, present both risks and opportunities as the country positions itself to attract capital and expand its deepwater supply chain.

The Venus development presents Meren with a material long-term growth opportunity within a fully carried structure, offering potential for future cash-flow generation and portfolio optionality with no upfront funding commitments.

South Africa Orange Basin, Block 3B/4B

On September 16, 2024, the Department of Mineral Resources and Energy for the Republic of South Africa granted an Environmental Authorization for exploration activities (drilling of up to 5 exploration wells) on the block. Following that decision, the legislative notification and appeals process in South Africa was suspended pending a Supreme Court of Appeal judgement in respect of Block 5/6/7. The operator has stated that the current plan is to drill the first exploration well on Block 3B/4B as soon as the Environmental Authorization is confirmed and has identified Nayla, a prospect that lies in the northwest of the license area, as the potential drilling target.

Equatorial Guinea, Blocks EG-18 and EG-31

In late 2025 the Company submitted requests for extensions to the exploration license terms for both blocks. On December 17, 2025, the Company received notification from the Ministry of Hydrocarbons and Mining Development in Equatorial Guinea approving extensions of up to two years to the first exploration sub period on each block.

During the course of 2025, the Company completed a number of data room exercises across the two blocks and remains actively engaged in advancing potential partnership discussions. Following industry interest during the data room phase, the Company is now transitioning into the next stage of activity, focused on advancing discussions with prospective partners. In parallel, the Company continues to coordinate with government and representatives from GEPetrol to define the forward plan for both blocks.

Should the Company successfully attract a farm-in partner(s) on acceptable terms for these blocks, subject to customary consents and approvals including governmental and regulatory permissions, the Company anticipates that newly formed JVs could be positioned to plan for appraisal and development as well as exploration drilling in late 2026 or 2027.

While there can be no assurance of securing partners on acceptable terms, the Company remains encouraged by the level of industry interest and continues to advance partnership discussions with confidence.

Shareholder Returns

The Company's capital allocation framework balances reinvestment in value-accretive organic opportunities with a commitment to sustainable shareholder returns, while preserving balance sheet strength and financial flexibility.

Following continued strong operating performance and after consideration of organic investment requirements and balance sheet resilience, the Company is pleased to announce that its Board has declared the distribution of the Company's first quarterly cash dividend in 2026 of approximately $25.1 million or $0.0371 per share. This dividend will be payable to shareholders of record at the close of business on March 20, 2026.

This dividend qualifies as an 'eligible dividend' for Canadian income tax purposes. Dividends for shares traded on the Toronto Stock Exchange ("TSX") will be paid in Canadian dollars on April 7, 2026; however, all US and foreign shareholders will receive USD funds. Dividends for shares traded on Nasdaq Stockholm will be paid in Swedish Krona in accordance with Euroclear principles at the earliest on April 10, 2026.

To execute the payment of the dividend, a temporary administrative cross border transfer closure will be applied by Euroclear from March 18, 2026, up to and including March 20, 2026, during which period shares of the Company cannot be transferred between the TSX and Nasdaq Stockholm.

Payment to shareholders who are not residents of Canada will be net of any Canadian withholding taxes that may be applicable. For further details, please visit: https://mereninc.com/investor-summary/total-shareholder-returns/.

The Board views this first quarterly dividend of 2026 to be prudent, having given due consideration to the Company's capital allocation options and the Company's overarching priority of maintaining a robust balance sheet under a range of market scenarios.

Notwithstanding the foregoing, the decision to declare any dividend or other shareholder distribution and the amount of future cash dividends declared and paid by Meren or shareholder distributions made by Meren, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time. These may include, without limitation, business performance, operating environment where Meren's assets are located, financial condition, growth plans, fluctuations in commodity prices, production levels, expected capital expenditure requirements, operating costs, royalties, foreign exchange rates, interest rates, compliance with any restrictions on the declaration and payment of dividends contained in any agreements to which Meren or any of its subsidiaries is a party from time to time (including, without limitation, financing agreements governing the RBL), and the satisfaction of liquidity and solvency tests imposed by the BC BCA for the declaration and payment of dividends. The actual amount, the record date and the payment date of any dividend are subject to the discretion of the Board. There can be no assurance that dividends will be paid at the current rate or at any rate in the future.

2026 Management Guidance

The Company's full-year 2026 production will be generated solely by its deepwater Nigerian assets. The 2026 Management Guidance includes W.I. production guidance range of 23.0 – 28.0 kboepd and entitlement production range of 28.0 – 33.0 kboepd with approximately 68% expected to be light and medium crude oil and 32% conventional natural gas on a W.I. basis and 73% and 27% respectively on an entitlement basis. Meren is expected to sell 8 cargoes of approximately one million barrels each during 2026.

The table below summarizes the Company's full-year 2026 Management Guidance. These estimates are based on a 2026 average Brent price of $63.0/bbl.

	2026 Guidance	2025 Actuals
WI production (kboepd) [i]	23.0 – 28.0	30.8
Entitlement production (kboepd) [ii]	28.0 – 33.0	35.1
EBITDAX ($ million) [iii]	270.0 – 360.0	440.7
Cash flow from operations ($ million) [iii]	185.0 – 255.0	261.8
Capital investments ($ million)	100.0 – 140.0	100.2

Notes:

i. Aggregate oil equivalent production data comprised of light and medium crude oil and conventional natural gas production net to the Company's W.I. in Agbami, Akpo and Egina fields. These production rates only include sold gas volumes and not those volumes used for fuel, reinjected or flared.

ii. Entitlement production is calculated using the economic interest methodology and includes cost recovery oil, royalty oil and profit oil and is different from working interest production that is calculated based on project volumes multiplied by the Company's effective working interest in each license.

iii. This table includes non-GAAP measures that do not have a standardized meaning prescribed by IFRS Accounting Standards and, therefore, may not be comparable with the calculation of similar measures by other companies. The Company believes that the presentation of these non-GAAP figures provides useful information to investors and shareholders as the measures provide increased transparency. EBITDAX is a non-GAAP measure. This is used as a performance measure to understand the financial performance from the Company's business operations without including the effects of the capital structure, tax rates, depreciation, depletion, amortization, impairment and exploration expenses. Cash flow from operations before working capital and interest payments is a non-GAAP measure. This represents cash generated by removing the impact of working capital movements from cash generated by operating activities. It is a measure commonly used to better understand cash flow from operations across periods on a consistent basis, and when viewed in combination with the Company's results provides a more complete understanding of the factors and trends affecting the Company's performance.

Notes

1. Aggregate oil equivalent production data comprised of light and medium crude oil and conventional natural gas production net to Meren's W.I. in Agbami, Akpo and Egina fields. These production rates only include sold gas volumes and not those volumes used for fuel, reinjected or flared.
2. Lifting entitlement production is calculated using the economic interest methodology and includes cost recovery oil, tax oil, royalty oil and profit oil and is different from working interest production that is calculated based on project volumes multiplied by Meren's effective working interest in each license.
3. Includes non-GAAP measures. Definitions and reconciliations to these non-GAAP measures are provided in Fourth Quarter 2025 MD&A.
4. Cash flow from operations before working capital adjustments and interest payments.
5. Please refer to the oil and gas advisory on page 8 for important information.
6. Based on Brent oil price forecast of ($/bbl): 2026 - $71.0; 2027 - $73.3; 2028 - $74.6; 2029 - $76.1; 2030 – $77.6; 2031 and beyond escalation rate of 2.0%.The valuation include the impact of a lower oil price deck used in this report relative to the deck used for YE'24, which included a forecast of ($/bbl): 2026 - $76.5; 2027 - $78.0; 2028 – 79.6; 2029 - $81.2; 2030 and beyond escalation rate of 2.0%
7. Net entitlement reserves are calculated using the economic interest methodology and include cost recovery oil, tax oil and profit oil, but exclude royalty oil, and are different from working interest reserves that are calculated based on project volumes multiplied by Meren's effective working interest.

Management Conference Call

Senior management will hold a conference call to discuss the results on Wednesday, February 25, 2026, at 09:00 (ET) / 14:00 (GMT) / 15:00 (CET). The conference call may be accessed via webcast.

Participants should use the following link to register for the live webcast:

https://meren-energy-fourth-quarter-results-february-2026.open-exchange.net/registration

1. Click on the link and complete the online registration form.
2. Upon registering you will receive a confirmation email with a sign in link and access code.

About Meren

Meren is a full-cycle Independent upstream oil and gas company with interests offshore Nigeria, Namibia, South Africa and Equatorial Guinea. Its main assets are producing and development assets in deepwater Nigeria. The Company holds a leading position in the Orange Basin including its effective interest in the Venus light oil project, offshore Namibia, and its direct interest in Block 3B/4B, offshore South Africa.

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Additional Information

This information is information that Meren is obliged to make public pursuant to the EU Market Abuse Regulation and information that Meren is required to make public pursuant to the Swedish Securities Market Act. The information was submitted for publication, through the agency of the contact persons set out above, at 5:00 p.m. ET on February 24, 2026.

Advisory Regarding Oil and Gas Information

The terms boe (barrel of oil equivalent) and MMboe (millions of barrels of oil equivalent) are used throughout this press release. Such terms may be misleading, particularly if used in isolation. Year-end 2025 reserves estimates are based on a conversion ratio of six thousand cubic feet per barrel of oil equivalent (6 Mcf: 1 boe), which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

RISC's report was prepared using Brent oil price forecast of ($/bbl): 2026 - $71.0; 2027 - $73.3; 2028 - $74.6; 2029 - $76.1; 2030 – $77.6; 2031 and beyond escalation rate of 2.0%. There is no assurance that the forecast prices will be attained and variances could be material. The recovery and reserves estimates of crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

The reserves estimates presented in this press release have been evaluated by RISC in accordance with NI 51-101 and the COGE Handbook, are effective December 31, 2025. The reserves presented herein have been categorized accordance with the reserves and resource definitions as set out in the COGE Handbook. The estimates of reserves in this press release may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation.

Reserves

Reserves are estimated remaining quantities of commercially recoverable oil, natural gas, and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data, the use of established technology, and specified economic conditions, which are generally accepted as being reasonable. Reserves are further categorized according to the level of certainty associated with the estimates and may be sub-classified based on development and production status.

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Oil and gas reserves and production referred to in this release are for conventional light and medium gravity oil and conventional natural gas.

Forward-Looking Information

Certain statements and information contained herein constitute "forward-looking information" (within the meaning of applicable Canadian securities legislation), including statements related to: the base dividend distribution; the declaration of the $25 million quarterly dividend; schedules and costs of drilling activity including those offshore Namibia, Nigeria and South Africa; the outcome and timing of exploration, appraisal and development activities including those offshore Namibia and Nigeria; the development of the Venus discovery; the ability of Meren to secure farminee partners on acceptable terms in Equatorial Guinea; the ability of Meren to deliver further growth or increased shareholder returns including by monetizing its assets; the ability of Meren to grow into a leading independent E&P; the continuing benefits from funded, high value growth opportunities, including the Venus oil project in the Orange Basin; expectations regarding free-cash flow; the ability of Meren to influence its JV parties to sustain and enhance production in Nigeria; and statements regarding access to business opportunities in Meren's regions of focus and unlocking new sources of growth capital. Such statements and information (together, "forward-looking statements") relate to future events or the Company's future performance, business prospects or opportunities.

All statements other than statements of historical fact may be forward-looking statements. Statements concerning proven and probable reserves and resource estimates may also be deemed to constitute forward-looking statements and reflect conclusions that are based on certain assumptions that the reserves and resources can be economically exploited. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as "seek", "anticipate", "plan", "continue", "estimate", "expect, "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions) are not statements of historical fact and may be "forward-looking statements". Forward-looking statements involve known and unknown risks, ongoing uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements, including statements pertaining to performance of commodity hedges, uninsured risks, regulatory and fiscal changes, availability of materials and equipment, unanticipated environmental impacts on operations, duration of the drilling program, availability of third party service providers and defects in title, the sustainability of Meren across oil and gas price cycles, the enhanced visibility and certainty over the use of capital, and statements regarding capital priorities. Forward-looking statements are based on a number of assumptions, including but not limited to, the ability of Meren to delivery further growth, the ability to have a Board comprised at all times of a majority of independent non-executive directors, high value growth opportunities will continue to be funded, and the ability to access business opportunities in Meren's regions of focus. No assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. The Company does not intend, and does not assume any obligation, to update these forward-looking statements, except as required by applicable laws. These forward-looking statements involve risks and uncertainties relating to, among other things, changes in macro-economic conditions and their impact on operations, changes in oil prices, reservoir and production facility performance, contractual performance, results of exploration and development activities, cost overruns, uninsured risks, regulatory and fiscal changes including defects in title, claims and legal proceedings, availability of materials and equipment, availability of skilled personnel, the need to obtain required approvals from regulatory authorities, timeliness of government or other regulatory approvals, actual performance of facilities, joint venture partner underperformance, availability of financing on reasonable terms, hedging, availability of third party service providers, equipment and processes relative to specifications and expectations and unanticipated environmental, health and safety impacts on operations, the failure to realize the anticipated benefits of the amalgamation and the influence of BTG as a significant shareholder on the actions of the Company. Actual results may differ materially from those expressed or implied by such forward-looking statements.

Meren

Meren Energy Inc. (previously called Africa Oil Corp.)

Report to Shareholders

For the Year Ended December 31, 2025

Q4 25

GLOSSARY

A	"Africa Energy"	means Africa Energy Corp. an international oil and gas exploration company that holds an effective 4.9% participating interest in the Exploration Right for Block 11B/12B offshore South Africa.
	"Amalgamation"	means the amalgamation transaction whereby BTG Oil & Gas exchanged its 50 percent interest in Meren Coop, held through its fully owned subsidiary BTG Pactual Holding S.à.r.l., in exchange for 239,828,655 newly issued shares in the Company.
	"Applicable law"	means all laws and regulations issued by authorities that have appropriate jurisdiction over the Company.
	"Azinam"	means Azinam Limited, a wholly owned subsidiary of Eco.
B	"Bcf"	means billion cubic feet.
	"boepd"	means barrels of oil equivalent per day.
	"BTG Holding"	means BTG Pactual Holding S.a.r.l.
	"BTG Oil & Gas"	means BTG Pactual Oil & Gas S.a.r.l.
C	"CGU"	means Cash Generating Unit. A Cash Generating Unit is defined as assets that are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets.
	"Chevron"	means Chevron Corp.
	"CIT"	means Corporate Income Tax.
	"Concessions"	means concessions, PSAs, PSCs and other similar agreements entered into with a host government providing for petroleum operations in a defined area and the division of petroleum production from the petroleum operations.
D	"DD&A"	means Depreciation, Depletion and Amortization.
E	"EBITDAX"	means Earnings Before Interest, Taxes, Depreciation & Impairment, Amortization and Exploration Expenses.
	"Eco"	means Eco (Atlantic) Oil & Gas Ltd.
	"Entitlement production"	means production that is calculated using the economic interest methodology and includes cost oil, profit oil, tax oil and royalty oil.
	"ESIA"	means Environmental and Social Impact Assessment.
F	"FEED"	means Front End Engineering and Design.
	"FID"	means Final Investment Decision.
	"FPSO"	means Floating Production Storage and Offloading.
G	"GHG"	means Greenhouse Gas.
	"GTCs"	means Gas Turbine Compressors.
I	"IFRS Accounting Standards"	means International Financial Reporting Standards as issued by the International Accounting Standards Board.
	"Impact"	means Impact Oil and Gas Ltd, a privately owned exploration company with a strategic focus on large scale, mid to deep water plays of sufficient materiality to be of interest to major companies. Impact has an asset base across the offshore margins of Southern and West Africa.
J	"JV"	means Joint Venture.
K	"Kenya entities"	means Centric Energy Kenya Limited, Africa Oil Kenya B.V Branch and Africa Oil Turkana Limited.
L	"LTIP"	means Long Term Incentive Plan.

M	"Mcf"	means million cubic feet.
	"Meren", "MER", or the "Company"	means Meren Energy Inc.
	"Meren Coop" or "Meren Coöperatief U.A."	means Meren Coöperatief U.A., previously known as Prime Coöperatief U.A., a company that holds interests in deepwater Nigeria production and development assets.
	"Meren 52"	means Meren Nigeria 52 Limited (previously named Prime 127 Nigeria Limited).
	"Meren 234"	means Meren 234 Nigeria Limited (previously named Prime 130 Nigeria Limited).
	"MD&A"	means Management's Discussion and Analysis.
	"Mbbl" and "MMbbl"	means one thousand and one million barrels, respectively.
	"Mboe" and "MMboe"	means thousands of barrels of oil equivalent and millions of barrels of oil equivalent, respectively.
N	"NCIB"	means Normal Course Issuer Bid.
	"NI 51-101"	means National Instrument 51-101 — Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators and the companion policies and forms thereto, as amended from time to time.
	"NI 52-109"	means National Instrument 52-109 - Certification of Disclosure in Issuers' Annual and Interim Filings and the companion policies and forms thereto, as amended from time to time.
	"NUPRC"	means Nigerian Upstream Petroleum Regulatory Commission.
P	"PIA"	means Petroleum Industry Act.
	"PML"	means Petroleum Mining Lease.
	"PML 2"	means the Petroleum Mining Lease containing the Akpo field.
	"PML 3"	means the Petroleum Mining Lease containing the Egina field.
	"PML 4"	means the Petroleum Mining Lease containing the Preowei field.
	"PML 52"	means the Petroleum Mining Lease containing the Agbami field.
	"PPL"	means Petroleum Prospecting License.
	"PPL 2003"	means the Petroleum Prospecting License containing the Ikija prospect
	"PPL 261"	means the Petroleum Prospecting License containing the South Egina prospect.
	"PPT"	means Profit Petroleum Tax.
	"PRMS"	means Petroleum Resources Management Reporting System.
	"PSA"	means Production Sharing Agreement.
	"PSC"	means Production Sharing Contract.
	"PSU"	means Performance Share Unit.
R	"RBL"	means Reserves Based Lending.
	"RSU"	means Restricted Share Unit.
S	"SOFR"	means Secured Overnight Financing Rate.
	"spud" or "spudded"	means the initial drilling for an oil well.
T	"TAM"	means planned turnaround maintenance.
	"TotalEnergies"	means TotalEnergies SE and subsidiaries.
	"TSX"	means Toronto Stock Exchange.
U	"US"	means United States.
W	"WI"	means working interest.
	"WI production"	means production based on the percentage of working interest owned.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis ("MD&A") focuses on significant factors that have affected the Company during the year ended December 31, 2025, and such factors that may affect its future performance. To better understand the MD&A, it should be read in conjunction with the Company's audited consolidated financial statements for the years ended December 31, 2025, and 2024, and related notes thereto.

The financial information in this MD&A is derived from the Company's audited consolidated financial statements which have been prepared in US dollars, in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards").

This MD&A was reviewed and approved by the Board of Directors. The effective date of this MD&A is February 24, 2026.

Additional information about the Company and its business activities is available on the Company's website at www.mereninc.com and on SEDAR+ at www.sedarplus.com.

The Company changed its name to Meren Energy Inc. on May 14, 2025, and was previously called Africa Oil Corp.

PROFILE AND STRATEGY

Meren is a Canadian oil and gas company with producing and development assets in deep-water offshore Nigeria. The Company also has a portfolio of development and exploration assets in West and South of Africa.

The Company's Common Shares are listed on the Toronto Stock Exchange in Canada and the Nasdaq Stockholm Exchange in Sweden, under the symbol 'MER'.

The Company's common shares also trade on the OTCQX Best Market ("OTCQX") in the U.S. under the ticker 'MRNFF'.

Meren's strategy is anchored in maintaining a resilient balance sheet through the cycle, prioritizing high-return organic investment in its core assets, and delivering sustainable shareholder returns from surplus free cash flow. This plan is supported by the Company's high netback production assets in Nigeria that are included in its interests in Petroleum Mining Leases ("PMLs") 2, 3, 4 and 52. These PMLs provide the Company with a long-life cash flowing asset base, to support its business objectives over the long term, and also present development opportunities for supporting future production together with the Company's interests in Petroleum Prospecting Licenses ("PPLs") 261 and 2003.

The Company's other core assets are comprised of its Orange Basin opportunity set including Blocks 2912 and 2913B offshore Namibia and Block 3B/4B, offshore South Africa, as well as Equatorial Guinean exploration and appraisal blocks (EG-18 and EG-31).

The Company is a unique investment opportunity, amongst its publicly-listed independent E&P peer group, for its Orange Basin opportunity set that includes an effective interest in the Venus light oil and associated gas discovery offshore Namibia. The Venus discovery, understood to be the largest oil discovery globally in 2022, has partially de-risked a new petroleum province in the Orange Basin that has significant further prospectivity.

HIGHLIGHTS AND OUTLOOK

Full-Year 2025, Q4 2025 AND POST PERIOD HIGHLIGHTS

- During 2025, closed the transformative Prime amalgamation to take full control of Prime's assets, doubling Meren's reserves and production;
- Distributed approximately $100 million to the Company's shareholders under the base dividend policy and repurchased 5.9 million shares at a cost of approximately $8 million;
- Achieved average daily W.I and entitlement production of 30,800 boepd and 35,100 boepd, respectively, for 2025, in line with the revised full-year management guidance;
- Sold three cargos in Q4 2025 at an average sales price of $64.4/bbl and twelve cargos in 2025 at an average sales price of $72.2/bbl, both of which were higher than average Dated Brent for the same periods;
- In 2025 reduced the RBL by $420.0 million, reducing interest expenses and ending 2025 with a debt balance of $330.0 million.
- End of 2025 cash balance of $174.7 million resulting in a net debt position of $155.3 million with a Net Debt/ EBITDAX of 0.4x as at December 31, 2025, with a RBL facility headroom of $138.4 million.
  - » EBITDAX of $440.7 million;
  - » Cashflow from operations before working capital adjustment of $261.8 million; and
  - » Cash capital investments of $100.2 million.
- Reported net loss of $31.6 million ($0.05/share) for full-year 2025, primarily from to a non-cash impairment of $105.3 million for the Agbami cash generating unit ("CGU") reflecting a more conservative oil price and cost outlook compared to prior assumptions.
- Following continued strong operating performance and after consideration of organic investment requirements and balance sheet resilience, the Board has declared the first quarterly dividend in 2026 of approximately $25.1 million;
- On February 2, 2026, the Company announced that Roger Tucker had stepped down from the role of President and CEO and as a director of Meren, and that Oliver Quinn had been appointed as his successor and joined the Board as a director.

- Meren's year-end 2025 reserves:
  - YE'25 reserves determination has delivered after-tax 1P NPV(10) and 2P NPV(10) valuations of $588 million (YE'24: $1,248 million) and $1,499 million (YE'24: $2,128 million) respectively.
  - YE'25 W.I. and net entitlement7 1P reserves of 48.8 MMboe (YE'24: 59.8 MMboe) and 62.5 MMboe (YE'24: 70.8 MMboe), respectively.
  - YE'25 W.I. and net entitlement 2P reserves of 87.7 MMboe (YE'24: 101.6 MMboe) and 107.4 MMboe (YE'24: 116.4 MMboe), respectively.
  - YE'25 aggregate W.I. 2P reserves and 2C contingent resources of 140.2 MMboe (YE'24: 129.6 MMboe).

FINANCIAL SUMMARY (1)

		Three months ended		Years ended	
Meren highlights	Unit	December 31, 2025	December 31, 2024	December 31, 2025	December 31, 2024
Net (loss)/ income	$'m	(90.8)	6.2	(31.6)	(279.1)
Net (loss)/ income per share – basic (2)	*$/ share*	*(0.13)*	*0.02*	*(0.05)*	*(0.62)*
Net debt position (3)	$'m	155.3	289.1	155.3	289.1
WI production (3)	boepd	28,100	34,400	30,800	34,000
Entitlement production (3)	boepd	31,500	39,000	35,100	38,800
Cash flow from operations (4, 5)	$'m	18.7	n/a	261.8	n/a
EBITDAX (4)	$'m	72.7	n/a	440.7	n/a
Capital investments (4)	$'m	19.8	n/a	100.2	n/a

(1) The table includes non-GAAP measures. Definitions and reconciliations to these non-GAAP measures are provided on pages 14 - 17.

(2) Based on the weighted average number of shares outstanding for the three months and year ended December 31, 2025, of 675,685,556 and 624,464,015 respectively, which accounts for the newly issued shares to BTG Oil & Gas on March 19, 2025.

(3) Net debt position and production numbers as presented for the comparative periods includes 100 percent of Meren Coop to be comparable with net debt position and production numbers for the three months and year ended December 31, 2025.

(4) Highlights are reported for the year 2025 only, on a constructed financial information basis, see pages 10 - 12 for further information.

(5) Cash flow from operations before working capital and interest payments.

OUTLOOK

Nigeria

Nigeria's macroeconomic and sector-specific reforms are beginning to show tangible results, with improved fiscal clarity, stronger government engagement, and targeted incentives aimed at sustaining investment in the oil and gas sector. The Federal Government has reaffirmed its support for upstream development through regulatory stability and commercial incentives, contributing to renewed capital commitment across offshore oil and gas projects. This improved investment climate is evidenced by recent final investment decisions on major developments such as Bonga North, Ubeta Gas Project, and HI Offshore Gas Project, which collectively signal growing confidence in Nigeria as a destination for long-term energy investment.

In collaboration with its JV Parties, the Company is continuing to advance the restart of the Akpo/Egina 2026 drilling campaign following the break in the 2025 program. Work is underway to secure a deepwater rig with the drilling of the Akpo Far East near-field prospect, the first planned well in the campaign. This will be followed by the drilling of further infill development wells in the Akpo and Egina fields in late 2026 and into early 2027. Notably, the pause in the drilling program has created a valuable opportunity for the interpretation of 4D seismic data focused on the maturation of infill well candidates.

The Akpo Far East prospect presents a strategically positioned fast-cycle tie-back opportunity that will utilise the existing Akpo facilities. The prospect lies about 5 km east of the currently producing Akpo field and the planned drilling approach will assess all prospective resource volumes identified within the prospect. To support this, efforts are ongoing to complete all the work required to spud the Akpo Far East exploratory well in 2026.

HIGHLIGHTS AND OUTLOOK - CONTINUED

Work is actively progressing on the remaining subsurface and development opportunities within the PML 2/3/4 license area. Preowei Field subsurface review and development validation activities continued in Q4 2025 with study results expected in H1 2026 to guide the timing and scope of an FID. The planned appraisal activity by TotalEnergies in the Egina South area in OPL 257, currently expected in 2026, may further de-risk adjacent resources and, if successful, indicate potential additional value for Meren through proximity to existing infrastructure.

In early 2026, Meren and its JV Parties in PML 2/3 successfully executed an amendment to the gas sales agreement that includes a revised index for gas pricing, locking in a long-term gas price that is more reflective of the current LNG economics compared to 2018 when the contract was initially signed. The amendment also includes a mechanism for the sellers to recover the historical difference between the interim gas price adjustment and the new index, starting from 2020 when the previous index ceased to be published. This historical amount will be recovered through an upward adjustment to the netback pricing that includes the handling fee for the gas sold.

In Agbami the FPSO unit life extension studies, to ensure long term asset integrity and to enhance operation performance of the facility are expected to conclude in 2026. Also, the ongoing 4D seismic interpretation and rig contracting activities for the Agbami infill drilling program remain on schedule. The Agbami infill drilling campaign is expected to commence in Q1 2027, following the planned arrival of the rig in Q4 2026 with the Ikija appraisal well being matured to initiate the campaign as the first well.

Namibia Orange Basin Development and Exploration, Blocks 2912 and 2913B

The Venus Field in Block 2913B remains the most advanced deepwater discovery in the Orange Basin and is expected to anchor Namibia's first large-scale offshore oil development. The project is being progressed by TotalEnergies (Operator, 50.5%) together with QatarEnergy (30.0%), NAMCOR (10.0%) and Impact Oil & Gas (9.5%). Through its shareholding in Impact, Meren holds an effective 3.8 percent indirect interest in the Venus development. Under Impact's carried-interest arrangement with TotalEnergies, Meren's exposure to all development and exploration costs on Blocks 2912 and 2913B remains fully funded through to first commercial production, without any financial cap.

The Environmental and Social Impact Assessment (ESIA) for the proposed Venus development has been completed and published, and the associated Environmental Clearance Certificate (ECC) application has been submitted to the relevant Namibian authorities. Completion of the ESIA represents a key regulatory milestone, further de-risking the project. FEED work is proceeding on the base-case concept of up to 40 subsea wells tied back to a single FPSO with a nameplate capacity of approximately 160,000 barrels per day of oil, with reinjection of associated gas offshore. Contractor bids have been received and are within expectation. The project schedule remains consistent with the current planning framework with FID targeted for 2026 and first oil in 2030, subject to the completion of negotiations between the operator and the government on enhanced fiscal terms for the project, which is expected to be the first producing oil field and the first deepwater development in Namibia.

The Venus development is regarded by the Namibian government as a strategic national project with the potential to establish Namibia as a new deepwater oil producer. Appraisal and exploration activities continue across the broader Orange Basin and additional prospects are being evaluated using newly acquired 3D seismic data on Blocks 2912 and 2913B.

Namibia's oil and gas sector remains active and supportive, with strong investment from international operators, rollout of a Local Content Policy, and infrastructure upgrades at the Walvis Bay and Lüderitz ports. Execution and infrastructure challenges, including marine services capacity, environmental approvals, and gas monetization, present both risks and opportunities as the country positions itself to attract capital and expand its deepwater supply chain.

The Venus development presents Meren with a material long-term growth opportunity within a fully carried structure, offering potential for future cash-flow generation and portfolio optionality with no upfront funding commitments.

South Africa Orange Basin, Block 3B/4B

On September 16, 2024, the Department of Mineral Resources and Energy for the Republic of South Africa granted an Environmental Authorization for exploration activities (drilling of up to 5 exploration wells) on the block. Following that decision, the legislative notification and appeals process in South Africa was suspended pending a Supreme Court of Appeal judgement in respect of Block 5/6/7. The operator has stated that the current plan is to drill the first exploration well on Block 3B/4B as soon as the Environmental Authorization is confirmed and has identified Nayla, a prospect that lies in the northwest of the license area, as the potential drilling target.

Equatorial Guinea, Blocks EG-18 and EG-31

In late 2025 the Company submitted requests for extensions to the exploration license terms for both blocks. On December 17, 2025, the Company received notification from the Ministry of Hydrocarbons and Mining Development in Equatorial Guinea approving extensions of up to two years to the first exploration sub period on each block.

During the course of 2025, the company completed a number of data room exercises across the two blocks and remains actively engaged in advancing potential partnership discussions. Following industry interest during the data room phase, the Company is now transitioning into the next stage of activity, focused on advancing discussions with prospective partners. In parallel, the Company continues to coordinate with government and representatives from GEPetrol to define the forward plan for both blocks.

Should the Company successfully attract a farm-in partner(s) on acceptable terms for these blocks, subject to customary consents and approvals including governmental and regulatory permissions, the Company anticipates that newly formed JVs could be positioned to plan for appraisal and development as well as exploration drilling in late 2026 or 2027.

While there can be no assurance of securing partners on acceptable terms, the Company remains encouraged by the level of industry interest and continues to advance partnership discussions with confidence.

Shareholder Returns

The Company's capital allocation framework balances reinvestment in value-accretive organic opportunities with a commitment to sustainable shareholder returns, while preserving balance sheet strength and financial flexibility.

Following continued strong operating performance and after consideration of organic investment requirements and balance sheet resilience, the Company is pleased to announce that its Board has declared the distribution of the Company's first quarterly cash dividend in 2026 of approximately $25.1 million or $0.0371 per share. This dividend will be payable to shareholders of record at the close of business on March 20, 2026.

This dividend qualifies as an 'eligible dividend' for Canadian income tax purposes. Dividends for shares traded on the Toronto Stock Exchange ("TSX") will be paid in Canadian dollars on April 7, 2026; however, all US and foreign shareholders will receive USD funds. Dividends for shares traded on Nasdaq Stockholm will be paid in Swedish Krona in accordance with Euroclear principles at the earliest on April 10, 2026.

To execute the payment of the dividend, a temporary administrative cross border transfer closure will be applied by Euroclear from March 18, 2026, up to and including March 20, 2026, during which period shares of the Company cannot be transferred between the TSX and Nasdaq Stockholm.

Payment to shareholders who are not residents of Canada will be net of any Canadian withholding taxes that may be applicable. For further details, please visit: https://mereninc.com/investor-summary/total-shareholder-returns/.

The Board views this first quarterly dividend of 2026 to be prudent, having given due consideration to the Company's capital allocation options and the Company's overarching priority of maintaining a robust balance sheet under a range of market scenarios. Future dividend declarations will be subject to customary Board approval and consents.

2026 MANAGEMENT GUIDANCE

The Company's full-year 2026 production will be generated solely by its deepwater Nigerian assets. The 2026 Management Guidance includes W.I. production guidance range of 23.0 – 28.0 kboepd and entitlement production range of 28.0 – 33.0 kboepd with approximately 68% expected to be light and medium crude oil and 32% conventional natural gas on a W.I. basis and 73% and 27% respectively on an entitlement basis. Meren is expected to sell 8 cargoes of approximately one million barrels each during 2026.

The table below summarizes the Company's full-year 2026 Management Guidance. These estimates are based on a 2026 average Brent price of $63.0/bbl.

	2026 Guidance	2025 Actuals
WI production (kboepd) (1)	23.0 – 28.0	30.8
Entitlement production (kboepd) (2)	28.0 – 33.0	35.1
EBITDAX ($ million) (3)	270.0 – 360.0	440.7
Cash flow from operations ($ million) (3)	185.0 – 255.0	261.8
Capital investments ($ million)	100.0 – 140.0	100.2

(1) Aggregate oil equivalent production data comprised of light and medium crude oil and conventional natural gas production net to the Company's W.I. in Agbami, Akpo and Egina fields. These production rates only include sold gas volumes and not those volumes used for fuel, reinjected or flared.

(2) Entitlement production is calculated using the economic interest methodology and includes cost recovery oil, royalty oil and profit oil and is different from working interest production that is calculated based on project volumes multiplied by the Company's effective working interest in each license.

(3) This table includes non-GAAP measures that do not have a standardized meaning prescribed by IFRS Accounting Standards and, therefore, may not be comparable with the calculation of similar measures by other companies. The Company believes that the presentation of these non-GAAP figures provides useful information to investors and shareholders as the measures provide increased transparency. EBITDAX is a non-GAAP measure. This is used as a performance measure to understand the financial performance from the Company's business operations without including the effects of the capital structure, tax rates, depreciation, depletion, amortization, impairment and exploration expenses. Cash flow from operations before working capital and interest payments is a non-GAAP measure. This represents cash generated by removing the impact of working capital movements from cash generated by operating activities. It is a measure commonly used to better understand cash flow from operations across periods on a consistent basis, and when viewed in combination with the Company's results provides a more complete understanding of the factors and trends affecting the Company's performance.

THE COMPANY'S SHAREHOLDING AND WORKING INTERESTS

The Company's material interests and material exploration partnership interests as at December 31, 2025, are summarized in the following table:

Meren's Direct Working Interests [(1)]

Country	Concession	License renewal	Working Interests	
Nigeria	PML 52 and PPL 2003 [(2)]	November 24, 2044	Meren	8%
			Chevron (Operator)	32%
			Famfa Oil	60% (carried)
	PML 2, 3, 4 and PPL 261 - PSA [(3)]	May 24, 2043	Meren	32%
			TotalEnergies (Operator)	48%
			SAPETRO	20% (carried)
South Africa	Block 3B/4B	October 26, 2024 [(4)]	Meren	18%
			TotalEnergies (Operator)	33%
			QatarEnergy	24%
			Azinam	5.25%
			Ricocure (Pty) Ltd	19.75%
Equatorial Guinea	EG-18	March 1, 2027[(5)]	Meren (Operator)	80%
			GEPetrol	20%
	EG-31	February 29, 2028	Meren (Operator)	80%
			GEPetrol	20%

Meren's Shareholding in Impact (39.5%)

Country	Concession	License renewal	Working Interests	
Namibia	PEL 56 (Block 2913B)	March 31, 2026	Impact	9.5%
			TotalEnergies	50.5%
			QatarEnergy	30%
			NAMCOR	10% (carried)
	PEL 91 (Block 2912)	October 1, 2027	Impact	9.5%
			TotalEnergies	47.2%
			QatarEnergy	28.3%
			NAMCOR	15% (carried)

(1) Net WI are subject to back-in rights or carried WI, if any, of the respective governments or national oil companies of the host governments.

(2) Production currently from PML 52 and potential future production from PPL 2003 is covered by a PSA framework, in which Meren owns an 8% WI.

(3) 50% of the production (currently from PMLs 2 and 3, future production from PML 4 and potential future production from PPL 261) is covered by a PSA framework, in which Meren owns a 32% WI. Meren's net WI in these assets is therefore 16%.

(4) The operator has submitted an application for license renewal. This is currently awaiting Government approval.

(5) The Company has the option to extend the term of the first exploration sub-period of Block EG-18 by a further twelve months from March 1, 2027, to February 28, 2028 (inclusive), at its sole discretion.

Information on the Company's equity interests in Africa Energy and Impact is included in "Equity Investments in Associates" on page 19.

BUSINESS UPDATE

SHAREHOLDER RETURNS

During 2025, the Company distributed approximately $100.2 million and repurchased a total of 5,905,853 at an approximate cost of $8.3 million for an aggregate return of $108.5 million for the year.

The Company's shareholder returns policy consists of an annual base dividend of $100.0 million, supplemented by additional distributions, either through dividends or share buybacks, equivalent to up to 50% of free cash flow generated after payment of the base dividend, each of which remains subject to determination by the Board in its discretion and to a variety of factors and conditions existing from time to time.

On this basis, and after payment of the $100 million base dividend, the Company did not generate additional free cash flow in 2025 available for further distributions and accordingly the aggregate return of $108.5 million represents the full extent of shareholder distributions for 2025.

As detailed in the Highlights and Outlook section, the Company has declared the distribution of the Company's first quarterly cash dividend in 2026 of approximately $25.1 million or $0.0371 per share.

Notwithstanding the foregoing, the decision to declare any dividend or other shareholder distribution and the amount of future cash dividends declared and paid by Meren or shareholder distributions made by Meren, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time. These may include, without limitation, business performance, operating environment where Meren's assets are located, financial condition, growth plans, fluctuations in commodity prices, production levels, expected capital expenditure requirements, operating costs, royalties, foreign exchange rates, interest rates, compliance with any restrictions on the declaration and payment of dividends contained in any agreements to which Meren or any of its subsidiaries is a party from time to time (including, without limitation, financing agreements governing the RBL), and the satisfaction of liquidity and solvency tests imposed by the BC BCA for the declaration and payment of dividends. The actual amount, the record date and the payment date of any dividend are subject to the discretion of the Board. There can be no assurance that dividends will be paid at the current rate or at any rate in the future.

Pursuant to the Company's current Normal Course Issuer Bid ("NCIB") share repurchase program that was launched on December 8, 2025, Meren is authorized to repurchase through the facilities of the TSX, Nasdaq Stockholm and/or alternative Canadian trading systems, as and when considered advisable by Meren, up to 21,636,913 Common Shares of the Company for a total maximum amount of $35.0 million, which represented 5% of its "public float" of 432,738,277 Common Shares as at November 24, 2025. As of the same date, Meren had 675,725,593 Common Shares issued and outstanding.

Purchases of Common Shares may occur over a period of up to twelve months commencing December 8, 2025, and ending on the earlier of December 7, 2026, the date on which the Company has purchased the maximum number of Common Shares permitted under the NCIB, and the date on which the NCIB is terminated by Meren. There cannot be any assurances as to the number of Common Shares that will ultimately be acquired by the Company. Any Common Shares purchased by Meren under the NCIB will be cancelled.

GROUP OPERATIONS

On March 19, 2025, the Company completed the transaction with BTG Oil & Gas to consolidate its interest in Meren Coöperatief U.A. (previously known as Prime Oil & Gas Coöperatief U.A) ("Meren Coop"). The transaction was completed by way of amalgamation whereby BTG Oil & Gas exchanged its 50 percent interest in Meren Coop, held through its fully owned subsidiary BTG Pactual Holding S.à.r.l., in exchange for 239,828,655 newly issued shares in the Company (the "amalgamation").

The production numbers included in the narrative discussion below include 100 percent of Meren Coop production numbers for all periods to have comparable production numbers for the purpose of this MD&A.

PRODUCTION AND OPERATIONS

Production Metrics – rounded

		Three months ended		Years ended	
	Unit	December 31, 2025	December 31, 2024	December 31, 2025	December 31, 2024
Total gross field production	boepd	207,400	270,300	241,900	273,600
Average daily WI production (1)	boepd	28,100	34,400	30,800	34,000
Average daily entitlement production	boepd	31,500	39,000	35,100	38,800
Oil volumes sold	MMbbl	3.0	-	12.0	9.0
Gas volumes sold	bcf	5.1	5.0	19.7	17.4
Oil/gas percentage split (2)	%	67%/33%	74%/26%	71%/29%	77%/23%

(1) Production allocation occurs periodically and can result in a change in production numbers previously reported.

(2) Calculated on a working interest basis.

The total gross field production in Q4 2025 decreased compared to Q4 2024, primarily due to the planned turnaround maintenance ("TAM") on the Agbami FPSO and, to a lesser extent, the expected natural reservoir decline across the portfolio together with the operational events described below. Throughout the quarter, production was actively managed in response to these challenges.

At Akpo and Egina, Q4 production was impacted by plant and compressor trips, including temporary shutdowns related to power supply issues, particularly during the second half of the quarter. These issues were actively managed through targeted operational interventions and maintenance activities, enabling operations and the fields to continue performing in line with expectations following resolution.

In addition to the planned extensive turnaround maintenance on the Agbami FPSO, production was impacted by additional work on the Gas Turbine Compressors ("GTCs") prior to and during the TAM exercise. The ramp-up following the full-field shutdown was further impacted by GTC start-up sequencing issues as well as planned work on the seawater injection system. The issues were addressed through focused repair and optimization efforts resulting in the gas compressors and the seawater injection pumps progressively brought back online by mid-January, two GTCs and one seawater injection pump were operational, with all GTCs fully online by mid-February. The maintenance and remediation work completed during the quarter is expected to support improved operational reliability and uptime going forward.

In Q4 2025, three oil liftings were allocated with a total sales volume of approximately 3.0 million barrels of oil at an average realized oil price of $64.4/bbl, compared to Dated Brent average of $63.7/bbl. In Q4 2024, no oil liftings were allocated.

In 2025, a total of 12 oil liftings were allocated with a total sales volume of approximately 12.0 million barrels of oil at an average realized oil price of $72.2/bbl, compared to Dated Brent average of $69.1/bbl. In 2024, 9 oil liftings were allocated with a total sales volume of approximately 9.0 million barrels at an average realized oil price of $84.6/bbl.

FINANCIAL

Total net revenues, cost of sales, gross profit, opex/boe, tax and net debt numbers included in the narrative discussion below, on a constructed financial information basis, include 100 percent of Meren Coop numbers for all periods to have comparable numbers for the purpose of this MD&A and includes certain adjustments and reclassifications in the comparative periods to conform with Meren accounting policies and presentation in the Company's Consolidated Statement of Net Income or Loss and Other Comprehensive Income or Loss following completion of the amalgamation.

Cash flow from operations, free cash flow, capex and EBITDAX numbers included in the narrative discussion below have been reported for the year 2025 only on a constructed financial information basis.

Constructed financial information (non-GAAP measure) to explain performance is included in the following tables to present on a consolidated basis, net income for 2025 and the cash flow statement for 2025, whereby the Meren Consolidated Statement of Net Income or Loss and Other Comprehensive Income or Loss and the Meren Consolidated Statement of Cash Flows for 2025 are combined with the Meren Coop Statement of Net Income and Comprehensive Income and the Meren Coop Statement of Cash Flows for the period until March 19, 2025. Adjustments included in the constructed financial information are to conform Meren Coop financial information with Meren accounting policies and for any transactions between Meren and Meren Coop prior to amalgamation for the purpose of presenting constructed financial information to explain performance.

The constructed financial information does not necessarily reflect what the combined company's financial condition and results of operations would have been had the amalgamation occurred on January 1, 2025. Adjustments have been made to prepare the constructed financial information, which are based on certain assumptions. Both the adjustments and the assumptions made are described in the footnotes to the constructed financial information. The constructed financial information is presented for illustrative purposes only and are not necessarily indicative of: (i) the operating or financial results that would have occurred had the amalgamation actually occurred at the times contemplated by the constructed financial information; or (ii) the results expected in future periods. The constructed financial information are non-GAAP measures. Refer to more information on the non-GAAP measures provided on pages 11 - 17.

Constructed financial information for purposes of explaining performance

Condensed Consolidated Statement of Net Income/ (Loss)

(Expressed in millions of United States Dollars)

Year ended	Meren 2025 per Financial Statements	Meren Coop for period from January 1, 2025, to March 19, 2025	Adjustments [1]	December 31, 2025
Oil and gas sales	559.9	323.5	-	883.4
Net Revenue	559.9	323.5	-	883.4
Commodity risk management contracts	2.2	-	-	2.2
Revenue	562.1	323.5	-	885.6
Cost of Sales				
Movements on overlift/underlift balances	(46.3)	(133.1)	-	(179.4)
Production costs	(166.6)	(54.3)	2.0	(218.9)
Depletion costs	(207.9)	(71.3)	-	(279.2)
Impairment charges	(105.3)	-	-	(105.3)
	(526.1)	(258.7)	2.0	(782.8)
Gross profit	36.0	64.8	2.0	102.8
General and administrative expenses	(36.4)	(6.2)	-	(42.6)
Operating (loss)/ profit	(0.4)	58.6	2.0	60.2
Finance income	4.1	2.4	-	6.5
Finance expense	(47.8)	(21.3)	-	(69.1)
Net financial items	(43.7)	(18.9)	-	(62.6)
Share of profit from investment in joint venture	2.9	-	(2.9)	-
Share of loss from investments in associates	(2.9)	-	-	(2.9)
Reversal of impairment of investment in joint venture	55.9	-	(55.9)	-
Profit before tax	11.8	39.7	(56.8)	(5.3)
Income tax	(43.4)	(34.0)	-	(77.4)
Net income/ (loss) attributable to common shareholders	(31.6)	5.7	(56.8)	(82.7)

(1) Adjustments to remove items related to Meren Coop as fully consolidated above.

BUSINESS UPDATE - CONTINUED

Condensed Consolidated Statement of Cash Flows

(Expressed in millions of United States Dollars)

Year ended	Meren 2025 per Financial Statements	Meren Coop for period from January 1, 2025, to March 19, 2025	Adjustments [1]	December 31, 2025
Cash flows generated by/ (used in):				
Operations				
Profit before tax	11.8	39.7	(56.8)	(5.3)
Adjustments as per financial statements	166.8	41.5	58.8	267.1
Net cash generated in operating activities before working capital	178.6	81.2	2.0	261.8
Changes in working capital	94.0	(8.2)	-	85.8
Net cash generated in operating activities	272.6	73.0	2.0	347.6
Investing				
Investments in oil and gas properties and intangible exploration assets	(75.6)	(22.6)	(2.0)	(100.2)
Investments in other fixed assets	(0.4)	-	-	(0.4)
Distribution received from joint venture	60.0	-	(60.0)	-
Distribution received from associates	31.6	-	-	31.6
Loan repaid by associated company	4.5	-	-	4.5
Interest income received	4.2	2.2	-	6.4
Cash acquired from Meren Coop consolidation [2]	380.4	-	(381.3)	(0.9)
Net cash generated/ (used) in investing activities	404.7	(20.4)	(443.3)	(59.0)
Financing				
Repayment RBL Facility	(420.0)	-	-	(420.0)
Repayment of principal portion of lease commitments	(0.7)	-	-	(0.7)
Dividends paid to shareholders	(100.2)	(120.0)	120.0	(100.2)
Repurchase of share capital	(8.3)	-	-	(8.3)
Interest expense paid	(34.8)	(10.8)	-	(45.6)
Net cash (used)/ generated in financing activities	(564.0)	(130.8)	120.0	(574.8)
Foreign exchange variation on cash and cash equivalents	-	-	-	-
Total cash flow	113.3	(78.2)	(321.3)	(286.2)
Cash and cash equivalents, beginning of the period	61.4	399.5	-	460.9
Cash and cash equivalents, end of the period	174.7	321.3	(321.3)	174.7

(1) Adjustments to remove items related to Meren Coop as Meren Coop fully consolidated above

(2) Reflects impact of net cash movement on the level of BTG Pactual Holding S.à.r.l.

BUSINESS UPDATE - CONTINUED

Financial Metrics [1,2]

		Three months ended		Years ended	
	Unit	December 31, 2025	December 31, 2024	December 31, 2025	December 31, 2024
Total net revenues	$'m	197.5	4.4	883.4	782.7
Cost of Sales [3]	$'m	277.9	(67.4)	782.8	428.2
Gross profit	$'m	(78.2)	71.8	102.8	354.5
Opex/boe [4,5]	$/boe	12.0	9.9	11.9	10.3
Cash flow from operations before working capital	$'m	18.7	n/a	261.8	n/a
Cash flow from operations	$'m	79.1	n/a	347.6	n/a
Free cash flow	$'m	59.9	n/a	288.6	n/a
Free cash flow/boe [5]	$/boe	20.7	n/a	22.5	n/a
Tax	$'m	(4.9)	44.2	77.4	120.5
Capex	$'m	19.8	n/a	100.2	n/a
Net Debt	$'m	155.3	289.1	155.3	289.1
EBITDAX	$'m	72.7	n/a	440.7	n/a
Net Debt/EBITDAX	ratio	0.4	n/a	0.4	n/a

(1) The table includes non-GAAP measures. Definitions and reconciliations to these non-GAAP measures are provided on pages 14 - 17.

(2) Some of the figures presented in the table have been reported on a constructed basis.

(3) Given the nature of the Company's operations in terms of oil cargo liftings and the variability in their frequency from one quarter to next, the non-cash accounting treatment of underlift/overlift and the timing between recording revenues and receipts of sales cash, leads to high variability in quarterly financial metrics. Please refer to the commentary in the rest of this section for the specific details of this period's changes relative to the corresponding historical period.

(4) Opex represents direct production costs.

(5) Boe is calculated on an entitlement basis.

Total Net Revenues [1]

		Three months ended		Years ended	
	Unit	December 31, 2025	December 31, 2024	December 31, 2025	December 31, 2024
Oil revenue	$'m	193.2	-	864.3	762.2
Gas revenue	$'m	4.3	4.4	19.1	20.5
Total net revenue	**$'m**	**197.5**	**4.4**	**883.4**	**782.7**
Realized oil prices [2]	$/bbl	64.4	-	72.2	84.6
Oil volumes sold	MMbbl	3.0	-	12.0	9.0
Realized gas prices	$'m/bcf	0.8	1.0	1.0	1.2
Gas volumes sold	Bcf	5.1	5.0	19.7	17.4

(1) Net revenues have been reported for the year 2025 and 2024 on a constructed financial information basis.

(2) Realized oil prices might be different to values calculated from the table above due to rounding.

BUSINESS UPDATE - CONTINUED

The increase in oil revenue in Q4 2025 was driven by 3 liftings in Q4 2025 compared to none in Q4 2024 as cargos that were initially scheduled for Q4 2024 were pushed into Q1 2025.

The increase in oil revenue in 2025 was mainly driven by higher liftings in 2025 despite a lower realized oil price of $72.2/bbl in 2025 compared to $84.6/bbl in 2024.

Cost of sales (1)

	Three months ended		Years ended	
$'m	December 31, 2025	December 31, 2024	December 31, 2025	December 31, 2024
Depletion costs	52.9	87.0	279.2	372.0
Cost of operations	34.7	35.7	151.7	146.1
Movements on overlift/ underlift balances	63.4	(204.8)	179.4	(171.2)
Royalties – oil and gas	7.3	14.0	41.1	70.2
Others	14.3	0.7	26.1	11.1
Impairment charges	105.3	-	105.3	-
Total cost of sales	**277.9**	**(67.4)**	**782.8**	**428.2**

(1) Cost of sales has been reported for the year 2025 and 2024 on a constructed financial information basis.

Cost of sales increased in Q4 2025 and 2025 compared to Q4 2024 and 2024 primarily due to anon-cash impairment recognized in relation to its oil and gas properties in the Agbami field CGU as a result of a combination of increased costs and lower oil prices, and cargos initially scheduled for Q4 2024 that were pushed into Q1 2025 resulting in a large overlift position in 2025 and a large underlift position in 2024 which is a credit to cost of sales. This increase in costs of sales was partly offset by lower depletion costs and lower royalties as a result of lower production volumes and lower oil prices.

As at December 31, 2025, the Company determined that there was an indicator of impairment in respect of its oil and gas properties related to the Agbami field CGU, reflecting a more conservative oil price and cost outlook compared to prior assumptions. This assessment was driven by recent oil price volatility and updated cost forecasts. A significant portion of the revised cost outlook relates to planned long-term life-extension activities required to enable the Agbami FPSO to continue operating reliably and safely through the end of the current license period. These activities are also expected to enhance the flexibility of the Agbami FPSO to support future infill drilling and potential nearby tie-in opportunities, consistent with the Company's long-term organic growth strategy. Such potential upside relates to contingent resources which are not included in the recoverable amount of the CGU for impairment testing purposes. The non-cash impairment does not reflect any adverse change in reservoir performance, reserves classification or the operational integrity of the Agbami field. The impairment resulted in a reduction in the deferred tax liability associated with oil and gas properties which has partially offset the impairment charge.

Other costs of sales mainly relate to the NDDC Levy, which concerns the Niger Delta Development Commission Levy imposed to fund the sustainable development of the Niger Delta region, the HCDF Levy, which concerns the Nigerian Content Development Fund and other costs incurred in Nigeria.

Opex/boe (1)

Opex/boe is a non-GAAP measure which represents production costs on a per barrel of oil equivalent basis (using entitlement production). This allows the Company to better analyze performance against prior periods on a comparable basis. The most direct financial statement measure is production costs. Entitlement production is calculated using the economic interest methodology and includes cost oil, profit oil and royalty oil and is different from WI production that is calculated based on project volumes multiplied by the effective WI in each Block.

		Three months ended		Years ended	
	Unit	December 31, 2025	December 31, 2024	December 31, 2025	December 31, 2024
Cost of operations	$'m	34.7	35.7	151.7	146.1
Entitlement production	MMboe	2.9	3.6	12.8	14.2
Opex/boe	**$/boe**	**12.0**	**9.9**	**11.9**	**10.3**

(1) Cost of operations and entitlement production have been reported for the year 2025 and 2024 on a constructed financial information basis.

Opex/boe increased in Q4 2025 compared to Q4 2024 primarily from lower entitlement production and in 2025 compared to 2024 primarily from lower entitlement production and higher cost of operations.

Entitlement production is used as the denominator as production costs include carry of costs that are recovered through entitlement production.

Cost of operations mainly relate to lifting costs from personnel, material and services from third parties.

BUSINESS UPDATE - CONTINUED

Cash flow from operations

Cash flow from operations before working capital is a non-GAAP measure. This represents cash generated by removing the impact from working capital from cash generated by operating activities and is a measure commonly used to better understand cash flow from operations across periods on a consistent basis and when viewed in combination with the Company's results provides a more complete understanding of the factors and trends affecting the Company's performance. A reconciliation from cash flow from operations to cash flow from operations before working capital is shown below:

	Three months ended		Years ended	
$'m	December 31, 2025	December 31, 2024 (1)	December 31, 2025 (1)	December 31, 2024 (1)
Cash flow from operations	79.1	n/a	347.6	n/a
Working capital adjustments included in cash flow from operations	(60.4)	n/a	(85.8)	n/a
Cash flow from operations before working capital	**18.7**	**n/a**	**261.8**	**n/a**

(1) Cash flow from operations has been reported for the year 2025 only on a constructed financial information basis.

Free cash flow and Free cash flow/boe

Free cash flow is a non-GAAP measure. This measure represents cash generated after costs, and is a measure commonly used to assess the Company's profitability.

Free cash flow/boe is a non-GAAP ratio which represents free cash flow on a per barrel of oil equivalent basis using entitlement production which allows the Company to better analyze performance against prior periods on a comparable basis. Entitlement production is calculated using the economic interest methodology and includes cost oil, profit oil and royalty oil and is different from WI production that is calculated based on project volumes multiplied by the effective WI in each Block.

A reconciliation from total cash flow (a GAAP measure) to free cash flow (a non-GAAP measure) is shown below:

		Three months ended		Years ended	
	Unit	December 31, 2025	December 31, 2024 (1)	December 31, 2025 (1)	December 31, 2024 (1)
Total cash flow	$'m	(2.0)	n/a	(286.2)	n/a
Add back dividends paid to shareholders	$'m	25.0	n/a	100.2	n/a
Add back repurchase of share capital	$'m	-	n/a	8.3	n/a
Add back debt service costs (2)	$'m	36.9	n/a	466.3	n/a
Free cash flow	**$'m**	**59.9**	**n/a**	**288.6**	**n/a**
Entitlement production	MMboe	2.9	n/a	12.8	n/a
Free cash flow/boe	**$/boe**	**20.7**	**n/a**	**22.5**	**n/a**

(1) Free cash flow and Free cash flow/boe have been reported for the year 2025 only on a constructed financial information basis.

(2) Debt service costs comprise interest payments, repayments and drawdowns of third-party borrowings.

Tax

The tax expense is made up of the following items:

$'m	Three months ended December 31, 2025	Three months ended December 31, 2024 (1)	Years ended December 31, 2025 (1)	Years ended December 31, 2024 (1)
Deferred income tax	(60.3)	(24.5)	(106.2)	(80.9)
Education tax	5.1	2.1	15.6	14.2
Corporate income tax	36.0	17.1	129.2	130.1
Withholding tax on dividends	12.0	15.0	36.5	22.5
Capital gains tax	-	33.0	-	33.0
Petroleum Profit Tax	-	-	-	(2.3)
Other taxes	2.3	1.5	2.3	3.9
Total tax	**(4.9)**	**44.2**	**77.4**	**120.5**

(1) Tax has been reported for the year 2025 only on a constructed financial information basis.

In Q4 2025, there was a tax credit. This is from a release of the deferred tax liability as a result of the non-cash impairment recognized to the Agbami CGU.

Education tax is imposed on every Nigerian company at a rate of 3.0% of the assessable profit in the period.

Corporate income tax is imposed at a rate of 30.0% of the assessable profits in Nigeria in the period.

Petroleum Profit Tax is a tax on the income of companies engaged in upstream petroleum operations in Nigeria. Since operating under the new PIA terms following conversion during 2023, the leases and licenses are no longer subject to PPT.

Other taxes relates to the Naseni (National Agency for Science and Engineering Infrastructure) Levy that is imposed in Nigeria based on 0.25% of profits before tax and the Police Fund Levy that is imposed in Nigeria based on 0.005% of net profit.

From January 1, 2026, a new 4% Development Levy on assessable profits is being introduced which will replace Education tax and the Naseni Levy.

Capital expenditure

Capital expenditure is made up of the following items:

$'m	Three months ended December 31, 2025	Three months ended December 31, 2024 (1)	Years ended December 31, 2025 (1)	Years ended December 31, 2024 (1)
Nigeria	17.3	n/a	93.8	n/a
Equatorial Guinea	2.8	n/a	6.6	n/a
South Africa	(0.3)	n/a	(0.2)	n/a
Total capex	**19.8**	**n/a**	**100.2**	**n/a**

(1) Capital expenditure has been reported for the year 2025 only on a constructed financial information basis.

Capital expenditure in Q4 2025 and 2025 in Nigeria mainly related to planned infill drilling on Egina and Akpo plus facilities costs on Agbami.

Net Debt

Net Debt is a non-GAAP measure. Net Debt is calculated as loans and borrowings less cash and cash equivalents.

As at/ $'m	Years ended December 31, 2025	Years ended December 31, 2024
Loans and borrowings	330.0	750.0
Cash and cash equivalents	(174.7)	(460.9)
Net Debt	**155.3**	**289.1**

As at December 31, 2025, the Company has $174.7 million of cash and cash equivalents and $330.0 million of debt (as at December 31, 2024 - $460.9 million of cash and cash equivalents and $750.0 million of debt). During 2025, the Company repaid $420.0 million under its RBL facility reducing outstanding debt to $330.0 million. RBL facility headroom of $138.4 million at the end of 2025.

BUSINESS UPDATE - CONTINUED

EBITDAX and Net Debt/EBITDAX

EBITDAX is a non-GAAP measure. This is used as a performance measure to understand the financial performance from the Company's business operations without including the effects of the capital structure, tax rates, DD&A, impairment expenses, unrealized results on commodity risk management contracts and by adding back realized results on commodity risk management contracts. A reconciliation from total profit (a GAAP measure) to EBITDAX (a non-GAAP measure) is shown below.

Net Debt/EBITDAX is a non-GAAP measure. Net Debt divided by EBITDAX is a measure of leverage.

	Three months ended		Years ended	
$'m	December 31, 2025	December 31, 2024	December 31, 2025 (1)	December 31, 2024
Total profit/ (loss)	(90.8)	n/a	(82.7)	n/a
Add back:				
Tax	(4.9)	n/a	77.4	n/a
Finance costs	12.5	n/a	69.1	n/a
Finance income	(0.5)	n/a	(6.5)	n/a
Impairment charges	105.3	n/a	105.3	n/a
Depletion, depreciation and amortization costs	53.3	n/a	280.3	n/a
Commodity risk management contracts	(2.2)	n/a	(2.2)	n/a
EBITDAX	**72.7**	**n/a**	**440.7**	**n/a**
Net Debt			155.3	n/a
Net Debt/EBITDAX			**0.4**	**n/a**

(1) EBITDAX and Net Debt/EBITDAX have been reported for the year 2025 only on a constructed financial information basis.

Crude Oil Marketing

In considering cargo liftings, the reader should note that the timing and the frequency of these can vary based on a number of factors such as reservoir performance; actual realized oil price; capex; opex; underlift/overlift positions and marine logistics. The revenue numbers reported include cost oil, profit oil and royalty oil where relevant for each field.

In most of the Group's oil offtake contracts, the Dated Brent component of the forward price at the time of entering the contract is not fixed but determined on or around the date of the lifting for spot cargos either on an average monthly basis, 5-days after bill of lading date or similar pricing mechanism. The average cargo size lifted is one million barrels of oil.

Oil sales were comprised of the following:

		Three months ended		Years ended	
Oil Sales	Unit	December 31, 2025	December 31, 2024	December 31, 2025 (1)	December 31, 2024 (1)
Gross crude oil sales					
Quantity in Mboe	Mboe	3,002.3	-	11,965.5	9,012.8
Average sales price	$/bbl	64.4	-	72.2	84.6
Average Bloomberg Dated Brent for the period	$/bbl	63.7	-	69.1	82.7

(1) Oil sales have been reported for the year 2025 and 2024 on a constructed financial information basis.

The Company sold 3 cargoes during Q4 2025 at a price of $64.4/bbl.

BUSINESS UPDATE - CONTINUED

Hedging

The Group's cash flow is exposed to fluctuations in the oil price. A decrease in oil price will lead to a reduction in oil revenue, and vice versa, but this is offset by an opposite movement in sales entitlement, royalties and taxes. The post-tax net entitlement production represents sales that the Group has physical price exposure.

The Group uses a mix of financial derivatives and physical forward sales contracts to manage its commodity price risk and ensure stability in cash flows. Its strategy is to hedge between 70-100% of its post-tax net entitlement production for the next 12-months. As of December 31, 2025, the group has a mix of physical and financial hedges, as per the table below.

H1 2026 breakdown	Mbbl	Fixed price $/bbl	Sold put $/bbl	Bought put $/bbl	Sold call $/bbl	Sold swap $/bbl
Collar	300	-	-	60.00	67.15	-
Fixed Price (Offtake)	2,000	62.09	-	-	-	-
Total	**2,300**					

H2 2026 breakdown	Mbbl	Fixed price $/bbl	Sold put $/bbl	Bought put $/bbl	Sold call $/bbl	Sold swap $/bbl
Swap	900	-	-	-	-	63.95
Three way put spread	450	-	45.00	60.00	65.78	-
Collar	300	-	-	60.00	74.00	-
Total	**1,350**					

Other non-GAAP measures

This MD&A includes non-GAAP measures, non-GAAP ratios and supplementary financial measures as further described herein. These non-GAAP figures do not have a standardized meaning prescribed by IFRS Accounting Standards and, therefore, may not be comparable with the calculation of similar measures by other companies. The Company believes that the presentation of these non-GAAP figures provides useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis.

NIGERIA

Following the amalgamation, the Company has direct interests in three producing fields, three undeveloped discoveries, and number of near-field exploration opportunities in deepwater Nigeria through four PMLs and two PPLs.

The three producing fields are Akpo (PML 2), Egina (PML 3) and Agbami (PML 52). The primary undeveloped oil discovery is Preowei (PML 4), which lies to the north of Egina and Akpo fields and is planned to be developed through a subsea tie-back development to the Egina FPSO. The other two undeveloped discoveries are Egina South (PPL 261), which lies to the southwest of Egina and Akpo fields, and the Ikija discovery (PPL 2003), which lies to the west of Agbami. The Company's assets are located in the deepwater area of the Niger Delta more than 100 km offshore Nigeria.

Please refer to pages 17 - 18 of the Company's Annual Information Form ("AIF") for the Year Ended December 31, 2025, for the detailed commercial information, and pages 39 - 48 of the same document for the detailed technical information on these assets. The AIF is available on SEDAR+ at www.sedarplus.ca or on the Company's website at www.mereninc.com.

BLOCK 3B/4B – SOUTH AFRICA

Meren, through a wholly-owned subsidiary, holds an 18.0% interest in Block 3B/4B, which lies in the Orange Basin. The Block 3B/4B legislative notification and appeals process is currently suspended pending a Supreme Court of Appeal judgment in respect of Block 5/6/7. The operator of Block 3B/4B currently plans to drill the first exploration well as soon as the Environmental Authorization is confirmed.

Please refer to the Company's AIF for the year-ended December 31, 2025, for further details on Block 3B/4B.

BLOCKS EG-18 AND EG-31 – EQUATORIAL GUINEA

The Company, through wholly-owned subsidiaries, holds an operated WI of 80.0% in each of Blocks EG-18 and EG-31, offshore Equatorial Guinea.

On December 17, 2025, the Company received notification from the Ministry of Hydrocarbons and Mining Development in Equatorial Guinea approving extensions of up to two years to the first exploration sub period on each block.

During Q4 2025 the Company continued dialogue with potential partners during its active data room process across both blocks and progressed discussions with the government and GEPetrol on forward plans with the aim of forming joint ventures capable of planning exploration drilling as early as late 2026 or 2027.

Please refer to the Company's AIF for the year-ended December 31, 2025, for further details on Blocks EG-18 and EG-31.

EQUITY INVESTMENTS IN ASSOCIATES

As at December 31, 2025, the Company held equity investments in two oil and gas companies, which provides exposure to several high-impact exploration drilling prospects in South Africa and Namibia.

The Company held the following equity investments in associates as of December 31, 2025:

	Africa Energy	Impact [(1)]
Issued and Outstanding	479,162,450	1,139,147,442
Shares held by Meren at December 31, 2024	55,396,483	449,464,396
Shares acquired in the period	-	-
Shares held by Meren at December 31, 2025	55,396,483	449,464,396
Meren's holding (%) – December 31, 2025	11.56%	39.46%
Meren's holding (%) – December 31 2024	19.67%	39.46%
Share price (CAD) on December 31, 2025	0.11	-
Exchange rate to USD on December 31, 2025	0.73	-

(1) Impact is a privately held UK company and no share price is available.

Impact

Impact is a private UK oil and gas exploration company with assets located offshore Namibia and South Africa. Please refer to the Company's AIF for the year-ended December 31, 2025, for further details on the Company's shareholding in Impact and the supplementary technical and commercial information.

The Company through its 39.5% shareholding in Impact Oil & Gas Limited has an effective 3.8% interest in Blocks 2912 and 2913B, offshore Namibia, with the latter block containing the Venus light oil discovery. The blocks are operated by a subsidiary of TotalEnergies. Under Impact's carried-interest arrangement with TotalEnergies, Meren's exposure to all development and exploration costs on Blocks 2912 and 2913B remains fully funded through to first commercial production, without any financial cap.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE

Following the amalgamation, the Company reiterates its commitment to be a responsible owner and operator, integrating sustainability considerations throughout its decision-making processes to support Company commercial objectives.

During 2025 there were no reported material HSEC incidents.

GHG emissions during the reporting period were in line with operational forecasts. Further details will be set out in the Company's annual Sustainability Report.

Activities continue on the Company's development assets with no material developments to be reported during the reporting period. The Block 3B/4B legislative notification and appeals process is currently suspended pending a Supreme Court of Appeal judgment in respect of Block 5/6/7.

The Company's 2024 Sustainability Report, published on May 12, 2025, is disclosed on the Company website, as with previous reports it contains more detailed information on the Company's performance and strategy related to sustainability matters. The Company's 2025 Sustainability Report will be published on the Company's website during the first half of 2026.

SELECTED ANNUAL INFORMATION

For the years ended	December 31, 2025	December 31, 2024	December 31, 2023
Statement of Net Income or Loss and Other Comprehensive Income or Loss:			
Revenue	562.1	-	-
Net (loss)/ income attributable to common shareholders ($'m)	(31.6)	(279.1)	87.1
Data per Common Share:			
Basic income/(loss) per share ($/share)	(0.05)	(0.62)	0.19
Diluted income/(loss) per share ($/share)	(0.05)	(0.62)	0.18
Balance Sheet:			
Financial liabilities ($'m)	333.8	3.3	-
Total assets ($'m)	1,951.9	615.2	966.2
Cash dividends (per share basis)	0.1484	0.05	0.05

In 2025, the Company recorded revenue, mainly related to oil sales, following the amalgamation with Meren Coop. In 2024 and 2023, the Company held a 50% investment in Meren Coop, accounted for as a Joint Venture and therefore no revenue was recognized in these years.

In 2025, the Company recorded a net loss attributable to common shareholders of $31.6 million and a net loss of $279.1 million in 2024. In 2025, the Company fully consolidated Meren Coop and partly reversed impairment on its investment in joint venture when the Company completed the transaction with BTG Oil & Gas to consolidate its interest in Meren Coop on March 19, 2025, and the loss was primarily from anon-cash impairment of $105.3 million to the Agbami CGU. In 2024, the Company recorded a net loss attributable to common shareholders of $279.1 million which is a decrease from the net income of $87.1 million recorded in 2023. In 2024, this was primarily made up of income from the Company's investment in Meren Coop of $226.0 million offset against losses from the Company's investment in associates of $38.7 million and an impairment in the Company's investment in Meren Coop of $436.7 million as the fair value of the Company's existing shareholding in Meren Coop was calculated based on the implied value of the Proposed Reorganization, which was in excess of the carrying value resulting in a non-cash impairment loss on the investment in Meren Coop.

In 2025, the basic and diluted loss per share was $0.05 (2024 – basic and diluted loss per share of $0.62). The loss per share in 2025 has arisen from a non-cash impairment recognized to oil and gas properties related to the Agbami CGU. In 2024, the basic and diluted loss per share was $0.62 (2023 – the basic income per share was $0.19 and the diluted income per share was $0.18). The loss per share has arisen primarily from the impairment recognized to the Company's investment in Meren Coop.

In 2025, the increase to financial liabilities is mainly from the RBL facility held by Meren Coop, which is now consolidated in the Group's balance sheet. In 2024, the increase to financial liabilities related to a lease liability recognized for lease of an office building.

In 2025, total assets have increased following the amalgamation and recognition of oil and gas interests in the Groups operations in Nigeria. In 2024 the decrease in total assets is primarily due to the decrease in cash balances and the decrease to the Company's investment in Meren Coop from the impairment recognized.

SUMMARY OF QUARTERLY INFORMATION

All financial information included in the narrative discussion below is based on the Consolidated Statement of Net Income or Loss and Other Comprehensive Income or Loss and considers the amalgamation closing on March 19, 2025.

Summarized quarterly results for the past eight quarters are as follows:

For the three months ended	31-Dec 2025	30-Sep 2025	30-Jun 2025	31-Mar 2025	31-Dec 2024	30-Sep 2024	30-Jun 2024	31-Mar 2024
Revenue	199.7	216.7	69.3	76.4	-	-	-	-
Net (loss)/ income attributable to common shareholders ($'m)	(90.8)	5.2	3.1	50.9	6.2	(289.2)	0.4	3.5
Weighted average shares – Basic '000	675,686	675,513	675,012	468,472	442,690	442,960	451,231	460,991
Weighted average shares – Diluted '000	675,686	682,770	682,039	476,836	449,667	442,960	464,890	474,746
Basic (loss)/ income per share ($)	(0.13)	0.01	0.00	0.11	0.02	(0.65)	0.00	0.01
Diluted (loss)/ income per share ($)	(0.13)	0.01	0.00	0.11	0.02	(0.65)	0.00	0.01

SUMMARY OF KEY ITEMS OF FINANCIAL PERFORMANCE IN THE YEARS ENDED DECEMBER 31, 2025, AND DECEMBER 31, 2024

	Three months ended		Years ended	
	December 31, 2025	December 31, 2024	December 31, 2025	December 31, 2024
Revenue	199.7	-	562.1	-
Gross (loss)/ profit	(78.2)	-	36.0	-
General and administrative expenses	(5.0)	(13.3)	(36.4)	(32.4)
Net (loss)/ income	(90.8)	6.2	(31.6)	(279.1)

Revenue

Revenue generated in Q4 2025 and 2025 was $199.7 million and $562.1 million respectively (Q4 2024 and 2024 – nil) and primarily related to 3 cargoes sold in Q4 2025 at an average price of $64.4/bbl and 5 additional cargoes sold in the period post amalgamation to the end of Q3 2025 at an average price of $70.4/bbl. Prior to the closing of the amalgamation on March 19, 2025, the Company did not report any revenue in its Consolidated Statement of Net Income or Loss and Other Comprehensive Income or Loss.

Gross profit

Gross loss reported in Q4 2025 and gross profit in 2025 was $78.2 million and $36.0 million respectively (Q4 2024 and 2024 – nil). Gross profit was impacted by costs of sales in Q4 2025 and 2025 of $277.9 million and $526.1 million respectively (Q4 2024 and 2024 – nil) and mainly comprised of non-cash impairment charges of $105.3 million to oil and gas properties related to the Agbami CGU, depletion costs of $52.9 million and $207.9 million respectively, net overlift movements of $63.4 million and $46.3 million respectively, and costs of operations of $34.7 million and $114.3 million respectively.

SUMMARY OF QUARTERLY INFORMATION - CONTINUED

General and administrative costs

On March 19, 2025, the Company announced the completion of the amalgamation to acquire the remaining 50% interest in Meren Coop in exchange for 239,828,655 newly issued common shares in Meren. This transaction falls under IFRS 3 under which acquisition related costs are expensed in the periods in which the costs are incurred, and the services are received.

The table below shows adjusted general and administrative expenses, which is a non-GAAP measure, by excluding the BTG Oil & Gas transaction related expenses and is meant to improve comparability between periods. The BTG Oil & Gas transaction related expenses also include certain LTIP charges for fully vested LTIP units as a result of the closing of the amalgamation.

	Three months ended		Years ended	
	December 31, 2025	December 31, 2024	December 31, 2025	December 31, 2024
General and administrative expenses	5.0	13.3	36.4	32.4
BTG Oil & Gas transaction related expenses	-	(0.7)	(9.0)	(6.9)
Adjusted general and administrative expenses	**5.0**	**12.6**	**27.4**	**25.5**

Adjusted general and administrative expenses, including share-based compensation charges relating to the LTIP and Stock Option Plan that are not impacted by the closing of the amalgamation, in Q4 2025 and 2025 amounted to $5.0 million and $27.4 million respectively (Q4 2024 and 2024 - $12.6 million and $25.5 million respectively). Share-based compensation charges not impacted by the closing of the amalgamation in Q4 2025 and 2025 amounted to $1.4 million and $3.7 million respectively (Q4 2024 and 2025 – $0.2 million and $1.5 million respectively) are impacted by movements in the share price of the Company and performance conditions.

Adjusted general and administrative expenses excluding share-based compensation charges amounted to $3.6 million in Q4 2025 compared to $12.4 million in Q4 2024. The decrease is mainly driven by cost allocations since closing of the amalgamation with these cost allocations reflected in Q4 2025.

Adjusted general and administrative expenses excluding share-based compensation charges amounted to $23.7 million in 2025, which is in line with 2024 amounting to $24.0 million.

SUMMARY OF KEY ITEMS OF FINANCIAL POSITION AS AT DECEMBER 31, 2025, AND DECEMBER 31, 2024

As at	December 31, 2025	December 31, 2024
Assets		
Oil and gas properties	1,413.5	-
Intangible exploration assets	43.7	29.3
Equity investments in associates	142.2	177.6
Cash and cash equivalents	174.4	61.4
Outstanding bank debt	330.0	-

Oil and gas properties

Oil and gas properties have increased following closing of the amalgamation to acquire the remaining 50% interest in Meren Coop following which Meren Coop is fully consolidated by the Company.

As at December 31, 2025, oil and gas properties amounted to $1,413.5 million (as at December 31, 2024 – nil) and related to the licenses PML 52 (covering part of the Agbami field), PML 2 (Akpo field), PML 3 (Egina field) and PML 4 (Preowei Field) in Nigeria.

Intangible exploration assets:

As at December 31, 2025, the carrying amount of the Company's intangible exploration assets in Equatorial Guinea was $24.5 million (as at December 31, 2024 – $17.9 million) and related to its 80% interest in Blocks EG-18 and EG-31.

As at December 31, 2025, the carrying amount of the Company's intangible exploration assets in South Africa was $19.2 million (as at December 31, 2024 - $11.4 million) and related to its 18.0% (as at December 31, 2024 – 17.0%) participating interest in the Block 3B/4B Exploration Right.

Equity investments in associates

As at December 31, 2025, the Company's investment in associates was $142.2 million compared to an investment value of $177.6 million as at December 31, 2024. The carrying value of the investments decreased by $35.4 million in 2025 mainly from the Company's share of the associates losses of $2.9 million in combination with a distribution by Impact of $31.6 million net to the Company's shareholding. The investment in Impact, holding the working interests in the Namibia Orange Basin Blocks 2913B and 2912, makes up $140.7 million of the total equity investments in associates.

Cash and cash equivalents

Cash and cash equivalents have increased following closing of the amalgamation to acquire the remaining 50% interest in Meren Coop following which Meren Coop is fully consolidated by the Company. As at December 31, 2025, the Company had $174.7 million cash and cash equivalents on hand, compared to a cash balance of $61.4 million as at December 31, 2024. The Company acquired cash balances on closing date of the amalgamation of $380.4 million, the Company received a distribution from Meren Coop of $60.0 million prior to the closing of the amalgamation, repaid $420.0 million of the RBL facility, returned $108.5 million to shareholders by way of dividends and share buybacks, received a distribution from Impact of $31.6 million, incurred capital and operational expenditure in respect of the licenses in Nigeria, Equatorial Guinea and South Africa, settled working capital balances and incurred general and administrative costs.

Outstanding bank debt

Outstanding bank debt increased following closing of the amalgamation to acquire the remaining 50% interest in Meren Coop following which Meren Coop is fully consolidated by the Company. Subsequent to closing of the amalgamation, the Company cancelled its corporate facility, repaid $420.0 million under the RBL facility, reducing outstanding bank debt to $330.0 million as at December 31, 2025. RBL facility headroom of $138.4 million at the end of 2025.

LIQUIDITY AND CAPITAL RESOURCES

As at December 31, 2025, the Company had cash balances of $174.7 million and net working capital balances (including cash balances) of $18.9 million negative. Net working capital is calculated as current assets less current liabilities as presented in the consolidated balance sheet as per December 31, 2025. The Company's primary source of liquidity is operating income in Nigeria and the remaining undrawn amounts on the RBL.

Reserves Based Lending Facility

Meren has a Reserves Based Lending Facility ("RBL") in place with $800.0 million in commitments from the date of the amalgamation. The total amount that can be drawn under the RBL is limited to the Borrowing Base Amount ("BBA"), which is subject to redeterminations on March 31 and September 30 of each year, limited by aggregate commitments. As of December 31, 2025, the BBA was $468.4 million, which will amortize as the RBL moves towards final maturity. On October 28, 2025, the Company voluntarily cancelled $100.0 million of its RBL commitments resulting in a remaining total commitment of $700.0 million.

The principal bore interest at Term SOFR + 4.00% until June 2025 and bears interest of Term SOFR + 4.25% until June 2027, then Term SOFR + 4.50% until final maturity on June 20, 2029. In addition, commitment fees of 40% of the margin are payable on the undrawn but available portion of the RBL, and commitment fees of 20% of the margin are payable on the unavailable portion of the RBL.

The RBL perimeter remains at the Meren Coop level – Meren Coop is the borrower, and Meren 52 and Meren 234 are the guarantors. The main security package is comprised of security over the shares, production assets, contracts and rights of the Nigerian entities - Meren 52 and Meren 234. In addition, RBL lenders have security over cash and cash equivalents held in project accounts, receivables against cargos sold and all relevant insurance policies of the three entities.

All financial and liquidity covenants covered by the RBL are restricted to these three entities. The entities shall ensure that total net debt to adjusted EBITDAX on each quarter is no greater than 3.0:1, that the historic debt service cover ratio for the preceding year is greater than 1.20:1, and that on each quarter of each year during each of the four successive quarters there are or will be sufficient funds available to the group to meet all relevant expenditure to be incurred in each of these four successive quarters as they fall due. The Company has been in compliance with the covenants in the three months ended December 31, 2025.

Material contractual commitments

In accordance with the terms of the production sharing contracts entered into by the Group along with other partners in respect of its oil fields and blocks, the Group has certain minimum exploration and development commitments with estimated capital expenditures in oil and gas properties of $0.3 billion as at December 31, 2025, $0.2 billion as at December 31, 2026, $0.1 billion as at December 31, 2027 and $0.1 billion as at December 31, 2028.

Future Funding Outlook

To finance its future acquisition, exploration, development and operating costs, the Company may require financing from external sources, including issuance of new shares, issuance of debt or executing farmout or disposition arrangements. There can be no assurance that such financing will be available to the Company or, if available, that it will be offered on terms acceptable to the Company.

The Company believes that its existing cash balances combined with anticipated funds flow from its operations and undrawn facilities will provide sufficient liquidity for the Company to meet its financing, operating and capex commitments as they fall due.

OUTSTANDING SHARE DATA

The following table outlines the maximum potential impact of share dilution upon full execution of outstanding convertible instruments as at the effective date of the MD&A.

Common shares outstanding	675,909,193
Outstanding share purchase options	22,616
Outstanding restricted share units	1,368,733
Outstanding performance share units	10,992,194
Full dilution impact on Common Shares outstanding	**688,292,736**

RELATED PARTY TRANSACTIONS

Transactions with Africa Energy:

On December 19, 2022, Africa Energy announced that it had secured a $5.0 million promissory note of which $2.0 million was provided by the Company and the remaining by other parties. On November 7, 2023, the promissory note provided by the Company and other parties to Africa Energy was increased by $3.3 million with $1.5 million of the increase provided by the Company by the end of the year ended December 31, 2024. No funds were provided during 2025, and $0.8 million was provided in the year ended December 31, 2024. The note was unsecured and matured on March 31, 2025, when the principal and accrued interest was repaid by Africa Energy in full. The note carried an annual interest rate of 15%. In the three months ended March 31, 2025, interest on the note amounted to $0.2 million (year ended December 31, 2024 - $0.5 million).

Transactions with Eco:

On July 26, 2024, the Company signed an agreement with Eco to acquire an additional 1.0% interest in Block 3B/4B from Azinam, in exchange for all common shares and warrants over common shares held by the Company in Eco. On January 13, 2025, the Company announced that it had completed this transaction. The Company's interest in Block 3B/4B increased by 1.0% to 18.0% and the Company ceased to be a shareholder in Eco. Meren will benefit from the carry agreed between Eco, TotalEnergies and QatarEnergy for this incremental interest.

Transactions with Impact:

On January 29, 2025, Impact distributed $31.6 million net to the Company's shareholding.

Transactions with BTG Oil & Gas:

The Company has recorded an indemnity asset of $21.6 million recognized under the deed of indemnity entered into between the Company and BTG Oil & Gas (see note 14).

Remuneration of Directors and Senior Management:

Remuneration of Non-Executive Directors and Senior Management includes all amounts earned and awarded to the Company's Board of Directors and Senior Management. Senior Management includes the Company's President and Chief Executive Officer, Chief Financial Officer, Chief Commercial and Operations Officer, Chief Operating Officer (position removed in 2025), Chief Technical Officer (position removed in 2025), Chief Legal Officer and Chief Human Resources Officer.

Directors' fees include Board and Committee Chair retainers. Management's short-term wages and benefits include salary, benefits, bonuses and any other cash-based compensation earned or awarded during the year. Share-based compensation includes expenses related to the Company's share purchase option plan as well as the Long-Term Incentive Plan.

For the years ended	December 31, 2025	December 31, 2024
Non-Executive Directors' fees	0.7	0.5
Non-Executive Directors' share-based compensation	1.4	0.6
Managements' short-term wages and benefits	7.1	7.3
Managements' share-based compensation	3.5	0.5
	12.7	**8.9**

COMMITMENTS AND CONTINGENCIES

The following commitments and contingencies are representative of the Company's net obligations at the effective date of the MD&A.

MEREN COÖPERATIEF U.A:

Under the Meren Coop Sale and Purchase Agreement completed on January 14, 2020, a deferred payment of $118.0 million, subject to adjustment, may be due to the seller contingent upon the timing of the final PML 52 tract participation in the Agbami field. The signing of the Securitization Agreement by Meren Coop in 2021 led to the Company reassessing its view of the likelihood of making a contingent consideration payment to the seller. The signing of the Securitization Agreement by Meren Coop does not constitute a redetermination of the tract participation and therefore does not trigger the payment of a contingent consideration under the Sale and Purchase Agreement but, at the Company's discretion, could trigger discussions with the seller. The outcome of this process is uncertain. In 2021, the Company recorded $32.0 million as contingent consideration and increased this to $40.4 million as at December 31, 2024, and to $43.4 million in the year ended December 31, 2025.

On June 25, 2021, Meren Nigeria 52 Limited (previously named Prime 127 Nigeria Limited) ("Meren 52"), a subsidiary of Meren Coop, signed a securitization agreement with two of the unit parties, Equinor and Chevron (the "Securitization Agreement"), whereby Equinor agreed to pay a security deposit to the two other JV parties to secure future payments due under that Securitization Agreement, pending a comprehensive resolution being reached among all unit parties in respect of the tract participation in the Agbami field by December 27, 2024. In accordance with the Securitization Agreement, on June 29, 2021, Meren 52 received from Equinor its portion of the security deposit in the form of a cash payment of $305.3 million. Meren 52 received an additional payment of $24.4 million on January 31, 2025, pursuant to the Securitization Agreement. Given no comprehensive resolution was reached by December 27, 2024, Meren 52 has recognized its portion of the security deposit and the additional receivable under the Securitization Agreement as other operating income on December 27, 2024. The process of implementing a new tract participation by the parties is ongoing and is subject to government approval. The parties will continue discussions to seek final resolution of the formal redetermination of the Agbami tract participation in respect of the period after December 27, 2024, however there is no certainty that such ongoing discussions will result in a final resolution.

Under the amended joint sale agreement between (among others) BTG Holding and the seller dated October 31, 2018, the seller could potentially claim that, given an additional payment has been received under the Securitization Agreement, this triggers a payment obligation of $54.6 million, exclusive of interest, capital taxes and certain deductions, contingent upon various criteria, with the outcome of this potential claim uncertain. Management considers the likelihood of any interest being payable to be unlikely. The Company has recorded an indemnity asset of $21.6 million under the deed of indemnity entered into between a subsidiary of the Company and BTG Oil & Gas for any costs suffered or incurred above $33.0 million post completion of the amalgamation, with the deed of indemnity backed by a $22.0 million letter of credit granted in favour a subsidiary of the Company. The letter of credit will remain in place for an initial period of two years and if a claim is not resolved in two years or is made after the two year period BTG Oil & Gas has undertaken to extend or reinstate the letter of credit.

WITHDRAWAL FROM KENYA:

On May 23, 2023, the Kenya entities along with TotalEnergies submitted withdrawal notices to the remaining joint venture party on Blocks 10BB, 13T and 10BA in Kenya, to unconditionally and irrevocably, withdraw from the entirety of the JOAs and PSCs for these concessions. The Company concurrently submitted notices to Ministry of Energy and Petroleum, requesting the government's consent to transfer all of its rights and future obligations under the PSCs to its remaining joint venture party. Government consent to the transfer was received on September 18, 2025, and the Company subsequently transferred all of its rights and future obligation of Blocks 10BB, 13T and 10BA to its remaining joint venture party with effect on and from June 30, 2023. In accordance with the JOA and PSC the Company retains economic participation for activities prior to June 30, 2023, which might result in additional costs for the Company. The Company continues to monitor the claim made against the operator by local communities in relation to past operations which may relate to the period prior to June 30, 2023. No provision has been recognized for this as at December 31, 2025.

SECURITIES AND GUARANTEES:

Under the conditions of the RBL facility, the main security package is comprised of security over the shares, production assets, contracts and rights of the Nigerian entities Meren 52 and Meren 234, cash and cash equivalents in the amount of $154.6 million as per December 31, 2025, that are held within the project accounts in Nigeria and The Netherlands, proceeds from the oil cargos sold and proceeds from the intercompany receivables between the Company and the Nigerian entities. Further, any and all claims relating to, and all returns of premium in respect of, all relevant insurance policies have been secured.

COMMITMENTS FROM FORWARD SALES:

The Group uses a mix of financial derivatives and physical forward sales contracts to manage its commodity price risk and ensure stability in cash flows. Its strategy is to hedge between 70-100% of its post-tax net entitlement production for the next 12-months. As at December 31, 2025, two cargos of the Group's expected lifted entitlement production for 2026 are covered by forward contracts. The average cargo lifted is for 1 million barrels of oil. The Group's triggers for these two cargos covered by forward contracts have been triggered at an average of $62.1 per barrel.

CRITICAL ACCOUNTING ESTIMATES

The Company's critical accounting estimates are defined as those estimates that have a significant impact on the portrayal of its financial position and operations and that require management to make judgements, assumptions and estimates in the application of IFRS Accounting Standards. Judgements, assumptions and estimates are based on historical experience and other factors that management believes to be reasonable under current conditions. As events occur and additional information is obtained, these judgements, assumptions and estimates may be subject to change.

USE OF ESTIMATES

The preparation of the consolidated financial statements in conformity with IFRS Accounting Standards requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting period. Such estimates include unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from these estimated amounts as future confirming events occur. Significant estimates used in the preparation of the consolidated financial statements include, but are not limited to, recovery of exploration costs capitalized in accordance with IFRS Accounting Standards, equity method accounting, valuation and impairment of equity investments and contingent consideration arising from the acquisition of Meren Coop.

The Company's material accounting policies can be found in the Company's audited consolidated financial statements for the years ended December 31, 2024, and December 31, 2025.

CLASSIFICATION OF JOINT ARRANGEMENTS

The Group is a party to transactions of non-operated Production Sharing Agreements ("PSAs"). The PSA transactions include the Group's proportionate share of the PSAs assets, liabilities and expenses, with items of a similar nature on a line-by-line basis, from the date that participation in the PSA arrangements commenced.

The Group has applied judgment in determining that it has joint control over the PSAs. This determination recognizes that all major decisions outside the original scope of the operations require unanimous approval by at least the Group and one or more of the PSAs partners.

The Group has determined that the relevant activities for its joint arrangements are those relating to the operating and capital decisions of the arrangement, such as approval of the capital expenditure program for each year and appointing, remunerating and terminating the key management personnel or service providers of the joint arrangement. The considerations made in determining joint control are similar to those necessary to determine control over subsidiaries.

Classifying the arrangement requires the Group to assess its rights and obligations arising from the arrangement. Specifically, the Group considers:

- The structure of the joint arrangement – whether it is structured through a separate vehicle.
- When the arrangement is structured through a separate vehicle, the Group also considers the rights and obligations arising from:
- The legal form of the separate vehicle;
- The terms of the contractual arrangement;
- Other facts and circumstances (when relevant).

As the Group has a proportionate share of the rights to the PSAs' assets and the obligations for the PSAs' liabilities, it classifies these interests as a Joint Operation under IFRS 11, and presents its proportionate share of the assets, liabilities, revenues and expenses on a line-by-line basis in the consolidated financial statements.

This assessment often requires significant judgement, and a different conclusion on joint control and also whether the arrangement is a joint operation or a joint venture, may materially impact the accounting.

If the Group did not have both joint control and a proportionate share of the rights to the PSAs' assets and obligations for the PSAs' liabilities, it would present only its net investment in the PSAs and its proportionate share of the PSAs' net income in the consolidated financial statements.

ACCOUNTING FOR LEASES AND JOINT OPERATIONS

Where the Group participates in a joint operation, either as a lease operator or non-operator party, determining whether to recognize and whether to measure a lease obligation involves judgement and requires identification of which entity has primary responsibility for the lease obligations entered into in relation to the joint operation's activities.

Where the joint operation (including all parties to that arrangement) has the right to control the use of the identified asset and all parties have a legal obligation to make payments to the third-party supplier, each joint operation participant would recognize its proportionate share of the lease related balances. This may arise where all parties to an unincorporated joint operation sign the lease agreement, or the joint operation is some sort of entity or arrangement that can sign in its own name.

However, where the Group is the lead operator and the sole signatory such that it is the one with the legal obligation to pay the third-party supplier, it would recognize 100% of the lease-related balances on its balance sheet. The Group would then need to assess whether the arrangement with the non-operator parties contains a sublease. This assessment would be based on the terms and conditions of each arrangement and may be impacted by the legal jurisdiction in which the joint arrangement operates.

Regardless of whether there is a sublease or not, the Group, in case it acts as the lead operator, would continue to recognize the lease liability for as long as it remains a party to the arrangement with the third-party supplier and has primary obligation to the lease payments.

CONSOLIDATION OF ENTITIES

When assessing control over a subsidiary, the Company is required to consider the nature of its relationship with the subsidiary, and whether strategic and operating decisions made by the subsidiary are made independently without the significant influence or control of the Company. Factors considered when assessing for control include share ownership, board composition and management involvement in the business. The determination of whether strategic and operating decisions made by the Company's subsidiaries (see note 27) are made independently without the significant influence or control of the Company requires judgement.

VALUATION OF INVESTMENTS

An investment in an associate or a joint venture is accounted for using the equity method from the date on which the investee becomes an associate or a joint venture. Investments in associates or joint ventures are initially recorded at cost. On acquisition of the investment in an associate or a joint venture, any excess of the cost of the investment over the share of the net fair value of the identifiable assets and liabilities of the investee is recognized as notional goodwill, which is included within the carrying amount of the investment. Significant assumptions developed by management used to determine the fair value of the non-current assets include estimates for the quantity of proved and probable petroleum reserves, future commodity prices, operating and capital costs as well as discount rates. The proved and probable petroleum reserves are prepared by the investee's independent petroleum engineers (management's experts).

Where contingent consideration has been recognized in an investment in an associate or joint venture, any revisions to the contingent consideration estimates after the date of acquisition, which have been considered as changes in estimates in accordance with IAS 8, are accounted for on a prospective basis. Any change in the liability as a result of the revised cash flows is adjusted to the cost of the asset and, in accordance with paragraph 37 of IAS 8, recognized as part of the associate or joint venture carrying amount rather than in profit or loss.

IMPAIRMENT OR REVERSAL OF IMPAIRMENT OF JOINT VENTURES AND ASSOCIATES

The amounts for investments in joint ventures and associates represents the Company's equity interest in other entities, where there is either joint control or significant influence. The Company assesses investments in associates for impairment whenever changes in circumstances or events indicate that the carrying value may not be recoverable. The process of determining whether there is an objective evidence of impairment considering circumstances or events which indicate that the carrying value may not be recoverable or calculating the recoverable amount requires judgement.

An area in which the Company applied judgement prior to the completion of the transaction with BTG Oil & Gas to consolidate its interest in Meren Coop relates to the equity investment in joint venture. On acquisition, judgements and estimates were used in determining fair values on acquisition for the purposes of the notional purchase price allocation. Subsequently, in assessing whether there were any indicators of impairment the Company considered any effects of Meren Coop's forward sales, the loan facility, and any operational and contractual implications on the future dividend stream when assessing for impairment indicators.

An area in which the Company has applied judgement relates to the equity investments in associates. In assessing whether there are any indicators of impairment the Company considered the movements in share price of the associates listed on public markets, the results of exploration and appraisal activities and future plans for the operations

HYDROCARBON RESERVE AND RESOURCE ESTIMATES

Oil and gas production assets, including facilities, are depreciated on a units-of-production ("UoP") basis at a rate calculated by reference to total proved and probable oil and gas reserves ("2P") determined in accordance with the principles contained in the SPE Petroleum Resources Management Reporting System ("PRMS") framework.

The Company estimates its 2P reserves based on information provided by reputable independent petroleum engineers, through the information provided by the respective operators. This information from reputable independent petroleum engineers concerns, amongst others, the geological and technical data on the size, depth, shape and grade of the hydrocarbon body and suitable production techniques and recovery rates.

2P reserves are determined using estimates of oil and gas in place, recovery factors, operating expenses, future development costs and future commodity prices; the latter having an impact on the total amount of recoverable reserves and the proportion of the gross reserves which are attributable to the host government under the terms of the Production-Sharing Agreements.

The current long-term Brent oil price assumption used in the estimation of proved and probable reserves is based on the IQRE long-term oil price forward curve.

As the economic assumptions used may change and, as additional geological information is obtained during the operation of a field, estimates of recoverable reserves may change.

UNITS-OF-PRODUCTION DEPRECIATION OF OIL AND GAS PROPERTIES

Oil and gas properties are depreciated using the UoP-method over total estimated proved and probable hydrocarbon reserves. This results in a depletion charge that is proportional to the depletion of the anticipated remaining production from the field.

The life of each item, which is assessed at least annually, has regard to both its physical life limitations and present assessments of economically recoverable reserves of the field at which the asset is located. These calculations require the use of estimates and assumptions, including the amount of recoverable reserves.

The calculation of the UoP-rate of depreciation could be impacted to the extent that actual production in the future is different from current forecast production based on total estimated proved and probable reserves, or future capital expenditure estimates change.

Changes to proven and probable reserves could arise due to changes in the factors or assumptions used in estimating reserves, including the effect on proved and probable reserves of differences between actual commodity prices and commodity price assumptions or unforeseen operational issues.

EXPLORATION AND EVALUATION COSTS

Exploration and evaluation costs are initially capitalized as intangible exploration assets with the intent to establish commercially viable reserves. The Company is required to make significant estimates and judgements about the future events and circumstances regarding whether the carrying amount of intangible exploration assets exceeds its recoverable amount (see note 6).

The carrying amounts of the Company's exploration and evaluation costs are reviewed at each reporting date to determine whether there is any indication of impairment. Exploration and evaluation assets are assessed for impairment if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. Should the carrying amount exceed the recoverable amount, an impairment loss is recognized.

Significant assumptions developed by management used to determine the recoverable amount include estimates for the quantity of contingent resources, future commodity prices, production forecasts, operating expenses, development costs, the likelihood of a successful farm out process, the timing of financial investment decision ("FID") and the discount rate. The contingent resources and production rates are prepared by the Company's independent petroleum engineers (management's experts).

Exploration and evaluation assets are assessed if facts and circumstances suggest that an impairment loss recognized in prior periods may no longer exist or may have decreased. An impairment reversal is recognized if there has been an increase in the asset's recoverable amount since the last impairment loss was recognized.

The changing worldwide demand for energy could result in a change in the assumptions used to determine the recoverable amount and could affect estimating the future cash flows which could impact the carrying amount of the Company's intangible exploration assets. The timing of when global energy markets transition from carbon-based sources to alternative energy sources is highly uncertain. Environmental considerations are built into our estimates through the use of significant assumptions in estimating fair value including future commodity prices and discount rates. The energy transition could impact the future prices of commodities and discount rates used to appraise oil and gas projects. Pricing assumptions used in the determination of recoverable amounts incorporate market expectations and the evolving worldwide demand for energy

PROVISION FOR SITE RESTORATION

Amounts used in recording a provision for site restoration are based on current legal and constructive requirements and current technology and price levels for the removal of facilities and plugging and abandoning of wells. Due to changes in relation to these items, the future cash outflows in relation to the site decommissioning and restoration can be difficult. To reflect the effects due to changes in legislation requirements, technology and price levels, the carrying amounts of site restoration provisions are reviewed on a regular basis.

On fields where the Group is required to contribute to site restoration costs, a provision is recorded to recognize the future commitment. An asset is created, as part of oil and gas interests, to represent the discounted value of the anticipated site restoration liability and depleted over the life of the field on a unit of production basis. The corresponding accounting entry to the creation of the asset recognizes the discounted value of the future liability. The discount applied to the anticipated site restoration liability is subsequently released over the life of the field and is charged to finance expense. Changes in site restoration costs and reserves are treated prospectively and consistent with the treatment applied upon initial recognition (see note 14).

REVENUE RECOGNITION

Judgement is required in determining when and how much revenue to recognize from contracts with customers. While the Group has determined that all revenue from contracts with customers is earned at a point in time, there is judgement involved in this consideration. Contractual arrangements for the sale of different products or with different terms may result in revenue being recognized over time.

There is also judgement involved in assessing whether the Group is the principal or agent in revenue transactions. In determining that the Group is acting as principal, the terms of the agreements were carefully considered and it was concluded that the Group controls the product before it is transferred to the customer. In alternate arrangements, the Group could be determined to be acting as agent.

Under the terms of existing contracts, the Group has determined that shipping or transportation services are not being provided to the customer, and that the only performance obligations are for the sale of crude oil and natural gas. Judgement is required in determining whether shipping is being provided as a service, and this impacts on the identification of performance obligations, whether all performance obligations are recognized at a point in time or over time, and the overall timing of revenue recognition.

Finally, judgement is required to determine whether the contractual arrangements contain only variable consideration, or also embedded derivatives, and if variable consideration, whether to exercise the constraint.

TAXES

Judgement is required to determine which arrangements are considered to be a tax on income as opposed to production costs. Judgement is also required to determine whether deferred tax assets are recognized in the statement of financial position. Deferred tax assets, including those arising from tax losses carried forward, require management to assess the likelihood that the Group will generate sufficient taxable earnings in future periods in order to utilize recognized deferred tax assets.

Assumptions about the generation of future taxable profits depend on management's estimates of future cash flows. These estimates of future taxable income are based on forecast cash flows from operations (which are impacted by production and sales volumes, oil and gas prices, reserves, production costs, decommissioning costs, capital expenditure, dividends and other capital management transactions) and judgement about the application of existing tax laws in each jurisdiction.

To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Group to realize the net deferred tax assets recorded at the reporting date could be impacted. In addition, future changes in tax laws in the jurisdictions in which the Group operates could limit the ability of the Group to obtain tax deductions in future periods.

SHARE BASED COMPENSATION

The estimated fair value of Performance share units ("PSUs") is calculated based on non-market performance conditions set by the Company which are initially determined at the time of grant. The Company assesses the progress of reaching the individual performance conditions during each reporting period. PSUs cliff vest three years from the date of grant, at which time the Board of Directors will assign a performance multiple ranging from nil to 200% to determine the ultimate vested number of PSUs. The awards are revalued every quarter based on the Company's share price and an estimate of the performance conditions at the quarter end. It is anticipated that PSU settlements will be made by issuing shares from treasury or cash, at the discretion of the Board of Directors (see note 21).

The estimated fair value of the Restricted share units ("RSUs") is initially determined at the time of grant. The awards are revalued every quarter based on the Company's share price. RSUs may be settled in shares issued from treasury or cash, at the discretion of the Board of Directors (see note 21).

GOING CONCERN

The consolidated financial statements for the year ended December 31, 2025, have been prepared on a going concern basis, which assumes that the Company will be able to realize its assets and discharge its liabilities in the normal course of business as they become due.

INTERNAL FINANCIAL REPORTING AND DISCLOSURE CONTROLS

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the Company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. Due to the amalgamation discussed above completed on March 19, 2025, the Company's disclosure controls and procedures have been updated to reflect the amalgamated disclosure controls and procedures.

Management, including the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of the Company's disclosure controls and procedures. As of December 31, 2025, the Chief Executive Officer and Chief Financial Officer have each concluded that the Company's disclosure controls and procedures, as defined in NI 52-109 - Certification of Disclosure in Issuer's Annual and Interim Filings, are effective to achieve the purpose for which they have been designed.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with IFRS Accounting Standards. Management is also responsible for the design of the Company's internal control over financial reporting in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS Accounting Standards.

The Company's internal controls over financial reporting include policies and procedures that: pertain to the maintenance of records that, in reasonable detail accurately and fairly reflect the transactions and disposition of assets; provide reasonable assurance that transactions are recorded as necessary to permit preparation of the financial statements in accordance with IFRS Accounting Standards and that receipts and expenditures are being made only in accordance with authorization of management and directors of the Company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the financial statements. Due to the amalgamation discussed above completed on March 19, 2025, the Company's disclosure controls and procedures have been updated to reflect the amalgamated disclosure controls and procedures.

Management, including the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of the Company's internal controls over financial reporting. As at December 31, 2025, the Chief Executive Officer and Chief Financial Officer have each concluded that the Company's internal controls over financial reporting, as defined in NI 52-109 - Certification of Disclosure in Issuer's Annual and Interim Filings, are effective to achieve the purpose for which they have been designed. Because of their inherent limitations, internal controls over financial reporting can provide only reasonable assurance and may not prevent or detect misstatements. Furthermore, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ADVISORY REGARDING OIL AND GAS INFORMATION

The terms boe (barrel of oil equivalent) and MMboe (millions of barrels of oil equivalent) are used throughout this report. Such terms may be misleading, particularly if used in isolation. The conversion ratio of six thousand cubic feet per barrel (6 Mcf:1 Bbl) of conventional natural gas to barrels of oil equivalent and the conversion ratio of 1 barrel per six thousand cubic feet (1 Bbl:6 Mcf) of barrels of oil to conventional natural gas equivalent is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to conventional natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

In this report, references are made to historical and potential future oil production in Nigeria and Namibia. In all instances these references are to light and medium crude oil category in accordance with NI 51-101 and the COGE Handbook.

Reserves are estimated remaining quantities of petroleum anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according to the level of certainty associated with the estimates and may be sub-classified based on development and production status. Proved Reserves are those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations. Probable Reserves are those additional quantities of petroleum that are less certain to be recovered than Proved Reserves, but which, together with Proved Reserves, are as likely as not to be recovered. Possible Reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

RISK FACTORS

With Board oversight, the Company proactively manages the identification, assessment and mitigation of risks, many of which are common to operations in the oil and gas industry as a whole, whilst others are unique to the Company. The realization of any of the risks listed below could have a material adverse effect on the Company's business, financial condition, reserves and results of operations, such list being non-exhaustive.

Risks that can materially affect the figures presented and disclosed in the Financial Statement and MD&A are described in the Company's Annual Information Form for the year ended December 31, 2025 ("AIF") available on SEDAR+ at www.sedarplus.ca or on Meren's website at www.mereninc.com/investor-summary/financial-reports-meetings-filings/.

The risks noted in the risk factors section comprises those that can materially affect the figures presented and disclosures in the Financial Statements and MD&A. The Company's Annual Information Form contains a more comprehensive list of risks that can affect the Company.

PRICES, MARKETS AND MARKETING OF CRUDE OIL AND NATURAL GAS

Crude oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond the control of the Company. World prices for oil and gas have fluctuated widely in recent years. Any material decline in prices could have an adverse effect on the Company's business and prospects. The Company may be required by government authorities to limit production due to OPEC+ quotas from time to time. The conflicts in Ukraine and the Middle East have impacted global markets and may continue to result in increased volatility in financial markets and commodity prices. The Company does not have a direct exposure to operations in Ukraine and the Middle East.

The Company may undertake hedging activities when efficient to do so, however, hedging may not fully mitigate, in whole or in part, the risk and effect of lower commodity prices or may limit upside in rising markets.

The Company or its investee company's ability to market its oil and gas may depend upon its ability to acquire space on vessels or in pipelines that deliver oil and gas to commercial markets. The Company could also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational issues affecting such pipelines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and gas and many other aspects of the oil and gas business.

HEDGING

The Group enters into agreements to receive fixed prices on its oil and gas production to offset the risk of revenue reduction if commodity prices decline. However, if commodity prices increase beyond the levels set in such agreements, the Group will not benefit from such increases.

LIQUIDITY AND CASH FLOW

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. Liquidity describes a company's ability to access cash. Companies operating in the upstream oil and gas industry require sufficient cash in order to fulfil their work commitments in accordance with contractual obligations, and to be able to potentially acquire strategic oil and gas assets and face potentially unexpected liabilities.

The Company could potentially issue debt or equity, extend its debt maturities and enter into farmout agreements to ensure it has sufficient available funds to meet current and foreseeable financial requirements.

The Company actively monitors its liquidity to ensure that its cash flows and working capital are adequate to support these financial obligations and the Company's capital programs. The Company will also adjust the pace of its activities to manage its liquidity position. Notwithstanding any mitigation efforts, the Company remains exposed to erosion of its balance sheet and revenues and may have difficulty in securing necessary funding, which may lead to insufficient liquidity.

CREDIT FACILITIES

The Company is party to credit facilities. The terms of the facility contain covenants and restrictions on the ability of the Company to, among other things, incur or lend additional debt, pay dividends and make restricted payments, and encumber its assets. The failure of the Company to comply with the covenants contained in the facility or to repay or refinance the facility by its maturity date could result in an event of default, which could, through acceleration of debt, enforcement of security or otherwise, materially and adversely affect the operating results and financial condition of the Company. As disclosed in the Financial Statements, the Company's revolving reserve-based loan (RBL) amortizes quarterly to the lower of commitments and the borrowing base assessment and matures on June 20, 2029.

CREDIT RISK

Credit risk is the risk of loss if counterparties do not fulfil their contractual obligations. Most of the Company's credit exposure relates to amounts due from its JV parties and receivables from crude oil sales. Sales are predominantly to investment-grade counterparties or supported by letters of credit/guarantees. A portion of the Company's cash is held by banks in foreign jurisdictions.

INTEREST RATE RISK

The Company floating-rate borrowings that reference SOFR and therefore could be exposed to volatility in interest rates that could constrain the company's cashflows.

SUBSTANTIAL CAPITAL REQUIREMENTS

Meren expects to make substantial capital expenditures for exploration, development and production of oil and gas reserves in the future. The Company's ability to access the equity or debt markets may be affected by any prolonged market instability. The inability to access the equity or debt markets for sufficient capital, at acceptable terms and within required time frames, could have a material adverse effect on the Company's financial condition, results of operations and prospects.

To finance its future acquisition, exploration, development and operating costs, the Company may require financing from external sources, including from the issuance of new shares, issuance of debt or execution of working interest farmout agreements. There can be no assurance that such financing will be available to the Company or, if available, that it will be offered on terms acceptable to the Company.

If additional financing is raised through the issuance of equity or convertible debt securities, control of the Company may change and the interests of shareholders in the net assets of the Company may be diluted. If unable to secure financing on acceptable terms, the Company may have to cancel or postpone certain of its planned exploration and development activities which may ultimately lead to the Company's inability to fulfil the minimum work obligations under the terms of its various concessions. Availability of capital will also directly impact the Company's ability to take advantage of acquisition opportunities.

FINANCIAL STATEMENTS PREPARED ON A GOING CONCERN BASIS

Meren's financial statements have been prepared on a going concern basis under which an entity is considered to be able to realize its assets and satisfy its liabilities in the ordinary course of business. There can be no assurances that the Company will be successful in completing additional financings, achieving profitability or completing future transactions.

RISKS INHERENT IN OIL AND GAS EXPLORATION, DEVELOPMENT, AND PRODUCTION

Oil and gas operations involve many risks, which, even with the combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Meren depends on its ability to find, acquire, develop and commercially produce oil and gas reserves. No assurance can be given that the Company will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, the Company may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. It is difficult to project the costs of implementing an exploratory, appraisal or development drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones, tools lost in the hole, equipment failures or malfunctions and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof. Without the continual addition of new reserves, any existing reserves associated with the Company's oil and gas assets at any particular time, and the production therefrom, could decline over time as such existing reserves are exploited. There is a risk that additional commercial quantities of oil and gas may not be discovered or acquired by the Company.

Meren's business is subject to all the risks and hazards inherent in businesses involved in the exploration for, and the acquisition, development, production and marketing of, oil and gas, many of which cannot be overcome even with a combination of experience and knowledge and careful evaluation. The risks and hazards typically associated with oil and gas operations include fire, explosion, blowouts, sour gas releases, pipeline ruptures and oil spills, each of which could result in substantial damage to oil and gas wells, production facilities, other property, the environment or personal injury, and such damages may not be fully insurable.

RISKS ASSOCIATED WITH DISCOVERING HYDROCARBONS

While the Company has historically made discoveries, there is no certainty that expenditures made on future exploration or development activities by Meren will result in discoveries of oil or gas in commercial quantities or that commercial quantities of oil and gas will be discovered, produced, or acquired by the Company. The portion of the Company's portfolio, which include prospects & leads require additional data to fully define their potential and significant changes to the resource estimates will occur with the incorporation of additional data and information. There is no certainty that any discovered resources will be commercially viable to produce. There is no certainty that any portion of undiscovered resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

RISKS ASSOCIATED WITH RESERVES AND RESOURCES VOLUME ESTIMATES

In the event of a discovery, reservoir parameters, such as porosity, permeability, net hydrocarbon pay thickness, fluid composition and water saturation, may vary from those assumed by the Company's independent third-party resource evaluator affecting the volume of hydrocarbon estimated to be present. Other factors such as the reservoir pressure, density and viscosity of the oil, solution gas/oil ratio, permeability, the presence or absence of water drive and the specific mineralogy of the reservoir rock will affect the volume of oil that can be recovered. Drill stem tests, or well tests, are commonly based on flow periods of one to five days and build up periods of one to three days to aid in understanding reservoir performance. Well test results include uncertainty and are not necessarily indicative of long-term performance or of ultimate recovery.

Furthermore, there are many uncertainties inherent in estimating quantities of oil and natural gas reserves and resources (contingent and prospective) and the future cash flows attributed to such reserves and resources. The actual production, revenues, taxes and development and operating expenditures with respect to the reserves and resources associated with the Company's assets will vary from estimates thereof and such variations could be material. Estimates of reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

RISKS ASSOCIATED WITH PRODUCTION GUIDANCE AND FORECASTING

Production guidance includes uncertainty around reservoir and well performance, reliability of production and process facilities, success of future drilling programs and execution of planned maintenance activities. Completion of future wells does not ensure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While structured maintenance plans, as well as close well, facility and operational supervision can contribute to maximizing production rates over time, production delays and declines from field operating conditions cannot be eliminated and may adversely affect production guidance, revenue and cash flow levels to varying degrees.

RISKS RELATING TO INFRASTRUCTURE

Meren is dependent on having available and functioning infrastructure relating to the properties and licenses on which it operates, such as roads, power and water supplies, pipelines and gathering systems, supply bases and associated services.

The amount of oil and gas that the Company can produce, and sell is subject to accessibility, availability, proximity and capacity of gathering, processing and pipeline systems. The lack of availability of capacity or a failure in any of the gathering, processing and pipeline systems, and in particular the processing facilities could result in the Company's inability to realize the full economic potential of its production or in a reduction of the price offered for the Company's production. Any significant change in market factors, terms of use or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Company's business financial condition, results of operations, cash flows and future prospects.

In Nigeria, gas export relies on the continued safe operations at the Nigeria LNG facility. Gas export restrictions could have an adverse effect on oil production, due to reductions in overall facility production to minimise flaring of associated gas. The supply chain for offshore is dependent upon existing ports and onshore infrastructure. Several factors, including social unrest onshore, have the potential to disrupt both the gas processing facilities and the upstream supply chain which could have detrimental impacts on cashflows.

In Equatorial Guinea, exploration efforts in Block EG-31 are targeting gas prospects located close to existing gas export and processing facilities. In the event of a discovery, the discovered fluids may not be compatible with the existing processing facilities resulting in additional cost which may result in the potential discovery being non-commercial. There may also be insufficient ullage in the facilities to accept additional capacity and without appropriate commercial arrangements it may not be possible to produce any potential discovery.

RISKS ASSOCIATED WITH THE AVAILABILITY OF EQUIPMENT AND STAFF

Meren's oil and gas exploration and development activities are dependent on the availability of drilling and related equipment and qualified staff in the particular areas where such activities are or will be conducted. For any operated drilling or seismic activities, the Company would rely on the availability of leased drilling rigs or seismic equipment used for its exploration and development activities. Shortages of such equipment or staff may affect the availability of such equipment to the Company and may delay Meren's exploration and development activities and result in lower production.

INCREASED COSTS AND SUPPLY DISRUPTION

A failure to secure the services and equipment necessary for the Company's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Company's financial performance and cash flows. The Company's operating and capital costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, and additional government intervention through stimulus spending or additional regulations. The Company's inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on its financial performance and cash flows. In addition, with rising inflation levels combined with global cost of living expenses, the Company may be faced with the challenge of how to attract and retain employees. Though Meren does not directly control procurement decisions associated with all of our assets, the Company works with its JV parties to ensure adequate contingency for cost inflation is incorporated into capital and operating budgets and that costs are controlled within budget.

SHARED OWNERSHIP AND DEPENDENCY ON JV PARTIES

The Company's operations are primarily conducted together with one or more JV parties through contractual arrangements, including unincorporated associations. In such instances, the Company may be dependent on, or affected by, the due performance and financial strength of its JV parties. If a JV party fails to perform or becomes insolvent, the Company may, among other things, risk losing rights or revenues or incur additional obligations or costs, experience delays, or be required to perform such obligations in place of its JV party. The Company and its JV parties may also, from time to time, have different opinions on how to conduct certain operations or on what their respective rights and obligations are under a certain agreement. If a dispute were to arise with one or more JV parties relating to a project, such dispute may have material adverse effect on the Company's or investee company's operations relating to such project.

RISKS RELATING TO CONCESSIONS, LICENSES AND CONTRACTS

Meren's operations are based on a relatively limited number of concession agreements, licenses and contracts. The rights and obligations under such concessions, licenses and contracts may be subject to interpretation and could also be affected by, among other things, matters outside the control of Meren. In case of a dispute, it cannot be certain that the view of the Company would prevail or that the Company otherwise could effectively enforce its rights which, in turn, could have significantly negative effects on Meren. Also, if the Company or any of its JV parties were found to have failed to comply with their obligations or liabilities under a concession, license or contract, including record-keeping, budgeting, and time scheduling requirements, the Company's or JV parties rights under such concession, license or contract may be terminated or otherwise relinquished in whole or in part. The Company cannot guarantee that requirements are adequately met by its JV parties, which could bring an increased risk of impairment and reduced future cash flow.

In May 2023, the Company submitted notices to withdraw from its concessions on Blocks 10BB, 13T and 10BA in Kenya. The Company's withdrawal from the concessions is subject to approvals from the Kenyan authorities and, while the Company is working with its JV parties and the authorities to effect a smooth withdrawal process, there can be no certainty that such approvals will be forthcoming on terms acceptable to all parties. Any delay or adverse outcome in the withdrawal process could result in additional costs, disputes or claims, and may adversely affect the Company's business, financial condition and results of operations.

GOVERNMENT REGULATIONS AND TAX RISK

The Company may be adversely affected by changes to applicable laws to which it is subject, and its host governments may implement new applicable laws, modify existing ones, or interpret them in a manner that is detrimental to the Company. Such changes to the laws to which the Company is subject could, amongst other things, result in a windfall tax, an increase in existing tax rates or the imposition of new ones or the Company may be subject to tax assessments, all of which on their own or taken together could have a material adverse effect on the Company's business, financial condition, results of operations and prospects of the Company's oil and gas assets.

As has become customary in Nigeria since 2019, the annual budget for Nigeria has been accompanied by a proposed finance bill that supports the revenue needs indicated in the annual budget. This bill could include changes to tax laws, including laws that can affect directly or indirectly the oil and gas industry.

Regulatory requirements affecting the oil and gas industry - including permitting rules, operational standards, local content requirements, and ongoing amendments to sector-specific legislation - may materially affect the Company's operations, timing of approvals, costs of compliance, fiscal terms, and continued access to concessions. These regulatory developments are incorporated within the Company's assessment of Government Regulations and Tax Risk.

INTERNATIONAL OPERATIONS

Meren participates in oil and gas projects located in emerging markets, primarily in Africa. Oil and gas exploration, development and production activities in these emerging markets are subject to significant political, economic, and other uncertainties that may adversely affect the Company's operations. The Company could be adversely affected by changes in applicable laws and policies in the countries where the Company has interests. Additional uncertainties include, but are not limited to, the risk of war, terrorism, expropriation, civil unrest, nationalization, renegotiation or nullification of existing or future concessions and contracts, the imposition of international sanctions, a change in crude oil or gas pricing policies, changes to taxation laws and policies, assessments and audits (including income tax) against the Company by regulatory authorities, difficulty or delays in obtaining necessary regulatory approvals, risks associated with potential future legal proceedings, and the imposition of currency controls. These uncertainties, all of which are beyond the Company's control, could have a material adverse effect on the Company's business, prospects and results of operations. In addition, if legal disputes arise related to oil and gas concessions acquired by the Company, they could be subject to the jurisdiction of courts other than those of Canada. The Company's recourse may be very limited in the event of a breach by a government or government authority of an agreement governing a concession in which the Company acquires an interest. The Company may require licenses or permits from various governmental authorities to carry out future exploration, development and production activities. There can be no assurance that the Company will be able to obtain all necessary licenses and permits when required.

FOREIGN CURRENCY EXCHANGE RATE RISK

The Company is exposed to changes in foreign exchange rates as expenses in international subsidiaries, oil and gas expenditures, or financial instruments may fluctuate due to changes in rates. The Company's exposure is partially offset by sourcing capital projects and expenditures in US dollars. The Company had no forward exchange contracts in place as at December 31, 2025.

DECOMMISSIONING

The Company is responsible for compliance with all applicable laws, regulations and contractual requirements regarding the decommissioning, abandonment and reclamation of the Company's assets at the end of their economic life.

HEALTH & SAFETY RISKS

The oil and gas industry involves inherent health and safety risks, including harsh and remote environments, heavy equipment, hazardous materials, high temperatures and high-pressure equipment. Meren is committed to operating in a safe and responsible manner, in alignment with international industry best practice and the laws and regulations of the countries where we operate. The Company maintains a Health & Safety policy, which is reviewed annually and outlines its commitments, including the governance processes and management systems used to ensure compliance with this policy. Where Meren does not operate, the Company engages with its JV Parties and operators on health and safety practices and monitors performance via quarterly reporting.

These efforts can help to reduce but not fully eliminate the risks associated with oil and gas activities, including fire, explosion, blowouts, gas releases, ruptures and personnel accidents. Should they occur, each of these hazards could result in substantial personal injury to employees, contractors or other bystanders, as well as damage to oil and gas wells, production facilities and other property. In this case, the Company could be exposed to fines, penalties and other legal liabilities, as well as reputational damage, including loss of license to operate, and such damages may not be fully insurable.

CLIMATE RISKS

Market Risks

Changing consumer preferences for low carbon sources of energy, transport and products and services may erode demand for oil and gas as alternatives come to market and gain scale. Although recent political developments in the United States and a recalibration of climate priorities in parts of the European Union have contributed to a more fragmented global policy landscape, market forces, capital allocation trends, and technological developments continue to drive the adoption of lower carbon solutions. As a result, reduced demand for oil and gas may result in stranded reserves or resources and negatively impact the Company's valuation and share price. In addition to limiting the Company's ability to sell into the market, these trends could lead to lower commodity prices in the medium and long-term, putting further pressure on revenues. In the short-term, unbalanced investment in traditional vs. new energy technologies and sources, combined with uncertain demand dynamics, may lead to commodity price volatility. Supply chains may also become constrained, as suppliers adjust their strategies and product mix in response to the energy transition, resulting in increasing costs for some goods and services.

The Company has conducted scenario analysis, which suggests the current portfolio remains competitive in a low demand environment. We update our analysis on a regular basis and ahead of new project sanction to minimize the risk of stranded assets. In order to remain resilient in an uncertain and volatile future commodity environment, the Company works with and through its parties to reduce operational costs as much as possible without sacrificing health and safety or longer-term efficiency and environmental or strategic goals. Additionally, the Company will maintain a prudent budget and financial strategy, including hedging as appropriate, to manage medium term oil price volatility ensure the business remains resilient in a low oil price scenarios.

Litigation Risks

Climate-related litigation is a rapidly evolving and increasingly important issue for our industry. The risk of legal challenges could rise as the costs of climate change mitigation and adaptation increase, and as more climate laws and agreements are put in place. Climate-related litigation could result in liabilities or loss of license related to current or historical activities' contribution to global emissions. We do not consider Meren at immediate risk of climate litigation but are monitoring developments closely. Even if the Company is not directly targeted by litigation, operations may be indirectly impacted by outcomes in related cases involving other oil and gas companies in jurisdictions where we operate. The Company will seek legal counsel as required to remain abreast of potential legal action and its implications for our business.

Regulatory Risks

Since the Paris Agreement was signed in 2015, countries have steadily enacted policies to enable the transition to a low carbon future and meet their Nationally Determined Contributions (NDCs). This includes the governments of countries where Meren conducts business. These policies may directly or indirectly increase the cost of doing business in these countries or potentially restrict the Company's ability to operate. Meren regularly monitors the evolving regulatory landscape, both globally and in the Company's countries of operation, to anticipate the impact of new climate-related measures and ensure the Company remains compliant. Additionally, the Company is developing a comprehensive energy transition strategy, including measures to minimize operational emissions in line with Paris Agreement objectives, which should help the Company to remain aligned with evolving regulatory requirements and minimize negative impacts.

Reputational Risk

Increased scrutiny, pressure and action by environmental activists, non-governmental organizations and other stakeholders may result in disruption to operations or loss of license to operate. Such disruption may negatively impact cash flows, returns or the value of our portfolio. Similarly, companies within the sector and our supply chain may make emissions performance and climate risk management explicit in partner or contract decisions. The Company has not been directly targeted by environmental activists but could be targeted in the future. To mitigate this risk, Meren proactively engages with the communities and other stakeholders where the Company operates to keep them informed about the impact of our operations on the environment and their livelihoods. The Company also ensures proper security is in place to minimize the impact of any potential disruptions and prevent harm to staff, bystanders and assets.

In addition to environmental activists, numerous banks and large institutional investors have communicated an intention to divest from or limit future exposure to fossil fuels, including oil and gas. Increasing investor and lender concerns regarding climate resilience could limit access to capital, increase the cost of that capital via higher interest rates or result in direct costs associated with new measures to meet investor expectations. Since 2020, Meren has published public climate disclosures aligned with the Taskforce for Climate-Related Financial Disclosures (TCFD) recommendations to proactively address investor and other stakeholder concerns regarding climate risk exposure. In addition, Meren regularly engages with investors and lenders to understand their climate policies and requirements and to inform them about the steps the Company is taking to manage climate risks. This includes development of a strategy to minimize operational emissions.

Physical Risks

Climate change has already resulted in significant shifts in global weather patterns, including an increase in the number and severity of heat waves, cold spells, droughts and storms, including hurricanes and tropical cyclones. Longer term, climate change may also result in rising sea levels due to melting polar ice caps. The physical effects of climate change have the potential to directly impact the Company's assets and operations. In 2022, the Company contracted a global climate risk analytics company to perform a quantified assessment of the physical climate risks facing the Company's assets under three IPCC climate scenarios: SSP1-2.6 (consistent with 1.8°C warming), SSP2-4.5 (consistent with 2.7°C warming) and SSP5-8.5 (consistent with 4.4°C warming). That analysis suggests exposure to future changes in physical climate hazards is relatively minimal compared to the historical baseline across all three scenarios. We will continue to monitor our assets' exposure to physical climate risks as our portfolio and the global scientific community's understanding of changing climate patterns evolves.

Other Environmental Risks

The regulatory frameworks in the Company's countries of operation extend beyond emissions to include broader areas of environmental concern, including water management, waste handling, soil pollution and biodiversity protection. These regulations typically include environmental licensing and permitting subject to the conduct of Environmental and Social Impact Assessments prior to any new exploration or development activity, as well as ongoing monitoring and reporting.

Non-compliance with environmental regulations can result in fines or permits being revoked, both of which could materially impact the Company's financial position or license to operate. Breaches could also lead to civil or criminal litigation, particularly in cases resulting in significant environmental damage.

The Company is committed to minimizing the broader environmental impact of its activities. The Company acts in compliance with the applicable environmental laws and regulations of its countries of operation and manages activities according to good international practice. This includes taking a rigorous approach to operational planning, including identifying potential environmental or social risks and impacts of operations, and obtaining and maintaining all necessary permits and licenses. The Company also consults with stakeholders on environmental issues that may affect them, investigates any environmental incidents, and maintains emergency response procedures for protection of the environment.

The Company assesses and puts measures in place to minimize impact on biodiversity and ecosystem services in line with the mitigation hierarchy to ensure that activities lead to no net loss of natural habitats. Where the Company is not the operator, it monitors environmental risk management via regular reports from JV parties and operators and participation in quarterly operating and technical committee meetings.

Though the Company endeavors to engage all relevant stakeholders proactively and early in the project planning process, environmental activism is increasing, and in some cases has resulted in delays or disruptions to activities, including delays to permitting where activists have challenged permits in courts. Meren has not to date suffered impacts to operations due to environmental activism. However, such delays could affect project economics by incurring additional costs or delaying forecast production and revenues.

The Company does not currently face any environmental fines or charges. However, accidents can occur and the unexpected nature of these events makes the timing and scope challenging to quantify with respect to financial impacts.

Insurance

The Company's involvement in oil and gas operations may result in the Company becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. While the Company obtains insurance in accordance with industry standards to address such risks, the nature of the risks facing the oil and gas industry is such that liabilities might exceed policy limits, the liabilities and hazards might not be insurable, or the Company might elect not to insure itself against such liabilities due to high premium costs or other reasons. The payment of such uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of an insurer, could have a material adverse effect on the Company's business, financial condition and results of operations. There can be no assurance that insurance will be available in the future.

INVESTMENTS IN ASSOCIATES AND INVESTMENTS IN JOINT VENTURES

The Company has invested in other frontier oil and gas exploration companies that face similar risks and uncertainties, which could have a material adverse effect on their businesses, prospects and results of operations. Such risks include, without limitation, equity risk, liquidity risk, commodity price risk, credit risk, currency risk, foreign investment risk, and changes in environmental regulations, economic, political or market conditions, or the regulatory environment in the countries in which they operate. The associates or joint ventures are entities in which the Company has some influence, including through its representation on their boards, but given its equal or minority interest, no or limited control over their decisions, including, without limitation, financial and operational policies, the Company has no or limited control over outcomes, performance and governance. The Company's access to information is subject to the contractual provisions of shareholder agreements. The Company is reliant on the information provided by investments and may not have the ability to independently verify such information. The Company's investments are not diversified over different types of investments and industries, rather, they are concentrated in one type of investment. If an associated company or jointly controlled entity in which the Company has invested fails, liquidates, or becomes bankrupt, the Company could face the potential risk of loss of some, or all, of its investments, and may be unable to recover any of its investments.

The Company's share price performance is subject to timely communication of financial and operational results. The Company is reliant on its associates and joint ventures for timely and accurate disclosures of material updates. Although the Company has procedures in place to maximise its oversight of such disclosures, including representation on the boards of its investee companies, failure to mitigate delays and/or inaccuracies in such disclosures could expose the Company to regulatory sanctions and shareholder legal action that could adversely impact the Company's finances and reputation.

RISK FACTORS - CONTINUED

LEGAL SYSTEM, LITIGATION AND REMEDIES

Meren's production, exploration, development and production activities are located in countries with legal systems that in various degrees differ from that of Canada. Rules, regulations and legal principles may differ in respect of matters of substantive law and of such matters as court procedure and enforcement. Almost all material exploration and production rights and related contracts of the Company are subject to the national or local laws and jurisdiction of the respective countries in which the operations are carried out. This means that the Company's ability to exercise or enforce its rights and obligations may differ between different countries and also from what would have been the case if such rights and obligations were subject to Canadian law and jurisdiction.

Meren's operations are, to a large extent, subject to various complex laws and regulations as well as detailed provisions in concessions, licenses and agreements that often involve several parties. If the Company was to become involved in legal disputes in order to defend or enforce any of its rights or obligations under such concessions, licenses, and agreements or otherwise, such disputes or related litigation could be costly, time consuming and the outcome would be highly uncertain. Even if the Company ultimately prevailed, such disputes and litigation may still have a substantially negative effect on the Company's business, assets, financial conditions, and its operations.

Securities legislation in certain of the provinces and territories of Canada provides purchasers with various rights and remedies when a reporting issuer's continuous disclosure contains a misrepresentation and ongoing rights to bring actions for civil liability for secondary market disclosure. Under the legislation, the directors would be liable for a misrepresentation. It may be difficult for investors to collect from the directors who are resident outside Canada on judgements obtained in courts in Canada predicated on the purchaser's statutory rights and on other civil liability provisions of Canadian securities legislation.

BRIBERY, CORRUPTION AND FRAUD

The Company is subject to various laws which aim to combat bribery, corruption and fraud, including the Corruption of Foreign Public Officials Act (Canada) and the Bribery Act 2010 (United Kingdom) and the Economic Crime and Corporate Transparency Act 2023 (United Kingdom). Failure to comply with such laws could subject the Company to, among other things, civil and criminal penalties, other remedial measures and legal expenses and reputational damage, each of which could adversely affect the Company's business, results in operations, and financial condition. Weaknesses in the anti-corruption legal and judicial system of certain countries may undermine the Company's or a host government's capacity to effectively detect, prevent and sanction corruption and fraud. To mitigate this risk, the Company has implemented an anti-corruption compliance and onboarding program for anyone that does business with the Company, anti-corruption training initiatives for its personnel and consultants, and an anti-corruption policy for its personnel, and consultants. However, the Company cannot guarantee that its personnel, contractors, or business partners have not in the past or will not in the future engage in conduct undetected by the onboarding processes and procedures adopted by the Company, and it is possible that the Company, its personnel or contractors, could be subject to investigations or charges related to bribery, corruption or fraud as a result of actions of its personnel or contractors.

SIGNIFICANT SHAREHOLDER

BTG Oil & Gas, an investment company which is a subsidiary of BTG Pactual, the largest investment bank in Latin America based in São Paulo, Brazil, owns approximately 35.5 percent of the aggregate common shares of the Company. BTG Oil & Gas's holdings may allow it to significantly affect substantially all the actions taken by the shareholders of the Company, including the election of directors. As long as BTG Oil & Gas maintains a significant interest in the Company, it is likely that BTG Oil & Gas will exercise significant influence on the ability of the Company to, among other things, enter into a change in control transaction of the Company and may also discourage acquisition bids for the Company. There is a risk that the interests of BTG Oil & Gas may not be aligned with the interests of other shareholders.

FORWARD-LOOKING STATEMENTS

Certain statements in this document may constitute forward-looking information or forward-looking statements under applicable Canadian securities law (collectively "forward-looking statements"). Forward-looking statements are statements that relate to future events, including the Company's future performance, opportunities or business prospects. All statements other than statements of historical fact may be forward-looking statements. Statements concerning proven and probable reserves and resource estimates may also be deemed to constitute forward-looking statements and reflect conclusions that are based on certain assumptions that the reserves and resources can be economically exploited. Any statements that express or involve discussions with respect to expectations, forecasts, assumptions, objectives, beliefs, projections, plans, guidance, predictions, future events or performance (often, but not always, identified by words such as "believes", "seeks", "anticipates", "expects", "continues", "may", "projects", "estimates", "forecasts", "pending", "intends", "plans", "could", "might", "should", "will", "would have" or similar words suggesting future outcomes) are not statements of historical fact and may be forward-looking statements.

By their nature, forward-looking statements involve assumptions, inherent risks and uncertainties, many of which are difficult to predict, and are usually beyond the control of management, that could cause actual results to be materially different from those expressed by these forward-looking statements. Undue reliance should not be placed on these forward-looking statements because the Company cannot assure that the forward-looking statements will prove to be correct. As forward-looking information addresses future conditions and events, it could involve risks and uncertainties including, but not limited to, risk with respect to macro-economic conditions and their impact on operations, regulations and taxes, civil unrest, corporate restructuring and related costs, capital and operating expenses, pricing and availability of financing and currency exchange rate fluctuations. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements.

Forward-looking statements include, but are not limited to, statements concerning:

- A change to the shareholder capital return program including the continuation of the based dividend policy, distribution of special dividends and/or the implementation of share buy-backs;
- Planned exploration, appraisal and development activity including both expected drilling, and geological and geophysical related activities;
- Proposed development plans;
- Future development costs and the funding thereof;
- Expected funding and development costs;
- Anticipated future financing requirements;
- Future sources of funding for the Company's capital program;
- Future capital expenditures and their allocation to exploration and development activities;
- Expected operating costs;
- Future sources of liquidity, ability to fully fund the Company's expenditures from cash flows, and borrowing capacity;
- Availability of potential farmout partners/ parties;
- The Company's ability to successfully identify, complete and integrate potential acquisition opportunities;
- Government or other regulatory consent for exploration, development, farmout, or acquisition activities;
- Future production levels;
- Future crude oil or natural gas prices;
- Future earnings;
- The Company's ability to deliver further growth and expectations regarding free-cash flow;
- Future asset acquisitions or dispositions and the anticipated strategic and financial benefits of those transactions;
- Future debt levels;
- Availability of committed credit facilities, including existing credit facilities, on terms and timing acceptable to the Company;
- Possible commerciality;
- Development plans or capacity expansions;
- Future ability to execute dispositions of assets or businesses;
- Future drilling of new wells;
- Ultimate recoverability of current and long-term assets;
- Ultimate recoverability of reserves or resources;
- The sustainability of the Company across oil and gas price cycles;
- Future foreign currency exchange rates;
- Future market interest rates;
- Future expenditures and future allowances relating to environmental matters;
- The Company's plans and targets to reduce the Company's net emissions;
- Dates by which certain areas will be explored or developed or will come on stream or reach expected operating capacity;
- The Company's ability to comply with future legislation or regulations;
- Future staffing level requirements; and
- Changes to any of the foregoing.

FORWARD-LOOKING STATEMENTS - CONTINUED

Statements relating to "reserves" or "resources" are forward-looking statements, as they involve the implied assessment, based on estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

These forward-looking statements are subject to known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others:

- Market prices for oil and gas;
- Uncertainty of estimates and projections relating to reserves, resources, production, revenues, costs and expenses;
- Changes in exploration or development project plans or capital expenditures;
- The Company's ability to explore, develop, produce and transport crude oil and natural gas to markets;
- Production and development costs and capital expenditures;
- The imprecise nature of reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids;
- Availability of financing;
- Uninsured risks;
- Changes in interest rates and foreign-currency exchange rates;
- Regulatory changes;
- Changes in the political or social climate in the regions in which the Company operates;
- Health, safety and environmental risks;
- Climate change legislation and regulation changes;
- Defects in title;
- Availability of materials and equipment;
- Timelines of government or other regulatory approvals;
- Ultimate effectiveness of design or design modification to facilities;
- The results of exploration, appraisal and development drilling and related activities;
- Short-term well test results on exploration and appraisal wells do not necessarily indicate the long-term performance or ultimate recovery that may be expected from a well;
- Pipeline or delivery constraints;
- Volatility in energy trading markets;
- Incorrect assessments of value when making acquisitions;
- Economic conditions in the countries and regions in which the Company carries on business;
- Governmental actions including changes to taxes or royalties, the imposition of tariffs or changes in environmental or other laws and regulations;
- The Company's treatment under governmental regulatory regimes and tax laws;
- Renegotiations of contracts;
- Results of litigation, arbitration or regulatory proceedings;
- Political uncertainty, including actions by terrorists, insurgent or other groups, or other armed conflict;
- Internal conflicts within states or regions;
- Dates by which certain areas will be explored or developed or will come onstream or reach expected operating capacity;
- The Company's ability to comply with future legislation or regulations;
- Future staffing level requirements; and
- Changes to any of the foregoing.

The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are interdependent, and management's future course of action would depend on its assessment of all available information at that time. Although management believes that the expectations conveyed by the forward-looking statements are reasonable based on the information available to it on the date such forward-looking statements were made, no assurances can be given that such expectations will prove to be correct, and such forward-looking statements included in, or incorporated by reference into, this document should not be unduly relied upon.

The forward-looking statements are made as of the date hereof or as of the date specified in the documents incorporated by reference into this document, as the case may be, and except as required by law, the Company undertakes no obligation to update publicly, re-issue, or revise any forward-looking statements, whether as a result of new information, future events or otherwise. This cautionary statement expressly qualifies the forward-looking statements contained herein.

Independent auditor's report

To the Shareholders of Meren Energy Inc. (previously called Africa Oil Corp.)

Our opinion

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of Meren Energy Inc. (previously called Africa Oil Corp.) and its subsidiaries (together, the Company) as at December 31, 2025 and 2024, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (IFRS Accounting Standards).

What we have audited

The Company's consolidated financial statements comprise:

- the consolidated balance sheets as at December 31, 2025 and 2024;
- the consolidated statements of net income or loss and other comprehensive income or loss for the years then ended;
- the consolidated statements of equity for the years then ended;
- the consolidated statements of cash flows for the years then ended; and
- the notes to the consolidated financial statements, comprising material accounting policy information and other explanatory information.

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Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada. We have fulfilled our other ethical responsibilities in accordance with these requirements.

Key audit matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the consolidated financial statements for the year ended December 31, 2025. These matters were addressed in the context of our audit of the consolidated financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

Key audit matter	How our audit addressed the key audit matter
Valuation of oil and gas properties acquired in the Meren Coop business acquisition	
Refer to note 2 – Basis of preparation, note 3 – Material accounting policies, and note 4 – Business combination to the consolidated financial statements. On March 19, 2025, the Company completed the transaction with BTG Oil & Gas to consolidate its interest in Meren Coöperatief U.A (previously known as Prime Oil and Gas Coöperatief U.A) (Meren Coop). The acquisition was completed by way of amalgamation whereby BTG Oil & Gas exchanged its 50 percent interest in Meren Coop, held through its fully owned subsidiary BTG Pactual Holding S.à.r.l., in exchange for	Our approach to addressing the matter included the following procedures, among others: • The work of management's experts was used in performing the procedures to evaluate the reasonableness of the acquired proved and probable oil and gas reserves used to determine the fair value of the oil and gas properties acquired. As a basis for using this work, the competence, capabilities and objectivity of management's experts were evaluated, the work performed was understood and the appropriateness of the work as audit

Key audit matter	How our audit addressed the key audit matter
239,828,655 newly issued shares in the Company. Management has regarded the acquisition as a business combination and has accounted for it using the acquisition method of accounting in accordance with IFRS 3. Management performed a final purchase price allocation (PPA) to allocate the consideration to the fair value of assets acquired and liabilities assumed. The fair value of oil and gas properties acquired was $1,538.1million. Management determined the fair value for oil and gas properties as the present value of estimated future cash flows arising from the continued use of the assets. Fair value for oil and gas properties is determined using a discounted cash flow model. The significant assumptions developed by management used to determine the fair value of the oil and gas properties acquired in the Meren Coop business acquisition include the quantity of proved and probable oil and gas reserves, future commodity prices, operating and capital costs and discount rates. The proved and probable oil and gas reserves are prepared by the Company's independent petroleum engineers (management's experts). We considered this a key audit matter due to (i) the significant judgment applied by management, including the use of management's experts, when determining the fair value of the oil and gas properties acquired in the Meren Coop business acquisition, including the development of the significant assumptions; (ii) a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating audit evidence relating to the significant assumptions used by management; and (iii) the audit effort involved the use of professionals with specialized skill and knowledge in the field of valuation and in the field of petroleum engineering and reserves estimation.	evidence was evaluated. The procedures performed also included evaluation of the methods and assumptions used by management's experts, and an evaluation of their findings. Professionals with specialized skill and knowledge in the field of petroleum engineering and reserves estimation assisted in this evaluation. • Tested how management determined the fair value of the oil and gas properties acquired, which included the following: – Read the purchase agreement. – Evaluated the appropriateness of management's discounted cashflow model and tested the mathematical accuracy thereof. – Tested the underlying data used by management in the discounted cash flow model. – Evaluated the reasonableness of the significant assumptions used by management in developing the underlying estimates, including: ○ quantity of proved and probable oil and gas reserves, operating and capital costs by considering the past performance of the oil and gas properties acquired, and whether these assumptions were consistent with evidence obtained in other areas of the audit; ○ future commodity prices by comparing those prices with other reputable third-party industry sourced commodity prices; and ○ the discount rate, through the assistance of professionals with specialized skill and knowledge in the field of valuation.

Key audit matter	How our audit addressed the key audit matter

Impact of oil and gas reserves on oil and gas properties for the Agbami field cash generating unit (CGU)
 	
Refer to note 2 – Basis of preparation, note 3 – Material accounting policies, and note 5 – Oil and gas properties to the consolidated financial statements.
 	
The Company had $1,413.5 million of net oil and gas properties as at December 31, 2025. Depletion expense was $207.9 million for the year then ended. Oil and gas properties are depleted using the Unit of Production (UoP) method over total estimated proved and probable oil and gas reserves.
 	
Oil and gas properties are grouped for recoverability assessment purposes into cash generating units (CGUs). At each reporting period, management assesses its CGUs to determine whether any indication of impairment exists. Where an indicator of impairment exists, with reference to total proved and probable oil and gas reserves, a formal estimate of the recoverable amount is made, which is considered to be the higher of the fair value less costs to dispose and value in use. An impairment loss is recognized if the carrying amount of the CGU exceeds its estimated recoverable amount.
 	
As at December 31, 2025, management determined there was an indicator of impairment in relation to the Agbami field CGU as a result of a combination of increased costs and lower oil prices.
 	
Management calculated the recoverable amount of the Agbami field CGU using a fair value less costs to dispose cashflow model, which is based on the discounted future after tax net cash flows of proved and probable oil and gas reserves. The proved and probable oil and gas reserves are prepared by management's experts.
 	
The significant assumptions used by management to determine the recoverable amount of the Agbami field CGU include the quantity of proved and probable oil and gas reserves, future
	Our approach to addressing the matter included the following procedures, among others:
	
	• The work of management's experts was used in performing the procedures to evaluate the reasonableness of the proved and probable oil and gas reserves used to determine the depletion expense and the recoverable amount of oil and gas properties in the Agbami field CGU. As a basis for using this work, the competence, capabilities and objectivity of management's experts was evaluated, the work performed was understood and the appropriateness of the work as audit evidence was evaluated. The procedures performed also included evaluation of the methods and assumptions used by management's experts, tests of the data used by management's experts and an evaluation of their findings. Professionals with specialized skill and knowledge in the field of petroleum engineering and reserves estimation assisted in this evaluation.
	• Tested how management determined the recoverable amount of the Agbami field CGU and depletion expense, which included the following:
	  – Evaluated the appropriateness of the methods used by management in making these estimates.
	  – Tested the data used in determining these estimates.
	  – Evaluated the reasonableness of significant assumptions used by management in developing the underlying estimates, including:
	    ○ quantity of proved and probable oil and gas reserves, operating and capital costs by considering the past performance of the Agbami field CGU, and whether these assumptions were consistent with evidence obtained in other areas of the audit;

Key audit matter	How our audit addressed the key audit matter
commodity prices, operating and capital costs and discount rates. During the year ended December 31, 2025, management recorded an impairment charge of $105.3 million on the oil and gas properties related to the Agbami field CGU. We considered this a key audit matter due to (i) the significant judgment by management, including the use of management's experts, when developing the expected future cash flows to determine the recoverable amount and the proved and probable oil and gas reserves; (ii) a high degree of auditor judgment, subjectivity and effort in performing procedures relating to the significant assumptions; and (iii) the audit effort involved the use of professionals with specialized skill and knowledge in the field of valuation and petroleum engineering and reserves estimation.	○ future commodity prices by comparing those prices with other reputable third party industry sourced commodity prices; and ○ the discount rate, through the assistance of professionals with specialized skill and knowledge in the field of valuation. • Recalculated the UoP rates used to calculate depletion expense for the Agbami field CGU.

Other information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis, which we obtained prior to the date of this auditor's report and the information, other than the consolidated financial statements and our auditor's report thereon, included in the Report to Shareholders, which is expected to be made available to us after that date.

Our opinion on the consolidated financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed on the other information that we obtained prior to the date of this auditor's report, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard. When we read the information, other than the consolidated financial statements and our auditor's report thereon, included in the Report to Shareholders, if we conclude that there is a material misstatement therein, we are required to communicate the matter to those charged with governance.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with IFRS Accounting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Plan and perform the group audit to obtain sufficient appropriate audit evidence regarding the financial information of the entities or business units within the Company as a basis for forming an opinion on the consolidated financial statements. We are responsible for the direction, supervision and review of the audit work performed for purposes of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this independent auditor's report is Khurram Asghar.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, Alberta, Canada
February 24, 2026

CONSOLIDATED BALANCE SHEET

(Expressed in millions of United States dollars)

As at	Note	December 31, 2025	December 31, 2024
ASSETS			
Non-current assets			
Oil and gas properties	5	1,413.5	-
Intangible exploration assets	6	43.7	29.3
Other tangible fixed assets		3.7	3.2
Equity investment in joint venture	7	-	328.4
Equity investments in associates	8	142.2	177.6
		1,603.1	538.5
Current assets			
Inventories	9	94.2	-
Investment held for sale	10	-	7.0
Loan to associated company	26	-	4.3
Trade and other receivables	11	77.7	4.0
Derivative financial instruments	29	2.2	-
Cash and cash equivalents	12	174.7	61.4
		348.8	76.7
Total assets		1,951.9	615.2
LIABILITIES AND EQUITY			
Equity attributable to common shareholders			
Share capital	13	1,536.2	1,195.8
Contributed surplus		95.5	87.4
Treasury share account		-	(0.4)
Deficit		(865.8)	(734.0)
Total equity attributable to common shareholders		765.9	548.8
Non-current liabilities			
Financial liabilities	15	265.2	2.6
Provisions	14	271.3	49.2
Deferred tax liabilities	24	281.8	-
		818.3	51.8
Current liabilities			
Financial liabilities	15	68.6	0.7
Trade and other payables	16	150.8	9.7
Current tax liabilities	24	48.5	-
Provisions	14	99.8	4.2
		367.7	14.6
Total liabilities		1,186.0	66.4
Total liabilities and equity attributable to common shareholders		1,951.9	615.2

The notes are an integral part of the consolidated financial statements.

Approved on behalf of the Board:

"MICHAEL EBSARY"

MICHAEL EBSARY, DIRECTOR

"OLIVER QUINN"

OLIVER QUINN, DIRECTOR

CONSOLIDATED STATEMENT OF NET INCOME OR LOSS AND OTHER COMPREHENSIVE INCOME OR LOSS

(Expressed in millions of United States dollars)

For the years ended	Note	December 31, 2025	December 31, 2024
Oil and gas sales	19	559.9	-
Net revenue		559.9	-
Commodity risk management contracts	29	2.2	-
Revenue		562.1	-
Cost of Sales			
Movements on overlift/underlift balances		(46.3)	-
Production costs	20	(166.6)	-
Depletion costs	5	(207.9)	-
Impairment charges	5	(105.3)	-
		(526.1)	-
Gross profit		36.0	-
General and administrative expenses		(36.4)	(32.4)
Operating loss		(0.4)	(32.4)
Finance income	22	4.1	7.6
Finance expense	23	(47.8)	(4.9)
Net financial items		(43.7)	2.7
Share of profit from investment in joint venture	7	2.9	226.0
Share of loss from investments in associates	8	(2.9)	(38.7)
Reversal of impairment/ (impairment) of investment in joint venture	7	55.9	(436.7)
Income/ (loss) before tax		11.8	(279.1)
Income tax	24	(43.4)	-
Net loss attributable to common shareholders		(31.6)	(279.1)
Total comprehensive loss		(31.6)	(279.1)
Net loss attributable to common shareholders per share			
Basic	25	(0.05)	(0.62)
Diluted	25	(0.05)	(0.62)
Weighted average number of shares outstanding for the purpose of calculating earnings per share			
Basic	25	624,464,015	449,431,803
Diluted	25	624,464,015	449,431,803

The notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENT OF EQUITY

(Expressed in millions of United States dollars)

For the years ended	Note	December 31, 2025	December 31, 2024
Share capital:	13(A)		
Balance, beginning of the year		1,195.8	1,265.3
Share issuance to BTG Oil & Gas under Amalgamation Agreement	13	353.2	-
Exercise of Share Options	13	0.4	0.5
Settlement of Restricted Share Units	13	1.1	0.5
Settlement of Performance Share Units	13	2.5	1.1
Weighted average value of shares cancelled	13	(16.8)	(71.6)
Balance, end of the year		1,536.2	1,195.8
Contributed surplus:			
Balance, beginning of the year		87.4	61.6
Excess of weighted value of shares cancelled	13	8.1	25.8
Balance, end of the year		95.5	87.4
Treasury account:			
Balance, beginning of the year		(0.4)	-
Shares purchased	13	(8.3)	(46.2)
Shares cancelled	13	8.7	45.8
Balance, end of the year		-	(0.4)
Deficit:			
Balance, beginning of the year		(734.0)	(432.3)
Dividends	13	(100.2)	(22.6)
Net income attributable to common shareholders		(31.6)	(279.1)
Balance, end of the year		(865.8)	(734.0)
Total equity attributable to common shareholders			
Balance, end of the year		765.9	548.8

The notes are an integral part of the consolidated financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

(Expressed in millions of United States dollars)

For the years ended	Note	December 31, 2025	December 31, 2024
Cash flows generated by/ (used in):			
Operations:			
Profit/ (loss) before tax		11.8	(279.1)
Adjustments for:			
(Reversal of) impairment of investment in joint venture	7	(55.9)	436.7
Share of loss from investments in associates	8	2.9	38.7
Share of profit from investment in joint venture	7	(2.9)	(226.0)
Unrealized result on commodity risk management contracts	29	(2.2)	-
Net financial items	22/23	43.7	(2.7)
Depletion, depreciation and amortisation	5	209.0	-
Impairment charges	5	105.3	-
Taxes	24	(135.9)	-
Other		2.8	(1.3)
Net cash generated/ (used) in operating activities before working capital		178.6	(33.7)
Changes in working capital	31	94.0	(14.8)
Net cash generated / (used) in operating activities		272.6	(48.5)
Investing:			
Investments in oil and gas properties and intangible exploration assets	5/6	(75.6)	(7.7)
Investments in other fixed assets		(0.4)	-
Distribution received from joint venture	7	60.0	36.0
Distribution received from associates	8	31.6	-
Equity investment in associates	8	-	(88.6)
Loan repaid by / (provided to) associated company	26	4.5	(1.0)
Interest income received		4.2	7.6
Cash acquired from Meren Coop consolidation	4	380.4	-
Net cash generated/ (used) in investing activities		404.7	(53.7)
Financing:			
Repayment RBL Facility		(420.0)	-
Repayment of principal portion of lease commitments	15	(0.7)	(0.5)
Dividends paid to shareholders	13	(100.2)	(22.6)
Repurchase of share capital	13	(8.3)	(45.3)
Interest expense paid		(34.8)	-
Net cash used in financing activities		(564.0)	(68.4)
Effect of exchange rate changes on cash and cash equivalents denominated in foreign currency		-	-
Increase/ (decrease) in cash and cash equivalents		113.3	(170.6)
Cash and cash equivalents, beginning of the year	12	61.4	232.0
Cash and cash equivalents, end of the year	12	174.7	61.4

The notes are an integral part of the consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2025, and December 31, 2024
(Expressed in millions of United States dollars unless otherwise indicated)

1. Incorporation and nature of business:

Meren Energy Inc. (collectively with its subsidiaries, "MER" or "Meren" or the "Company" or the "Group") was incorporated on March 29, 1993, under the laws of British Columbia and is an international oil and gas exploration and production company based in Canada with oil and gas interests in Africa. The Company's registered address is 25th Floor, 666 Burrard Street, Vancouver, B.C., Canada V6C 2X8. The Company changed its name to Meren Energy Inc. on May 14, 2025, and was previously called Africa Oil Corp.

2. Basis of preparation:

A. Statement of compliance:

The Company prepares its consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards"). The policies applied in these consolidated financial statements are based on IFRS Accounting Standards issued and outstanding as at February 24, 2026, the date the Board of Directors approved the statements.

B. Basis of measurement:

The consolidated financial statements have been prepared on the historical cost basis. Where there are assets and liabilities calculated on a different basis, this fact is disclosed in the material accounting policy. The Company uses the full cost method of accounting for exploration costs. Identifiable assets acquired and liabilities assumed in the transaction with BTG Oil & Gas were measured at its acquisition date fair value based on guidance in IFRS 13 as per note 4. Certain comparative figures have been reclassified to conform with the financial statements presentation in the current year following completion of the transaction with BTG. The Company has changed the presentation of its share of profit from investment in joint venture and associated companies in the Consolidated Statement of Net Income or Loss and Other Comprehensive Income or Loss. The Company has also changed the presentation of interest income received in the Consolidated Statement of Cash Flows.

C. Functional and presentation currency:

These consolidated financial statements are presented in United States (US) dollars. The functional currencies of the Company's individual entities are US dollars, which represents the currency of the primary economic environment in which the entities operate.

The consolidated financial statements are expressed in millions of US dollars unless otherwise indicated.

D. Use of estimates and judgements:

The preparation of financial statements in conformity with IFRS Accounting Standards requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Information about significant areas of estimation and critical judgements in applying accounting policies that have the most significant effect on the amounts recognized in the consolidated financial statements are noted below, with further details of the assumptions contained in the relevant note.

i. Classification of joint arrangements

These consolidated financial statements include transactions of non-operated Production Sharing Agreements ("PSAs"). The PSA transactions include the Group's proportionate share of the PSAs assets, liabilities and expenses, with items of a similar nature on a line-by-line basis, from the date that participation in the PSA arrangements commenced.

The Group has applied judgment in determining that it has joint control over the PSAs. This determination recognizes that all major decisions outside the original scope of the operations require unanimous approval by at least the Group and one or more of the PSAs partners.

The Group has determined that the relevant activities for its joint arrangements are those relating to the operating and capital decisions of the arrangement, such as approval of the capital expenditure program for each year and appointing, remunerating and terminating the key management personnel or service providers of the joint arrangement. The considerations made in determining joint control are similar to those necessary to determine control over subsidiaries.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

Classifying the arrangement requires the Group to assess its rights and obligations arising from the arrangement. Specifically, the Group considers:

- The structure of the joint arrangement – whether it is structured through a separate vehicle;
- When the arrangement is structured through a separate vehicle, the Group also considers the rights and obligations arising from;
  - » The legal form of the separate vehicle;
  - » The terms of the contractual arrangement; and
  - » Other facts and circumstances (when relevant).

As the Group has a proportionate share of the rights to the PSAs' assets and the obligations for the PSAs' liabilities, it classifies these interests as a Joint Operation under IFRS 11, and presents its proportionate share of the assets, liabilities, revenues and expenses on a line-by-line basis in the consolidated financial statements.

This assessment often requires significant judgement, and a different conclusion on joint control and also whether the arrangement is a joint operation or a joint venture, may materially impact the accounting.

If the Group did not have both joint control and a proportionate share of the rights to the PSAs' assets and obligations for the PSAs' liabilities, it would present only its net investment in the PSAs and its proportionate share of the PSAs' net income in the consolidated financial statements.

ii. Accounting for leases and joint operations

Where the Group participates in a joint operation, either as a lease operator or non-operator party, determining whether to recognize and whether to measure a lease obligation involves judgement and requires identification of which entity has primary responsibility for the lease obligations entered into in relation to the joint operation's activities.

Where the joint operation (including all parties to that arrangement) has the right to control the use of the identified asset and all parties have a legal obligation to make payments to the third-party supplier, each joint operation participant would recognize its proportionate share of the lease related balances. This may arise where all parties to an unincorporated joint operation sign the lease agreement, or the joint operation is some sort of entity or arrangement that can sign in its own name.

However, where the Group is the lead operator and the sole signatory such that it is the one with the legal obligation to pay the third-party supplier, it would recognize 100% of the lease-related balances on its balance sheet. The Group would then need to assess whether the arrangement with the non-operator parties contains a sublease. This assessment would be based on the terms and conditions of each arrangement and may be impacted by the legal jurisdiction in which the joint arrangement operates.

Regardless of whether there is a sublease or not, the Group, in case it acts as the lead operator, would continue to recognize the lease liability for as long as it remains a party to the arrangement with the third-party supplier and has primary obligation to the lease payments.

iii. Valuation of investments:

An investment in an associate or a joint venture is accounted for using the equity method from the date on which the investee becomes an associate or a joint venture. Investments in associates or joint ventures are initially recorded at cost. On acquisition of the investment in an associate or a joint venture, any excess of the cost of the investment over the share of the net fair value of the identifiable assets and liabilities of the investee is recognized as notional goodwill, which is included within the carrying amount of the investment. Significant assumptions developed by management used to determine the fair value of the non-current assets include estimates for the quantity of proved and probable oil and gas reserves, future commodity prices, operating and capital costs as well as discount rates. The proved and probable oil and gas reserves are prepared by the investee's independent petroleum engineers (management's experts).

Where contingent consideration has been recognized in an investment in an associate or joint venture, any revisions to the contingent consideration estimates after the date of acquisition, which have been considered as changes in estimates in accordance with IAS 8, are accounted for on a prospective basis. Any change in the liability as a result of the revised cash flows is adjusted to the cost of the asset and, in accordance with paragraph 37 of IAS 8, recognized as part of the associate or joint venture carrying amount rather than in profit or loss.

iv. Recoverability of oil and gas properties

The Group assesses each asset or cash generating unit (CGU) (excluding goodwill, which is assessed annually regardless of indicators) each reporting period to determine whether any indication of impairment exists. Where an indicator of impairment exists, with reference to total proved and probable oil and gas reserves ('2P'), a formal estimate of the recoverable amount is made, which is considered to be the higher of the fair value less costs to dispose and value in use. The assessments require the use of estimates and assumptions such as long-term oil prices, future production volumes, discount rates, operating costs, development costs, decommissioning costs, reserve volumes (see Hydrocarbon reserve and resource estimates) and operating performance (which includes production and sales volumes). These estimates and assumptions are subject to risk and uncertainty and changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

Fair value is determined as the amount that would be obtained from the sale of the asset in an arm's length transaction between knowledgeable and willing parties. Fair value for oil and gas properties is generally determined as the present value of estimated future cash flows arising from the continued use of the assets, which includes estimates such as the future development costs and eventual disposal, using assumptions that an independent market participant may take into account. Fair value for oil and gas properties is determined using a discounted cash flow model. Cash flows are discounted to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset/CGU. Significant assumptions developed by management used to determine the fair value of the non-current assets include estimates for the quantity of proved and probable oil and gas reserves, future commodity prices, operating and capital costs as well as discount rates. The proved and probable oil and gas reserves are prepared by the Company's independent petroleum engineers (management's experts).

v. Impairment of joint ventures and associates

The amounts for investments in joint ventures and associates represents the Company's equity interest in other entities, where there is either joint control or significant influence. The Company assesses investments in associates for impairment whenever changes in circumstances or events indicate that the carrying value may not be recoverable. The process of determining whether there is an objective evidence of impairment considering circumstances or events which indicate that the carrying value may not be recoverable or calculating the recoverable amount requires judgement.

An area in which the Company applied judgement prior to the completion of the transaction with BTG Oil & Gas to consolidate its interest in Meren Coop relates to the equity investment in joint venture. On acquisition, judgements and estimates were used in determining fair values on acquisition for the purposes of the notional purchase price allocation. Subsequently, in assessing whether there were any indicators of impairment the Company considered any effects of Meren Coop's forward sales, the loan facility, and any operational and contractual implications on the future dividend stream when assessing for impairment indicators.

An area in which the Company has applied judgement relates to the equity investments in associates. In assessing whether there are any indicators of impairment the Company considered the movements in share price of the associates listed on public markets, the results of exploration and appraisal activities and future plans for the operations.

vi. Hydrocarbon reserve and resource estimates

Oil and gas production assets, including facilities, are depleted on a units-of-production ("UoP") basis at a rate calculated by reference to total proved and probable oil and gas reserves ("2P") determined in accordance with Canadian National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and incorporating the estimated future development cost of developing and extracting reserves.

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. 2P reserves are determined using estimates of oil and gas in place, recovery factors, operating expenses, future development costs and future commodity prices; the latter having an impact on the total amount of recoverable reserves and the proportion of the gross reserves which are attributable to the host government under the terms of the Production-Sharing Agreements. The Company's reserves are evaluated annually and reported to the Company by its independent petroleum engineers (management's experts).

The current long-term Brent oil price assumption used in the estimation of proved and probable oil and gas reserves is based on independent petroleum engineers long-term oil price forward curve.

As the economic assumptions used may change and, as additional geological information is obtained during the operation of a field, estimates of recoverable reserves may change.

vii. Units-of-production depreciation of oil and gas properties

Oil and gas properties are depleted using the UoP-method over total estimated proved and probable oil and gas reserves and incorporating the estimated future development cost of developing and extracting reserves. This results in a depletion charge that is proportional to the depletion of the anticipated remaining production from the field.

The life of each item, which is assessed at least annually, has regard to both its physical life limitations and present assessments of economically recoverable reserves of the field at which the asset is located. These calculations require the use of estimates and assumptions, including the amount of recoverable reserves.

The calculation of the UoP-rate of depreciation could be impacted to the extent that actual production in the future is different from current forecast production based on total estimated proved and probable oil and gas reserves, or change in future development cost estimates.

Changes to proved and probable oil and gas reserves could arise due to changes in the factors or assumptions used in estimating reserves, including the effect on proved and probable oil and gas reserves of differences between actual commodity prices and commodity price assumptions or unforeseen operational issues.

viii. Exploration and evaluation costs

Exploration and evaluation costs are initially capitalized as intangible exploration assets with the intent to establish commercially viable reserves. The Company is required to make significant estimates and judgements about the future events and circumstances regarding whether the carrying amount of intangible exploration assets exceeds its recoverable amount (see note 6).

The carrying amounts of the Company's exploration and evaluation costs are reviewed at each reporting date to determine whether there is any indication of impairment. Exploration and evaluation assets are assessed for impairment if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. Should the carrying amount exceed the recoverable amount, an impairment loss is recognized.

Significant assumptions developed by management used to determine the recoverable amount include estimates for the quantity of contingent resources, future commodity prices, production forecasts, operating expenses, development costs, the likelihood of a successful farm out process, the timing of financial investment decision ("FID") and the discount rate. The contingent resources and production rates are prepared by the Company's independent petroleum engineers (management's experts).

Exploration and evaluation assets are assessed if facts and circumstances suggest that an impairment loss recognized in prior periods may no longer exist or may have decreased. An impairment reversal is recognized if there has been an increase in the asset's recoverable amount since the last impairment loss was recognized.

The changing worldwide demand for energy could result in a change in the assumptions used to determine the recoverable amount and could affect estimating the future cash flows which could impact the carrying amount of the Company's intangible exploration assets. The timing of when global energy markets transition from carbon-based sources to alternative energy sources is highly uncertain. Environmental considerations are built into our estimates through the use of significant assumptions in estimating fair value including future commodity prices and discount rates. The energy transition could impact the future prices of commodities and discount rates used to appraise oil and gas projects. Pricing assumptions used in the determination of recoverable amounts incorporate market expectations and the evolving worldwide demand for energy.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

ix. Provision for site restoration:

Amounts used in recording a provision for site restoration are based on current legal and constructive requirements, current technology, price levels for the removal of facilities and plugging and abandoning of wells. Due to changes to these items, the future cash outflows in relation to the site decommissioning and restoration can be difficult to determine. To reflect the effects due to changes in legislation requirements, technology and price levels, the carrying amounts of site restoration provisions are reviewed on a regular basis.

On fields where the Group is required to contribute to site restoration costs, a provision is recorded to recognize the future commitment. An asset is created, as part of oil and gas interests, to represent the discounted value of the anticipated site restoration liability and depleted over the life of the field on a unit of production basis. The corresponding accounting entry to the creation of the asset recognizes the discounted value of the future liability. The discount applied to the anticipated site restoration liability is subsequently released over the life of the field and is charged to finance expense. Changes in site restoration costs and reserves are treated prospectively and consistent with the treatment applied upon initial recognition (see note 14).

x. Revenue recognition

Judgement is required in determining when and how much revenue to recognize from contracts with customers. While the Group has determined that all revenue from contracts with customers is earned at a point in time, there is judgement involved in this consideration. Contractual arrangements for the sale of different products or with different terms may result in revenue being recognized over time.

There is also judgement involved in assessing whether the Group is the principal or agent in revenue transactions. In determining that the Group is acting as principal, the terms of the agreements were carefully considered and it was concluded that the Group controls the product before it is transferred to the customer. In alternate arrangements, the Group could be determined to be acting as agent.

Under the terms of existing contracts, the Group has determined that shipping or transportation services are not being provided to the customer, and that the only performance obligations are for the sale of crude oil and natural gas. Judgement is required in determining whether shipping is being provided as a service, and this impacts on the identification of performance obligations, whether all performance obligations are recognized at a point in time or over time, and the overall timing of revenue recognition.

Finally, judgement is required to determine whether the contractual arrangements contain only variable consideration, or also embedded derivatives, and if variable consideration, whether to exercise the constraint.

xi. Taxes

Judgement is required to determine which arrangements are considered to be a tax on income as opposed to production costs. Judgement is also required to determine whether deferred tax assets are recognized in the statement of financial position. Deferred tax assets, including those arising from tax losses carried forward, require management to assess the likelihood that the Group will generate sufficient taxable earnings in future periods in order to utilize recognized deferred tax assets.

To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Group to realize the net deferred tax assets recorded at the reporting date could be impacted. In addition, future changes in tax laws in the jurisdictions in which the Group operates could limit the ability of the Group to obtain tax deductions in future periods.

xii. Share based compensation

The estimated fair value of Performance share units ("PSUs") is calculated based on non-market performance conditions set by the Company which are initially determined at the time of grant. The Company assesses the progress of reaching the individual performance conditions during each reporting period. PSUs cliff vest three years from the date of grant, at which time the Board of Directors will assign a performance multiple ranging from nil to 200% to determine the ultimate vested number of PSUs. The awards are revalued every quarter based on the Company's share price and an estimate of the performance conditions at the quarter end. It is anticipated that PSU settlements will be made by issuing shares from treasury or cash, at the discretion of the Board of Directors (see note 21).

The estimated fair value of the Restricted share units ("RSUs") is initially determined at the time of grant. The awards are revalued every quarter based on the Company's share price. RSUs may be settled in shares issued from treasury or cash, at the discretion of the Board of Directors (see note 21).

xiii. Contingencies

Contingencies are subject to measurement uncertainty as the related financial impact will only be confirmed by the outcome of a future event. The assessment of contingencies requires the application of judgements and estimates including the determination of whether a present obligation exists, and the reliable estimation of the timing and amount of cash flows required to settle the contingencies.

xiv. Going concern

These consolidated financial statements for the year ended December 31, 2025, have been prepared on a going concern basis, which assumes that the Company will be able to realize its assets and discharge its liabilities in the normal course of business as they become due.

3. Material accounting policies:

The accounting policies set out below have been applied consistently to all years presented in these consolidated financial statements and have been applied consistently by the Company and its subsidiaries.

A. Basis of consolidation:

i. Subsidiaries:

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that are currently exercisable are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

ii. Jointly controlled operations and jointly controlled assets:

Interests in joint arrangements are classified as either joint operations or joint ventures, depending on the rights and obligations of the parties to the arrangement. Joint operations arise when the Company has rights to the assets and obligations for the liabilities of the arrangement. The Company recognizes its share of assets, liabilities, revenues and expenses of a joint operation. A significant portion of the Company's operating cash flows is derived through joint operations which are involved in the development and production of crude oil and gas in Nigeria. Joint ventures arise when the Company has rights to the net assets of the arrangement. Joint ventures are accounted for under the equity method.

iii. Transactions eliminated on consolidation:

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

B. Equity method:

Investments in joint ventures and associates are accounted for using the equity method. Investments of this nature are recorded at original cost. Investments in joint ventures or associates which arise from a loss in control of a subsidiary are recorded at fair value on the date of the loss of control. The investment is adjusted at each reporting date for the Company's share of the profit or loss of the investment after the date of acquisition. The investor's share of the profit or loss of the investee is also recognized in the Company's Statement of Net Income or Loss and Other Comprehensive Income or Loss. Distributions received reduce the carrying amount of the investment.

The Company assesses its investments in joint ventures and associates for an objective evidence of impairment considering circumstances or events which indicate that the carrying value may not be recoverable. If such circumstances or events exist, the carrying amount of the investment is compared to its recoverable amount. The recoverable amount is the higher of the investment's fair value less costs to dispose and its value in use. The investment is written down to its recoverable amount when its carrying amount exceeds the recoverable amount.

C. Business combinations

Business combinations are accounted for using the acquisition method as at acquisition date, which is the date on which control is transferred to the Group. The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at acquisition date fair value and the amount of any previously held interest in the acquiree.

Under the acquisition method the identifiable assets acquired, liabilities assumed and non-controlling interest, if any, are recognized and measured at their fair value at the date of acquisition. Fair value for oil and gas properties is generally determined as the present value of estimated future cash flows arising from the continued use of the assets using a discounted cash flow model. Any excess of the purchase price plus any non-controlling interest over the value of the net assets acquired is recognized as goodwill. Any deficiency of the purchase price over the value of the net assets acquired is credited to net earnings. When a business combination is achieved in stages, the Company re-measures its pre-existing interest at the acquisition date fair value and recognizes the resulting gain or loss, if any, in the Statement of Net Income or Loss and Other Comprehensive Income or Loss. Contingent consideration transferred in a business combination is measured at fair value on the date of acquisition.

Acquisition related costs are expensed as incurred and included in general and administrative expenses, except if related to the issue of debt or equity securities.

D. Oil and gas properties

Oil and gas properties are aggregated exploration and evaluation tangible assets, and development expenditures associated with the production of proved and probable oil and gas reserves. Development expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including unsuccessful development or delineation wells, is capitalized within 'Oil and gas properties'. These assets are depreciated/amortized on a UoP basis over the 2P reserves of the field concerned from the commencement of production, taking into account future development expenditures necessary to bring those reserves into production.

i. Initial recognition

Oil and gas properties 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 the decommissioning obligation and, for qualifying assets, borrowing costs.

Qualifying assets are those that necessarily take a substantial period of time to build and from which future benefits accrue to the Group. Capitalization continues up to the date that all the substantial activities necessary to get the asset ready for its intended use are complete.

Capitalized expenditure relating to the Group's carried interest is recorded in line with the Group's accounting policy.

The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. Subsequent costs are included in the asset's carrying amount or recognized as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost can be measured reliably. The carrying amount of the replaced part is derecognized.

When a development project moves into the production stage, the capitalization of certain construction/development costs ceases and costs are expensed, except for costs which qualify for capitalization relating to oil and gas property asset additions, improvements or new developments.

ii. Depletion

Oil and gas properties are depleted from the commencement of production, on a UoP basis, which is the ratio of oil and gas production in the period to the estimated quantities of the 2P reserves at the end of the period plus the production in the period, on a field-by-field basis.

Facilities included in oil and gas production assets are depreciated on a UoP basis over the economic useful life of the field concerned. Costs used in the UoP calculation comprise the net carrying amount of capitalized costs plus the estimated future field development costs.

Changes in the estimates of reserves or future field development costs are dealt with prospectively. Oil and gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the field storage tank. Rights and concessions are depleted on the UoP basis over the total proved and probable oil and gas reserves of the relevant area.

iii. Maintenance, inspection and repairs

Expenditure on major maintenance refits, inspections 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 Group, the expenditure is capitalized. Where part of the asset replaced was not separately considered as a component and therefore not depreciated separately, the replacement value is used to estimate the carrying amount of the replaced asset(s) which is immediately written off. Inspection costs associated with major maintenance programs are capitalized and amortized over the period to the next inspection. All other day-to-day repairs and maintenance costs are expensed as incurred.

iv. Disposal/ sale of assets

Net proceeds from any disposal of oil and gas interests are recorded as a gain or loss on disposal recognized in the Statement of Net Income or Loss and Other Comprehensive Income or Loss to the extent that the net proceeds exceed or are less than the appropriate portion of the net capitalized costs of the asset.

E. Recoverability of oil and gas properties

The Group assesses each asset or cash generating unit (CGU) (excluding goodwill, which is assessed annually regardless of indicators) each reporting period to determine whether any indication of impairment exists. Where an indicator of impairment exists, with reference to total proved and risk-adjusted probable reserves, a formal estimate of the recoverable amount is made, which is considered to be the higher of the fair value less costs to dispose and value in use. The assessments require the use of estimates and assumptions such as long-term oil prices (considering current and historical prices, price trends and related factors), discount rates, operating costs, future capital requirements, decommissioning costs, exploration potential, reserves (see Hydrocarbon reserve and resource estimates above) and operating performance (which includes production and sales volumes). These estimates and assumptions are subject to risk and uncertainty. Therefore, there is a possibility that changes in circumstances will impact these projections, which may impact the recoverable amount of assets and/or CGUs.

Fair value is determined as the amount that would be obtained from the sale of the asset in an arm's length transaction between knowledgeable and willing parties. Fair value for oil and gas properties is generally determined as the present value of estimated future cash flows arising from the continued use of the assets, which includes estimates such as the cost of future expansion plans and eventual disposal, using assumptions that an independent market participant may take into account. Cash flows are discounted to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset/CGU.

F. Intangible exploration assets

i. Pre-exploration expenditures:

Costs incurred prior to obtaining the legal rights to explore an area are recognized in the Statement of Net Income or Loss and Other Comprehensive Income or Loss as incurred.

ii. Exploration expenditures:

Exploration expenditures include costs associated with the acquisition of a license interest, directly attributable general and administrative costs, expenditures incurred in the process of determining oil and gas exploration targets, and exploration drilling costs. All exploration expenditures with common geological structures and shared infrastructure are accumulated together within intangible exploration assets. The Company does not aggregate exploration expenditures above the segment level for the purpose of impairment testing. Costs are not depleted until such time as the exploration phases on the license area are complete, the license area is relinquished, or commercially viable reserves have been discovered and extraction of those reserves is determined to be technically feasible.

If commercial reserves are established and technical feasibility for extraction demonstrated, then the related capitalized intangible exploration costs are transferred into a CGU within oil and gas interests subsequent to determining that the assets are not impaired (see "Impairment" below). Where results of exploration drilling indicate the presence of hydrocarbons which are ultimately not considered commercially viable, all related costs are recognized in the Statement of Net Income or Loss and Other Comprehensive Income or Loss.

Net proceeds from any disposal or farmout of an intangible exploration asset are recorded as a reduction in intangible exploration assets.

iii. Development and production costs:

All costs incurred after the technical feasibility and commercial viability of producing hydrocarbons has been demonstrated are capitalized within oil and gas interests on a CGU basis.

G. Impairment:

i. Financial assets carried at amortized cost:

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

The Company recognizes loss allowances for expected credit losses ("ECLs") on its financial assets measured at amortized cost. Due to the nature of its financial assets, the Company measures loss allowances at an amount equal to expected lifetime ECLs.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in the Statement of Net Income or Loss and Other Comprehensive Income or Loss.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in the Statement of Net Income or Loss and Other Comprehensive Income or Loss.

ii. Non-financial assets:

The carrying amounts of the Company's non-financial assets, including the Company's equity investments, other than oil and gas properties, intangible exploration assets, inventories and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment or reversals of impairment.

Intangible exploration assets are assessed for impairment when they are reclassified to property and equipment, as oil and gas properties, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. If any such indication exists, then the asset's recoverable amount is estimated. For goodwill and other intangible assets that have indefinite lives or that are not yet available for use, an impairment test is completed each reporting period.

For the purpose of impairment testing, assets are grouped together into a CGU. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to dispose.

In assessing value in use, the estimated future cash flows are discounted to their present value using a post-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of 2P reserves. In determining fair value less costs to dispose, recent market transactions are taken into account, if available, and a post-tax discount rate is applied. In the absence of such transactions, an appropriate valuation model is used.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in the Statement of Net Income or Loss and Other Comprehensive Income or Loss. Impairment losses recognized in respect of CGU's are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the unit (group of units) on a pro rata basis.

If there is an indicator that a previous impairment may no longer exist or may have decreased, the recoverable amount of the relevant asset or its CGU is calculated and compared against the carrying amount. The impairment is reversed to the extent that the asset or its CGU's recoverable amount does not exceed the carrying amount that would have been determined if no impairment had been recognized. An impairment reversal is recognized in the Statement of Net Income or Loss and Other Comprehensive Income or Loss.

Other non-financial assets are subject to impairment tests whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Where the carrying value of an asset exceeds its recoverable amount (i.e. the higher of value in use and fair value less costs to sell), the asset is written down accordingly.

H. Leases

Leases are accounted for by recognising a right-of-use asset and a lease liability except for:

- Leases of low value assets; and
- Leases with a duration of 12 months or less.

Lease liabilities are measured at the present value of the contractual payments due to the lessor over the lease term, discounted using the interest rate implicit in the lease or if that rate cannot be readily determined the discount rate is determined by reference to the Company's incremental borrowing rate on commencement of the lease. Variable lease payments are only included in the measurement of the lease liability if they depend on an index or rate. In such cases, the initial measurement of the lease liability assumes the variable element will remain unchanged throughout the lease term. Other variable lease payments are expensed in the period to which they relate.

On initial recognition, the carrying value of the lease liability also includes:

- amounts expected to be payable under any residual value guarantee;
- the exercise price of any purchase option granted in favour of the Company if it is reasonably certain to assess that option;
- any penalties payable for terminating the lease, if the term of the lease has been estimated on the basis of termination option being exercised.

Right of use assets are initially measured at the amount of the lease liability, reduced for any lease incentives received, and increased for:

- lease payments made at or before commencement of the lease;
- initial direct costs incurred; and
- the amount of any provision recognized where the Company is contractually required to dismantle, remove or restore the leased asset.

Subsequent to initial measurement lease liabilities increase as a result of interest charged at a constant rate on the balance outstanding and are reduced for lease payments made. Right-of-use assets are amortised on a straight-line basis over the remaining term of the lease or over the remaining economic life of the asset if this is judged to be shorter than the lease term.

When the Company revises its estimate of the term of any lease, it adjusts the carrying amount of the lease liability to reflect the payments to make over the revised term, which are discounted using a revised discount rate. In this case an equivalent adjustment is made to the carrying value of the right-of-use asset, with the revised carrying amount being amortised over the remaining (revised) lease term. If the carrying amount of the right-of-use asset is adjusted to zero, any further reduction is recognised in profit or loss.

I. Investments held for sale

Investments held for sale are measured at the lower of their carrying amount and fair value less costs to sell. Costs to sell are the incremental costs directly attributable to the disposal of an asset. The criteria for held for sale classification is regarded as met only when the sale is highly probable, and the asset or disposal group is available for immediate sale in its present condition. The Company has committed to the plan to dispose of the asset and the disposal is expected to be completed within one year from the date of the classification.

J. Inventories

Inventories mainly comprise materials. These are stated at the lower of cost and net realizable value. Purchase cost includes costs of bringing material inventory to their present location and condition, including freight and handling charges. Cost is determined using the weighted average method. Net realizable value is the estimated selling price in the ordinary course of business, less selling expenses.

If carrying value exceeds the net realizable amount, a write down is recognized. The write-down may be reversed in a subsequent period if the circumstances which caused it no longer exist.

K. Trade receivables

Trade receivables are amounts due from customers for crude oil and gas sold or services performed in the ordinary course of business and represent the Group's right to an amount of consideration that is unconditional (i.e., only the passage of time is required before payment of the consideration is due). Trade receivables are recognized initially at fair value and subsequently measured at amortized cost using the effective interest method, less any allowance for expected credit losses.

L. Cash and cash equivalents

Cash and cash equivalents includes cash on hand and deposits held with financial institutions with maturities of three months or less that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

M. Financial instruments:

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or have been transferred and the Company has transferred substantially all risks and rewards of ownership. Financial assets and liabilities are offset and the net amount is reported in the Balance Sheet when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis or realize the asset and settle the liability simultaneously.

At initial recognition, the Company classifies its financial instruments either as fair value through profit and loss, fair value through other comprehensive income or at amortized cost depending on the purpose for which the instruments were acquired. The Company has instruments recognized at fair value through profit and loss and amortized cost.

Financial assets and liabilities at amortized cost:

Financial assets and liabilities at amortized cost include accounts receivable, loans receivable, accounts payable and debt and are initially recognized at the amount required to be received or paid, less, when material, a discount to reduce the receivables or payables to fair value. Subsequently, these assets and liabilities are measured at amortized cost using the effective interest method. Financial assets and liabilities are classified as current assets and liabilities if payment is due within twelve months. Otherwise, they are presented as non-current assets and liabilities.

Financial assets at fair value through profit or loss (FVTPL):

Financial assets measured at FVTPL are assets which do not qualify as financial assets at amortized cost or at fair value through other comprehensive income.

N. Derivative financial instruments and hedge accounting

The Group is exposed to certain risks relating to its ongoing business operations. The primary risk managed using derivative instruments is commodity price risk. The Group uses forward commodity contracts and derivative financial instruments to hedge its commodity price risk.

On the forward commodity contracts, hedge accounting is not considered applicable as the own-use exception applies: the Group does not enter into physical oil contracts other than to meet the Group's expected sales requirements. These arrangements therefore fall outside the scope of IFRS 9 and are classified as normal sales contracts that are accounted for on an accrual basis.

The Group's derivative financial instruments are initially recognized at fair value on the date on which the derivative contracts are entered into and are subsequently remeasured at fair value, with subsequent changes in fair value recognized in profit and loss. Derivatives are carried as financial assets when the fair value is positive and as financial liabilities when the fair value is negative.

O. Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

i. Provision for site restoration:

On fields where the Group is required to contribute to site restoration costs, a provision is recorded to recognize the future commitment, which is recorded at the discounted value of the future liability. The discount applied to the anticipated site restoration liability is subsequently released over the life of the field and is charged to finance expense. Changes in site restoration costs and reserves are treated prospectively and consistent with the treatment applied upon initial recognition.

The corresponding accounting entry to the creation of the liability is the recognition of an asset, as part of oil and gas interests, to represent the discounted value of the anticipated site restoration liability and depleted over the life of the field on a unit of production basis.

ii. Contingent Consideration:

The amount recognized as contingent consideration is the best estimate of the consideration required to settle the obligation at the reporting date, taking into account the risks and uncertainties surrounding the obligation.

The provision for contingent consideration is partly related to the initial acquisition of 50% interest in Meren Coop. At the date of this acquisition, an estimate of the fair value of the contingent consideration was determined and included as part of the cost of the acquisition. Subsequent to this acquisition, contingent consideration is accounted for as a financial liability in line with IFRS 9. Until completion of the transaction with BTG Oil & Gas to consolidate its interest in Meren Coop, the change in the liability, as a result of the revised cash flows, was adjusted to the cost of the investment and recognized as part of the investment's carrying amount rather than in profit or loss.

The provision for contingent consideration is also partly related to the Amended and Restated Joint Sale Agreement with Petrobras International Braspetro B.V. ("Petrobras") dated October 31, 2018, relating to the acquisition of the remaining 50% in Meren Coop.

The estimates involved in assessing the value of the contingent consideration include the expected timing of payments, the expected settlement value, the likelihood of settlement and the probability of the assessed outcomes occurring. There is significant judgement used in the determination of these estimates.

iii. Performance share units ("PSUs"):

The Company has a long-term incentive plan (see note 21). Eligible plan participants may be granted PSUs. PSUs are accounted for as cash-based awards and recorded as a liability. The estimated fair value of the awards is initially determined at the time of grant. The awards are revalued every quarter based on the Company's share price and the change is recorded as share-based compensation in the Statement of Net Income or Loss and Other Comprehensive Income or Loss. The estimated fair value of the awards is calculated based on non-market performance conditions set by the Company which are initially determined at the time of grant. The Company assesses the progress of reaching the individual performance conditions during each reporting period. PSUs cliff vest three years from the date of grant and the estimated fair value of the grant will be expensed evenly throughout the remaining vesting period. PSUs may be settled in shares issued from treasury or cash, at the discretion of the Board of Directors.

iv. Restricted share units ("RSUs"):

The Company has a long-term incentive plan (see note 21). Eligible plan participants may be granted RSUs. RSUs are accounted for as cash-based awards and recorded as a liability. The estimated fair value of the awards is initially determined at the time of grant. The awards are revalued every quarter based on the Company's share price and the change is recorded as share-based compensation in the Statement of Net Income or Loss and Other Comprehensive Income or Loss. RSUs granted to Non-Executive Directors cliff vest three years from the date of grant. The estimated fair value of RSUs are expensed evenly throughout the remaining vesting period. RSUs may be settled in shares issued from treasury or cash, at the discretion of the Board of Directors.

P. Long term debt:

Long-term debt is initially measured at fair value less transaction costs that are directly attributable to the acquisition or issue of the debt. Subsequently, long-term debt is measured at amortized cost using the effective interest method. Long-term debt is classified as current if the liability is due to be settled within twelve months from the reporting date. All other debt is classified as non-current.

Q. Trade and other payables

Trade payables are obligations to pay for goods and services that have been acquired in the ordinary course of business from suppliers. Trade payables are presented as current liabilities, unless payment is not due within 12 months after the reporting period. They are recognized initially at their fair value and subsequently measured at amortized cost using the effective interest method.

R. Dividends

Dividend liabilities are recognized when the Company's shareholders have the right to receive the payment when the dividend is approved by the Board of Directors of the Company.

S. Sales of crude oil and natural gas

Revenue from contracts with customers is recognized when or as the Group satisfies a performance obligation by transferring a promised good or service to a customer. A good or service is transferred when the customer obtains control of that good or service. As such, revenue is recognized when control of the goods or service transfers to the customer, it is probable that the economic benefits will flow to the Group and the revenue can be reliably measured.

The measurement of revenue, when a performance obligation is satisfied, is based on the amount of the transaction price (excluding estimates of variable consideration that are constrained) that is allocated to that performance obligation, excluding discounts, sales taxes, excise duties and similar levies.

The Group assesses its revenue arrangements against specific criteria in order to determine if it is acting as principal or agent. If the Group acts in the capacity of an agent rather than as the principal in a transaction, then the revenue recognized is the net amount of commission made by the Group. The Group has concluded that it is acting as a principal in all of its revenue arrangements, as described below:

Revenue from the sale of crude oil and natural gas is recognized when control of the goods transfers to the customer. The transfer of control of the crude oil and natural gas sold usually coincides with title passing to the customer and the customer taking physical possession. This generally occurs when the product is physically transferred into a vessel, pipe or other delivery mechanism.

Crude oil transaction prices under forward contracts are based on a contract price for the Dated Brent component plus or minus a differential.

In most of the Group's oil offtake contracts, the Dated Brent component of the forward price at the time of entering the contract is not fixed but determined on or around the date of the lifting for spot cargos either on an average monthly basis, 5-days after bill of lading date or similar pricing mechanism. If the Group wants to utilize the oil offtake contract for commodity risk management, it can either fix the Dated Brent component or utilize a trigger pricing mechanism. For the trigger pricing mechanism, when the forward price curve falls below a certain trigger price for a certain month, this mechanism provides an irrevocable instruction to an offtaker to fix the Dated Brent price component of a cargo. The trigger price is based on a percentage of the Brent forward curve at the time the instruction was given for the month of the expected lifting. If the forward price curve does not fall below that threshold, the respective cargo is sold at spot.

The performance obligation is satisfied and payment is due upon delivery, FOB, to the buyer. At this point in time, at the bill of lading date, a trade receivable is recognized and there are generally 30 days between revenue recognition and payment. There are no obligations for returns, refunds, warranties nor other obligations when control has been transferred. The Group principally satisfies its performance obligations at a point in time.

Revenue from crude oil transactions not covered under oil offtake contracts, arises from the production and lifting of crude oil on an entitlements basis. Under the entitlements method, revenue reflects the Group's share of production under the terms of the relevant production sharing contracts, regardless of which participant has actually made the sale and invoiced the production. This is achieved by applying the following approach in dealing with imbalances between actual sales and entitlements.

- Crude oil entitlement underlifts are recognized at the market price of oil at the balance sheet date. The excess of product sold during the period over the participant's ownership share of production is recognized by the Group (acting as underlifter) as an asset in trade and other receivables with a corresponding credit to cost of sales. The Group's underlift receivable is the right to receive additional oil from future production without the obligation to fund the production of that additional oil.
- Crude oil entitlement overlifts are treated as a purchase of crude oil by the overlifter from the underlifter and are also recognized at the market price of oil at the balance sheet date. The excess of product purchased during the period over the participant's ownership share of production is recognized by the Group (acting as overlifter) as a liability in trade and other payables with a corresponding charge to cost of sales. An overlift liability is the obligation to deliver oil out of the Group's equity share of future production.

Revenues resulting from the production of oil under PSAs is recognized for those amounts relating to the Group's cost recoveries and the Group's share of the remaining production.

T. Royalties

Obligations arising from royalty arrangements and other types of taxes that do not satisfy the criteria of IAS 12 'Income Taxes' are accrued or paid and included in production costs. This is considered to be the case when the royalties are imposed under government authority and the amount payable is based on physical quantities produced or as a percentage of revenue, rather than taxable income. In some cases, the equivalent amount of royalties is also presented in revenues to differentiate between the portion of revenue lifted by the operator on behalf of the Group to settle the Group's royalty liabilities and the associated royalties as part of production costs. In cases where the Group itself pays for the royalties in cash, these are included in production costs as a single line item.

U. Production costs

The costs of producing oil are charged to the income statement in the period in which they are incurred. Production costs include movements in underlift and overlift balances.

V. Employee benefits

Employee benefits are recognized as they accrue in the Statement of Net Income or Loss and Other Comprehensive Income or Loss, based on the terms of employment.

W. Finance income and expenses:

Finance income and expenses are recognized as they accrue in the Statement of Net Income or Loss and Other Comprehensive Income or Loss, using the effective interest method.

X. Income tax:

Income tax expense comprises current and deferred tax. Income tax expense is recognized in the Statement of Net Income or Loss and Other Comprehensive Income or Loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized for:

- temporary differences on the initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit or loss.
- temporary differences related to investments in subsidiaries, associates and joint arrangements to the extent that the Group is able to control the timing of the reversal of the temporary differences and it is probable that they will not reverse in the foreseeable future;
- taxable temporary differences arising on the initial recognition of goodwill.

Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis, or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

On May 23, 2023, the International Accounting Standards Board ("IASB") issued an amendment to IAS 12 Income Taxes in response to International Tax Reform and specifically the Pillar Two Global Anti-Base Erosion Rules ("Pillar Two Rules") published by the Organization for Economic Co-operation and Development ("OECD"). The Amendments introduce a mandatory temporary exception to the accounting for deferred taxes arising from the jurisdictional implementation of the Pillar Two model rules; and disclosure requirements for affected entities to help users of the financial statements better understand an entity's exposure to Pillar Two income taxes arising from that legislation, particularly before its effective date. The Company adopted the mandatory temporary exception immediately. The remaining disclosure requirements have no effect on the Company's consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

Y. Earnings per share:

Basic earnings per share is calculated by dividing net income/(loss) attributable to the common shareholders by the weighted average number of Common Shares outstanding during the year. Diluted earnings per share is determined by adjusting the net income/(loss) attributable to the common shareholders and the weighted average number of Common Shares outstanding for the effects of dilutive instruments such as options and Long Term Incentive Plans ("LTIP") granted to employees. The weighted average number of diluted shares is calculated in accordance with the treasury stock method. The treasury stock method assumes that the proceeds received from the exercise of all potentially dilutive instruments are used to repurchase Common Shares at the average market price. The PSUs are considered to be contingently issuable and are included in the calculation of diluted EPS as if the conditions of the contingency are deemed to have been met based on the information available at the end of the reporting period. PSUs are only included in the diluted EPS calculation if the effect is dilutive. RSUs are included in full in the diluted EPS calculation only if the effect is dilutive.

Z. Foreign currency

Monetary assets and liabilities denominated in foreign currencies are translated into US dollars at exchange rates prevailing at the balance sheet date and non-monetary assets and liabilities are translated at rates in effect on the date of the transaction. Revenues and expenses are translated at exchange rates at the date of transaction. Exchange gains or losses arising from translation are included in the Statement of Net Income or Loss and Other Comprehensive Income or Loss.

AA. New and amended standards adopted by the Company:

The Company has applied the following standards and amendments for the first time for its annual reporting period commencing January 1, 2025:

- IAS 21 - Lack of Exchangeability. The amendments help entities to determine whether a currency is exchangeable into another currency, and which spot exchange rate to use when it is not. There was no material impact to the Company's financial statements.

AB. New standards and interpretations not yet adopted:

Certain new accounting standards and amendments to accounting standards have been published that are not mandatory for December 31, 2025, reporting periods and have not been early adopted by the Company. The Company's assessment of the impact of these new standards and amendments is set out below:

- IFRS 18 Presentation and Disclosure in Financial Statements - on April 9, 2024, the International Accounting Standards Board (IASB) issued IFRS 18 Presentation and Disclosure in Financial Statements, which aims to improve how companies communicate their financial statements, with a focus on information about financial performance in the statement of profit or loss.

  The standard adds new subtotals, categories for income and expenses, and mandates disclosure of management performance measures. It also enhances rules around aggregation and disaggregation. Adoption is retrospective, and the Corporation is currently assessing system changes, preparing draft disclosures, and planning comparative restatements ahead of the January 1, 2027, effective date;

- Amendments to the Classification and Measurement of Financial Instruments – Amendments to IFRS 9 and IFRS 7 (effective for annual periods beginning on or after January 1, 2026);

- Annual improvements to IFRSs: Volume 11 (effective for annual periods beginning on or after January 1, 2026);

- IFRS 19 Subsidiaries without Public Accountability: Disclosures (effective for annual periods beginning on or after January 1, 2027).

Apart from IFRS 18, these amendments are not expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

4. Business combination:

On March 19, 2025, the Company completed the transaction with BTG Oil & Gas to consolidate its interest in Meren Coop. The transaction was originally announced on June 24, 2024. The acquisition increased the Company's ownership in core cash generating assets and brought in a new, strategically aligned cornerstone investor, BTG Pactual. It is also expected to enable enhanced shareholder returns and the creation of a materially stronger growth proposition. The acquisition was completed by way of amalgamation whereby BTG Oil & Gas exchanged its 50 percent interest in Meren Coop, held through its fully owned subsidiary BTG Pactual Holding S.à.r.l., in exchange for 239,828,655 newly issued shares in the Company. The primary assets acquired are an indirect 8% interest in Petroleum Mining License ("PML") 52 as well as Petroleum Prospecting License ("PPL") 2003 and an indirect 16% interest in PMLs 2, 3 and 4 as well as PPL 261. PML 52 and PPL 2003 are operated by affiliates of Chevron and covers part of the producing Agbami field. PMLs 2, 3 and 4 and PPL 261 are operated by affiliates of TotalEnergies and contain the producing Akpo and Egina fields as well as the Preowei and Egina South discoveries.

The acquisition date for accounting purposes corresponds to the completion of the transaction on March 19, 2025. The acquisition is regarded as a business combination and has been accounted for using the acquisition method of accounting in accordance with IFRS 3. A final purchase price allocation ("PPA") has been performed to allocate the consideration to fair value of assets acquired and liabilities assumed. The PPA is performed as of the acquisition date. The closing share price of CAD 2.09 and closing USD/CAD currency exchange rate of 1.4193 on March 19, 2025, were used as a basis for measuring the value of the consideration, as set forth below, and includes the Company's previously held 50% interest in Meren Coop prior to March 19, 2025.

Expressed in millions of United States dollars	
Value of share consideration to BTG Oil & Gas	353.2
Value of previous interest held in Meren Coop	327.8
Total value of consideration	681.0

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

Each identifiable asset and liability is measured at its acquisition date fair value based on guidance in IFRS 13. Trade receivables are recognized at gross contractual amounts due, as they relate to large and credit-worthy customers. Historically, there has been no significant uncollectible trade receivables in Meren Coop.

The following table shows the initial purchase price allocation as included in the Company's Report to Shareholders as per March 31, 2025, as well as the final purchase price allocation. The recognized amounts of assets and liabilities assumed as at the date of acquisition as reflected in the final purchase price allocation include some updates compared to the initial purchase price allocation based on new information regarding income taxes and information received from the operators related to site restoration provision, impacting the purchase price allocation as of the acquisition date and this final purchase price allocation is in line with the preliminary purchase price allocation as included in the Company's Report to Shareholders as per June 30, 2025, and September 30, 2025.

The recognized amounts of assets and liabilities assumed as at the date of acquisition were as follows:

Final purchase price allocation

	Initial purchase price allocation	Final purchase price allocation	Variance
Assets acquired			
Oil and gas properties	1,476.2	1,538.1	61.9
Inventories	95.4	95.4	-
Indemnity asset (note 14)	21.6	21.6	-
Trade and other receivables	233.5	233.5	-
Cash and cash equivalents (1)	380.4	380.4	-
Total assets acquired	2,207.1	2,269.0	61.9
Liabilities assumed			
Non-current financial liabilities	451.5	451.5	-
Non-current provisions	165.4	132.2	(33.2)
Deferred tax liabilities	343.3	374.3	31.0
Current financial liabilities	298.5	298.5	-
Trade and other payables	164.6	164.6	-
Current tax liabilities	48.2	112.3	64.1
Current provisions (note 14)	54.6	54.6	-
Total liabilities assumed	1,526.1	1,588.0	61.9
Net assets and liabilities recognized	681.0	681.0	-
Value of share consideration to BTG Oil & Gas	353.2	353.2	-
Value of previously held interest in Meren Coop (note 7)	327.8	327.8	-
Total value of consideration	681.0	681.0	-

(1) Cash and cash equivalents includes $59.1 million of cash held in the amalgamated company.

In the period from the acquisition date to December 31, 2025, the revenue and loss included in the Consolidated Statement of Net Income or Loss and Other Comprehensive Income or Loss relating to the acquired entities was $562.1 million and $53.7 million respectively. Acquisition-related costs for the year ended December 31, 2024, and the year ended December 31, 2025, were included in general and administrative expenses and amounted to $6.9 million and $9.0 million, respectively.

If the acquisition had taken place on January 1, 2025, the estimated revenue and loss of the combined Group for the year ended December 31, 2025, would have been approximately $885.6 million and $82.7 million respectively. In determining these amounts, management assumed that no material fair value adjustments would have been required if the acquisition had occurred on January 1, 2025. These figures may not be indicative of the results that would have been achieved if the acquisition had actually taken place on January 1, 2025.

5. Oil and gas properties:

	Nigeria
Costs	
At January 1, 2025	-
Acquired under amalgamation	1,538.1
Remeasurement of site restoration provisions	119.4
Additions	69.2
At December 31, 2025	1,726.7
Depletion and impairments	
At January 1, 2025	-
Depletion	(207.9)
Impairment charges	(105.3)
At December 31, 2025	(313.2)
Oil and gas properties as at December 31, 2025	1,413.5

As at December 31, 2025, oil and gas properties amounted to $1,413.5 million and related to the licenses PML 52 (covering part of the Agbami field), PML 2 (Akpo field), PML 3 (Egina field) and PML 4 (Preowei Field) in Nigeria. Future development costs of $511.8 million were included in determination of the depletion expense for the year ended December 31, 2025.

The Company recognized a change in estimate of $119.4 million in oil and gas properties which related for $122.9 million to the remeasurement of the site restoration provisions acquired under the amalgamation in accordance with IAS 37 and for $3.5 million negative to the periodic re-assessment of variables such as projected decommissioning cost per well, discount rates and economic lives of the fields (see note 14).

The Company carries out impairment tests of individual cash-generating units when impairment triggers are identified.

As at December 31, 2025, the Company determined that there was an indicator of impairment in respect of its oil and gas properties related to the Agbami field CGU, reflecting a more conservative oil price and cost outlook compared to prior assumptions. This assessment was driven by recent oil price volatility and updated cost forecasts. A significant portion of the revised cost outlook relates to planned long-term life-extension activities required to enable the Agbami FPSO to continue operating reliably and safely through the end of the current license period. The impairment does not reflect any adverse change in reservoir performance, reserves classification or the operational integrity of the Agbami field.

The Company calculated the recoverable amount of the CGU using a fair value less costs to dispose discounted cash flow model. The recoverable amount was determined using discounted future after tax net cash flows of proved and probable oil and gas reserves using forecast prices and costs prepared by management's expert at December 31, 2025.

It was determined that the carrying value exceeded the recoverable value of $298.0 million and non-cash impairment charges of $105.3 million were recognized on the Group's oil and gas properties related to the CGU.

The applied discount rate has been determined to be in line with the discount rate applied on March 19, 2025, when the Company acquired its additional interest in Meren Coop.

Future commodity prices is a key assumption and has significant impact on the net present value. Forecasted oil and gas prices are based on management's estimates and available market data. Information about market prices in the near future can be derived from the futures contract market. The information about future prices is less reliable on a long-term basis, as there are fewer observable market transactions going forward. In assessing value in use, oil prices for the period up to 2036 are based on Brent prices as forecasted by Independent Qualified Reserve Engineers (IQRE) Analysis, ranging from $63/bbl to $86/bbl, and on management's long-term price assumptions thereafter (2% inflation from 2036 onwards).

Operating and capital costs are calculated based on various technical assumptions, such as expected production profiles and the best estimate of the related cost. The long-term inflation rate is assumed to be 2%.

A change in the future operating and capital costs by 5% would impact the impairment recognized by approximately $20.0 million.

A change in the future oil price by 5% would impact the impairment recognized by approximately $22.0 million.

A change in the discount rate by 1% would impact the impairment recognized by approximately $12.0 million.

Actual outcomes may differ from these illustrative impairment sensitivities, as changes in individual assumptions are typically accompanied by management actions and adjustments to development and operating plans.

Changes in input factors, either positive or negative would likely significantly change the actual impairment amount compared to the illustrative sensitivities above.

Material contractual commitments

In accordance with the terms of the production sharing contracts entered into by the Group along with other partners in respect of its oil fields and blocks, the Group has certain minimum exploration and development commitments with estimated capital expenditures in oil and gas properties of $0.3 billion as at December 31, 2025, $0.2 billion as at December 31, 2026, $0.1 billion as at December 31, 2027, and $0.1 billion as at December 31, 2028.

6. Intangible exploration assets:

	Intangible exploration assets		
	Equatorial Guinea	South Africa	Total
At January 1, 2024	13.4	5.7	19.1
Additions	4.5	5.7	10.2
At December 31, 2024	17.9	11.4	29.3
Additions	6.6	7.8	14.4
At December 31, 2025	24.5	19.2	43.7

As at December 31, 2025, the carrying amount of the Company's intangible exploration assets in Equatorial Guinea was $24.5 million and related to its 80% interest in Blocks EG-18 and EG-31 (as at December 31, 2024 – $17.9 million).

As at December 31, 2025, the carrying amount of the Company's intangible exploration assets in South Africa was $19.2 million for its 18.0% (as at December 31, 2024 – 17.0%) participating interest in the Block 3B/4B Exploration Right (as at December 31, 2024 - $11.4 million).

On July 26, 2024, the Company signed an agreement with Eco to acquire an additional 1.0% interest in Block 3B/4B from Azinam Limited, Eco (Atlantic) Oil and Gas Ltd.'s ("Eco") wholly owned subsidiary, in exchange for all common shares and warrants over common shares held by the Company in Eco. On January 13, 2025, the Company announced that it had completed this transaction. The Company's interest in Block 3B/4B increased by 1.0% to 18.0% and the Company ceased to be a shareholder in Eco. The fair value of the Company's investment in Eco on the day of the transaction was $8.0 million, which has been recorded as an addition to intangible exploration assets.

As at December 31, 2025, no intangible exploration assets have been transferred to oil and gas properties as commercial reserves have not been established and technical feasibility for extraction has not been demonstrated.

7. Equity investment in joint venture:

Meren Coöperatief U.A (previously known as Prime Oil and Gas Coöperatief U.A.) ("Meren Coop"):

On March 19, 2025, the Company announced the completion of the amalgamation with BTG Oil & Gas ("the amalgamation) to consolidate the remaining 50% interest in Meren Coop in exchange for 239,828,655 common shares issued in Meren. Following completion of the amalgamation, Meren Coop is fully consolidated by the Company as from March 19, 2025 (see note 4).

The following table shows the Company's carrying value of the non-controlling 50% interest in Meren Coop as at December 31, 2025, and December 31, 2024. The carrying value as per March 19, 2025, of $327.8 million has been assigned to the fair value of assets acquired and liabilities assumed as per note 4.

	December 31, 2025	December 31, 2024
Balance, beginning of the period	328.4	572.5
Share of joint venture profit	2.9	226.0
Distributions received from Meren Coop	(60.0)	(36.0)
Revaluation of contingent consideration	0.6	2.6
Reversal of impairment / (Impairment)	55.9	(436.7)
Impact of amalgamation	(327.8)	-
Balance, end of the period	-	328.4

In the period up to and including March 19, 2025, the Company recognized an income of $2.9 million, relating to its investment in Meren Coop (year ended December 31, 2024 - $226.0 million).

In the period up to and including March 19, 2025, Meren Coop made one distribution of $120.0 million gross, with a net payment to the Company of $60.0 million. In the year ended December 31, 2024, Meren Coop made one distribution of $72.0 million gross, with a net payment to the Company of $36.0 million.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

As at December 31, 2024, management determined there was an objective evidence of impairment in relation to the Company's shareholding in Meren Coop as a result of the significant decrease in the Meren share price between June 24, 2024, when the Company announced the Proposed Reorganization and December 31, 2024. The fair value of the 50% shareholding in Meren Coop decreased as the fair value considers the number of Meren shares that were agreed in relation to the purchase of the additional interest in Meren Coop and the trading value of Meren shares, as this is an observable fair value input under IFRS Accounting Standards. As at December 31, 2024, the fair value of the Company's existing shareholding in Meren Coop was calculated to be $328.4 million based on the implied value of the Proposed Reorganization, resulting in a non-cash impairment loss on the investment in Meren Coop of $436.7 million for the year ended December 31, 2024. As at March 19, 2025, management determined there was an objective evidence of impairment reversal based on the Meren share price when the Company announced the completion of the amalgamation. The fair value of the 50% shareholding in Meren Coop was calculated to be $327.8 million, resulting in a non-cash impairment reversal on the investment in Meren Coop of $55.9 million for the three months ended March 31, 2025.

The following tables summarizes Meren Coop's financial information for the period up to and including March 19, 2025, and the year ended December 31, 2024. Following completion of the amalgamation on March 19, 2025, Meren Coop is fully consolidated by the Company.

Meren Coop's Statement of Net Income and Comprehensive Income

	Period ended March 19, 2025	Year ended December 31, 2024 (1)
Revenue	323.5	782.7
Cost of Sales		
Production costs (2)	(187.4)	(48.3)
Depletion costs	(71.3)	(372.0)
	(258.7)	(420.3)
Gross profit	64.8	362.4
Other operating income (3)	-	329.7
General and administrative expenses	(6.2)	(28.2)
Operating profit	58.6	663.9
Finance income	2.4	6.4
Finance expense (4)	(21.3)	(97.8)
Net financial items	(18.9)	(91.4)
Profit before tax	39.7	572.5
Income tax (5)	(34.0)	(120.5)
Net income and comprehensive income for the period	5.7	452.0
Proportionate share of Meren Coop's profit and comprehensive income for the period	2.9	226.0
Proportionate share of Meren Coop's net income	2.9	226.0

(1) Certain comparative figures have been reclassified to conform with the presentation of the Company's Consolidated Statement of Net Income or Loss and Other Comprehensive Income or Loss following completion of the amalgamation.

(2) As at March 19, 2025, Meren Coop was in a lower net underlift position compared to December 31, 2024. This resulted in a loss of $133.1 million in the Statement of Net Income and Comprehensive Income for the period ended March 19, 2025 (year ended December 31, 2024 – profit of $171.2 million) included in production costs.

(3) Other operating income in the year ended December 31, 2024, relates to the release of the previously recognized $305.3 million provision for the security deposit received from Equinor during 2021 and the recognition of an additional $24.4 million receivable pursuant to the Securitization Agreement.

(4) Finance expense is primarily made up of interest expenses incurred on external facilities and accretion expenses incurred on the decommissioning liability. Finance costs for the period ended March 19, 2025, also included a $3.7 million accounting loss on a purchased Asian put option and a zero-premium Asian Dated Brent Collar (year ended December 31, 2024 – $7.1 million accounting loss on a purchased Asian Dated put options).

(5) In the period ended March 19, 2025, there is a tax charge of $34.0 million (year ended December 31, 2024 - $120.5 million). The tax charge is primarily made up of Corporate Income tax and Education tax, withholding tax on dividends of ten percent and deferred income tax. Other operating income of $329.7 million in the year ended December 31, 2024, was subject to ten percent Capital Gains Tax in Nigeria lowering the effective tax rate for the year.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

Supplementary information: Meren Coop's Statement of Cash Flows

	Period ended March 19, 2025	Year ended December 31, 2024 [1]
Cash flows generated by/ (used in)		
Profit before tax	39.7	572.5
Adjustments for:		
Depletion costs	71.3	372.0
Net financial items	18.9	91.4
Taxes	(47.7)	(201.4)
Change in provision for security deposit received	-	(305.3)
Other	(1.0)	1.3
Cash generated from operating activities before working capital	81.2	530.5
Changes in working capital	(8.2)	11.6
Net cash generated from operating activities	73.0	542.1
Expenditures on oil and gas properties	(22.6)	(152.5)
Interest income received	2.2	5.1
Net cash used in investing activities	(20.4)	(147.4)
Distributions paid to shareholders	(120.0)	(72.0)
Interest expense paid	(10.8)	(71.9)
Derivatives	-	(3.2)
Net cash used in financing activities	(130.8)	(147.1)
Foreign exchange variation on cash and cash equivalents	-	(0.3)
Total cash flow	(78.2)	247.3
Cash and cash equivalents, beginning of the period	399.5	152.2
Cash and cash equivalents, end of the period	321.3	399.5

(1) Certain comparative figures have been reclassified to conform with the presentation of the Company's Consolidated Statement of Cash Flows following completion of the amalgamation.

8. Equity investments in associates:

The Company holds the following equity investments in associates:

	Africa Energy Corp.	Eco (Atlantic) Oil and Gas Ltd	Impact Oil and Gas Ltd	Total
Shares held at December 31, 2025	55,396,483	-	449,464,396	
Ownership at December 31, 2025	11.6%	-	39.5%	
At January 1, 2024	24.8	7.6	102.3	134.7
Share of loss from equity investments	(42.1)	(0.6)	(16.1)	(58.8)
Reversal of impairment of equity investments	20.1	-	-	20.1
Additional investments	-	-	88.6	88.6
Reclassification to Investment held for sale	-	(7.0)	-	(7.0)
At December 31, 2024	2.8	-	174.8	177.6
Share of loss from equity investments	(0.4)	-	(2.5)	(2.9)
Loss on dilution of equity investments	(0.9)	-	-	(0.9)
Distribution received	-	-	(31.6)	(31.6)
At December 31, 2025	1.5	-	140.7	142.2

In the year ended December 31, 2025, the Company recognized a loss of $3.8 million (year ended December 31, 2024 – loss of $38.7 million). The Company also recognized a gain of $0.9 million in the year ended December 31, 2025, on the shares in Eco (Atlantic) Oil and Gas Ltd classified as Investment held for sale, resulting in a total loss from investments in associates of $2.9 million in the year ended December 31, 2025.

As at December 31, 2025, the Company determined that there were no indicators of impairment for its investments in Africa Energy Corp. or Impact Oil and Gas Ltd.

A. Africa Energy Corp. ("Africa Energy"):

Africa Energy is an oil and gas exploration company with an interest in South Africa.

As at December 31, 2025, the market value of the Company's investment in Africa Energy was $4.5 million based on the share price of CAD 0.11 (as at December 31, 2024 - $5.8 million). The carrying value is less than the market value from significant impairments recognized by Africa Energy.

On March 31, 2025, Africa Energy announced the closing of a private placement of common shares, including the issue of common shares for debt. Meren did not participate in this private placement and as a result its shareholding in Africa Energy has been reduced from 19.7% as at December 31, 2024, to 11.6% as at December 31, 2025.

B. Eco (Atlantic) Oil and Gas Ltd. ("Eco"):

On July 26, 2024, the Company signed an agreement with Eco to acquire an additional 1.0% interest in Block 3B/4B from Azinam Limited, Eco's wholly owned subsidiary, in exchange for all common shares and warrants over common shares held by the Company in Eco. Following the announcement of this transaction, the investment in Eco was reclassified to an investment held for sale (see note 10). On January 13, 2025, the Company announced the completion of this transaction.

C. Impact Oil and Gas Ltd ("Impact"):

Impact is an oil and gas exploration company with interests in Namibia and South Africa.

On January 10, 2024, the Company announced a strategic farmout agreement between its investee company Impact, and TotalEnergies, that allows the Company to continue its participation in the Venus oil development project and the follow-on exploration and appraisal campaign on Blocks 2913B and 2912 with no upfront costs. At the date hereof, Impact has a 9.5% interest in Blocks 2912 and 2913B that is fully carried for all joint venture costs, with no cap, through to first commercial production. This agreement provides Impact with a full interest-free carry loan over all of Impact's remaining development, appraisal and exploration costs on the Blocks from January 1, 2024 ("Effective Date"), until the date on which Impact receives the first sales proceeds from oil production on the Blocks ("First Oil Date"). On and from the First Oil Date, the carry is repayable to TotalEnergies in kind from 60% of Impact's after-tax cash flow, net of all joint venture costs, including capital expenditures. During the repayment of the carry, Impact will pool its entitlement barrels with those of TotalEnergies for more regular off-takes and a more stable cashflow profile and will also benefit from TotalEnergies' marketing and sales capabilities.

On January 29, 2025, Impact distributed $31.6 million net to the Company's shareholding.

The following tables summarize Impact's financial information, based on a best estimate basis, for the year ended December 31, 2025, and December 31, 2024. The Company is not aware of any material changes to the financial information.

Balance Sheet

As at	December 31, 2025	December 31, 2024
Cash and cash equivalents included in current assets	40.7	125.1
Other current assets	0.4	1.7
Non-current assets (1)	317.1	316.5
Current liabilities	(1.4)	(0.8)
Non-current liabilities	(0.6)	-
Net assets of Impact	356.2	442.5
Percentage ownership	39.5	39.5
Proportionate share of Impact's net assets	140.7	174.8

Statement of Net Loss and Comprehensive Loss from continuing operations

For the years ended	December 31, 2025	December 31, 2024
Net loss and comprehensive loss from continuing operations	(6.3)	(40.8)
Proportionate share of Impact's loss	(2.5)	(16.1)

(1) As at December 31, 2025, the carrying value of non-current assets included a fair value adjustment of $190.0 million (as at December 31, 2024 - $96.4 million).

9. Inventories:

Inventories relate to well supplies and operational spare parts to be used in the oil production process in Nigeria.

10. Investment held for sale:

On July 26, 2024, the Company signed an agreement with Eco to acquire an additional 1.0% interest in Block 3B/4B from Azinam Limited, Eco's wholly owned subsidiary, in exchange for all common shares and warrants over common shares held by the Company in Eco. Following the announcement of this transaction, the investment in Eco was reclassified to an investment held for sale. On January 13, 2025, the Company announced the completion of this transaction with the result that the Company is no longer a shareholder in Eco.

11. Trade and other receivables:

	December 31, 2025	December 31, 2024
Trade receivables	5.6	-
Underlift position	12.2	-
Short-term receivables with partners	32.7	-
Prepaid expenses and accrued income	2.5	2.4
Other receivables	24.7	1.6
Total accounts receivable and prepaid expenses	77.7	4.0

The excess of product sold during the period over the participant's ownership share of production is recognized by the Group as an underlift asset with a corresponding credit to production costs. An underlift receivable is the right to receive oil out of the Group's equity share of future production.

The short-term receivables with partners mainly relate to the Group's share in the receivables of its joint operations in Nigeria.

Other receivables include an indemnity asset of $21.6 million recognized under the deed of indemnity entered into between the Company and BTG Oil & Gas (see note 14).

As at December 31, 2025, and December 31, 2024, all receivables are due within one year and no provision for expected credit losses has been recognised.

12. Cash and cash equivalents:

Cash and cash equivalents include short-term deposits made for varying periods of between one day and three months, depending on the immediate cash requirements of the Group, and earn interest at varying rates.

13. Share capital:

A. The Company is authorized to issue an unlimited number of common shares with no par value.

B. Issued:

	December 31, 2025		December 31, 2024	
	Shares	Amount	Shares	Amount
Balance, beginning of the period	439,078,170	1,195.8	463,831,871	1,265.3
Share issuance to BTG Oil & Gas under amalgamation Agreement	239,828,655	353.2	-	-
Exercise of Share Options	367,600	0.4	647,000	0.5
Settlement of Restricted Share Units	836,323	1.1	271,063	0.5
Settlement of Performance Share Units	1,974,498	2.5	577,968	1.1
Cancellation of shares repurchased	(6,176,053)	(16.8)	(26,249,732)	(71.6)
Balance, end of the period	675,909,193	1,536.2	439,078,170	1,195.8

The Company launched a share buyback program on December 6, 2024, that ended on December 5, 2025, under which 2.5 million Meren common shares were repurchased during the year ended December 31, 2024, of which 2.2 million Meren common shares were cancelled during the year ended December 31, 2024. In the three months ended March 31, 2025, a total of 5.9 million Meren common shares were repurchased and 6.2 million Meren common shares were cancelled during the three months ended March 31, 2025. Following March 31, 2025, no further shares were purchased in the period to December 31, 2025. The Company launched a new share buyback program on December 8, 2025, under which no Meren common shares have been repurchased during 2025.

The balance of share capital has been reduced by determining the average per-share amounts in the share capital account, before cancellation of shares repurchased, and applying this to the numbers of shares cancelled. The difference between the reduction in share capital and the amount paid for shares repurchased has been added to the balance of contributed surplus.

In the year ended December 31, 2025, the Board of Directors approved and paid four dividends of $0.0371 per share for a total amount of $100.2 million.

14. Provisions:

	Site restoration	Contingent consideration	Share-based compensation	Others	Total
At January 1, 2024	5.5	37.8	14.1	-	57.4
Charges	-	-	1.5	-	1.5
Unwinding of discount	0.2	2.6	-	-	2.8
Settlements	-	-	(8.3)	-	(8.3)
At December 31, 2024	5.7	40.4	7.3	-	53.4
Acquired under amalgamation	129.4	54.6	-	2.8	186.8
Changes in estimates	119.4	-	-	-	119.4
Charges	-	-	6.3	1.4	7.7
Unwinding of discount	9.2	2.9	-	-	12.1
Settlements	-	-	(8.3)	-	(8.3)
At December 31, 2025	263.7	97.9	5.3	4.2	371.1
Non-current	5.7	40.4	3.1	-	49.2
Current	-	-	4.2	-	4.2
At December 31, 2024	5.7	40.4	7.3	-	53.4
Non-current	263.7	-	3.4	4.2	271.3
Current	-	97.9	1.9	-	99.8
At December 31, 2025	263.7	97.9	5.3	4.2	371.1

A. Site restoration

The provision for site restoration amounted to $263.7 million as per December 31, 2025 (as at December 31, 2024 - $5.7 million). The fair value of the provision for site restoration mainly relates to Nigeria and was based on the estimated future cash flows to decommission the oil and gas properties at the end of their useful life. The discount rate used to determine the net present value of the decommissioning obligation was 4.8% (as at December 31, 2024 – 3.5%) based on a risk-free rate with a similar maturity to that of the timing of the expected cash flows and a long-term inflation rate of 2.3% (as at December 31, 2024 – 2%).

The site restoration provisions acquired under the amalgamation represents the present value of decommissioning costs relating to the acquired oil and gas properties, which are expected to be incurred up to the economic cut-off dates of the Agbami, Akpo and Egina fields. These provisions have been calculated based on the cash flow estimates as provided by the operators of the fields. The fair value of the site restoration provisions acquired on amalgamation totalling $129.4 million have been calculated using a credit-adjusted discount rate in accordance with IFRS 3, which has subsequently been re-measured using a risk-free rate in accordance with IAS 37 resulting in a change in estimate of $122.9 million.

The undiscounted costs at December 31, 2025, are estimated to be approximately $0.6 billion, net to the Company, and include the costs of physical well abandonment and site remediation. The costs are expected to be incurred up to the economic cut-off dates of the Agbami, Akpo and Egina fields, ranging from 2043 to 2044, which is when the producing oil and gas properties are expected to cease operations. In the year ended December 31, 2025, the Group revised its provision for decommissioning liabilities downwards by $3.5 million resulting from periodic re-assessment of projected decommissioning cost per well, discount rates and economic lives of the fields.

An increase in the inflation rate by 1% would increase the site restoration provision recognized by approximately $53.1 million.

A decrease in the discount rate of 1% would increase the site restoration provision recognized by approximately $49.3 million.

B. Contingent consideration

Under the Meren Coop Sale and Purchase Agreement completed on January 14, 2020, a deferred payment of $118.0 million, subject to adjustment, may be due to the seller contingent upon the timing of the final PML 52 tract participation in the Agbami field. The signing of the Securitization Agreement by Meren Coop in 2021 led to the Company reassessing its view of the likelihood of making a contingent consideration payment to the seller. The signing of the Securitization Agreement by Meren Coop does not constitute a redetermination of the tract participation and therefore does not trigger the payment of a contingent consideration under the Sale and Purchase Agreement but, at the Company's discretion, could trigger discussions with the seller. The outcome of this process is uncertain. In 2021, the Company recorded $32.0 million as contingent consideration and increased this to $40.4 million as at December 31, 2024, and to $43.4 million in the year ended December 31, 2025. The deferred payment is expected to be due in the three months ended March 31, 2026, and has therefore been presented as a short term provision as per December 31, 2025.

On June 25, 2021, Meren Nigeria 52 Limited (previously named Prime 127 Nigeria Limited) ("Meren 52"), a subsidiary of Meren Coop, signed a securitization agreement with two of the unit parties, Equinor and Chevron (the "Securitization Agreement"), whereby Equinor agreed to pay a security deposit to the two other JV parties to secure future payments due under that Securitization Agreement, pending a comprehensive resolution being reached among all unit parties in respect of the tract participation in the Agbami field by December 27, 2024. In accordance with the Securitization Agreement, on June 29, 2021, Meren 52 received from Equinor its portion of the security deposit in the form of a cash payment of $305.3 million. Meren 52 received an additional payment of $24.4 million on January 31, 2025, pursuant to the Securitization Agreement. Given no comprehensive resolution was reached by December 27, 2024, Meren 52 has recognized its portion of the security deposit and the additional receivable under the Securitization Agreement as other operating income on December 27, 2024. The process of implementing a new tract participation by the parties is ongoing and is subject to government approval. The parties will continue discussions to seek final resolution of the formal redetermination of the Agbami tract participation in respect of the period after December 27, 2024, however there is no certainty that such ongoing discussions will result in a final resolution.

Under the amended joint sale agreement between (among others) BTG Holding and the seller dated October 31, 2018, the seller could potentially claim that, given an additional payment has been received under the securitization agreement, this triggers a payment obligation of $54.6 million, exclusive of interest, capital taxes and certain deductions, contingent upon various criteria, with the outcome of this potential claim uncertain. Management considers the likelihood of any interest being payable to be unlikely. The Company has recorded an indemnity asset of $21.6 million under the deed of indemnity entered into between a subsidiary of the Company and BTG Oil & Gas on February 19, 2025, for any costs suffered or incurred above $33.0 million post completion of the amalgamation, with the deed of indemnity backed by a $22.0 million letter of credit granted in favour a subsidiary of the Company. The letter of credit will remain in place for an initial period of two years and if a claim is not resolved in two years or is made after the two year period BTG Oil & Gas has undertaken to extend or reinstate the letter of credit.

15. Financial liabilities:

	Reserves Based Lending Facility	Lease Liability	Total
At January 1, 2024	-	-	-
Initial recognition of IFRS 16 lease liability	-	3.7	3.7
Repayments	-	(0.4)	(0.4)
At December 31, 2024	-	3.3	3.3
Acquired under amalgamation	750.0	-	750.0
Initial recognition of IFRS 16 lease liability	-	1.1	1.1
Repayments	(420.0)	(0.6)	(420.6)
At December 31, 2025	330.0	3.8	333.8
Non-current	-	2.6	2.6
Current	-	0.7	0.7
At December 31, 2024	-	3.3	3.3
Non-current	262.3	2.9	265.2
Current	67.7	0.9	68.6
At December 31, 2025	330.0	3.8	333.8

A. Reserves Based Lending Facility

On amalgamation the Company acquired a Reserves Based Lending Facility ("RBL") of $800.0 million of which $750.0 million was drawn. On October 28, 2025, the Company voluntarily cancelled $100.0 million of its RBL commitments resulting in a remaining total commitment of $700.0 million. The total amount that can be drawn under the RBL is limited to the Borrowing Base Amount ("BBA"), which is subject to redeterminations on March 31 and September 30 of each year, limited by aggregate commitments. As of December 31, 2025, the BBA was $468.4 million, which will amortize as the RBL moves towards final maturity. The RBL matures on June 20, 2029, but amortizes each quarter as per the lower of commitments and the BBA.

The principal bore interest at Term SOFR + 4.00% until June 2025 and bears interest of Term SOFR + 4.25% until June 2027, then Term SOFR + 4.50% until final maturity on June 20, 2029. In addition, commitment fees of 40% of the margin are payable on the undrawn but available portion of the RBL, and commitment fees of 20% of the margin are payable on the unavailable portion of the RBL.

The RBL perimeter remains at the Meren Coop level - Meren Coop is the borrower, and Meren 52 Nigeria Limited and Meren 234 Nigeria Limited (previously named Prime 130 Nigeria Limited) ("Meren 234") are the guarantors. The main security package is comprised of security over the shares, production assets, contracts and rights of the Nigerian entities - Meren 52 and Meren 234. In addition, RBL lenders have security over cash and cash equivalents held in project accounts, receivables against cargos sold and all relevant insurance policies of the three entities.

All financial and liquidity covenants covered by the RBL are restricted to these three entities. The Meren Coop entities shall ensure that total net debt to adjusted EBITDAX on each quarter is no greater than 3.0:1, that the historic debt service cover ratio for the preceding year is greater than 1.20:1, and that on each quarter of each year during each of the four successive quarters there are or will be sufficient funds available to the group to meet all relevant expenditure to be incurred in each of these four successive quarters as they fall due. The Company has been in compliance with the covenants in the year ended December 31, 2025.

In the event that the BBA reduces to an amount below the outstanding RBL balance, the Company would be required to repay the difference immediately.

B. Corporate Facility

On May 22, 2025, the Company cancelled its $65.0 million Corporate Facility.

16. Trade and other payables:

	December 31, 2025	December 31, 2024
Short-term payables with partners	97.9	-
Crude oil overlift payable	26.1	-
Accruals	24.0	7.7
Other payables	2.8	2.0
Total trade and other payables	150.8	9.7

The short-term payables with partners mainly relate to the Group's share in the payables of its joint operations in Nigeria.

The Group's excess of crude oil purchased during the year over its entitlement share of production, is recognized as a crude oil overlift payable balance with a corresponding charge to cost of sales. An overlift liability is the obligation to deliver oil out of the Group's equity share of future production.

All trade and other payables are due within one year.

17. Commitments and contingencies:

A. Contingent consideration:

For information on the contingent consideration in relation to the historical acquisition of Meren Coop, refer to Note 14B.

B. Withdrawal from Kenya:

On May 23, 2023, the Kenya entities along with TotalEnergies submitted withdrawal notices to the remaining joint venture party on Blocks 10BB, 13T and 10BA in Kenya, to unconditionally and irrevocably, withdraw from the entirety of the JOAs and PSCs for these concessions. The Company concurrently submitted notices to Ministry of Energy and Petroleum, requesting the government's consent to transfer all of its rights and future obligations under the PSCs to its remaining joint venture party. Government consent to the transfer was received on September 18, 2025, and the Company subsequently transferred all of its rights and future obligation of Blocks 10BB, 13T and 10BA to its remaining joint venture party with effect on and from June 30, 2023. In accordance with the JOA and PSC the Company retains economic participation for activities prior to June 30, 2023, which might result in additional costs for the Company. The Company continues to monitor the claim made against the operator by local communities in relation to past operations which may relate to the period prior to June 30, 2023. No provision has been recognized for this as at December 31, 2025.

C. Securities and guarantees

Under the conditions of the RBL facility, the main security package is comprised of security over the shares, production assets, contracts and rights of the Nigerian entities Meren 52 and Meren 234, cash and cash equivalents in the amount of $152.9 million as per December 31, 2025, that are held within the project accounts in Nigeria and The Netherlands, proceeds from the oil cargos sold and proceeds from the intercompany receivables between the Company and the Nigerian entities. Further, any and all claims relating to, and all returns of premium in respect of, all relevant insurance policies have been secured.

D. Commitments from forward sales

The Group uses a mix of financial derivatives and physical forward sales contracts to manage its commodity price risk and ensure stability in cash flows. Its strategy is to hedge between 70-100% of its post-tax net entitlement production for the next 12-months. As at December 31, 2025, two cargos of the Group's expected lifted entitlement production for 2026 are covered by forward contracts. The average cargo lifted is for 1 million barrels of oil. The Group's triggers for these two cargos covered by forward contracts have been triggered at an average of $62.1 per barrel.

18. Segment information:

The Group operates within several geographical areas. All revenue and therefore gross profit as reported by the Company is currently derived from operations in Nigeria.

For segment information about oil and gas properties and intangible exploration assets, see note 5 and 6.

19. Net Revenue:

Revenue for the years ended December 31, 2025, and December 31, 2024, is comprised of the following:

For the years ended	December 31, 2025	December 31, 2024
Oil revenue	545.5	-
Gas revenue	14.4	-
Total net revenue	559.9	-

In the year ended December 31, 2025, total revenue amounted to $559.9 million (year ended December 31, 2025 - nil), of which $545.5 million related to the Group's sales of crude oil to customers. Under the conditions of the Offtake Agreement, an aggregate of at least 90% of the Group's cargos is required to be delivered to one of the lenders.

In the year ended December 31, 2025, the Group was allocated 8 oil liftings, with a total sales volume of 8 million barrels at an average realized oil price of USD $68.2/bbl.

Prior to March 19, 2025, the Company equity accounted for its investment in Meren Coop and therefore no revenue has been reported before this date. See note 7 for further details.

20. Production costs:

Production costs for the years ended December 31, 2025, and December 31, 2024, is comprised of the following:

For the years ended	December 31, 2025	December 31, 2024
Cost of operations	114.3	-
Royalties	29.4	-
Others	22.9	-
Total production costs	166.6	-

Cost of operations mainly relate to lifting costs from personnel, material and services from third parties.

21. Share based compensation:

In the year ended December 31, 2025, the Company recognized a total of $6.3 million in share-based compensation expense relating to the Long-Term Incentive Plan ("LTIP") and Stock Option Plan (year ended December 31, 2024 – $1.5 million).

A. Share purchase options:

At the 2016 Annual General and Special Meeting the Company's shareholders approved the terms of the stock option plan (the "Stock Option Plan"). The Stock Option Plan provided that the aggregate number of Common Shares which could be reserved for issuance as incentive share purchase options could not exceed 3.5% of the Common Shares outstanding, and option exercise prices would reflect current trading values of the Company's shares. The term of any option granted under the Stock Option Plan was fixed by the Board of Directors and could not exceed five years from the date of grant. The Company ceased awarding share purchase options under the Stock Option Plan in 2021 and did not issue any share purchase options between 2022 and 2025. Instead, the Company now awards PSUs to executives and staff under the Company's LTIP. Refer to note 21B for further information on the Company's PSUs.

The Company's outstanding share purchase options are as follows:

	December 31, 2025		December 31, 2024	
	Number of options	Weighted average exercise price (CAD$)	Number of options	Weighted average exercise price (CAD$)
Outstanding, beginning of the year	457,616	1.23	1,104,616	1.20
Forfeited	-	-	-	-
Exercised	(435,000)	1.21	(647,000)	1.17
Balance, end of the year	22,616	1.61	457,616	1.23

The following table summarizes information regarding the Company's share purchase options outstanding and exercisable at December 31, 2025:

Weighted Average Exercise price (CAD$/share)	Number outstanding	Number exercisable	Weighted average remaining contractual life in years
1.61	22,616	22,616	0.63

In the year ended December 31, 2025, the Company did not recognize a share based payment expense (year ended December 31, 2024 - nil), related to share purchase options.

B. Performance share units ("PSUs"):

On April 19, 2016, the shareholders of the Company approved a new long term incentive plan which was subsequently amended and restated following shareholder approval on April 20, 2022. Under the terms of the LTIP, eligible plan participants may be granted PSUs and RSUs. The LTIP provides that an aggregate number of Common Shares which may be reserved for issuance in respect of grants of RSUs and PSUs shall not exceed 28,256,682 shares, which represents approximately 4% of the issued and outstanding Common Shares of the Company as at December 31, 2025. PSUs are notional share instruments which track the value of the Common Shares and are subject to non-market performance conditions related to key strategic, financial and operational milestones. PSUs cliff vest three years from the date of grant, at which time the Board of Directors will assign a performance multiple ranging from nil to 200% to determine the ultimate vested number of PSUs. PSUs are awarded to executives and from 2022 are awarded to staff, replacing share options. They may be settled in shares issued from treasury or cash, at the discretion of the Board of Directors.

The Company's PSUs outstanding are as follows:

	December 31, 2025	December 31, 2024
	Number of PSUs	Number of PSUs
Outstanding, beginning of the year	7,609,689	7,122,839
Granted	6,242,388	3,968,993
Forfeited	(811,168)	-
Vested	(4,445,461)	(3,482,143)
Balance, end of the year	8,595,448	7,609,689

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In the year ended December 31, 2025, 4,445,461 PSUs vested in which 2,471,228 PSUs were settled for a cash payment of $3.8 million and the remaining were settled via the issuance of Common Shares of the Company (year ended December 31, 2024 - $5.3 million).

The Company accounts for PSUs as share-based awards whereby the estimated fair value of the grant is expensive throughout the remaining vesting period. In the year ended December 31, 2025, the Company recognized $4.9 million in share-based compensation expenses relating to the PSUs (year ended December 31, 2024 - $0.9 million) with the increase mainly caused by accelerated charges and changes in the expected outcome of performance multiples.

C. Restricted share units (“RSUs”):

RSUs granted to Non-Executive Directors cliff vest three years from the date of grant. The estimated fair value of RSUs are expensed evenly throughout the remaining vesting period. RSUs are no longer awarded to executives, and only PSU’s are awarded. RSUs may be settled in shares issued from treasury or cash, at the discretion of the Board of Directors.

The Company’s RSUs outstanding are as follows:

	December 31, 2025	December 31, 2024
	Number of RSUs	Number of RSUs
Outstanding, beginning of the year	1,174,553	1,278,318
Granted	969,068	541,621
Vested	(1,383,688)	(645,386)
Balance, end of the year	759,933	1,174,553

In the year ended December 31, 2025, 1,383,688 RSUs vested with 547,365 being settled for a cash payment of $0.8 million and the remaining were settled via the issuance of Common Shares of the Company (year ended December 31, 2024 - $0.6 million).

The Company accounts for RSUs as share-based awards whereby the estimated fair value of the grant is expensed evenly throughout the remaining vesting period. In the year ended December 31, 2025, the Company recognized $1.4 million in share-based compensation relating to the RSUs (year ended December 31, 2024 - $0.6 million) with the increase mainly caused by accelerated charges.

22. Finance income:

For the years ended	December 31, 2025	December 31, 2024
Interest income on cash and cash equivalents	3.9	7.1
Interest income from associated companies	0.2	0.5
Total finance income	4.1	7.6

23. Finance expense:

For the years ended	December 31, 2025	December 31, 2024
Interest expense on RBL	30.4	-
Commitment fees	4.3	3.4
Unwinding of site restoration provision	9.2	0.2
Others	3.9	1.3
Total finance expense	47.8	4.9

24. Income tax:

For the years ended	December 31, 2025	December 31, 2024
Current tax expense	135.9	-
Deferred tax income	(92.5)	-
Total income tax	43.4	-

The tax on the Group's profit before tax differs from the theoretical amount that would arise using the tax rate of Canada as follows:

The tax rate consists of the combined federal and provincial statutory tax rates for the Company for the years ended December 31, 2025, and December 31, 2024. The differences between the actual income tax expense and the expected Canadian federal and provincial statutory corporate income tax expense/ (recovery) related to the withholding tax on distributed dividends, education tax in Nigeria, income from result in Joint Venture that is not taxable and non taxable expense from over/underlift movements.

For the years ended	December 31, 2025	December 31, 2024
Net profit/ (loss) and comprehensive profit/ (loss)	11.8	(279.1)
Combined federal and provincial statutory income tax rate	27.0%	27.0%
Expected expense/ (recovery)	3.2	(75.4)
Foreign rate differences	0.6	0.1
Expenses not deductible for tax purposes	9.0	0.4
Creation of unrecorded tax losses	12.1	7.4
Non-deductible withholding tax on dividend	18.5	-
Education tax and Naseni fee	15.1	-
Equity earnings	(15.1)	(48.9)
Tax charge	43.4	-

The Company has estimated non-capital losses carried forward of $180.1 million in Canada which expire from 2026 through 2045. The Company has estimated capital losses carried forward of $12.9 million in Canada. The Company has estimated deductible temporary differences of $114.1 million in Canada.

At December 31, 2025, the Group has estimated losses carried forward of $1.3 billion that are indefinitely available for offsetting against future taxable profits in The Netherlands.

At December 31, 2025, resulting from the absence of projected taxable profits in the near foreseeable future in both Canada and The Netherlands, the Company did not recognize a deferred tax asset (as at December 31, 2024 - nil).

Specification of deferred tax assets and tax liabilities

As at	Accelerated allowances
At January 1, 2025	-
Acquired under amalgamation	374.3
Deferred tax credit	(92.5)
At December 31, 2025	281.8

As at	December 31, 2025	December 31, 2024
Deferred tax assets		
Temporary differences	5.4	-
	5.4	-
Deferred tax liabilities		
Accelerated allowances	287.2	-
	287.2	-
Total deferred tax	281.8	-

This specification of deferred tax assets and tax liabilities does not agree to the face of the balance sheet due to the netting off of balances in the balance sheet when they relate to the same jurisdiction.

Deferred tax liabilities are mainly recognised for the timing difference of depreciation on the Group's Nigerian assets for tax purposes (accelerated) compared to accounting purposes. Of the deferred tax liabilities as at 31 December 2025 of $281.8 million, $57.9 million is expected to be reversed within 12 months.

No deferred tax liabilities were recognised for temporary differences associated with investments in subsidiaries because the Group is in a position to control the timing of the reversal of the temporary differences and it is probable that such differences will not reverse in the foreseeable future.

Pillar Two income taxes

The Group is subject to the global minimum top-up tax ('Pillar Two') legislation, which has entered into force on 31 December 2023 and is effective as of January 1, 2024, onwards. The Group is active in Canada, United Kingdom, The Netherlands, Nigeria, Equatorial Guinea and South Africa.

Based on the Pillar Two legislation, the Group is subject to an additional top-up tax for the difference between the effective tax rate per tax jurisdiction as calculated under Pillar Two and a minimum tax rate of 15%.

The Group makes use of the so-called transitional CbCR safe harbour rules, using the (provisional) 2025 Country-by Country report and underlying financial statements. These rules are expected to apply for all countries where the Group operates.

The Qualified Domestic Minimum Top-up Tax ('QDMTT') will be applicable in Canada and the Income Inclusion Rule ('IRR') will be applicable with respect to the countries where the Group operates. No top-up tax is included in consolidated tax expense since the safe harbour rules are met.

Each of the subsidiaries is legally responsible for the minimum top-up taxes payable in the jurisdiction in which they operate. The Company is liable for the minimum top-up taxes under the IRR and charges this back to the respective subsidiaries.

The Group has applied the temporary mandatory exemption under IFRS to recognise and disclose deferred tax assets and liabilities related to Pillar Two income taxes and recognises income tax in the reporting period in which it is payable or refundable.

25. Net loss per share:

For the years ended	December 31, 2025			December 31, 2024		
		Weighted Average			Weighted Average	
	Net loss	Number of shares	Per share amounts	Net loss	Number of shares	Per share amounts
Basic loss per share						
Net loss attributable to common shareholders	(31.6)	624,464,015	(0.05)	(279.1)	449,431,803	(0.62)
Effect of dilutive securities	-	-	-	-	-	
Dilutive loss per share	(31.6)	624,464,015	(0.05)	(279.1)	449,431,803	(0.62)

In the year ended December 31, 2025, the Company used an average market price of CAD $1.83 per share (year ended December 31, 2024 – all potential dilutive shares were considered antidilutive as the Company reported a loss) to calculate the dilutive effect of share purchase options. Dilutive securities include share purchase options, RSUs and PSUs as the inclusion of these reduces the net income per share. In the year ended December 31, 2025, 2,707 options, 715,525 RSUs and 7,003,347 PSUs, were anti-dilutive and were not included in the calculation of dilutive income per share (year ended December 31, 2024, 200,636 options, 1,174,553 RSUs and 5,655,586 PSUs, were anti-dilutive and were not included in the calculation of dilutive income per share). PSU's are awarded a performance multiple ranging from nil to 200% which leads to an increase in the dilutive and anti-dilutive potential of these instruments.

26. Related party transactions:

A. Transactions with Africa Energy:

On December 19, 2022, Africa Energy announced that it had secured a $5.0 million promissory note of which $2.0 million was provided by the Company and the remaining by other parties. On November 7, 2023, the promissory note provided by the Company and other parties to Africa Energy was increased by $3.3 million with $1.5 million of the increase provided by the Company by the end of the year ended December 31, 2024. No funds were provided during 2025, $0.8 million was provided in the year ended December 31, 2024. The note was unsecured and matured on March 31, 2025, when the principal and accrued interest was repaid by Africa Energy in full. The note carried an annual interest rate of 15%. In the three months ended March 31, 2025, interest on the note amounted to $0.2 million (year ended December 31, 2024 - $0.5 million).

B. Transactions with Eco:

On July 26, 2024, the Company signed an agreement with Eco to acquire an additional 1.0% interest in Block 3B/4B from Azinam, in exchange for all common shares and warrants over common shares held by the Company in Eco. On January 13, 2025, the Company announced that it had completed this transaction. The Company's interest in Block 3B/4B increased by 1.0% to 18.0% and the Company ceased to be a shareholder in Eco. Meren will benefit from the carry agreed between Eco, TotalEnergies and QatarEnergy for this incremental interest.

C. Transactions with Impact:

On January 29, 2025, Impact distributed $31.6 million net to the Company's shareholding.

D. Transactions with BTG Oil & Gas:

On March 19, 2025, the Company completed the transaction with BTG Oil & Gas to consolidate its interest in Meren Coop (see note 4). The Company has recorded an indemnity asset of $21.6 million recognized under the deed of indemnity entered into between the Company and BTG Oil & Gas (see note 14).

E. Remuneration of Directors and Senior Management:

Remuneration of Non-Executive Directors and Senior Management includes all amounts earned and awarded to the Company's Board of Directors and Senior Management. Senior Management includes the Company's President and Chief Executive Officer, Chief Financial Officer, Chief Commercial and Operations Officer, Chief Operating Officer (position removed in 2025), Chief Technical Officer (position removed in 2025), Chief Legal Officer and Chief Human Resources Officer.

Directors' fees include Board and Committee Chair retainers. Management's short-term wages and benefits include salary, benefits, bonuses and any other cash-based compensation earned or awarded during the year. Share-based compensation includes expenses related to the Company's Share Option Plan as well as the LTIP.

For the years ended	December 31, 2025	December 31, 2024
Non-Executive Directors' fees	0.7	0.5
Non-Executive Directors' share-based compensation	1.4	0.6
Managements' short-term wages and benefits	7.1	7.3
Managements' share-based compensation	3.5	0.5
	12.7	8.9

27. Subsidiaries

The Company has the following wholly owned subsidiaries; Meren Nigeria 234 Ltd. (Nigeria), Meren Nigeria 52 Ltd. (Nigeria), Meren Coöperatief U.A. (Netherlands), Meren International Holdings B.V. (Netherlands), Meren Turkana B.V. (Netherlands), Africa Oil Kenya B.V. (Netherlands), Meren Holdings B.V. (Netherlands), Africa Oil Alpha B.V (Netherlands), Africa Oil Beta B.V (Netherlands), Meren Centric B.V (Netherlands), Africa Oil Turkana Ltd. (Kenya), Centric Energy (Kenya) Ltd. (Kenya), Meren Services Limited (England & Wales), Meren Nigeria Overseas Corp. (British Columbia) and Meren SA Energy Corp. (British Columbia).

28. Capital management:

The Company's objective when managing capital structure is to maintain balance sheet strength in order to ensure the Company's strategic exploration, appraisal and business development objectives are met while providing an appropriate return to shareholders relative to the risk of the Company's underlying assets.

The Company manages its capital structure and makes adjustments to it based on changes in economic conditions and the risk characteristics of the underlying assets. In order to maintain or adjust the capital structure, the Company may issue additional shares, issue debt, execute working interest farm-out arrangements and revise its capital expenditures program. In addition, the Company manages its cash and cash equivalents balances based on forecasted capital outlays and foreign exchange risks in order to ensure that the risk of negative foreign exchange effects are minimized while ensuring that interest yields on account balances are appropriate. The Company considers its capital structure to include shareholder's equity, debt and working capital. The Company does not have externally imposed capital requirements.

29. Financial risk management:

The Company's activities expose it to a variety of financial risks that arise as a result of its operating, exploration, appraisal and financing activities such as:

- credit risk;
- liquidity risk; and
- market risk.

This note presents information about the Company's exposure to each of the above risks, the Company's objectives, policies and processes for measuring and managing risk, and the Company's management of capital. Further quantitative disclosures are included throughout these consolidated financial statements.

A. Credit risk:

Credit risk is the risk of loss if counterparties do not fulfill their contractual obligations. The majority of the Company's credit exposure relates to amounts due from the Company's joint ventures and amounts receivable from the sale of crude oil. Approximately 90% of the Company's crude oil is sold to customers rated A+/Aa2 by S&P/Moody's. All other oil sales are made to companies that are either investment grade, are a subsidiary of an investment grade entity, or have its payment obligations supported by a letter of credit or guarantee issued by an investment grade entity. The risk of the Company's joint venture parties defaulting on their obligations per their respective joint operating and farmout agreements is mitigated as there are contractual provisions allowing the Company to default joint venture parties who are non-performing and reacquire any previous farmed out working interests. The maximum exposure for the Company is equal to the sum of its cash and accounts receivable. As at December 31, 2025, the Company held $15.9 million (as at December 31, 2024 - $1.1 million) of cash in financial institutions outside of Canada, the Netherlands and the UK. The Company held no cash (as at December 31, 2024 – $20.9 million) in short-term deposits in countries outside of Canada, the Netherlands and the UK with lending banks with stable credit ratings.

B. Liquidity risk:

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. Liquidity describes a company's ability to access cash. Companies operating in the upstream oil and gas industry, during the exploration and development phase, require sufficient cash in order to fulfill their work commitments in accordance with contractual obligations, deliver stated shareholder returns, and to be able to potentially acquire strategic oil and gas assets.

The Company will potentially issue equity and debt and enter into farmout agreements with joint venture parties to ensure the Company has sufficient available funds to meet current and foreseeable financial requirements. The Company actively monitors its liquidity to ensure that its cash flows and working capital are adequate to support these financial obligations and the Company's capital programs.

At December 31, 2025, the Company had $174.7 million of cash and cash equivalents and $468.4 million of the RBL available which provides the liquidity to fund operations and allows for increased liquidity if required for operations and acquisitions. The RBL matures on June 20, 2029, but amortizes each quarter as per the lower of commitments and the BBA.

The Company will also adjust the pace of its exploration and appraisal activities and any M&A activity to manage its liquidity position. The existing cash balance, the undrawn amounts under both facilities and cash flow from operations, are sufficient to fund the Company's obligations as they become due.

In relation to the amounts drawn under the RBL as at December 31, 2025, the Company has no liabilities that mature on June 30, 2026, based on the currently approved BBA profile, subject to the results of the next redetermination. An amount of $67.7 million will mature between six months and one year, $108.0 million will mature between one year and two years with the remaining balance of $154.3 million due between two and five years (as at December 31, 2024 – no maturities of its material contractual liabilities in excess of six months).

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

The table below analyses the Group's financial liabilities into relevant maturity groupings based on the remaining period at the balance sheet date to the contractual maturity date. The Group has further financial liabilities in relation to interest on the RBL. The size of these interest payments depends on the outstanding loan balance of the RBL and the applicable SOFR interest rate.

	December 31, 2025	December 31, 2024
Non-current		
Repayment within 1-2 years:		
- Reserve based lending facility (1)	124.6	-
- Lease liability	1.2	0.7
Repayment within 2-5 years:		
- Reserve based lending facility (1)	162.5	-
- Lease liability	1.7	1.9
	290.0	2.6
Current		
Repayment within 6 months:		
- Reserve based lending facility (1)	13.2	
- Lease liability	0.4	0.3
- Short-term payables with partners	97.9	-
- Other payables	2.8	2.0
Repayment after 6 months:		
- Reserve based lending facility (1)	79.3	-
- Lease liability	0.5	0.4
	194.1	2.7

(1) Includes estimated interest payments related to the RBL facility. Payments were estimated based on the interest rate at December 31, 2025, and the estimated average outstanding loan balance of each period under the existing RBL, see note 15.

C. Market risk:

Market risk is the risk that changes in market prices, such as foreign exchange rates, interest rates, commodity prices and share prices, will affect the Company's income or the value of the financial instruments.

i. Foreign currency exchange rate risk:

The Company is exposed to changes in foreign exchange rates as expenses in international subsidiaries, oil and gas expenditures, or financial instruments may fluctuate due to changes in rates. The Company's exposure to foreign currency exchange risk is mitigated by the fact that the Company sources the majority of its capital projects and expenditures in US dollars. The Company has not entered into any instruments to manage foreign exchange risk.

ii. Interest rate risk:

The RBL has a variable interest rate, that is referenced to Secured Overnight Financing Rate ("SOFR") and exposes the Company to interest rate risk when drawn.

Management considers the Group's exposure to interest rate risk to be related to the remaining RBL principal amounts of $330.0 million. As such, the Group has substantial floating-rate borrowings which are partially offset by cash held at variable rates. Therefore, a change in interest rates at the reporting date is likely to affect profit and loss of the Group. The Group's financing agreements make reference to SOFR. Also refer to note 15 to these consolidated financial statements.

The following table demonstrates the sensitivity of the Group's profit before tax from a reasonably possible change in interest rates of the floating rate borrowings (with all other variables held constant). The impact on equity is the same as the impact on profit before tax.

Increase/ (decrease) in interest rates	Effect on profit before tax increase/ (decrease)
For the year ended	December 31, 2025
+2.5%	(9.0)
-2.5%	9.0

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - CONTINUED

iii. Commodity price risk:

The Company has a direct interest in three producing fields within PMLs 2, 3 and 52, all with significant levels of production. Its strategy is to hedge between 70-100% of its post-tax net entitlement production for the next 12-months. Physical sales are with counterparties including oil supermajors. The counterparties are part of groups with investment grade credit ratings.

Of the cargoes expected for the year ended December 31, 2026, 2 cargoes have the trigger price mechanism activated at an average price of $62.1/bbl.

As at 31 December 2025, the Company holds derivatives, as outlined in the tables below, that are designated as a financial asset at fair value through profit or loss. These derivatives were all entered into in 2025. As such, any gains or losses arising from changes in the fair value of these derivative are taken directly to profit or loss.

	Term	bbl	Sold put $/bbl	Bought put $/bbl	Sold call $/bbl	Sold swap $/bbl	FV at December 31, 2025/ $'m
Asian Dated Brent Zero cost collar	January 1, 2026, to March 31, 2026	300,000	-	60.00	67.15	-	0.4
Asian Dated Brent Swap	June 1, 2026, to September 30, 2026	600,000	-	-	-	63.58	2.0
Asian Dated Brent three -way put spread	October 1. 2026 to December 31, 2026	450,000	45.00	60.00	65.78	-	(0.2)
						Total	2.2

Crude oil price sensitivity

The table below summarizes the impact on profit before tax for changes in crude oil prices. The analysis is based on the assumption that the average crude oil price moves 25% resulting in a change of approximately $17.0/bbl, with all other variables held constant. Reasonably possible movements in crude oil prices were determined based on a review of the last years' historical prices and economic forecasters' expectations.

Increase/ (decrease) in crude oil prices	Effect on profit before tax increase/ (decrease)
For the year ended	December 31, 2025
Increase $17.0/bbl	35.2
Decrease $17.0/bbl	(35.2)

30. Financial assets and liabilities:

The accounting policies for financial assets and liabilities have been applied to the line items below:

Assets

December 31, 2025	Total	Amortised cost	Fair value through profit and loss
Trade and other receivables (1)	63.0	63.0	-
Derivative financial instruments	2.2	-	2.2
Cash and cash equivalents	174.7	174.7	-
	239.9	237.7	2.2

December 31, 2024			
Loan to associated company	4.3	4.3	-
Trade and other receivables (1)	1.6	1.6	-
Cash and cash equivalents	61.4	61.4	-
	67.3	67.3	-

Liabilities

December 31, 2025	Total	Amortised cost
Reserve based lending facility	330.0	330.0
Lease liability	3.8	3.8
Trade and other payables (2)	100.7	100.7
	434.5	434.5

December 31, 2024		
Lease liability	3.3	3.3
Trade and other payables (2)	2.0	2.0
	5.3	5.3

(1) Underlift position and prepayments are not included in trade and other receivables as not deemed to be financial instruments.

(2) Crude oil overlift payable and accruals are not included in trade and other payables as not deemed to be financial instruments.

The fair value of cash and cash equivalents, trade and other receivables, and trade and other payables approximate their carrying value due to the short-term maturity of these instruments.

The fair value of the reserve based lending facility approximates its carrying value due to the fact that the facility has a variable interest rate, that is referenced to SOFR.

For financial assets measured at fair value in the balance sheet, the following fair value measurement hierarchy is used:

- Level 1: based on quoted prices in active markets;
- Level 2: based on inputs other than quoted prices as within level 1, that are either directly or indirectly observable;
- Level 3: based on inputs which are not based on observable market data.

Based on this hierarchy, financial assets and liabilities measured at fair value can be detailed as follows:

- Derivative financial instruments - $2.2 million – level 2.

Assessment of the significance of a particular input to the fair value measurement requires judgement and may affect the placement within the fair value hierarchy level.

31. Supplementary information:

The following table reconciles the changes in non-cash working capital as disclosed in the consolidated statement of cash flows:

For the years ended	December 31, 2025	December 31, 2024
Relating to		
Changes in current assets	181.5	(1.5)
Changes in current liabilities	(87.5)	(13.3)
Changes in non-cash working capital	94.0	(14.8)

32. Subsequent events:

In January 2026, Meren and its JV Parties in PML 2/3 successfully executed an amendment to the gas sale agreement that includes a revised index for gas pricing, locking a long-term gas price that is more reflective of the current LNG economics compared to 2018 when the contract was initially signed. The amendment also includes a mechanism for the sellers to recover the historical difference between the interim gas price adjustment and the new index, starting from 2020 when the previous index ceased to be published. This historical amount will be recovered through an upward adjustment to the netback pricing that includes the handling fee for the gas sold.

On February 24, 2026, the Company's Board declared the first quarterly dividend in 2026 of approximately $25.1 million ($0.0371 per share) payable in April 2026 to shareholders of record at the close of business on March 20, 2026.

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