Meren

Meren Energy Inc.

Delivering Value Through Every Cycle

Third Quarter 2026 Results

11th November 2026

www.mereninc.com

Speakers



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Agenda

Introduction

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Business Outlook

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Forward-Looking Statements

This presentation contains certain statements and information that constitute "forward-looking information" within the meaning of applicable Canadian securities laws. All statements other than statements of historical fact are forward-looking statements.

Forward-looking statements in this presentation include, but are not limited to, statements relating to future production, capital expenditures, cash flows, future funding requirements, dividends and shareholder returns, liquidity, debt levels, business strategy, farm-downs, development, exploration and appraisal activities, project timing, and management guidance.

Management guidance, outlook and associated estimates contained in this presentation constitute future-oriented financial information and are provided to assist readers in understanding management's current expectations concerning future performance.

Forward-looking statements are based on management's current expectations and assumptions and involve known and unknown risks and uncertainties that may cause actual results or events to differ materially from those expressed or implied. These risks include, among others, changes in commodity prices, operating and technical risks, project timing, regulatory approvals, availability of financing, and general economic and market conditions.

Readers are cautioned not to place undue reliance on forward-looking statements. Forward-looking statements speak only as of the date of this presentation, and the Company undertakes no obligation to update or revise such statements except as required by applicable law.

For a discussion of material risk factors and assumptions, please refer to the Company's Management's Discussion and Analysis for the period ended September 30, 2026 and Annual Information Form for the Year Ended December 31, 2025 available on SEDAR+ and on our website (www.mereninc.com).

Highlights

Delivering Operational Targets – Strong Financials – Back to Drilling

1. Production & financial performance on track to meet full-year guidance
2. Balance sheet strengthened: net debt reduced to $185m, with $328m liquidity providing financial flexibility
3. Shareholder returns: fourth dividend of $25m declared, taking 2026 distributions to $100m
4. Back to growth: multi-year Nigeria programme underway - drilling and interventions from Q4, FPSOs life extension, Preowei and Egina South advancing

Capital Returns

Dividends YTD

$100m

Since Prime amalgamation in Mar'25

$200m

Balance Sheet Strength

Net Debt to EBITDAX[1]

0.5x

Liquidity

Cash / RBL Headroom

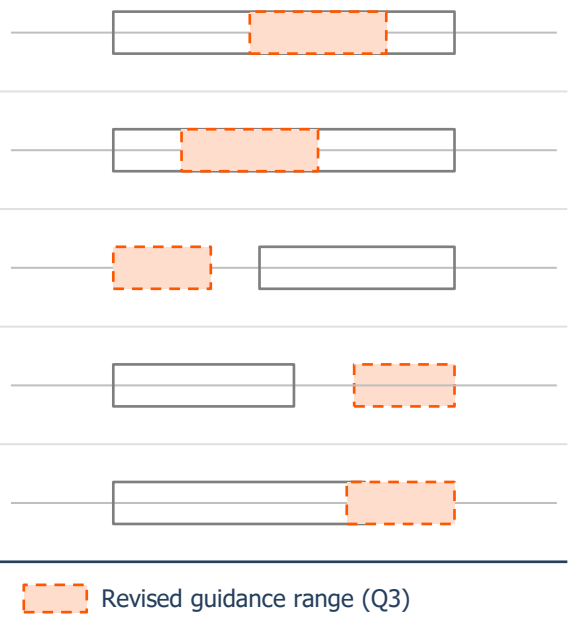
$328m

1) EBITDAX/CFFO are not generally accepted IFRS terms. Refer to Reader Advisory Section (slide 15) of this document for important information on non-IFRS measures.

Full-Year 2026 Management Guidance

Production ranges narrowed; EBITDAX and CFFO raised; Capex lowered

GUIDANCE RANGES



Original 2026 guidance range Revised guidance range (Q3)

2026 GUIDANCE

Metric	Original	Revised	9M'26 actual
W.I. production (1) kboepd	23 – 28	**25 – 27**	26.9
Entitlement production (2) kboepd	28 – 33	**29 – 31**	29.8
Capital investments $ million	100 – 140	**70 – 90**	38.0
EBITDAX (3) $ million	270 – 360	**390 – 440**	332.3
CFFO (3,4) Cash flow from operations, $ million	185 – 255	**250 – 280**	213.0

Full-year Brent assumption

~$98/bbl

Up from ~$86/bbl, lifting EBITDAX and cash flow

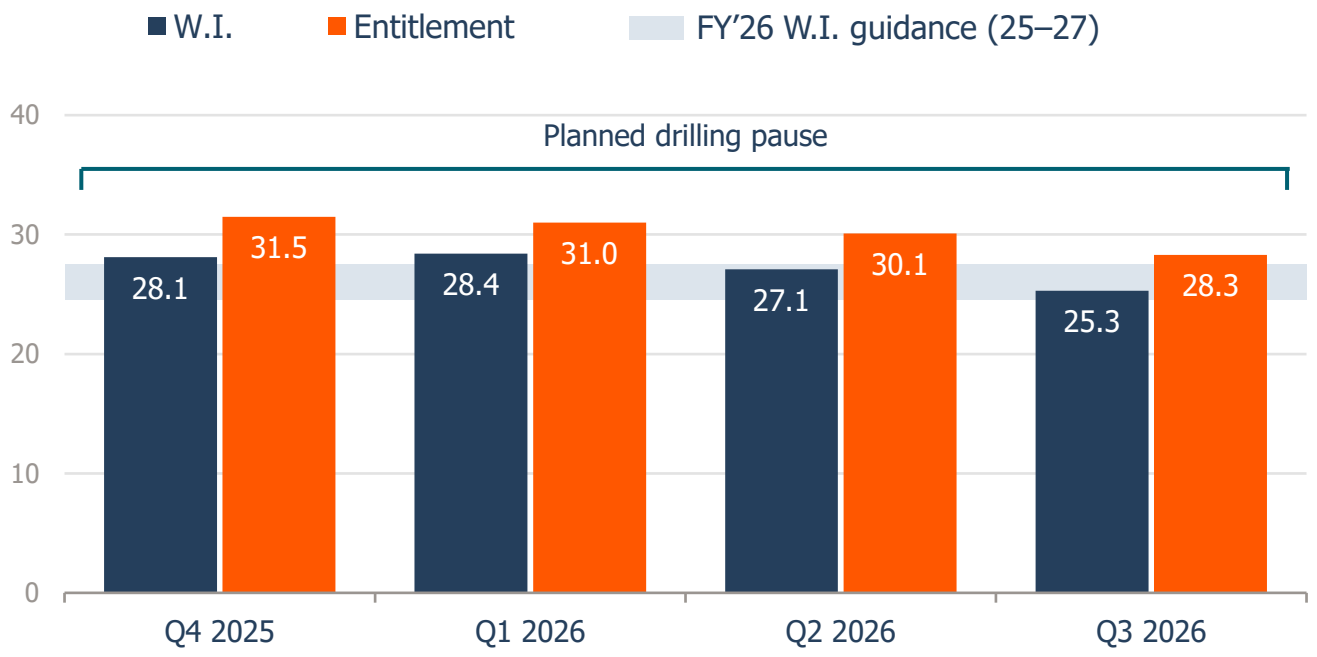
Lower capital investments

The PML 52/ PPL 2003 rig now arrives in Q1 2027, moving spend out of 2026 into 2027, and reduces capital investments guidance to $70–90 million

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, tax 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) EBITDAX/CFFO are not generally accepted IFRS terms. Refer to Reader Advisory Section (slide 15) of this document for important information on non-IFRS measures.
4) CFFO is cash flow from operations before working capital and interest expenses.

Production Performance

Average daily production (kboepd) – production on track for FY'26 guidance; drilling restart underway



Why the pause:
Drilling activity was paused to allow time for re-interpretation of 4D seismic and to optimise future drilling and well activity

Drilling returns to all three fields and more…

Nov. 2026

Rig arrives at Akpo/Egina fields
Start of PMLs 2 and 3 drilling campaign

Q1 2027

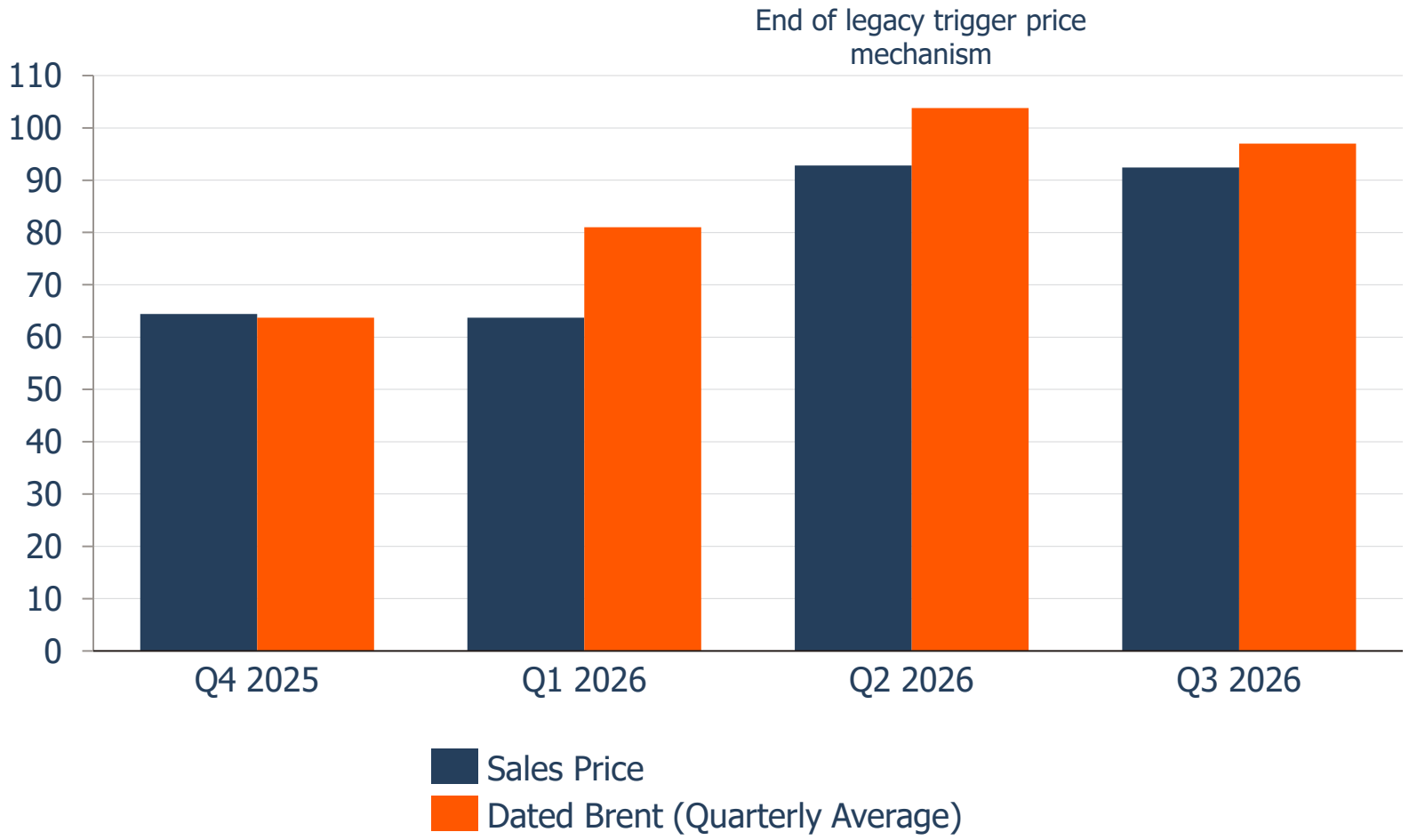
Rig arrives at Agbami field
Rig mobilised for PML 52 and PPL 2003 drilling campaign

2027+

Infill, exploration & appraisal
Infill wells across Akpo, Egina, Agbami, Akpo Far East exploration and Ikija appraisal wells

Oil Sales

Achieved a ~$5.5/bbl premium to Dated Brent on Q3 liftings



Average Q3'26 Sales Price

$92.4/bbl

Jul/Aug Dated Brent: $86.9/bbl

Meren's Dated Brent Premium

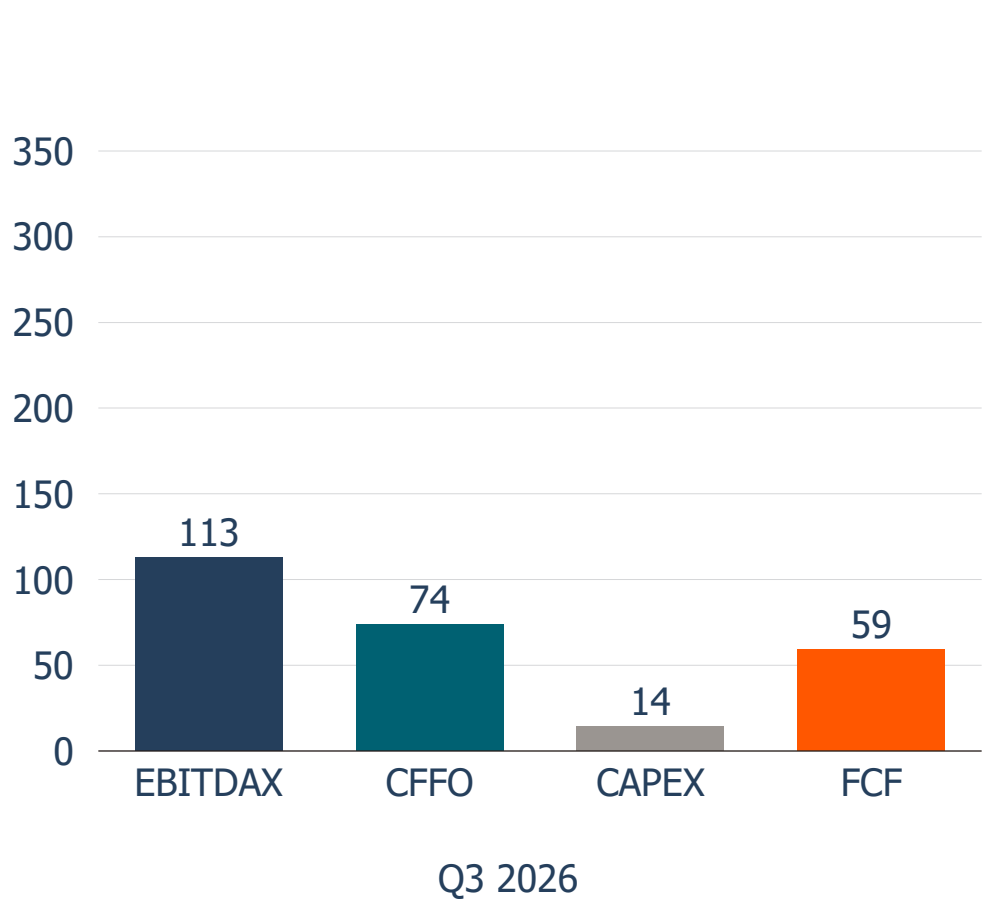
+$5.5/bbl

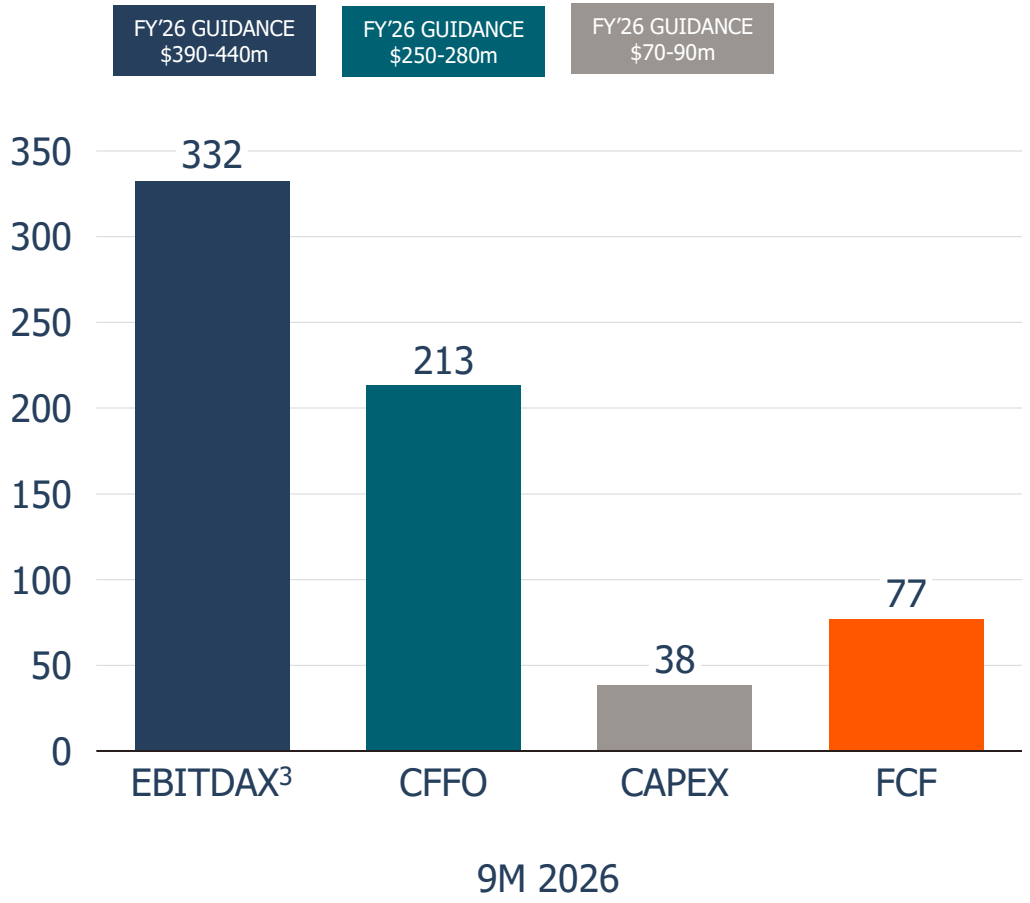
2027 growth funding protected:

Collars on a portion of production, with an average of ~$70/bbl floor and upside to ~$93/bbl

Q3 Financial Highlights

EBITDAX[1] / CFFO[1,2] / Capex / FCF[1] ($ Million)

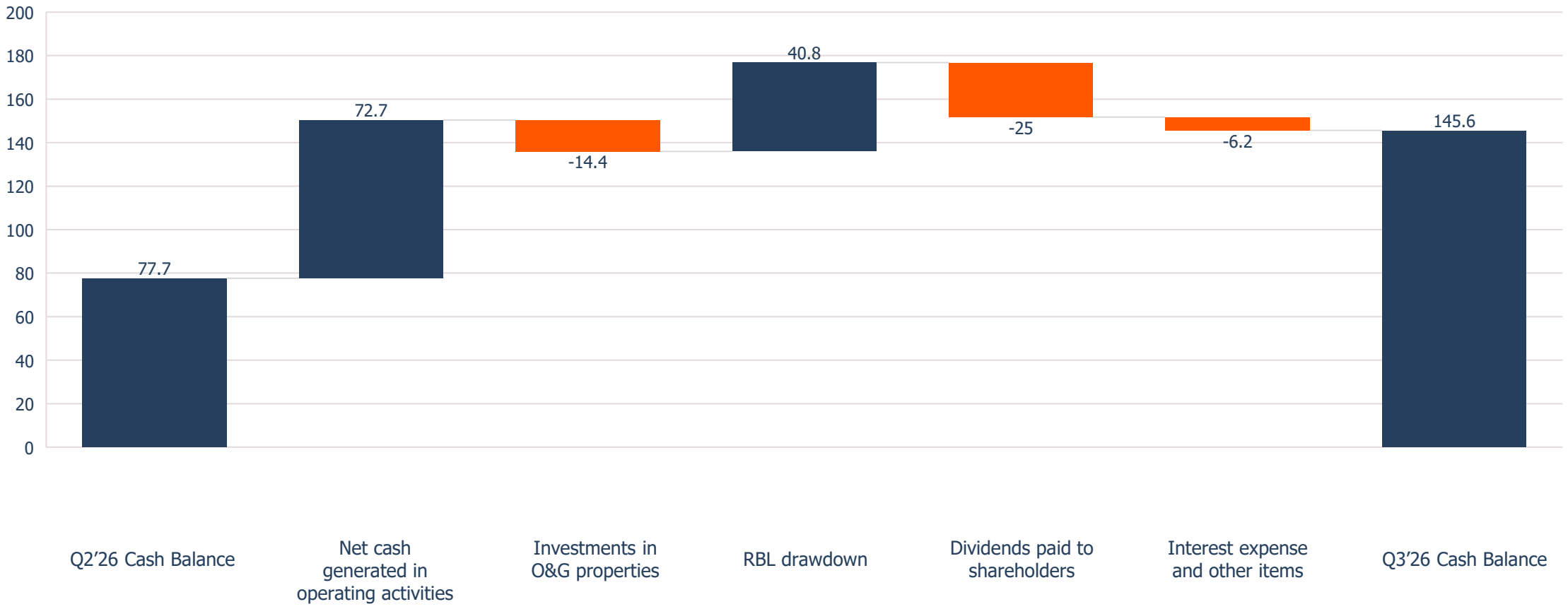




1) EBITDAX/CFFO/FCF are not generally accepted IFRS terms. Refer to Reader Advisory Section (slide 15) of this document for important information on non-IFRS measures.
2) CFFO is cash flow from operations before working capital and interest expenses.
3) In line with industry practice, Q1 2026 EBITDAX has been restated to $111.1m to conform with the revised EBITDAX definition which excludes Meren's share of losses from associates.

Q3 Cash Movements[1]

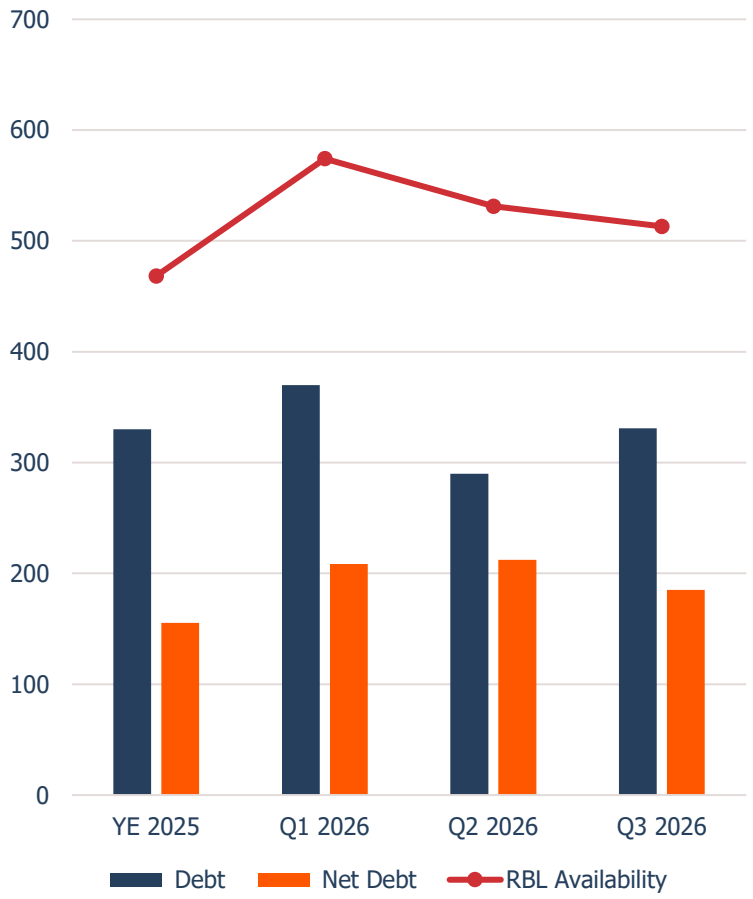
Cash Balances & Q3'26 Movements ($ Million)



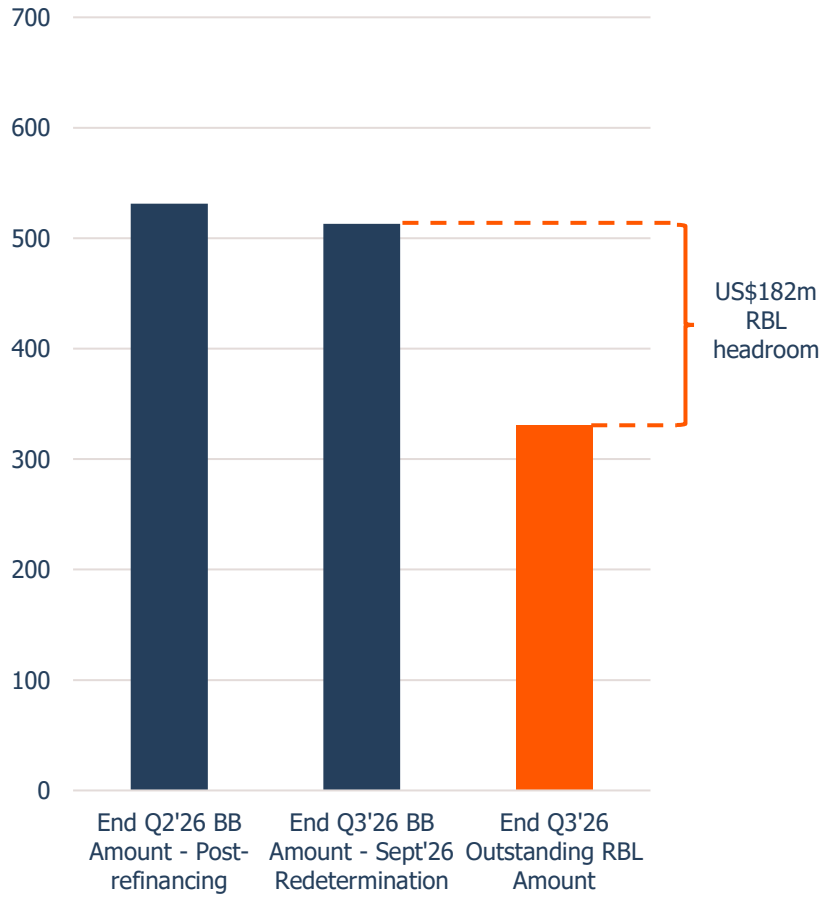
1) Refer to Q3 2026 Shareholder Report for more information

Liquidity Management

Debt, net debt and borrowing base amounts (US$M)



Borrowing base redetermination and headroom (US$M)



Q3'26 RBL Drawdown
$40.8m

End Q3'26 Liquidity Position
$328m

End Q3'26 Net Debt Position
$185m
(YE'25: $155m)

End Q3'26 Net Debt/EBITDAX
0.5x

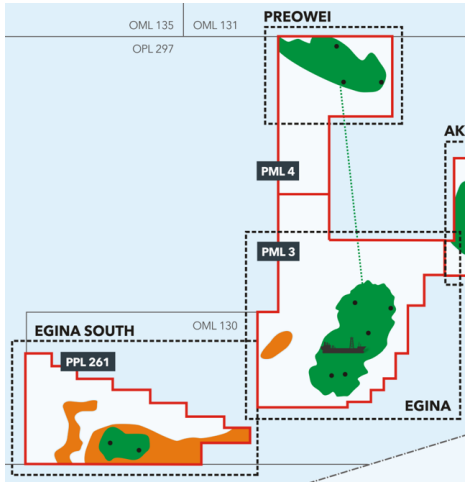
The Next 12 Months: Nigeria Growth Activity Restarts

Activities resume across all three hubs, with a clearer path for the Egina tie-backs

NIGERIA ACTIVITY – NEXT 12 MONTHS

YE'2026	**Akpo & Egina well interventions** Three low-cost workovers on existing producing wells to restore and add output ahead of the drilling campaign
YE'2026	**Akpo Far East (AFE-1X) exploration well** Near-field prospect targeting shallow B sands (~6 MMboe net)[2]. Success could support a low-cost, short-cycle, tie-back with the potential to be onstream in 2027
YE'2026	**Agbami & Akpo FPSO life extension ongoing** Operator asset integrity and life-extension programmes to support future drilling and tie-backs
2027	**PML 52 / PPL 2003 rig expected Q1 2027** Three firm Agbami infill wells plus Ikija appraisal. Ikija is an oil discovery in PPL 2003 on trend with Agbami – a potential tie-back. Sequencing being finalised with the operator
2027	**Ongoing Drilling Activity**

EGINA TIE-BACKS – NEXT 12 MONTHS



Preowei (PML 4)

Subsea tie-back to the Egina FPSO; concept and costs being optimised ahead of FEED

~10 kboe/d net to Meren at plateau[3]

Egina South (PPL 261)

Second potential Egina tie-back; 2027 appraisal on adjacent OPL 257 to define the resource and path to development

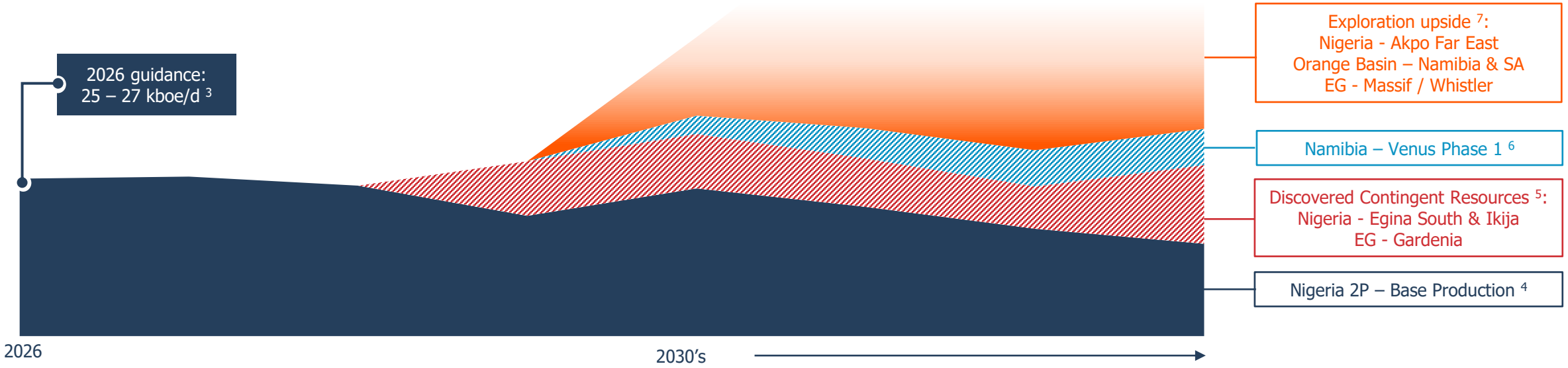
Potential similar to Preowei

YE'2026	**Operator targets Preowei FEED restart**
2027	**Egina South appraisal well (OPL 257)**
Late 2027	**Preowei FID targeted – first Egina tie-back**

1) Timelines are operator targets, subject to partner and regulatory approvals and may change.
2) Prospective resources; Meren management's internal estimate (net, unrisked), prepared by Toyosi Awe, a qualified reserves auditor. Not evaluated or verified by RISC. Exploration well: no certainty of discovery or commercial development. See Reader Advisory on Slide 17.
3) Preowei – net to Meren based on the gross field plateau rate of 60 kboe/d per RISC (effective 1 January 2026) and Meren's working interest. Refer to "Forward Looking Statements" on slide 14.

Organic Growth Underpins Long-Term Production Outlook

W.I. net to Meren [1,2]



1) This slide contains forward-looking information regarding future production. Actual results may differ materially. Refer to "Forward-Looking Statements" on slide 14 for important information.
2) Reliance on third parties. Certain data has been derived from operators, JV partners and independent reports and has not been independently verified by Meren.
3) Meren's Management Full-Year 2026 W.I. Production Guidance. This is subject to operational, subsurface, JV partner, regulatory and macro risk, and other risks and uncertainties, including those described under "*Risk Factors*" in Meren's Annual Information Form for the Year Ended December 31, 2025.
4) Nigeria 2P profile post-2026 is taken from the independent report prepared by RISC for Meren's NI 51-101 Statement of Reserves for YE'2025 and reflects proved plus probable reserves; there is no certainty that reserves will be produced at the rates or on the timing shown.
5) 2C discovered contingent resources (Egina South, Ikija, Gardenia) are not reserves and do not have demonstrated economic viability. A significant portion may never be reclassified as reserves. Refer to slides 15-17 for important information.
6) Namibia — Venus Phase 1 profile is Meren's internal estimate based on the operator's public statements and ESIA report (160 kbopd plateau), assuming Meren's 3.8% effective interest. Meren is not a JV partner at the license level and holds its interest through its shareholding in Impact Oil & Gas. Project timing, capacity, cost and FID remain subject to the operator's decisions and joint venture approvals. There is no assurance of a commercial development.
7) Exploration upside (Akpo Far East, Orange Basin — Namibia & SA, EG Massif/Whistler) represent unrisked prospective resources and are illustrative only. They are not production forecasts, guidance, or targets, and there can be no assurance of discovery, appraisal success, commercial development, or production.

Q&A

Forward Looking Statements

Certain statements and information contained herein may constitute "forward-looking information" or forward-looking statements under applicable Canadian or Swedish securities laws (collectively "forward-looking statements"). Forward-looking statements in this presentation include, but are not limited to, statements related to: base dividend distribution; target dividend distribution of $100 million per year; the maintenance of minimum liquidity of $150 million and a Net Debt/EBITDAX ratio below 1.0x; timing and the pricing of future Nigerian oil liftings; liquidity headroom; future borrowing base redeterminations and future payments under the RBL facility; statements related to 2026 Management Guidance, including future working interest and entitlement production, EBITDAX, CFFO and capital investment ranges and the Dated Brent price assumption on which that guidance is based; long-term production outlook and profiles extending beyond the guidance period, including production from reserves, contingent resources and prospective resources; expected plateau production rates, field lives, first-oil dates and development concepts for the Venus, Preowei, Egina South, Ikija and Gardenia projects; expected incremental production from well workover and infill drilling programmes; estimated future gross project capital costs, including those for Ikija and Gardenia; schedules, costs and outcomes of exploration, appraisal and development activity, including offshore Namibia, Nigeria, Equatorial Guinea and South Africa; the anticipated timing of final investment decisions and the intention to report NI 51-101 compliant reserves and contingent resources for Venus following FID; the expectation that projects will be funded, carried or otherwise require no upfront capital expenditure; the availability and quantum of fiscal incentives, tax remissions and production tax credits under Nigerian law, including eligibility under the New Deep Offshore Oil and Gas Projects Incentives (Tax Remission) Order and the timing of any related FID; the grant, renewal, extension or acknowledgement by governmental authorities of licences, permits and exploration periods, including in South Africa, Namibia and Equatorial Guinea; the outcome of appeals and permitting processes; the potential unitisation of Egina South across PPL 261 and OPL 257; potential access to spare LNG processing capacity in Equatorial Guinea; the ability of Meren to secure farm-in partners on acceptable terms in Equatorial Guinea; estimates of future net revenue, including NPV10 values; the ability of Meren to deliver further growth or increased shareholder returns including by monetizing its assets; the ability of Meren to grow into a leading independent E&P; the continuing benefits from funded, high value growth opportunities, including the Venus oil project in the Orange Basin; expectations regarding free-cash flow; the ability of Meren to influence its JV 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.

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, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes that the expectations reflected in those forward-looking statements are reasonable, but 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 oil prices, results of exploration and development activities, uninsured risks, regulatory changes, defects in title, availability of materials and equipment, timeliness of government or other regulatory approvals, actual performance of facilities, availability of financing on reasonable terms, availability of third party service providers, equipment and processes relative to specifications and expectations and unanticipated environmental impacts on operations.

Actual results may differ materially from those expressed or implied by such forward-looking statements. This update contains certain forward-looking information that reflect the current views and/ or expectations of management of the Company with respect to its performance, business and future events including statements with respect to financings and the Company's plans for growth and expansion. Such information is subject to a number of risks, uncertainties and assumptions, which may cause actual results to be materially different from those expressed or implied including the risk that the Company is unable to obtain required financing and risks and uncertainties inherent in oil exploration and development activities. Readers are cautioned that the assumptions used in the preparation of such information, such as market prices for oil and gas and chemical products, the Company's ability to explore, develop, produce and transport crude oil and natural gas to markets and the results of exploration and development drilling and related activities, 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 information. The Company assumes no future obligation to update these forward-looking information except as required by applicable securities laws.

Certain data in this presentation was obtained from various external data sources, and the Company has not verified such data with independent sources. Accordingly, no representation or warranty, express or implied, is made and no reliance should be placed, on the fairness, accuracy, correctness, completeness or reliability of that data, and such data involves risks and uncertainties and is subject to change based on various factors.

No reliance may be placed for any purposes whatsoever on the information contained in this presentation or on its completeness. The Company and its members, directors, officers and employees are under no obligation to update or keep current information contained in this presentation, to correct any inaccuracies which may become apparent, or to publicly announce the result of any revision to the statements made herein except where they would be required to do so under applicable law, and any opinions expressed in them are subject to change without notice, whether as a result of new information or future events. No representation or warranty, express or implied, is given by the Company or any of its subsidiaries undertakings or affiliates or directors, officers or any other person as to the fairness, accuracy, correctness, completeness or reliability of the information or opinions contained in this presentation, nor have they independently verified such information, and any reliance you place thereon will be at your sole risk. Without prejudice to the foregoing, no liability whatsoever (in negligence or otherwise) for any loss howsoever arising, directly or indirectly, from any use of this presentation or its contents or otherwise arising in connection therewith is accepted by any such person in relation to such information.

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Non-IFRS Measures

References are made to "Earnings Before Interest, Tax, Depreciation, Amortization and Exploration Expenses ("EBITDAX"), cash flow from operations ("CFFO") and free cash flow to firm ("FCF"). These are not generally accepted accounting measures under International Financial Reporting Standards (IFRS) and do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with definitions of EBITDAX, CFFO and FCF that may be used by other public companies. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. Management believes that non-IFRS measures are useful supplemental measures that may assist shareholders and investors in assessing the cash generated by and the financial performance and position of the Company. Management also uses non-IFRS measures internally in order to facilitate operating performance comparisons from period to period, prepare annual operating budgets and assess the Company's ability to meet its future capital expenditure and working capital requirements.

- 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 and impairment expenses.
- 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.
- 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.

Refer to Q3 2026 Report to Shareholders for a reconciliation of non-IFRS measures to the reported accounts.

All dollar amounts are in United States dollars unless otherwise indicated.

Oil and Gas Information

The reserves estimates presented have been evaluated by RISC in accordance with NI 51-101 and the COGE Handbook, are effective January 1, 2026. The reserves presented herein have been categorized accordance with the reserves and resource definitions as set out in the COGE Handbook. The estimates of reserves in this document may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. The production forecasts are based on the RISC report prepared for the Company dated February 2026, effective as of January 1, 2026.

Aggregate oil equivalent production data are comprised of light and medium crude oil and conventional natural gas. These production rates only include sold gas volumes and not those volumes used for fuel, reinjected or flared. Net entitlement production is calculated using the economic interest methodology and includes cost recovery oil, tax oil and profit oil and is different from working interest production that is calculated based on project volumes multiplied by Meren's effective working interest in each license.

The terms BOE (barrel of oil equivalent) is used throughout this presentation. 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.

These slides contain estimates for future production. These are based on the Company's NI 51-101 document and Meren management's internal estimates, including management's internal estimate of ~6 MMboe (net) for the Akpo Far East B-sand prospect, which has not been validated by RISC. These constitute forward looking statements and there is no guarantee that actual results will be in line with these estimates. These represent management's best estimates at present time, are subject to various uncertainties, and future performance of the assets can't be guaranteed. Please refer to Forward-Looking Statements at the front of this presentation for more details. In relation to Namibia Meren management's view is directional and based on public statements by the operator regarding potential scale of recoverable resources there is no assurance there will be a commercial development for the Venus oil discovery.

Reader Advisory

"contingent resources": quantities of petroleum estimated, at a given date, to be potentially recoverable from known accumulations using established or developing technology, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies are conditions that must be satisfied for a portion of contingent resources to be classified as reserves that are: (a) specific to project being evaluated; and (b) expected to be resolved within a reasonable timeframe. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources estimated discovered recoverable quantities associated with a project in early evaluation stage.

"prospective resources" means those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development.

The resource estimates contained herein are estimates only and there is no guarantee that the estimated resources will be recovered. Volumes of resources have been presented based on a company interest. There is no certainty that it will be commercially viable to produce any portion of the "contingent resources" referred to in this presentation. In the case of "prospective resources" there is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources referred to in this presentation.

Uncertainty Ranges for Contingent Resources

Estimates of resource volumes can be categorized according to the range of uncertainty associated with the estimates. Uncertainty ranges are described in the COGE Handbook as low, best and high estimates as follows:

A "low estimate" (1C) is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

A "best estimate" (2C) is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

A "high estimate" (3C) is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

The resource estimates contained herein are estimates only and there is no guarantee that the estimated resources will be recovered. Volumes of resources have been presented based on a Company interest. Certain volumes are arithmetic sums of multiple estimates of contingent resources, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of resources and appreciate the differing probabilities of recovery associated with each class. The estimates of resources for individual properties may not reflect the same confidence level as estimates of resources for all properties, due to the effects of aggregation.

Egina South

The Company has an indirect 16% interest in PPL 261 which is a deep-water Nigerian concession that includes the Egina South field. The product types reasonably anticipated from this field are light and medium oil and conventional natural gas. The contingent resources related to the Company's interest have been evaluated by RISC (UK) Limited ("RISC") for Meren in accordance with Canadian National Instrument 51-101 – Standards for Oil and Gas Activities ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") with an effective date of January 1, 2026. The significant positive factors relating to the estimate include: hydrocarbons confirmed by two wells (EGS-1, EGS-2); reservoir intervals analogous to the producing Egina field; proximity (~20 km) to existing Egina FPSO infrastructure. The significant negative factors relating to the estimate include: approximately 11% of the discovered volumes lie outside PPL 261, so commercialisation may be contingent on unitisation; only the discovered western block is presently proven; and the East blocks are largely undiscovered. The total estimate project cost to achieve commercial production is currently estimated at approximately $1.5 billion (gross field) and is subject to high uncertainty. The anticipated recovery technology is a subsea tie-back to Egina FPSO. The specific contingencies relating to the estimate are as follows: unitisation of PPL 261 and OPL 257 may be required; development sanction (FID) pending; appraisal drilling and JV/regulatory approvals outstanding. RISC estimates the chance of development for Egina South at 62%.

Continued on the next slide.

Reader Advisory

Ikija

The Company has an indirect 8% interest in PPL 2003 which is a deep-water Nigerian concession that includes the Ikija field. The product types reasonably anticipated from this field are light and medium crude oil. The contingent resources related to the Company's interest have been evaluated by RISC for Meren in accordance with the COGE Handbook with an effective date of January 1, 2026. The significant positive factors relating to the estimate include: discovery confirmed by Ikija-1 (net oil and gas pay, ~45 deg API); located on-trend with the producing Agbami hub. The significant negative factors relating to the estimate include: remains an undeveloped discovery; drilling schedule has slipped (2025 to 2027), introducing uncertainty over first-oil timing. The total estimate project cost to achieve commercial production is currently estimated at approximately $1.1 billion (gross field) and is subject to high uncertainty. The anticipated recovery technology is a subsea tie-in (~25km) to Agbami FPSO. The specific contingencies relating to the estimate are as follows: further appraisal required; development sanction (FID) pending; commercial viability not yet demonstrated. RISC estimates chance of development for Ikija at 19%.

Gardenia

Gardenia in Block EG-31 is a shallow-water gas discovery in Equatorial Guinea operated with an 80% interest by Meren. The product types reasonably anticipated from this field are conventional natural gas and condensate. The contingent resources related to the Company's interest have been evaluated by RISC for Meren in accordance with the COGE Handbook with an effective date of January 1, 2026. The significant positive factors relating to the estimate include: Gas/condensate confirmed and flow-tested (18.6 MMscf/d gas, 1,300 bbl/d condensate); defined four-way dip-closed structure; existing export infrastructure (~30 km pipelines to Alba/Punta Europa) traverses the block. The significant negative factors relating to the estimate include: cost estimates are Class 5 (-50%/+100%) reflecting low engineering maturity; Alba platform integrity and opex-sharing arrangements not yet confirmed; economic cut-off not yet applied. The total estimate capital cost is currently estimated at approximately $275 million (gross field) and is subject to high uncertainty. The anticipated recovery technology is a producing two-well (90 MMscfd) subsea tie-back to the Alba Complex. The specific contingencies relating to the estimate are as follows: FID pending (pre-feasibility/concept-screening stage); a standalone development could require additional volumes from other undiscovered prospects; and stakeholder agreements outstanding. RISC estimates the chance of development for Gardenia at 23%.

Uncertainty Ranges for Prospective Resources

Estimates of resource volumes can be categorized according to the range of uncertainty associated with the estimates. Uncertainty ranges are described in the COGE Handbook as low, best and high estimates as follows:

A "low estimate" (1U) is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

A "best estimate" (2U) is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

A "high estimate" (3U) is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

Akpo Far East – B Sands

The Company has an indirect 16% interest in PML 2 which is a deepwater Nigerian concession that includes the Akpo Far East exploration prospect. The product types reasonably anticipated from this field are condensate and conventional natural gas, in case of a successful commercial discovery. The prospective resources associated with the B-sand target are Meren management's internal estimate, prepared by Toyosi Awe, reserves coordinator and employee of Meren Energy, and a Qualified Reserves Auditor for the purposes of NI 51-101 and the COGE Handbook, with an effective date of 10th November 2026. The estimate will be audited in accordance with NI 51-101 and the COGE Handbook for the Company's year-end 2026 reserves report. The estimated chance of commerciality is 51%. The B-sand prospective resources have not been evaluated, validated or verified by RISC and are not included in RISC's report effective January 1, 2026.

Meren

Thank you

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