Meren

Suite 2500
666 Burrard Street,
Vancouver, B.C. Canada V6C 2X8
info@mereninc.com
mereninc.com

NEWS RELEASE

MEREN ANNOUNCES FIRST QUARTER 2026 RESULTS AND SECOND QUARTERLY DIVIDEND OF 2026

May 12, 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 ended March 31, 2026, and is pleased to declare its second quarterly distribution of $25 million for this year.

Meren President and CEO, Oliver Quinn commented: *"I am pleased to report another quarter of robust operational and financial results, with production on track and the successful refinancing of our reserve-based lending facility. The conflict in the Middle East has created the most significant disruption to global oil supply on record, driving major price volatility. As international buyers seek alternatives to Middle Eastern supply routes, West Africa's deepwater basins are emerging as a strategically vital source of secure and reliable hydrocarbons. Meren, with its pillars of strong balance sheet, high netback production and deep portfolio of organic growth opportunities, is well positioned to benefit as the strategic value of West African energy assets is repriced."*

Quarterly Highlights*

- **Financial**
  - Recorded EBITDAX of $100.2 million and cash flow from operations before working capital of $79.0 million, reflecting the continued strong cash-generative nature of the portfolio.
  - Disciplined capital investments of $8.9 million, primarily directed toward the Nigerian operations.
  - Recorded a non-cash hedging charge of $37.2 million, driven by mark-to-market revaluation of derivatives and a $0.4 million cash settlement on expired derivatives, as oil prices rose during the quarter.
  - Reported a net loss of $42.2 million, principally driven by the non-cash derivative charge and share of associate losses, excluding these items the adjusted net loss was limited to $13.0 million.
- **Balance Sheet & Shareholder Returns**
  - Successfully refinanced the RBL facility, enhancing liquidity through increased commitments of $600 million (accordion to $1 billion), extending maturity to March 2032 and reducing the average margin.
  - Strong liquidity position with cash of $161.6 million, net debt of $208.4 million, Net Debt/EBITDAX of 0.5x, together with $204.2 million of available RBL headroom.
  - Declared the second 2026 quarterly dividend of $25.1 million ($0.0371/share), bringing YTD distributions to $50.2 million.
- **Operational**
  - Delivered average daily W.I. production of 28,400 boepd and entitlement production of 31,000 boepd, with performance on track to achieve full-year guidance, supported by the post-turnaround recovery following the planned Q4 2025 Agbami maintenance.
  - Unit operating costs of $14.6/boe on an entitlement basis, broadly in line with the prior year period.
- **Commercial**
  - Sold one cargo (approximately 1 MMbbl) lifted in February 2026, at an all-in sales price of $63.7/bbl, which compares to the average Bloomberg Dated Brent price of $71.1/bbl for February 2026.

* All dollar amounts in this press release are U.S. Dollars unless otherwise indicated. The highlights include non-GAAP measures. Definitions and reconciliations to these non-GAAP measures are provided on pages 12-14 of the First Quarter 2026 Report to Shareholders.

- Following the amendment of the PML 2/3 gas sales agreement in January 2026, to secure higher gas prices aligned with the buyers' current LNG economics, Meren recognized additional gas revenue of $40.8 million.

2026 First Quarter Results Highlights[1]

		Three months ended		Years ended
Meren Highlights	Unit	March 31, 2026	March 31, 2025	December 31, 2025
Net (loss)/ income	$'m	(42.2)	50.9	(31.6)
Net (loss)/ income per share – basic[2]	$/ share	(0.06)	0.11	(0.05)
Net debt position	$'m	208.4	191.6	155.3
WI production	boepd	28,400	35,000	30,200
Entitlement production	boepd	31,000	39,500	34,500
Cash flow from operations[3]	$'m	79.0	(0.9)	272.6
EBITDAX	$'m	100.2	12.6	399.3
Capital investments	$'m	8.9	3.6	75.6

(1) The table includes non-GAAP measures. Definitions and reconciliations to these non-GAAP measures are provided on pages 12-14 of the First Quarter 2026 Report to Shareholders.

(2) Based on the weighted average number of shares outstanding for the three months ended March 31, 2025, and year ended December 31, 2025, of 468,472,433 and 624,464,015 respectively, which accounts for the newly issued shares to BTG Oil & Gas on March 19, 2025.

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

Outlook

Nigeria

In collaboration with its JV Parties, the Company continues to make good progress towards the restart of drilling and intervention activities across Akpo and Egina following the 2025 pause. Work to secure a deepwater drilling unit is advancing, with rig mobilisation expected in H2 2026. The Akpo Far East exploration well is planned as the first well in the upcoming campaign, followed by a return to drilling on the Akpo and Egina fields, with production from these wells expected in early 2027. In parallel, well intervention activities are being planned across selected existing wells to support and sustain production ahead of the broader drilling campaign.

The Akpo Far East prospect remains a strategically positioned, fast cycle tie back opportunity utilising existing Akpo infrastructure in case of exploration success. This prospect has an unrisked, best estimate, gross field prospective resource volume of 143.6 MMboe, or approximately 23.0 MMboe net to Meren's 16% working interest. The targeted hydrocarbons are predicted to be light, high gas-oil ratio ("GOR") oil equivalent to those found in the Akpo field. If successful, initial production could be achieved from existing production manifolds with the potential to add significant reserves. Prospect maturation activities continue, with current efforts focused on well optimisation and final well design, supporting the planned well spud later in 2026.

Work remains active across PMLs 2/3 licence areas, with reservoir management and infill well evaluation continuing across both Akpo and Egina, and further opportunities remaining under active consideration.

Subsurface studies and scenario assessments on the Preowei field ("PML 4") continued into Q1 2026, with progress on subsurface maturation activities and updated resource estimates to support the timing and scope of a potential final investment decision ("FID"). Activity for the Egina South oil discovery, including planned appraisal drilling by TotalEnergies on the extension of this discovery in the neighbouring OPL 257 during 2026, continues to offer potential upside through proximity to existing Egina FPSO infrastructure.

For PML 52 (Agbami) and PPL 2003 (Ikija), activity during the period focused on progressing the first phase of the upcoming drilling program, which is scheduled to commence in Q4 2026, starting with the Ikija appraisal well. In parallel, Agbami continued to recover from the planned Q4 2025 turnaround and maintenance campaign. The broader infill drilling program for Agbami remains on track, with six infill wells currently planned across 2027 and 2028.

Nigeria's macroeconomic and sector-specific reforms continue to gain traction, with improved fiscal clarity, regulatory stability and targeted government incentives supporting renewed investment in the country's upstream sector. This improved investment climate is evidenced by recent developments, including the recommencement of work on Shell's ~$20 billion Bonga Southwest project, with the FID expected in 2027, and ExxonMobil's advancement of the Owowo deepwater project, representing a further ~$8 billion of investment in Nigeria's offshore oil sector. Collectively, these milestones underscore growing confidence in Nigeria as a long-term destination for large-scale energy investment.

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

<u>Status and Operator Updates</u>

The Venus discovery in Block 2913B remains the most advanced offshore development project in Namibia and is described by the operator and government as the anchor project for the country's first deepwater oil development. The Field Development Plan ("FDP") has been submitted by TotalEnergies as the operator and is under review by the Namibian authorities, initiating formal engagement toward a potential FID, subject to completion of regulatory, fiscal and environmental processes. 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.

Based on public disclosures by TotalEnergies, Venus is a fully appraised discovery with a defined development concept. The project is expected to be developed as a large-scale deepwater subsea system tied back to a floating production, storage and offloading vessel ("FPSO"), consistent with comparable deepwater developments globally. Front-end engineering and design ("FEED") has been finalized, providing a mature technical basis for development planning.

<u>Project Scale, Development Maturity and Indicative Timing</u>

Publicly presented materials from TotalEnergies describe Venus phase 1 development as a project to recover approximately 750 million barrels of oil, with a planned production capacity of around 150 thousand barrels per day. The development concept targets first oil potentially in 2030, subject to FID timing by the end of 2026.

TotalEnergies has indicated that estimated capital costs have been firmed up through competitive EPC bidding, supporting readiness for a potential FID in 2026. The project design incorporates measures to minimize emissions intensity, including reinjection of associated gas and a stated development objective of maintaining a comparatively low upstream emissions profile for a deepwater project.

While these timelines and metrics reflect the operator's current public statements, they remain forward-looking and contingent on regulatory approvals, fiscal finalization and execution milestones.

<u>National Readiness and Enabling Framework</u>

In parallel with project maturation, Namibia continues to prepare for potential offshore oil and gas development:

- Upstream Petroleum Unit ("UPU"): Oversight of the upstream sector has been consolidated within a dedicated unit in the Office of the President, with responsibility for technical review of development plans, coordination of fiscal and regulatory matters, and petroleum governance, including local content considerations.
- Petroleum Legislation and Local Content: Government communications indicate ongoing consultation on petroleum legislation and a national local content framework, with an emphasis on skills development, domestic supplier participation and institutional capacity ahead of any future production.
- Ports and Logistics: The Namibian Ports Authority has outlined phased expansion plans at Lüderitz and Walvis Bay to support offshore energy activities, including oil and gas supply base capacity, quay wall expansions and interim use of existing facilities during early project phases.

<u>Strategic Context</u>

Disclosures by both the operator and government consistently frame Venus as a potential catalyst for establishing Namibia as a new deepwater oil producer. While typical execution risks remain for a frontier offshore development, ongoing regulatory engagement, a finalized FEED package and firmed capital cost estimates support continued progress towards FID.

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 suspension was lifted in March 2026, and a specialist panel is being appointed to review the environmental authorization appeals process and make a recommendation to the Minister. The timing of this review process remains uncertain. 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

The Company continues to progress partnership discussions on both blocks, supported by significant levels of industry interest, and remains actively engaged with government, third-party infrastructure and GEPetrol representatives to advance the forward plan.

Should the Company successfully attract a farm-in partner on acceptable terms, and subject to customary consents and approvals including governmental and regulatory permissions, the newly formed JV could be positioned to commence appraisal, development and exploration drilling on EG-31, potentially from 2027, with EG-18 to follow thereafter.

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 these discussions with confidence.

Shareholder Returns

The Company is pleased to announce that its Board has declared the distribution of the Company's second 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 May 21, 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 June 8, 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 June 11, 2026.

To execute the payment of the dividend, a temporary administrative cross border transfer closure will be applied by Euroclear from May 19, 2026, up to and including May 21, 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 the base annual distribution policy 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 and Actuals

The Company's full-year 2026 Management Guidance is unchanged and is copied here for completeness.

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.

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, based on 8 cargo liftings.

	2026 Guidance	Q1 2026 Actuals
WI production (kboepd) (1)	23.0 – 28.0	28.4
Entitlement production (kboepd) (2)	28.0 – 33.0	31.0
EBITDAX ($ million) (3)	270.0 – 360.0	100.2
Cash flow from operations ($ million) (3)	185.0 – 255.0	79.0
Capital investments ($ million)	100.0 – 140.0	8.9

(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.

Management Conference Call

Senior management will hold a conference call to discuss the results on Wednesday, May 13, 2026, at 09:00 (ET) / 14:00 (BST) / 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-first-quarter-results-may-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.

For further information, please contact:

Shahin Amini
Head of IR and Communications
shahin.amini@mereninc.com
T: +44 (0)20 8017 1511

Burson Buchanan
Financial PR & Communications Advisor
Energy@Buchanan.uk.com
T: +44 (0)20 7466 5000

Visit us at www.mereninc.com.

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 May 12, 2026.

Advisory Regarding Oil and Gas Information

Aggregate oil equivalent production data in this press release are comprised of light and medium crude oil and conventional natural gas production.

The terms boe (barrel of oil equivalent) is used throughout this press release. Such terms may be misleading, particularly if used in isolation. Production data are based on a conversion ratio of six thousand cubic feet per barrel (6 Mcf: 1bbl). This conversion ratio 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. Petroleum references in this press release are to light and medium gravity crude oil and conventional natural gas in accordance with NI 51-101 and the COGE Handbook.

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 2026 Management Guidance; timing of the Nigerian drilling campaigns; expected capital investment levels and timing of capital expenditure; the potential of Akpo Far East exploration prospect; the timing to drill the Akpo Far East well; development of near-field discoveries in Nigeria (Preowei, Egina South and Ikija); economic outlook for Nigeria and the scope of the development of its oil and gas industry; the potential impact of geopolitical events, including conflict in the Middle East, on global oil markets and valuations, including in West Africa; timing of the FID for the Venus project; first oil date for the Venus project; 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; future shareholder returns and the sustainability of future dividend distributions; the ability of Meren to influence its JV partners 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 deliver 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.

Report to Shareholders

For the Year Ended March 31, 2026

Q1 26

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	"FDP"	means Field Development Plan.
	"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 thousand 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 field.
	"PPL 261"	means the Petroleum Prospecting License containing the Egina field.
	"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	"UPU"	means Upstream Petroleum Unit.
	"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 three months ended March 31, 2026, 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 unaudited interim condensed consolidated financial statements for the three months ended March 31, 2026, and 2025, and also should be read in conjunction with the 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 unaudited interim condensed 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 May 12, 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.

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

FIRST QUARTER 2026 AND POST PERIOD HIGHLIGHTS

- **Financial**
  - » Recorded EBITDAX of $100.2 million and cash flow from operations before working capital of $79.0 million.
  - » Capital investments of $8.9 million, mostly spend on the Nigerian operations.
  - » Recorded a non-cash hedging charge of $37.2 million, driven by mark-to-market revaluation of derivatives and a $0.4 million cash settlement on expired derivatives, as oil prices rose during the quarter.
  - » Recorded net loss of $42.2 million, principally driven by the non-cash derivative charge and share of associate losses, adjusted net loss of $13.0 million.
- **Balance Sheet & Shareholder Returns**
  - » Successfully refinanced the RBL facility, increasing commitments to $600 million (accordion to $1 billion), extending maturity to March 2032 and reducing the average margin.
  - » Cash of $161.6 million, net debt of $208.4 million, Net Debt/EBITDAX of 0.5x, with $204.2 million of RBL headroom.
  - » Declared the second 2026 quarterly dividend of $25.1 million ($0.0371/share), bringing YTD distributions to $50.2 million.
- **Operational**
  - » Average daily W.I. production of 28,400 boepd and entitlement production of 31,000 boepd, on track to achieve full-year guidance, supported by the recovery from the planned Q4 2025 Agbami turnaround maintenance.
  - » Unit operating costs of $14.6/boe on an entitlement basis, broadly in line with the prior year period.
- **Commercial**
  - » Sold one cargo (approximately 1 MMbbl) lifted in February 2026, at an all in sales price of $63.7/bbl, which compares to the average Bloomberg Dated Brent price of $71.1/bbl for February 2026.
  - » Following the amendment of the PML 2/3 gas sales agreement in January 2026, to lock in higher gas prices that are reflective of the buyers' current LNG economics, Meren recognized additional gas revenue of $40.8 million.

FINANCIAL SUMMARY [(1)]

The comparative period numbers as included in this financial summary are no longer presented on a constructed financial information basis. The comparative period numbers are derived from the interim condensed consolidated financial statements for the three months ended March 31, 2025, and from the consolidated financial statements for the year ended December 31, 2025. Comparative period numbers will therefore be different compared to those presented in the Management's Discussion and Analysis for the three months ended March 31, 2025, and for the year ended December 31, 2025.

		Three months ended		Years ended
Meren highlights	Unit	March 31, 2026	March 31, 2025	December 31, 2025
Net (loss)/ income	$'m	(42.2)	50.9	(31.6)
Net (loss)/ income per share - basic [(2)]	*$/ share*	*(0.06)*	*0.11*	*(0.05)*
Net debt position	$'m	208.4	191.6	155.3
WI production	boepd	28,400	35,000	30,200
Entitlement production	boepd	31,000	39,500	34,500
Cash flow from operations [(3)]	$'m	79.0	(0.9)	272.6
EBITDAX	$'m	100.2	12.6	399.3
Capital investments	$'m	8.9	3.6	75.6

(1) The table includes non-GAAP measures. Definitions and reconciliations to these non-GAAP measures are provided on pages 12 - 14.

(2) Based on the weighted average number of shares outstanding for the three months ended March 31, 2025, and year ended December 31, 2025, of 468,472,433 and 624,464,015 respectively, which accounts for the newly issued shares to BTG Oil & Gas on March 19, 2025.

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

OUTLOOK

Nigeria

In collaboration with its JV Parties, the Company continues to make good progress towards the restart of drilling and intervention activities across Akpo and Egina following the 2025 pause. Work to secure a deepwater drilling unit is advancing, with rig mobilisation expected in H2 2026. The Akpo Far East exploration well is planned as the first well in the upcoming campaign, followed by a return to drilling on the Akpo and Egina fields, with production from these wells expected in early 2027. In parallel, well intervention activities are being planned across selected existing wells to support and sustain production ahead of the broader drilling campaign.

The Akpo Far East prospect remains a strategically positioned, fast cycle tie back opportunity utilising existing Akpo infrastructure in case of exploration success. This prospect has an unrisked, best estimate, gross field prospective resource volume of 143.6 MMboe, or approximately 23.0 MMboe net to Meren's 16% working interest. The targeted hydrocarbons are predicted to be light, high gas-oil ratio ("GOR") oil equivalent to those found in the Akpo field. If successful, initial production could be achieved from existing production manifolds with the potential to add significant reserves. Prospect maturation activities continue, with current efforts focused on well optimisation and final well design, supporting the planned well spud later in 2026.

Work remains active across PMLs 2/3 licence areas, with reservoir management and infill well evaluation continuing across both Akpo and Egina, and further opportunities remaining under active consideration.

Subsurface studies and scenario assessments on the Preowei field ("PML 4") continued into Q1 2026, with progress on subsurface maturation activities and updated resource estimates to support the timing and scope of a potential final investment decision ("FID"). Activity for the Egina South oil discovery, including planned appraisal drilling by TotalEnergies on the extension of this discovery in the neighbouring OPL 257 during 2026, continues to offer potential upside through proximity to existing Egina FPSO infrastructure.

For PML 52 (Agbami) and PPL 2003 (Ikija), activity during the period focused on progressing the first phase of the upcoming drilling program, which is scheduled to commence in Q4 2026, starting with the Ikija appraisal well. In parallel, Agbami continued to recover from the planned Q4 2025 turnaround and maintenance campaign. The broader infill drilling program for Agbami remains on track, with six infill wells currently planned across 2027 and 2028.

Nigeria's macroeconomic and sector-specific reforms continue to gain traction, with improved fiscal clarity, regulatory stability and targeted government incentives supporting renewed investment in the country's upstream sector. This improved investment climate is evidenced by recent developments, including the recommencement of work on Shell's ~$20 billion Bonga Southwest project, with the FID expected in 2027, and ExxonMobil's advancement of the Owowo deepwater project, representing a further ~$8 billion of investment in Nigeria's offshore oil sector. Collectively, these milestones underscore growing confidence in Nigeria as a long term destination for large scale energy investment.

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

Status and Operator Updates

The Venus discovery in Block 2913B remains the most advanced offshore development project in Namibia and is described by the operator and government as the anchor project for the country's first deepwater oil development. The Field Development Plan ("FDP") has been submitted by TotalEnergies as the operator and is under review by the Namibian authorities, initiating formal engagement toward a potential FID, subject to completion of regulatory, fiscal and environmental processes. 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.

Based on public disclosures by TotalEnergies, Venus is a fully appraised discovery with a defined development concept. The project is expected to be developed as a large-scale deepwater subsea system tied back to a floating production, storage and offloading vessel ("FPSO"), consistent with comparable deepwater developments globally. Front-end engineering and design ("FEED") has been finalized, providing a mature technical basis for development planning.

Project Scale, Development Maturity and Indicative Timing

Publicly presented materials from TotalEnergies describe Venus phase 1 development as a project to recover approximately 750 million barrels of oil, with a planned production capacity of around 150 thousand barrels per day. The development concept targets first oil potentially in 2030, subject to FID timing by the end of 2026.

TotalEnergies has indicated that estimated capital costs have been firmed up through competitive EPC bidding, supporting readiness for a potential FID in 2026. The project design incorporates measures to minimize emissions intensity, including reinjection of associated gas and a stated development objective of maintaining a comparatively low upstream emissions profile for a deepwater project.

While these timelines and metrics reflect the operator's current public statements, they remain forward-looking and contingent on regulatory approvals, fiscal finalization and execution milestones.

National Readiness and Enabling Framework

In parallel with project maturation, Namibia continues to prepare for potential offshore oil and gas development:

- Upstream Petroleum Unit ("UPU"): Oversight of the upstream sector has been consolidated within a dedicated unit in the Office of the President, with responsibility for technical review of development plans, coordination of fiscal and regulatory matters, and petroleum governance, including local content considerations.
- Petroleum Legislation and Local Content: Government communications indicate ongoing consultation on petroleum legislation and a national local content framework, with an emphasis on skills development, domestic supplier participation and institutional capacity ahead of any future production.
- Ports and Logistics: The Namibian Ports Authority has outlined phased expansion plans at Lüderitz and Walvis Bay to support offshore energy activities, including oil and gas supply base capacity, quay wall expansions and interim use of existing facilities during early project phases.

Strategic Context

Disclosures by both the operator and government consistently frame Venus as a potential catalyst for establishing Namibia as a new deepwater oil producer. While typical execution risks remain for a frontier offshore development, ongoing regulatory engagement, a finalized FEED package and firmed capital cost estimates support continued progress towards FID.

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 suspension was lifted in March 2026, and a specialist panel is being appointed to review the environmental authorization appeals process and make a recommendation to the Minister. The timing of this review process remains uncertain. 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

The Company continues to progress partnership discussions on both blocks, supported by significant levels of industry interest, and remains actively engaged with government, third-party infrastructure and GEPetrol representatives to advance the forward plan.

Should the Company successfully attract a farm-in partner on acceptable terms, and subject to customary consents and approvals including governmental and regulatory permissions, the newly formed JV could be positioned to commence appraisal, development and exploration drilling on EG-31, potentially from 2027, with EG-18 to follow thereafter.

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 these discussions with confidence.

HIGHLIGHTS AND OUTLOOK - CONTINUED

Shareholder Returns

The Company is pleased to announce that its Board has declared the distribution of the Company's second 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 May 21, 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 June 8, 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 June 11, 2026.

To execute the payment of the dividend, a temporary administrative cross border transfer closure will be applied by Euroclear from May 19, 2026, up to and including May 21, 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 the base annual distribution policy 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 Management Guidance is unchanged and is copied here for completeness.

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.

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, based on 8 cargo liftings.

	2026 Guidance	Q1 2026 actuals
WI production (kboepd) (1)	23.0 - 28.0	28.4
Entitlement production (kboepd) (2)	28.0 - 33.0	31.0
EBITDAX ($ million) (3)	270.0 - 360.0	100.2
Cash flow from operations ($ million) (3)	185.0 - 255.0	79.0
Capital investments ($ million)	100.0 - 140.0	8.9

(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 March 31, 2026, are summarized in the following table:

Meren's Direct Working Interests [1]

Country	Concession	License renewal	Working Interests	
Nigeria	PML 52 [2]	November 24, 2044	Meren	8%
			Chevron (Operator)	32%
	PPL 2003 [2]	February 14, 2028	Famfa Oil	60% (carried)
	PML 2, 3, 4 [3]	May 24, 2043	Meren	32%
			TotalEnergies (Operator)	48%
	PPL 261 - PSA [3]	May 24, 2028	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 [6]	Impact	9.5%
			TotalEnergies	45.25%
			QatarEnergy	35.25%
			NAMCOR	10% (carried)
	PEL 91 (Block 2912)	October 1, 2027	Impact	9.5%
			TotalEnergies	42.48%
			QatarEnergy	33.02%
			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.
(6) The Operator has submitted an application which extends the validity of the Exploration License. This is currently awaiting Government acknowledgement.

Information on the Company's equity interests in Africa Energy and Impact is included in "Equity Investments in Associates" on page 16.

BUSINESS UPDATE

SHAREHOLDER RETURNS

On February 24, 2026, the Company declared the first 2026 quarterly dividend of approximately $25.1 million or $0.0371 per share with payment during April 2026. The Company is pleased to announce that its Board has declared the distribution of the Company's second 2026 quarterly cash dividend 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 May 21, 2026.

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. Meren has not repurchased any shares since the renewal of its current NCIB program in December 2025.

GROUP OPERATIONS

Production and Operations

The comparative period production numbers as included in this section are no longer presented on a constructed financial information basis to be consistent with the comparative period financials as included in this Management's Discussion and Analysis that are derived from the interim condensed consolidated financial statements for the three months ended March 31, 2025, and from the consolidated financial statements for the year ended December 31, 2025. Comparative period production numbers will therefore relate to the period since March 19, 2025 when the Company completed the transaction with BTG Oil & Gas to consolidate its interest in Meren Coop (the "Amalgamation") and will therefore be different compared to those presented in the Management's Discussion and Analysis for the three months ended March 31, 2025, and for the year ended December 31, 2025.

Production Metrics – rounded

		Three months ended		Years ended
	Unit	March 31, 2026	March 31, 2025	December 31, 2025
Total gross field production	boepd	220,100	275,600	237,000
Average daily WI production (1)	boepd	28,400	35,000	30,200
Average daily entitlement production	boepd	31,000	39,500	34,500
Oil volumes sold	MMbbl	1.0	1.0	8.0
Gas volumes sold	bcf	5.2	0.7	15.7
Oil/gas percentage split (2)	%	66%/34%	71%/29%	70%/30%

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

(2) Calculated on a working interest basis.

BUSINESS UPDATE - CONTINUED

Total gross field production in Q1 2026 continued to strengthen following the planned Agbami FPSO turnaround maintenance completed in late 2025, with the progressive stabilisation of gas compression and seawater injection systems supporting improving performance through the quarter. Natural reservoir decline across the portfolio and several operational factors, described below, also influenced the quarter, with production actively managed in response throughout.

At Akpo and Egina, Q1 2026 production was supported by ongoing maintenance activities and proactive asset management throughout the quarter, contributing to strong uptime and production levels in line with expectations.

At Agbami, production during Q1 2026 reflected the ongoing ramp-up following the late-2025 turnaround maintenance that involved a planned full-field shutdown. Gas turbine compressor availability and start-up sequencing presented near-term constraints early in the quarter, resulting in periods of reduced oil rates and some elevated flaring. These were addressed through targeted repair and optimization efforts, resulting in improved gas compression performance, reliability and uptime as the quarter progressed. The work completed is expected to support continued operational improvement into Q2 2026.

In Q1 2026, one oil lifting was allocated in February 2026 with a sales volume of approximately one million barrels of oil at a realized oil price of $63.7/bbl, compared to a Dated Brent average for Q1 2026 of $81.0/bbl. Lifting schedules were adjusted through the quarter to reflect evolving production performance and inventory positions, including revisions to the Agbami February and March lifting windows.

Post Q1 2026, two oil liftings were allocated to the Company, one with an all-in realized oil price of $63.6/bbl, which had a fixed Dated Brent component of $59.6/bbl from a legacy 2025 trigger mechanism and the other with an all-in realized oil price of $122.0/bbl.

FINANCIAL

The comparative period numbers as included in this section are no longer presented on a constructed financial information basis. The comparative period numbers are derived from the interim condensed consolidated financial statements for the three months ended March 31, 2025, and from the consolidated financial statements for the year ended December 31, 2025, as presented below. Comparative period numbers will therefore be different compared to those presented in the Management's Discussion and Analysis for the three months ended March 31, 2025, and for the year ended December 31, 2025.

		Three months ended		Years ended
	Unit	March 31, 2026	March 31, 2025	December 31, 2025
Revenue	$'m	114.3	76.4	559.9
Commodity risk management contracts	$'m	(37.6)	-	2.2
Movements on overlift/ underlift balances [1]	$'m	66.5	(41.9)	(46.3)
Production costs	$'m	(57.7)	(9.3)	(166.6)
Depletion costs	$'m	(49.2)	(12.1)	(207.9)
Impairment charges	$'m	-	-	(105.3)
Gross profit	$'m	36.3	13.1	36.0

(1) 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.

Revenues

		Three months ended		Years ended
	Unit	March 31, 2026	March 31, 2025	December 31, 2025
Oil revenue	$'m	64.3	75.7	545.5
Gas revenue	$'m	50.0	0.7	14.4
Total revenue	$'m	**114.3**	**76.4**	**559.9**
Realized oil prices [1]	$/bbl	63.7	75.6	68.2
Oil volumes sold	MMbbl	1.0	1.0	8.0
Realized gas prices	$'m/bcf	1.8	1.0	0.9
Gas volumes sold	Bcf	5.2	0.7	15.7

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

BUSINESS UPDATE - CONTINUED

The decrease in oil revenue in Q1 2026 compared to Q1 2025 was mainly driven by a lower realized oil price of $63.7/bbl in Q1 2026 compared to $75.6/bbl in Q1 2025. During Q1 2025 prior to March 19 when the Company completed the Amalgamation, an additional 4 cargo liftings occurred with an average realized oil price of $80.5/bbl. See Management's Discussion and Analysis as per December 31, 2025, for more information.

The increase in gas revenue in Q1 2026 compared to Q1 2025 was mainly driven by the fact that the Company and its JV Parties in PML 2/3 successfully executed an amendment to the gas sale agreement during Q1 2026 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 pricing that includes the handling fee for the gas sold. The amendment to the gas sale agreement resulted in the immediate revision of the gas pricing retrospectively as from June 2025 with the Company recognizing gas revenues of $13.7 million primarily covering the period from June 2025, with this receivable forming part of trade receivables outstanding as at March 31, 2026. In addition, the Company calculated the fair value of the future upward adjustments to the pricing to cover the period from 2020 to June 2025 using a discount rate that considers the credit risk of the counterparties in the agreement resulting in the recognition of a receivable of $27.1 million. Gas revenues related to the recovery of the arrears recognized under the amended gas sales agreement therefore amounted to $40.8 million. During Q1 2025 prior to March 19, 2025, when the Company completed the Amalgamation, additional gas revenue was recognized of $4.7 million. See Management's Discussion and Analysis as per December 31, 2025, for more information.

Commodity risk management contracts

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. The derivatives held by the Company under its hedging strategy have been designated as a financial liability at fair value through profit or loss. As such, any gains or losses arising from changes in the fair value of these derivatives are taken directly to profit or loss which has resulted in a non-cash charge to the income statement during Q1 2026 of $37.6 million as a result of rising oil prices during the quarter.

Movements on overlift/ underlift balances

During Q1 2026 Meren lifted one oil cargo with lifted oil volumes being lower than Meren's net entitlement oil volumes resulting in a net underlift movement, compared to an overlift movement in Q1 2025. During Q1 2025 prior to March 19, 2025, when the Company completed the Amalgamation, an additional 4 cargo liftings occurred resulting in a further overlift position for the quarter. See Management's Discussion and Analysis as per December 31, 2025, for more information.

Production costs

	Three months ended		Years ended
$'m	March 31, 2026	March 31, 2025	December 31, 2025
Cost of operations	40.9	7.4	114.3
Royalties – oil and gas	12.1	1.5	29.4
Others	4.7	0.4	22.9
Total production costs	**57.7**	**9.3**	**166.6**

Production costs in Q1 2026 are higher compared to Q1 2025 in the table above as the comparative period only included production costs since March 19, 2025, when the Company completed the Amalgamation. Production costs during Q1 2025 prior to March 19, 2025, amounted to $52.3 million, giving total production costs for Q1 2025 of $61.6 million. See Management's Discussion and Analysis as per December 31, 2025, for more information. On that basis, the decrease in production costs from $61.6 million to $57.7 million amounted to $3.9 million and was mainly driven by lower production volumes.

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

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	March 31, 2026	March 31, 2025	December 31, 2025
Cost of operations	$'m	40.9	7.4	114.3
Entitlement production	MMboe	2.8	0.5	9.9
Opex/boe	$/boe	**14.6**	**14.8**	**11.5**

See Management's Discussion and Analysis as per December 31, 2025, for more information about opex/boe for Q1 2025 including the period prior to March 19, 2025, when the Company completed the Amalgamation, which amounted to $13.4/boe. The increase from $13.4/boe in Q1 2025 to $14.6/boe during Q1 2026 was mainly driven by lower entitlement production volumes.

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

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	March 31, 2026	March 31, 2025	December 31, 2025
Cash flow from operations	(27.4)	36.4	178.6
Excluding working capital adjustments included in cash flow from operations	106.4	(37.3)	94.0
Cash flow from operations before working capital	**79.0**	**(0.9)**	**272.6**

During Q1 2025 prior to March 19, 2025, when the Company completed the Amalgamation, additional cash flow from operations of $75.0 million was generated giving total cash flow from operations for Q1 2025 of $111.4 million and additional cash flow from operations before working capital of $100.7 million was generated giving total cash flow from operations before working capital for Q1 2025 of $99.8 million. See Management's Discussion and Analysis as per December 31, 2025, for more information.

Free cash flow

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.

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	March 31, 2026	March 31, 2025	December 31, 2025
Total cash flow	$'m	(13.1)	367.0	113.3
Add back dividends paid to shareholders	$'m	-	-	100.2
Add back repurchase of share capital	$'m	-	8.3	8.3
Add back debt service costs including drawdowns (1)	$'m	(22.7)	135.0	455.5
Free cash flow	$'m	**(35.8)**	**510.3**	**677.3**

(1) Debt service costs including drawdowns comprise interest payments, loan modification fees, repayments and drawdowns of third-party borrowings.

BUSINESS UPDATE - CONTINUED

Free cash flow for Q1 2026 decreased compared to Q1 2025. Free cash flow in Q1 2025 included cash acquired as part of the Amalgamation of $380.4 million, distributions received from Meren Coop prior to March 19, 2025, when the Company completed the Amalgamation, of $60.0 million and distributions received from associated companies of $31.6 million. See Management's Discussion and Analysis as per December 31, 2025, for more information.

Tax

The tax expense is made up of the following items:

		Three months ended		Years ended
	Unit	March 31, 2026	March 31, 2025	December 31, 2025
Current tax expense	$'m	12.2	16.0	135.9
Deferred tax expense/ (income)	$'m	26.9	(12.2)	(92.5)
Total tax	$'m	**39.1**	**3.8**	**43.4**

The current tax expense is mainly made up of withholding tax on dividends and corporate income tax at a rate of 30.0% of assessable profits in Nigeria, the Development Levy (new since 2026) that is imposed on every Nigerian company at a rate of 4.0% of assessable profits and that replaces the Education tax and the Naseni Levy that apply to every Nigerian company at a rate of 3.0% and 0.25% respectively until December 31, 2025.

Capital expenditure

Capital expenditure is made up of the following items:

	Three months ended		Years ended
$'m	March 31, 2026	March 31, 2025	December 31, 2025
Nigeria	7.6	1.8	69.2
Equatorial Guinea	1.2	1.7	6.6
South Africa	0.1	0.1	(0.2)
Total capex	**8.9**	**3.6**	**75.6**

Capital expenditure increased in Q1 2026 compared to Q1 2025 as the comparative period only included production costs since March 19, 2025, when the Company completed the Amalgamation. Capital expenditure during Q1 2025 prior to March 19, 2025, amounted to $24.6 million, giving total capex for Q1 2025 of $28.2 million. See Management's Discussion and Analysis as per December 31, 2025, for more information. Decrease in capex from $28.2 million to $8.9 million was mainly driven by ongoing infill drilling on Egina during Q1 2025.

Net Debt

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

	Three months ended		Years ended
As at/ $'m	March 31, 2026	March 31, 2025	December 31, 2025
Loans and borrowings	370.0	620.0	330.0
Cash and cash equivalents	(161.6)	(428.4)	(174.7)
Net Debt	**208.4**	**191.6**	**155.3**

As at March 31, 2026, the Company has $161.6 million of cash and cash equivalents and $370.0 million of debt (as at December 31, 2025 - $174.7 million of cash and cash equivalents and $330.0 million of debt). During Q1 2026, the Company refinanced its RBL facility and drew down $40.0 million increasing outstanding debt to $370.0 million.

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		Twelve months ended
$'m	March 31, 2026	March 31, 2025	March 31, 2026
Total profit/ (loss)	(42.2)	50.9	(124.7)
Add back:			
Tax	39.1	3.8	78.7
Finance costs	21.6	2.8	66.6
Finance income	(1.3)	(1.1)	(4.3)
Impairment charges/ (reversals)	-	(55.9)	105.3
Depletion, depreciation and amortization costs	49.5	12.1	246.4
Unrealized result on commodity risk management contracts	37.6	-	35.4
Realized result on commodity risk management contracts	(4.1)	-	(4.1)
EBITDAX	**100.2**	**12.6**	**399.3**
Net Debt			208.4
Net Debt/ EBITDAX			**0.5**

Net debt/ EBITDAX has been calculated on a rolling basis comprising Q2 2025 until Q1 2026, therefore not impacted by Q1 2025 when the Company completed the Amalgamation on March 19, 2025.

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.

For spot cargos, the Dated Brent component of the price is not fixed but determined on or around the date of the lifting 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		Year ended
Oil Sales	Unit	March 31, 2026	March 31, 2025	December 31, 2025
Gross crude oil sales				
Quantity in Mboe	Mboe	1,008.8	1,001.5	8,007.0
Average sales price	$/bbl	63.7	75.6	68.2
Average Bloomberg Dated Brent for the period	$/bbl	81.0	75.7	69.1

The Company sold 1 cargo in February 2026, at an all-in price of $63.7/bbl.

During Q1 2025 prior to March 19, 2025, when the Company completed the Amalgamation, an additional 4 cargo liftings occurred with an average realized oil price of $80.5/bbl. See Management's Discussion and Analysis as per December 31, 2025, for more information.

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 March 31, 2026, the group has a mix of physical and financial hedges, as per the table below.

Q2 2026 breakdown	Mbbl	Fixed price $/bbl	Sold put $/bbl	Bought put $/bbl	Sold call $/bbl	Sold swap $/bbl
Fixed Price (Offtake)	1,000	59.6	-	-	-	-
Total	**1,000**					

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	**1,650**					

H1 2027 breakdown	Mbbl	Fixed price $/bbl	Sold put $/bbl	Bought put $/bbl	Sold call $/bbl	Sold swap $/bbl
Collar	150	-	-	72.50	94.90	-
Total	**150**					

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 suspension was lifted in March 2026, and a specialist panel is being appointed to review the environmental authorization appeals process and make a recommendation to the Minister. The timing of this review process remains uncertain. 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.

The Company remains in active discussions with potential partners and continues to progress forward planning for both blocks.

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 March 31, 2026, 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 March 31, 2026:

	Africa Energy	Impact [(1)]
Issued and Outstanding	479,162,450	1,139,147,442
Shares held by Meren at December 31, 2025	55,396,483	449,464,396
Shares acquired in the period	-	-
Shares held by Meren at March 31, 2026	55,396,483	449,464,396
Meren's holding (%) – March 31, 2026	11.56%	39.46%
Meren's holding (%) – December 31 2025	11.56%	39.46%
Share price (CAD) on March 31, 2026	0.26	-
Exchange rate to USD on March 31, 2026	0.72	-

(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. Impact's interest in these blocks (9.5%) is fully carried for all JV costs through an arrangement with TotalEnergies, through to first commercial production, without any financial cap.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE

The Company's Sustainability Strategy supports the Company's goal of the creation of long-term stakeholder value through aligning with or surpassing applicable regulatory requirements; building effective and adaptive risk management approaches; being a trusted partner for our stakeholders and a good neighbour to our local communities.

During Q1 2026 there were no reported material HSEC incidents.

GHG emissions during the reporting period were in line with operational forecasts. Flaring at the Agbami FPSO in Nigeria was elevated during early Q1 2026 following turn-around maintenance, flaring has subsequently declined as production has been resumed.

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. In Namibia, the ESIA for the Venus development was submitted to regulatory authorities on January 12, 2026. The Operator has applied for an Environmental Clearance Certificate to permit construction and operational activities.

The Company's 2025 Sustainability Report will be published on the Company's website during Q2 2026. As with previous reports it contains more detailed information on the Company's performance and strategy related to sustainability matters.

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-Mar 2026	31-Dec 2025	30-Sep 2025	30-Jun 2025	31-Mar 2025	31-Dec 2024	30-Sep 2024	30-Jun 2024
Revenue	114.3	197.5	216.7	69.3	76.4	-	-	-
Net (loss)/ income attributable to common shareholders ($'m)	(42.2)	(90.8)	5.2	3.1	50.9	6.2	(289.2)	0.4
Weighted average shares – Basic '000	675,944	675,686	675,513	675,012	468,472	442,690	442,960	451,231
Weighted average shares – Diluted '000	675,944	675,686	682,770	682,039	476,836	449,667	442,960	464,890
Basic (loss)/ income per share ($)	(0.06)	(0.13)	0.01	0.00	0.11	0.02	(0.65)	0.00
Diluted (loss)/ income per share ($)	(0.06)	(0.13)	0.01	0.00	0.11	0.02	(0.65)	0.00

SUMMARY OF KEY ITEMS OF FINANCIAL PERFORMANCE IN THE THREE MONTHS ENDED MARCH 31, 2026, AND MARCH 31, 2025

	Three months ended	
	March 31, 2026	March 31, 2025
Revenue	114.3	76.4
Gross profit	36.3	13.1
General and administrative expenses	(8.2)	(13.5)
Net (loss)/ income	(42.2)	50.9

Revenue

Revenue generated in Q1 2026 was $114.3 million (Q1 2025 - $76.4 million) and primarily related to 1 cargo sold in Q1 2026 at a price of $63.7/bbl and additional gas revenue recognized under the amended gas sales agreement of $40.8 million. There was one cargo sold in Q1 2025 at a price of $75.6/bbl.

Gross profit

Gross profit reported in Q1 2026 was $36.3 million (Q1 2025 - $13.1 million). Gross profit was impacted by changes in the fair value of oil derivative contracts resulting in a non-cash charge to the income statement of $37.6 million as a result of rising oil prices during the quarter.

General and administrative costs

On March 19, 2025, the Company announced the completion of the Amalgamation. 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 Amalgamation related expenses and is meant to improve comparability between periods. The Amalgamation related expenses also include certain LTIP charges for fully vested LTIP units as a result of the closing of the Amalgamation.

	Three months ended	
	March 31, 2026	March 31, 2025
General and administrative expenses	8.2	13.5
Amalgamation related expenses	-	(7.6)
Adjusted general and administrative expenses	**8.2**	**5.9**

SUMMARY OF QUARTERLY INFORMATION - CONTINUED

Adjusted general and administrative expenses in Q1 2026 amounted to $8.2 million (Q1 2025 - $5.9 million). Share-based compensation charges in Q1 2026 amounted to $3.4 million (Q1 2025 – $1.2 million) and 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 $4.7 million in Q1 2026, in line with Q1 2025.

Net (loss) / income and Adjusted net loss

Net (loss)/ income as reported by the Company in its interim condensed consolidated financial statements can be impacted by items that are not reflective of the Company's underlying performance for the period. This might impact the comparability of the results of the Company between periods.

Adjusted net loss is a non-GAAP measure. This measure adjusts for the following items and is meant to improve comparability between periods:

- Impairment and reversal of impairment is adjusted since this affects the economics of an asset for the lifetime of that asset, not only the period in which it is impaired, or the impairment is reversed.
- Share of loss from investments in associates is adjusted since the associated companies are in the exploration phase with the results not being reflective of the Company's underlying performance for the period.
- Other items of income and expenses are adjusted when the impact on net income in the period is not reflective of the Company's underlying performance for the period.
- Tax effects of the above-mentioned adjustments to net income.

A reconciliation from net (loss)/ income to adjusted net loss is shown below:

		Three months ended		Years ended
	Unit	March 31, 2026	March 31, 2025	December 31, 2025
Net (loss)/ income	$'m	**(42.2)**	**50.9**	**(31.6)**
Adjusted for:				
Impact of amended gas sales agreement [(1)]	$'m	(38.8)	-	-
Impairment charges	$m	-	-	105.3
Commodity risk management contracts	$m	37.6	-	(2.2)
Realized results on commodity risk management contracts	$m	(4.1)	-	-
Result on RBL modification	$m	10.4	-	-
(Reversal of impairment)/ impairment investment in Prime	$'m	-	(55.9)	(55.9)
Share of loss from investments in associates	$'m	10.9	2.0	2.9
Tax effects on adjustments	$m	13.2	-	(31.6)
Adjusted net loss	$'m	**(13.0)**	**(3.0)**	**(13.1)**
Adjusted net loss attributable to common shareholders per share				
Basic		(0.02)	(0.01)	(0.02)
Diluted		(0.02)	(0.01)	(0.02)
Weighted average number of shares outstanding for the purpose of calculating adjusted net loss per share				
Basic		675,943,545	468,472,433	624,464,015
Diluted		675,943,545	468,472,433	624,464,015

(1) Total gas revenues recognized under the amended gas sales agreement of $40.8 million offset against recovery of gas receivable of $2.0 million.

SUMMARY OF QUARTERLY INFORMATION - CONTINUED

SUMMARY OF KEY ITEMS OF FINANCIAL POSITION AS AT MARCH 31, 2026, AND DECEMBER 31, 2025

As at	March 31, 2026	December 31, 2025
Assets		
Oil and gas properties	1,371.9	1,413.5
Intangible exploration assets	45.0	43.7
Equity investments in associates	131.3	142.2
Cash and cash equivalents	161.6	174.7
Outstanding bank debt	370.0	330.0

Oil and gas properties

As at March 31, 2026, oil and gas properties amounted to $1,371.9 million (as at December 31, 2025 - $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. The decrease during the quarter mainly related to depletion charges partly offset by capex additions.

Intangible exploration assets:

As at March 31, 2026, the carrying amount of the Company's intangible exploration assets in Equatorial Guinea was $25.7 million (as at December 31, 2025 - $24.5 million) and related to its 80% interest in Blocks EG-18 and EG-31.

As at March 31, 2026, the carrying amount of the Company's intangible exploration assets in South Africa was $19.3 million (as at December 31, 2025 - $19.2 million) and related to its 18.0% (as at December 31, 2025 - 18.0%) participating interest in the Block 3B/4B Exploration Right.

Equity investments in associates

As at March 31, 2026, the Company's investment in associates was $131.3 million compared to an investment value of $142.2 million as at December 31, 2025. The carrying value of the investments in Q1 2026 from the Company's share of the associates losses of $10.9 million. Impact recognized an impairment to its non-Namibia oil and gas interests of approximately $26.6 million with the Company's share of the loss being approximately $10.5 million. The investment in Impact, holding the working interests in the Namibia Orange Basin Blocks 2913B and 2912, makes up $130.2 million of the total equity investments in associates.

Cash and cash equivalents

As at March 31, 2026, the Company had $161.6 million cash and cash equivalents on hand, compared to a cash balance of $174.7 million as at December 31, 2025. The Company drew $40.0 million on the RBL facility, paid $10.4 million of fees on the refinancing of the RBL, 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 drawdowns of $40.0 million under the refinanced RBL facility, increasing outstanding bank debt to $370.0 million as at March 31, 2026. RBL facility headroom of $204.2 million at the end of Q1 2026.

LIQUIDITY AND CAPITAL RESOURCES

As at March 31, 2026, the Company had cash balances of $161.6 million and net working capital balances (including cash balances) of $82.7 million. Net working capital is calculated as current assets less current liabilities as presented in the consolidated balance sheet as per March 31, 2026. The Company's primary source of liquidity is operating income in Nigeria and the remaining undrawn amounts on the RBL.

Reserves Based Lending Facility

On March 27, 2026, the Company successfully amended its Reserves Based Lending ("RBL") Facility, significantly increasing its debt capacity and extending its debt maturity profile. The RBL facility will have a total commitment of $600.0 million with an accordion feature permitting an increase in the total facility size up to $1 billion. 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 March 31, 2026, the BBA was $574.2 million (December 31, 2025 - $468.4 million), which will amortize as the RBL moves towards final maturity.

The amended facility will accrue interest at the applicable SOFR rate plus 4.00% until March 27, 2029, increasing to 4.25% until final maturity on March 27, 2032. This represents a loan-life average margin reduction of 0.125% compared to the previous facility terms. 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, 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 March 31, 2026.

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.

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	676,115,307
Outstanding restricted share units	1,316,069
Outstanding performance share units	10,391,709
Full dilution impact on Common Shares outstanding	687,823,085

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 this increased to $43.4 million by 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 of 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 March 31, 2026.

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 $116.6 million as per March 31, 2026, 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 March 31, 2026, one cargo of the Group's expected lifted entitlement production for Q2-2026 is covered by forward contracts. The average cargo lifted is for 1 million barrels of oil. The Group's trigger for this cargo covered by a forward contract has been triggered at $59.6 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 year ended 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, where 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 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 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 Amalgamation relates to the equity investment in a 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

CRITICAL ACCOUNTING ESTIMATES - CONTINUED

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 13).

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 21).

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.

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.

GOING CONCERN

The consolidated financial statements for the three months ended March 31, 2026, 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 March 31, 2026, 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 March 31, 2026, 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/.

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 base 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;

FORWARD-LOOKING STATEMENTS - CONTINUED

- 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.

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.

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

(Expressed in millions of United States dollars)

For the three months ended	Note	March 31, 2026	March 31, 2025
Revenue	4	114.3	76.4
Commodity risk management contracts	27	(37.6)	-
Movements on overlift/underlift balances	5	66.5	(41.9)
Production costs	6	(57.7)	(9.3)
Depletion costs	12	(49.2)	(12.1)
Gross profit		36.3	13.1
General and administrative expenses		(8.2)	(13.5)
Operating income/ (loss)		28.1	(0.4)
Finance income	7	1.3	1.1
Finance expense	8	(21.6)	(2.8)
Net financial items		(20.3)	(1.7)
Share of profit from investment in joint venture		-	2.9
Share of loss from investments in associates	14	(10.9)	(2.0)
Reversal of impairment of investment in joint venture	9	-	55.9
(Loss)/ income before tax		(3.1)	54.7
Income tax	10	(39.1)	(3.8)
Net (loss)/ income attributable to common shareholders		(42.2)	50.9
Total comprehensive (loss)/ income		(42.2)	50.9
Net (loss)/ income attributable to common shareholders per share			
Basic	11	(0.06)	0.11
Diluted	11	(0.06)	0.11
Weighted average number of shares outstanding for the purpose of calculating earnings per share			
Basic	11	675,943,545	468,472,433
Diluted	11	675,943,545	476,836,682

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

INTERIM CONDENSED CONSOLIDATED BALANCE SHEET

(Expressed in millions of United States dollars)

As at	Note	March 31, 2026	December 31, 2025
ASSETS			
Non-current assets			
Oil and gas properties	12	1,371.9	1,413.5
Intangible exploration assets	13	45.0	43.7
Other tangible fixed assets		3.3	3.7
Equity investments in associates	14	131.3	142.2
Other long-term receivables	15	21.5	-
		1,573.0	1,603.1
Current assets			
Inventories	16	98.8	94.2
Trade and other receivables	15/17	139.2	77.7
Derivative financial instruments	27	-	2.2
Cash and cash equivalents	18	161.6	174.7
		399.6	348.8
Total assets		1,972.6	1,951.9
LIABILITIES AND EQUITY			
Equity attributable to common shareholders			
Share capital	19	1,536.6	1,536.2
Contributed surplus		95.5	95.5
Treasury share account		-	-
Deficit		(933.1)	(865.8)
Total equity attributable to common shareholders		699.0	765.9
Non-current liabilities			
Financial liabilities	20	372.7	265.2
Provisions	21	275.3	271.3
Deferred tax liabilities		308.7	281.8
		956.7	818.3
Current liabilities			
Financial liabilities	20	0.9	68.6
Trade and other payables	22	115.8	150.8
Derivative financial liability	27	35.0	-
Current tax liabilities		38.6	48.5
Dividends	23	25.1	-
Provisions	21	101.5	99.8
		316.9	367.7
Total liabilities		1,273.6	1,186.0
Total liabilities and equity attributable to common shareholders		1,972.6	1,951.9

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

Approved on behalf of the Board:

"MICHAEL EBSARY"

MICHAEL EBSARY, DIRECTOR

"OLIVER QUINN"

OLIVER QUINN, DIRECTOR

INTERIM CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(Expressed in millions of United States dollars)

For the three months ended	Note	March 31, 2026	March 31, 2025
Share capital:	19 (A)		
Balance, beginning of the period		1,536.2	1,195.8
Share issuance to BTG Oil & Gas under Amalgamation Agreement	19	-	353.2
Settlement of Restricted Share Units	19	0.1	1.1
Settlement of Performance Share Units	19	0.3	1.5
Weighted average value of shares cancelled	19	-	(16.8)
Balance, end of the period		1,536.6	1,534.8
Contributed surplus:			
Balance, beginning of the period		95.5	87.4
Excess of weighted value of shares cancelled	19	-	8.1
Balance, end of the period		95.5	95.5
Treasury share account:			
Balance, beginning of the period		-	(0.4)
Shares purchased	19	-	(8.3)
Shares cancelled	19	-	8.7
Balance, end of the period		-	-
Deficit:			
Balance, beginning of the period		(865.8)	(734.0)
Dividends	19	(25.1)	(25.0)
Net (loss)/ income attributable to common shareholders		(42.2)	50.9
Balance, end of the period		(933.1)	(708.1)
Total equity attributable to common shareholders			
Balance, end of the period		699.0	922.2

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

INTERIM CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS

(Expressed in millions of United States dollars)

For the three months ended	Note	March 31, 2026	March 31, 2025
Cash flows generated by/ (used in):			
Operations:			
(Loss)/ profit before tax		(3.1)	54.7
Adjustments for:			
Reversal of impairment of investment in joint venture	9	-	(55.9)
Share of loss from investments in associates	14	10.9	2.0
Share of profit from investment in joint venture		-	(2.9)
Result on commodity risk management contracts	27	37.6	-
Settlement of commodity risk management contracts	27	(0.4)	-
Net financial items	7/8	20.3	1.7
Depletion, depreciation and amortisation	12	49.5	12.1
Share-based compensation		3.4	4.0
Recognized gas receivable	15	(27.1)	-
Taxes	10	(12.2)	(16.0)
Other		0.1	(0.6)
Net cash generated/ (used) in operating activities before working capital		79.0	(0.9)
Changes in working capital		(106.4)	37.3
Net cash (used)/ generated in operating activities		(27.4)	36.4
Investing:			
Investments in oil and gas properties and intangible exploration assets	12/13	(8.9)	(3.6)
Distribution received from joint venture		-	60.0
Distribution received from associates	14	-	31.6
Loan repaid by / (provided to) associated company		-	4.5
Interest income received		0.5	0.9
Cash acquired from Meren Coop consolidation		-	380.4
Net cash (used)/ generated in investing activities		(8.4)	473.8
Financing:			
Drawdown/ (repayment) RBL Facility		40.0	(130.0)
RBL modification fees		(10.4)	-
Repayment of principal portion of lease commitments	20	(0.2)	(0.1)
Repurchase of share capital	19	-	(8.3)
Interest expense paid		(6.7)	(4.9)
Net cash generated/ (used) in financing activities		22.7	(143.3)
Effect of exchange rate changes on cash and cash equivalents denominated in foreign currency		-	0.1
(Decrease)/ increase in cash and cash equivalents		(13.1)	367.0
Cash and cash equivalents, beginning of the year	18	174.7	61.4
Cash and cash equivalents, end of the year	18	161.6	428.4

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

NOTES TO INTERIM CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

For the three months ended March 31, 2026, and March 31, 2025
(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.

2. Basis of preparation:

A. Statement of compliance:

The Company prepares its interim condensed consolidated financial statements in accordance with Canadian generally accepted accounting principles for interim periods, specifically International Accounting Standard ("IAS") 34 Interim Financial Reporting as issued by the International Accounting Standards Board. They are condensed as they do not include all the information required for full annual financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards") and they should be read in conjunction with the consolidated financial statements for the year ended December 31, 2025.

The policies applied in these interim condensed consolidated financial statements are based on IFRS Accounting Standards and IAS 34.

These interim condensed consolidated financial statements were approved for issuance by the Company's Board of Directors on May 12, 2026.

B. Basis of measurement:

The interim condensed 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.

C. Functional and presentation currency:

These interim condensed 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 interim condensed 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 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. Items subject to estimates and judgement have been described in the Company's audited consolidated financial statements for the year ended December 31, 2025.

E. Going concern

These interim condensed consolidated financial statements for the three months ended March 31, 2026, 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:

Material accounting policies used in the preparation of these interim condensed consolidated financial statements are described in the Company's consolidated financial statements for the year ended December 31, 2025.

On January 1, 2026, the Company adopted amendments to the Classification and Measurement of Financial Instruments – Amendments to IFRS 9 and IFRS 7. The amendments clarify that a financial liability is derecognized on the 'settlement date' and introduce an accounting policy choice to derecognize financial liabilities settled using an electronic payment system before the settlement date. Other clarifications include the classification of financial assets with ESG linked features via additional guidance on the assessment of contingent features. Clarifications have been made to non-recourse loans and contractually linked instruments. There was no material impact to the Company's financial statements.

On January 1, 2026, the Company adopted annual improvements to IFRSs: Volume 11. The amendments in Volume 11 focus on five key IFRS Accounting Standards. There was no material impact to the Company's financial statements.

Other new accounting standards and amendments to accounting standards have been published that are not mandatory for March 31, 2026, reporting periods and have not been early adopted by the Company. These are as follows:

- 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;
- 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. Revenue:

Revenue for the three months ended March 31, 2026, and March 31, 2025, is comprised of the following:

For the three months ended	March 31, 2026	March 31, 2025
Oil revenue	64.3	75.7
Gas revenue	50.0	0.7
Total revenue	114.3	76.4

In January 2026, the Company 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 resulting in the recognition of gas revenues of $40.8 million (see Note 15).

5. Movements in overlift/ underlift balances:

The movement in overlift/ underlift balances amounted to profit of $66.5 million (three months ended March 31, 2025 - charge of $41.9 million) and related to the Group's excess of its entitlement production for the period over its crude oil sales during the period. Also refer to notes 17 and 22.

6. Production costs:

Production costs for the three months ended March 31, 2026, and March 31, 2025, is comprised of the following:

For the three months ended	March 31, 2026	March 31, 2025
Cost of operations	40.9	7.4
Royalties	12.1	1.5
Others	4.7	0.4
Total production costs	57.7	9.3

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

On March 19, 2025, the Company completed the transaction with BTG Oil & Gas to consolidate its interest in Meren Coop resulting in the comparative period reflecting production costs since this date only.

7. Finance income:

For the three months ended	March 31, 2026	March 31, 2025
Interest income on cash and cash equivalents	0.4	0.9
Interest income from associated companies	-	0.2
Unwinding of receivables (see Note 15)	0.9	-
Total finance income	1.3	1.1

8. Finance expense:

For the three months ended	March 31, 2026	March 31, 2025
Interest expense on RBL	6.9	1.6
Commitment fees	1.0	0.6
Result on RBL modification	10.4	-
Unwinding of site restoration provision	3.1	0.5
Others	0.2	0.1
Total finance expense	21.6	2.8

9. Reversal of impairment of investment in joint venture:

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 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.

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.

10. Income tax

For the three months ended	March 31, 2026	March 31, 2025
Current tax expense	12.2	16.0
Deferred tax expense/ (income)	26.9	(12.2)
Total income tax	39.1	3.8

11. Net result per share:

For the three months ended	March 31, 2026			March 31, 2025		
		Weighted Average			Weighted Average	
	Net loss	Number of shares	Per share amounts	Net income	Number of shares	Per share amounts
Basic (loss)/ income per share						
Net (loss)/ income attributable to common shareholders	(42.2)	675,943,545	(0.06)	50.9	468,472,433	0.11
Effect of dilutive securities	-	-	-	-	8,364,249	-
Dilutive (loss)/ income per share	(42.2)	675,943,545	(0.06)	50.9	476,836,682	0.11

In the three months ended March 31, 2026, 5,480 options, 1,316,069 RSUs and 10,502,816 PSUs, were anti-dilutive as the Company reported a net loss and were not included in the calculation of dilutive income per share (three months ended March 31, 2025, 285,493 options, were anti-dilutive and not included in the calculation of dilutive income per share). In the three months ended March 31, 2025, the Company used an average market price of CAD $1.97 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.

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.

12. 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**
Additions	7.6
At March 31, 2026	**1,734.3**
Depletion and impairments	
At January 1, 2025	-
Depletion	(207.9)
Impairment charges	(105.3)
At December 31, 2025	**(313.2)**
Depletion	(49.2)
At March 31, 2026	**(362.4)**
Oil and gas properties as at March 31, 2026	**1,371.9**

As at March 31, 2026, oil and gas properties amounted to $1,371.9 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 (as at December 31, 2025 - $1,413.5 million).

In 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 21).

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 oil price volatility at that time 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 and non-cash impairment charges of $105.3 million were recognized on the Group's oil and gas properties related to the CGU.

As at March 31, 2026, the Company determined that there were no indicators of impairment or impairment reversal for its oil and gas properties.

13. Intangible exploration assets:

	Intangible exploration assets		
	Equatorial Guinea	South Africa	Total
At January 1, 2025	17.9	11.4	29.3
Additions	6.6	7.8	14.4
At December 31, 2025	24.5	19.2	43.7
Additions	1.2	0.1	1.3
At March 31, 2026	25.7	19.3	45.0

As at March 31, 2026, the carrying amount of the Company's intangible exploration assets in Equatorial Guinea was $25.7 million and related to its 80% interest in Blocks EG-18 and EG-31 (as at December 31, 2025 – $24.5 million).

As at March 31, 2026, the carrying amount of the Company's intangible exploration assets in South Africa was $19.3 million for its 18.0% (as at December 31, 2025 – 18.0%) participating interest in the Block 3B/4B Exploration Right (as at December 31, 2025 - $19.2 million).

As at March 31, 2026, the Company determined that there were no indicators of impairment for its intangible exploration assets.

14. Equity investments in associates:

The Company holds the following equity investments in associates:

	Africa Energy Corp.	Impact Oil and Gas Ltd	Total
Shares held at March 31, 2026	55,396,483	449,464,396	
Ownership at March 31, 2026	11.6%	39.5%	
At January 1, 2025	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
Share of loss from equity investments	(0.4)	(10.5)	(10.9)
At March 31, 2026	1.1	130.2	131.3

In the three months ended March 31, 2026, the Company recognized a loss of $10.9 million (three months ended March 31, 2025 – loss of $2.0 million).

As at March 31, 2026, 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 March 31, 2026, the market value of the Company's investment in Africa Energy was $10.2 million based on the share price of CAD 0.26 (as at December 31, 2025 - $4.5 million). The carrying value is less than the market value from significant impairments recognized by Africa Energy.

B. 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.

Impact recognized an impairment to its non-Namibia oil and gas interests of approximately $26.6 million with the Company's share of the loss being approximately $10.5 million as recognized during the three months ended March 31, 2026.

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

15. Other long term receivables

	Gas receivable
At January 1, 2026	-
Recognition gas receivable	27.1
Recovery	(2.0)
Unwinding of discount	0.9
At March 31, 2026	26.0
Non-current	21.5
Current	4.5
At March 31, 2026	26.0

In January 2026, the Company 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 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 pricing that includes the handling fee for the gas sold. The amendment to the gas sale agreement resulted in the immediate revision of the gas pricing retrospectively as from June 2025 with the Company recognizing gas revenues of $13.7 million primarily covering the period from June 2025, with this receivable forming part of trade receivables outstanding as per March 31, 2026 (see Note 17). In addition, the Company calculated the fair value of the future upward adjustments to the net back pricing to cover the period from 2020 to June 2025 using a discount rate that considers the credit risk of the counterparties in the agreement resulting in the recognition of a receivable of $27.1 million. Total gas revenues recognized under the amended gas sales agreement therefore amounted to $40.8 million.

16. Inventories:

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

17. Trade and other receivables:

	March 31, 2026	December 31, 2025
Trade receivables	21.3	5.6
Underlift position	66.4	12.2
Short-term receivables with partners	17.3	32.7
Prepaid expenses and accrued income	3.6	2.5
Gas receivable (see Note 15)	4.5	-
Other receivables	26.1	24.7
Total accounts receivable and prepaid expenses	139.2	77.7

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 movements on overlift/underlift balances. 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 21).

18. 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.

19. Share capital:

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

B. Issued:

	March 31, 2026		December 31, 2025	
	Shares	Amount	Shares	Amount
Balance, beginning of the period	675,909,193	1,536.2	439,078,170	1,195.8
Share issuance to BTG Oil & Gas under amalgamation Agreement	-	-	239,828,655	353.2
Exercise of Share Options	-	-	367,600	0.4
Settlement of Restricted Share Units	26,332	0.1	836,323	1.1
Settlement of Performance Share Units	179,782	0.3	1,974,498	2.5
Cancellation of shares repurchased	-	-	(6,176,053)	(16.8)
Balance, end of the period	676,115,307	1,536.6	675,909,193	1,536.2

The Company launched a share buyback program on December 6, 2024, that ended on December 5, 2025. In the year ended December 31, 2025, a total of 5.9 million Meren common shares were repurchased and 6.2 million Meren common shares were cancelled. The Company launched a new share buyback program on December 8, 2025, under which no Meren common shares have been repurchased during the three months ended March 31, 2026, and year ended December 31, 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 three months ended March 31, 2026, the Board of Directors approved a dividend of $0.0371 per share which was declared in February 2026 and paid in April 2026 for a total amount of approximately $25.1 million.

20. Financial liabilities:

	Reserves Based Lending Facility	Lease Liability	Total
At January 1, 2025	-	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
Drawdowns	40.0	-	40.0
Result on RBL modification	10.4	-	10.4
RBL modification fees	(10.4)	-	(10.4)
Repayments	-	(0.2)	(0.2)
At March 31, 2026	370.0	3.6	373.6
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
Non-current	370.0	2.7	372.7
Current	-	0.9	0.9
At March 31, 2026	370.0	3.6	373.6

A. Reserves Based Lending Facility

On March 27, 2026, the Company successfully amended its Reserves Based Lending ("RBL") Facility, significantly increasing its debt capacity and extending its debt maturity profile. The RBL facility will have a total commitment of $600.0 million with an accordion feature permitting an increase in the total facility size up to US$1 billion. 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 at March 31, 2026, the BBA was $574.2 million, which will amortize as the RBL moves towards final maturity (as at December 31, 2025 - $468.4 million).

The amended facility will accrue interest at the applicable SOFR rate plus 4.00% until March 27, 2029, increasing to 4.25% until final maturity on March 27, 2032. This represents a loan-life average margin reduction of 0.125% compared to the previous facility terms. 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, 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 March 31, 2026.

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

On March 27, 2026, the Company amended its RBL Facility. As the amendment did not result in a substantially different financial liability under IFRS 9, the modification was accounted for by adjusting the carrying amount of the RBL to reflect the net present value of the modified future cash flows, discounted at the original effective interest rate, with the resulting difference recognized as a modification loss of $10.4 million in finance expense.

The modification loss is primarily attributable to the transaction fees incurred on the amended facility. When the Company acquired its interest in Meren Coop through the amalgamation with BTG Oil & Gas in March 2025, the RBL was recognized at fair value in accordance with IFRS 3, which resulted in no deferred transaction costs being carried on the balance sheet at the date of the refinancing. As a result, the full value of the new transaction fees is reflected in the modification loss. Fees incurred in connection with the refinancing have been capitalized and will be amortized over the remaining term of the RBL using the effective interest rate method.

21. Provisions:

	Site restoration	Contingent consideration	Share-based compensation	Others	Total
At January 1, 2025	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
Charges	-	-	3.4	0.2	3.6
Unwinding of discount	3.1	-	-	-	3.1
Settlements	-	-	(1.0)	-	(1.0)
At March 31, 2026	266.8	97.9	7.7	4.4	376.8
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
Non-current	266.8	-	4.1	4.4	275.3
Current	-	97.9	3.6	-	101.5
At March 31, 2026	266.8	97.9	7.7	4.4	376.8

A. Site restoration

The provision for site restoration amounted to $266.8 million as at March 31, 2026 (as at December 31, 2025 - $263.7 million). The fair value of the provision for site restoration mainly relates to Nigeria and is 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, 2025 – 4.8%) 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, 2025 – 2.3%).

In the year ended December 31, 2025, the site restoration provisions acquired under the amalgamation represented 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 totaling $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. In addition, 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.

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 this increased to $43.4 million by 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.

22. Trade and other payables:

	March 31, 2026	December 31, 2025
Short-term payables with partners	75.1	97.9
Crude oil overlift payable	13.8	26.1
Accruals	24.2	24.0
Other payables	2.7	2.8
Total trade and other payables	115.8	150.8

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 movements on overlift/underlift balances. An overlift liability is the obligation to deliver oil out of the Group's equity share of future production.

23. Dividends

On February 24, 2026, the Company declared the first 2026 quarterly dividend of approximately $25.1 million or $0.0371 per share with payments made to shareholders during April 2026.

24. Commitments and contingencies:

A. Contingent consideration:

For information on the contingent consideration in relation to the historical acquisition of Meren Coop, refer to Note 21B.

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 March 31, 2026.

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 $116.6 million as per March 31, 2026, 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. The average cargo lifted is for 1 million barrels of oil. As at March 31, 2026, one cargo of the Group's expected lifted entitlement production for Q2 2026 is covered by a forward contract. The forward contract price trigger for this cargo has been activated at $59.6 per barrel.

25. 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 12 and 13.

26. Related party transactions:

There are no material related party transactions to report for the three months ended March 31, 2026.

27. 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 interim condensed 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 March 31, 2026, the Company held $48.3 million (as at December 31, 2025 - $15.9 million) of cash in financial institutions outside of Canada, the Netherlands and the UK. The Company held no cash (as at December 31, 2025 – no cash) 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 March 31, 2026, the Company had $161.6 million of cash and cash equivalents and $204.2 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 March 27, 2032, 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 March 31, 2026, the Company has no liabilities that mature on March 31, 2027, based on the currently approved BBA profile, subject to the results of the next redetermination. An amount of $67.7 million will mature between one year and two years, with the remaining balance of $302.3 million due between two and six years.

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 RBL principal amount of $370.0 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 20 to these interim condensed consolidated financial statements.

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, 1 cargo in Q2 2026 has the trigger price mechanism activated at a price of $59.6/bbl.

As at March 31, 2026, the Company holds derivatives, as outlined in the table below, that are designated as a financial liability at fair value through profit or loss. As such, any gains or losses arising from changes in the fair value of these derivative are taken directly to profit or loss. The Asian Dated Brent Zero Cost Collar with the term relating to Q1 2026 was settled in cash in early April.

	Term	bbl	Sold put $/bbl	Bought put $/bbl	Sold call $/bbl	Sold swap $/bbl	FV at March 31, 2026/ $'m
Asian Dated Brent Zero Cost Collar	January 1, 2026, to March 31, 2026	300,000	-	60.0	67.15	-	(3.7)
Asian Dated Brent Swap	July 1, 2026, to September 30, 2026	600,000	-	-	-	63.58	(13.4)
Asian Dated Brent three-way put spread	October 1. 2026 to December 31, 2026	450,000	45.00	60.00	65.78	-	(7.5)
Asian Dated Brent Swap	July 1, 2026, to December 31, 2026	300,000	-	-	-	64.69	(5.3)
Asian Dated Brent deferred premium collar	July 1, 2026, to December 31, 2026	300,000	-	60.0	74.0	-	(5.1)
Asian Dated Brent deferred premium collar	January 1, 2027, to March 31, 2027	150,000	-	72.5	94.9	-	-
						Total	(35.0)

28. Subsequent events:

On May 12, 2026, the Company's Board declared the second quarterly dividend in 2026 of approximately $25.1 million ($0.0371 per share) payable in June 2026 to shareholders of record at the close of business on May 21, 2026.

Meren

mereninc.com