Central Petroleum LIMITED

# ANNUAL REPORT 2026


Central Petroleum Limited

ACN 083 254 308

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# CHAIR’S LETTER

Dear Shareholders,

FY2026 has been a year of change and I am pleased, as Chair of Central Petroleum, to present the 2026 Annual Report, including our first Sustainability Report.

Most significantly, our new gas contracts have delivered higher revenues and margins, highlighting our increased resilience and critical role as the reliable supplier of about 50% of the Northern Territory’s gas demand at a time when other supply has been uncertain.

We have secured new multi-year gas contracts that have underwritten the investment in two new wells at Palm Valley and, if these wells are successful, we will see our aggregate gas production increase by about 40%. We look forward to significantly higher cash flows as the new wells come online.

Our cash flows will also be boosted by over $7 million per year after we made our final delivery of gas to repay our gas overlift position in May of this year.

The gas supply position in the Northern Territory, however, remains uncertain as Beetaloo Basin gas production is brought online and the market impact of the proposed federal domestic gas reservation scheme remains unknown. Regardless, our established reserves and infrastructure give us a competitive cost advantage and we have already contracted some 80% of our gas expected production over the next three years.

Improved cash flows have given us options to allocate capital, and we have made a number of strategic decisions regarding our exploration portfolio this year. Firstly, our strategic expansion into the well-known, and proven Otway and Cooper Basins gives us access to a number of highly-prospective exploration targets close to existing infrastructure and markets. Success in the Otway could double our group gas production, and the Cooper provides opportunity for new oil reserves at a time when Australia’s liquid fuel energy security is in the spotlight.

We have also reduced our Amadeus Basin sub-salt exploration exposure, retaining an interest only in the more prospective areas. We now have a better-balanced portfolio which includes: cash-generating assets, with near-field exploration upside; exploration potential in proven basins with access to east coast markets; and exposure to sub-salt plays with helium and hydrogen potential.

Our current Palm Valley drilling program and upcoming exploration programs will take first priority for our capital in 2026/2027, and we expect increasing cash flows to be available from mid-2027 for allocation towards other growth initiatives, shareholder returns and debt reduction.

I thank Central’s Board, management and staff for their dedication, commitment to safety and operational excellence and I acknowledge the ongoing support of our stakeholders, suppliers, local communities, and traditional owners.

With improving cash flows and some exciting exploration targets to be drilled in the next year, I am confident that we are well-placed to deliver positive results and I look forward to updating you as the year unfolds.

Thank you,

**Agu Kantsler, Chair**

17 September 2026

# CHIEF EXECUTIVE OFFICER'S LETTER

Dear fellow Shareholders,

The past year presented its share of challenges, but Central made meaningful progress in strengthening its cash-generating business and building a more balanced portfolio of growth opportunities. This was achieved despite ongoing uncertainty in gas markets and limited production constraints.

A key achievement was the implementation of our gas contracting strategy, securing firm multi-year Northern Territory gas contracts which have underwritten two new Palm Valley wells and reduced our reliance on the Northern Gas Pipeline. If successful, these wells could increase Central's total production by around 40%, while more than 80% of expected gas production over the next three years is now contracted under fixed-price arrangements. The recent repayment of our overlifted gas liability will also release more than $7 million in annual cash flow and strengthen capital flexibility.

The underlying strength in our operating business became more visible through the year. Aggregate revenues increased by 3% and operating margins by 5%, despite lower volumes from natural field decline and oil offtake constraints. Gas production returned to full capacity by mid-year, and we continue to seek a solution for the full commercialisation of our oil sales.

We enter FY2027 with a clear path to stronger operating results through new Palm Valley production, lower costs and successful commercial strategies.

We have high-graded and diversified our growth portfolio, expanding into the proven Otway and Cooper Basins where three exploration wells are planned in 2027 near existing infrastructure and key east coast markets.

We also rationalised our exploration portfolio, withdrawing from two Amadeus Basin exploration permits after a multi-year process to find participants to share the significant exploration cost. Whilst this will reduce ongoing exploration costs, it resulted in a one-off $5.9 million impairment charge, which contributed to the statutory loss of $4.9 million.

Capital allocation remains disciplined and responsive to market conditions, including new Beetaloo gas supply, a proposed domestic gas reservation policy and evolving gas market fundamentals across the Northern Territory and east coast markets. Despite these uncertainties, Central's reserves, infrastructure, and operating history support its position as a reliable, low-cost Northern Territory gas producer.

We deferred drilling new Mereenie wells pending clarity on the future gas market, while committing to drill five exploration and appraisal wells over the next 18 months across Palm Valley and the Cooper and Otway Basins.

During FY2026, we also initiated modest shareholder return and anti-dilutionary measures through $0.9 million of buy-back and cash-settlement arrangements for employee equity incentives.

Subject to operating performance and market conditions, free cash flow expected in the second half of 2027 should provide greater flexibility to balance growth, debt reduction and shareholder returns.

We start FY2027 in a strong financial position, with $20 million in cash reserves and up to $18 million available under our expanded debt facility to fund Palm Valley drilling and Otway and Cooper exploration activity.

Finally, we end the year with a Total Recordable Injury Frequency Rate of Nil. This reflects the dedication and hard work of our staff and contractors, allowing us to maintain a strong track record of safety in one of Australia most harsh environments.

I thank my fellow Directors for their support, and our management team and staff for their commitment to safely implementing Central's strategy.

Central enters FY2027 financially resilient, strategically focused, and better placed to convert its contracted production base and disciplined growth program into long-term shareholder value.

Sincerely,

**Leon Devaney, CEO**
17 September 2026

# OPERATING AND FINANCIAL REVIEW

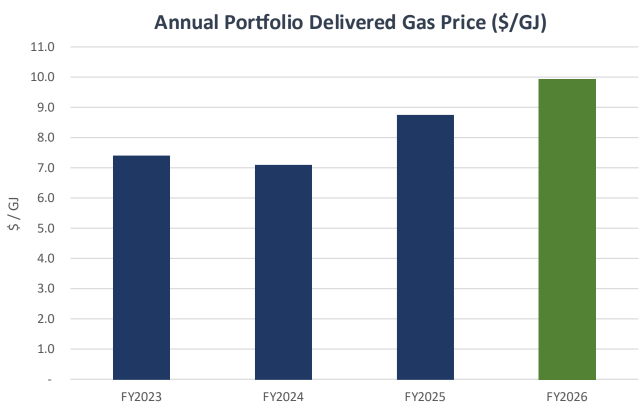
## OPERATING HIGHLIGHTS

Central delivered a strong underlying operating performance in FY2026:

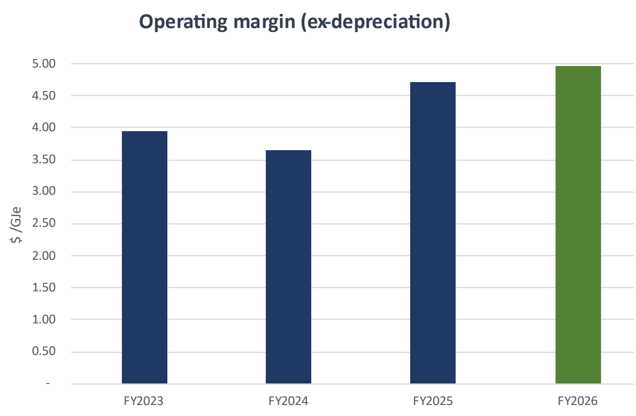
- Sales revenue increased 3% to $44.7 million
- Operating margin, excluding depreciation, increased 5% to $4.96/GJe, supported by a 14% increase in the average realised gas price
- Underlying EBITDAX was $17.0 million
- Net cashflow from operations was $15.6 million after net interest payments
- Cash balance at 30 June 2026 of $20.41 million, after investing $11.2 million in new exploration acreage.

Key strategic achievements during the year included:

- Secured new multi-year gas contracts from 2026 to 2034, increasing cash flow certainty and supporting the final investment decision for two new Palm Valley wells, which if successful, could lift gas production by 40% from late 2026
- Completed the final delivery to repay previously overlifted gas in May 2026, releasing an expected $7 million per year in future cash flow
- Increased the existing loan facility by $15 million to provide working capital support for accelerated Palm Valley drilling
- Expanded into the proven Cooper and onshore Otway Basins, acquiring interests in PEP 169 in Victoria and Cooper Basin retention leases and exploration permits, with at least three exploration wells expected in the next 18 months
- Rationalised the exploration portfolio and reduced costs by exiting two Amadeus Basin exploration permits
- Implemented the Company's first shareholder returns program through an on-market share buy-back, acquiring and cancelling 2,185,130 shares and cash-settling 8,552,586 employee share rights during the year




Average delivered gas price increased 14% to $9.96/GJe




Operating margin (excluding depreciation) increased 5% to $4.96/GJe

# OPERATING AND FINANCIAL REVIEW

## FINANCIAL REVIEW

The Consolidated Entity recorded a loss after income tax of $4.9 million for the year ended 30 June 2026, compared with a restated profit of $6.7 million in FY2025.

The result included $5.9 million of impairment costs for relinquished exploration tenements and $5.7 million of other exploration costs, including $2.7 million for preparation and procurement for the two Palm Valley wells planned for FY2027. The FY2025 profit included a $1.2 million gain on the sale of land previously held by the Mereenie joint venture partners.

To support comparability, EBITDAX, EBITDA and EBIT are presented against the underlying FY2025 results.

The table below shows key metrics for the Group:

| Key Metrics | Total 2026 | Total 2025* | Change | % Change |
|---|---|---|---|---|
| Net Sales Volumes | | | | |
| - Natural Gas (TJ) | **4,261** | 4,453 | (192) | (4)% |
| - Oil & Condensate (bbls) | **14,773** | 30,006 | (15,233) | (51)% |
| Sales Revenue ($'000) | **44,747** | 43,626 | 1,121 | 3% |
| Gross Profit ($'000) | **15,031** | 15,043 | (12) | – |
| Underlying EBITDAX[1] ($'000) | **16,998** | 18,615 | (1,617) | (9)% |
| Underlying EBITDA[2] ($'000) | **11,297** | 16,937 | (5,640) | (33)% |
| Underlying EBIT[3] ($'000) | **4,208** | 9,540 | (5,332) | (56)% |
| Underlying profit after tax[4] ($'000) | **1,015** | 6,179 | (5,164) | (84)% |
| Statutory (loss)/profit after tax ($'000) | **(4,918)** | 6,733 | (11,651) | (173)% |
| Net cashflow from operations[5] ($'000) | **10,344** | 14,304 | (3,960) | (28)% |
| Capital expenditure[6] ($'000) | **5,511** | 8,544 | (3,033) | (35)% |

* Restated - Refer note 2 to the financial statements for details of prior period restatements.
1 Underlying EBITDAX is Earnings before Interest, Tax, Depreciation, Amortisation, Impairment, Exploration costs and certain other items not related to normal ongoing operations (refer reconciliation below).
2 Underlying EBITDA is Earnings before Interest, Tax, Depreciation, Amortisation, Impairment and certain other items not related to normal ongoing operations.
3 Underlying EBIT is Earnings before Interest, Tax and certain other items not related to normal ongoing operations.
4 Underlying profit / loss after tax is statutory profit after tax, before certain other items not related to normal ongoing operations.
5 Cashflow from operations includes cash outflows associated with exploration activities.
6 Capital expenditure on tangible assets.

Underlying EBITDAX, EBITDA and EBIT are non-IFRS measures presented to help explain the Group's underlying performance. They are not audited, although the figures are drawn from the audited financial statements. A reconciliation to profit before tax is provided below.

**Underlying EBITDAX**

Underlying EBITDAX was $17.0 million, down 9% from $18.6 million in FY2025. Higher revenue was offset by higher unit production costs that were driven by lower production volumes and non-recurring general and administrative costs associated with business development initiatives.

Underlying EBITDAX is used by management as an indicative measure of operating performance because it excludes finance costs, certain non-cash items, exploration costs and significant one-off transactions. It is reconciled to statutory profit below.

Underlying EBITDAX remains an indicative measure only. It includes non-cash items, such as $0.6 million of share-based payments (2025: $0.6 million), and recognised revenue may differ from cash receipts where take-or-pay gas revenue is deferred until gas is taken or forfeited.

# OPERATING AND FINANCIAL REVIEW

| Reconciliation of statutory profit before tax to Underlying EBITDAX | 2026<br>$'000 | 2025*<br>$'000 |
|---|---|---|
| Statutory profit before tax | (4,918) | 6,733 |
| Impairment of exploration assets | 5,869 | - |
| Change in fair value of deferred purchase consideration for a previous business combination | 64 | 679 |
| Profit on disposal of land | – | (1,233) |
| **Underlying profit before tax** | **1,015** | **6,179** |
| Net finance costs | 3,193 | 3,361 |
| **Underlying EBIT** | **4,208** | **9,540** |
| Depreciation and amortisation | 7,089 | 7,397 |
| **Underlying EBITDA** | **11,297** | **16,937** |
| Exploration expenses | 5,701 | 1,678 |
| **Underlying EBITDAX** | **16,998** | **18,615** |

* Restated - Refer note 2 to the financial statements for details of prior period restatements.

**Sales Volumes**

Sales volumes were 6% lower than FY2025 at 4.3 PJe, reflecting first-half oil offtake constraints, pipeline restrictions and natural field decline. Drilling of the first of two Palm Valley appraisal wells commenced in July 2026, with gas production from these wells expected later in the year.

Oil sales under our existing Crude Oil Processing Services Agreement (COPSA) were suspended indefinitely from mid-June 2026 following changes to oil specification requirements. Central continues to seek alternative commercial arrangements for Mereenie produced oil.

| Product | Unit | FY 2026 | FY 2025 |
|---|---|---|---|
| Gas | PJ | 4.3 | 4.5 |
| Crude and Condensate | bbls | 14,773 | 30,006 |
| **Total** | **PJe** | **4.3** | **4.6** |

Note: Oil is converted to Petajoule equivalent (PJe) at 5.816 GJe/bbl.

**Sales Revenue**

Despite lower sales volumes, revenue increased 3% to $44.7 million, supported by higher portfolio pricing from new supply contracts that commenced on 1 January 2025. Average realised prices increased 10% to $10.10/GJe. Revenue included $0.8 million released from deferred take-or-pay balances (2025: $1.3 million).

**Gross Profit**

Gross profit of $15.0 million was consistent with restated FY2025. Unit gross profit increased 6% to $3.46/GJe, reflecting higher average sales prices. Cost of sales per GJe increased 4% due to lower sales volumes, inflation and higher unit prices for repayment of overlifted gas, which was fully repaid in May 2026. Excluding depreciation, operating margin increased 5% to $4.96/GJe and is expected to improve in FY2027 as gas purchases for overlift repayment cease and sales volumes increase following the Palm Valley drilling program.

**Impairment Write-down**

Central withdrew from two Amadeus Basin exploration permits after assessing their commercial prospects, retention costs, future exploration requirements and relative prospectivity. An impairment charge of $5.9 million was recognised as a result.

**Net Assets/Liabilities**

At 30 June 2026, the Group had net assets of $34.2 million, compared with a restated $39.4 million at 30 June 2025, reflecting the current year loss before share-based payments.

**Debt**

In April 2026, the loan facility was increased by $15 million to provide working capital for accelerated drilling at Palm Valley. The facility is available for drawdown until 31 December 2026, with no principal repayments due before 31 March 2027 and no early repayment penalties.

During the year the Group capitalised $2.1 million of interest into the loan facility. The balance of the loan at 30 June 2026 was $25.5 million, with a further $17.5 million undrawn and available until 31 December 2026, if required, to fund development activity.

At 30 June 2026 the Group had net debt of $5.0 million (2025: net cash of $3.9 million), reflecting the $11.2 million investment to acquire interests in exploration tenements in the Otway and Cooper basins and $4.4 million in costs relating to the current Palm Valley drilling program.

The consolidated debt ratio was 0.24 at 30 June 2026 (2025: 0.23), calculated as total debt divided by total assets. Debt service is supported by long-term gas sales contracts and the Group's certified oil and gas reserves.

**Net Cash Flow**

Cash balances decreased by $7.1 million during the year, following investments of $11.2 million to acquire exploration interests in the Otway and Cooper basins and $4.5 million in capital projects, including early works for surface facilities and connections for the two new Palm Valley wells.

Net cash flow from production operations before capital expenditure was $19.9 million, compared with $21.0 million in FY2025, as higher revenue was offset by increased production costs, royalties and overlift settlement payments.

After net interest payments of $0.1 million, corporate and staff expenses of $4.3 million and exploration activities of $5.2 million, net cash from operating activities was $10.3 million (2025: $14.3 million).

**Recovery of staff costs**

Following a review of costs allocated to operated joint ventures, Central revised its allocation of fixed and contingent staff costs. The over-recovery of staff costs understated net general and administrative expenses and overstated production costs in 2024 and 2025. A provision has been recognised for amounts expected to be credited to third party joint venturers, and the affected prior-year financial statement line items have been restated.

**Five Year Comparative Data**

The following table is a five-year comparative analysis of the Consolidated Entity's key financial information. The balance sheet information is as at 30 June each year and all other data is for the financial years then ended.

| | 2022<br>$ MILLION | 2023<br>$ MILLION | 2024*<br>$ MILLION | 2025*<br>$ MILLION | 2026<br>$ MILLION |
|---|---|---|---|---|---|
| **Financial Data[1]** | | | | | |
| Operating revenue | 42.15 | 39.26 | 37.15 | 43.63 | **44.75** |
| Exploration expenditure (excluding impairment) | 21.65 | 13.09 | 3.99 | 1.68 | **5.70** |
| Profit/(loss) after income tax | 21.32 | (7.96) | 11.94 | 6.73 | **(4.92)** |
| EBITDAX | 53.31 | 15.96 | 27.07 | 19.17 | **16.93** |
| Underlying EBITDAX | 16.75 | 15.75 | 13.27 | 18.62 | **17.00** |
| Property, plant and equipment | 53.85 | 60.19 | 55.58 | 57.68 | **60.88** |
| Cash | 21.65 | 13.83 | 24.99 | 27.47 | **20.41** |
| Borrowings | (30.81) | (27.53) | (23.16) | (23.39) | **(25.54)** |
| Net Assets (Total Equity) | 26.53 | 19.39 | 32.08 | 39.43 | **34.20** |
| Net Working Capital (Net current assets) | 22.31 | 7.11 | 15.52 | 22.92 | **12.29** |

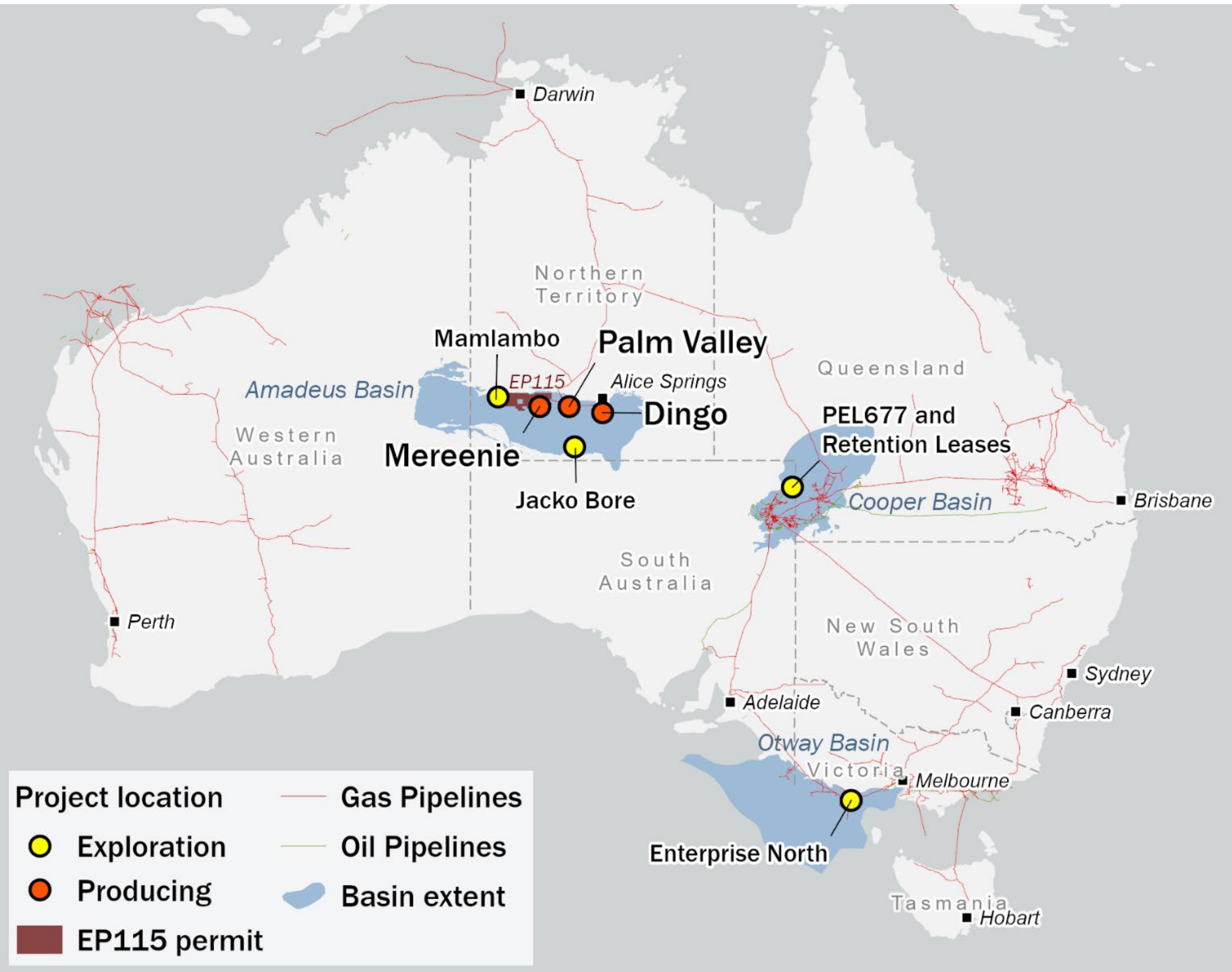
*Restated – refer Note 2 to the financial Statements for details
[1] In October 2021, Central sold a 50% interest in its producing gas fields

| | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|
| **Operating Data** | | | | | |
| Gas Sales (TJ) | 5,993 | 4,664 | 4,377 | 4,453 | **4,261** |
| Oil Sales (barrels) | 47,197 | 30,293 | 26,304 | 30,006 | **14,773** |
| **No. of employees at 30 June** | 88 | 80 | 81 | 82 | **86** |

## OPERATIONS AND ACTIVITIES

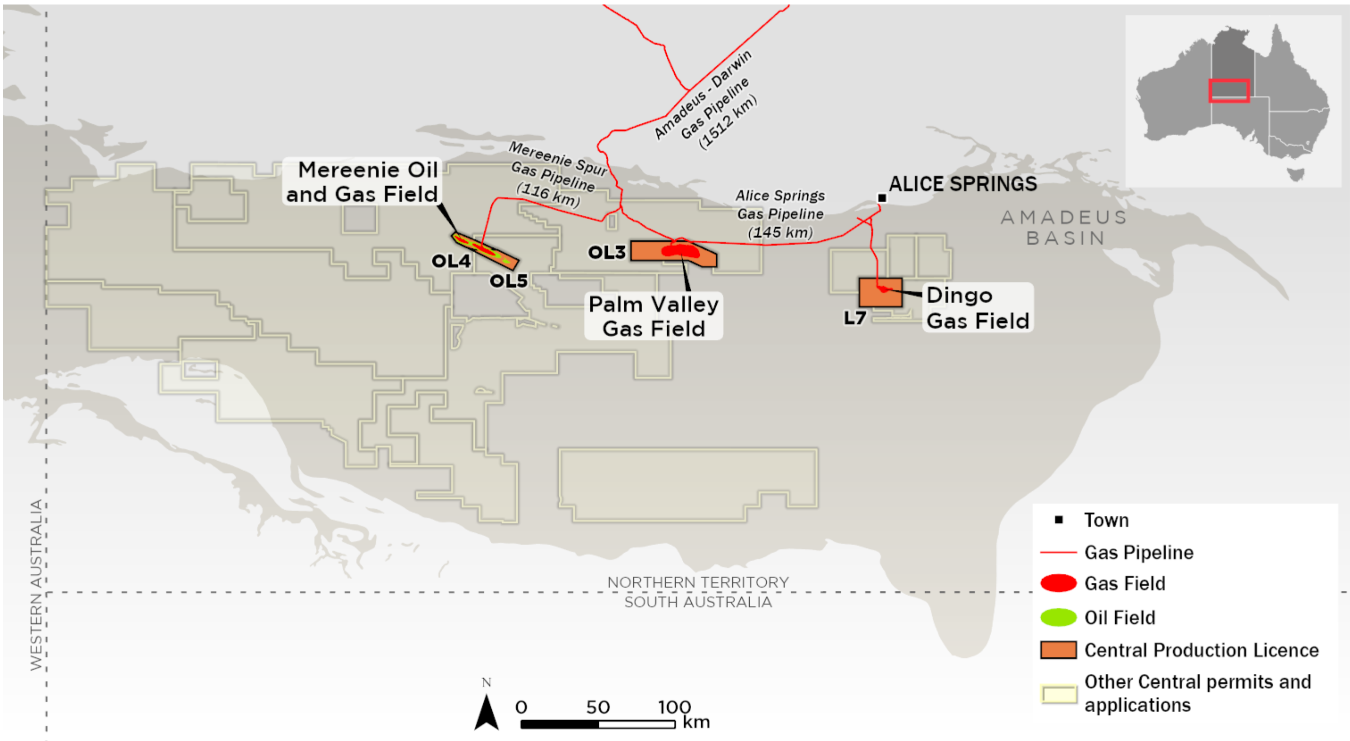
Central Petroleum Limited is an ASX-listed oil and gas producer, with a portfolio of producing and prospective tenements across the Northern Territory (NT). Central is the operator of the largest conventional onshore producing gas fields in the NT, supplying industrial customers, electricity generators and gas distributors from three producing fields in central Australia.

In addition to its established NT production operations, Central has a pipeline of growth opportunities which include exploration, appraisal and development projects in some of Australia's premier hydrocarbon producing basins – the Amadeus Basin (NT), Cooper Basin (South Australia) and onshore Otway Basin (Victoria).



Location of Central's oil and gas projects

## Producing Assets




Location of Central's producing oil and gas fields

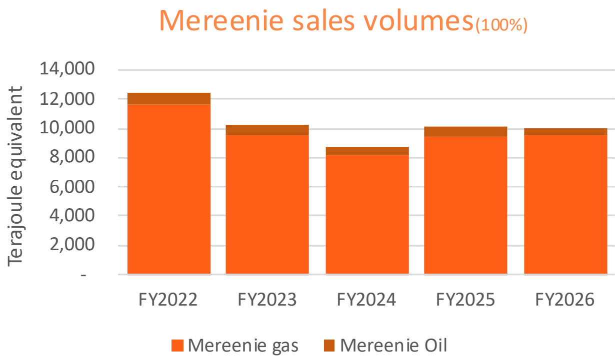
### Mereenie Oil and Gas Field (OL4 and OL5)

25% Interest (Operator)

| Reserves & Resources (Central share)[1] | Unit | 1P | 2P | 2C |
|---|---|---|---|---|
| Gas | PJ | 28.6 | 39.1 | 45.6 |
| Oil | mmbbl | 0.31 | 0.37 | 0.05 |
| Total[2] | PJe | 30.4 | 41.2 | 45.9 |

1 Reserves and resources are as at 30 June 2026. 2C gas resources include 27 PJ attributable to the Stairway Sandstone.

2 Oil converted at 5.816 PJ/mmbbl




**Operations**

Full field gas production for the year was 9.5 PJ, averaging 26.0 TJ/d. Central's share of Mereenie gas and oil sales for FY2026 was 2.4 PJe, consistent with the previous year, despite temporary production constraints in the first half of the year associated with revised oil specification requirements under the existing COPSA, which led to the indefinite suspension of oil sales from mid-June. Alternative offtake arrangements for unsold oil were secured to maintain full gas production from mid-December. Central continues to seek alternative commercial arrangements for Mereenie's oil production.

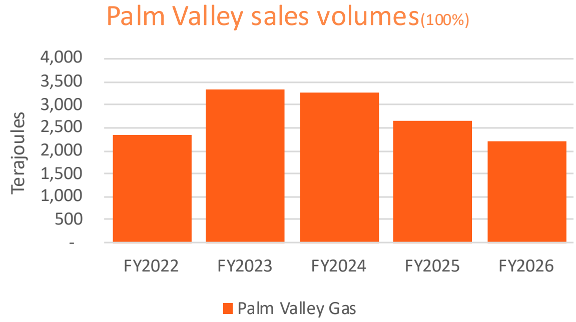
After continued strong performance from the newest production wells, proved and probable (2P) gas reserves were revised upwards by 2.7 PJ (net to Central) before production for the year, an increase of 7%.

## Palm Valley Gas Field (OL3)

### 50% interest (Operator)

| Reserves & Resources (Central share)[1] | Unit | 1P | 2P | 2C |
|---|---|---|---|---|
| Gas | PJ | 8.4 | 9.2 | 6.5 |

[1] Reserves and resources are as at 30 June 2026.




**Operations**

Central's share of Palm Valley gas sales for FY2026 was 1.1 PJ.

Production from the Palm Valley field averaged 6.0 TJ/d through FY2026 (2025: 7.3 TJ/day), recording an aggregate of 2.2 PJ (2025: 2.7 PJ), reflecting natural field decline.

**New wells**

Joint venture FID for two new appraisal/development wells was approved in April. Site preparation, approvals and procurement was finalised in the fourth quarter and drilling commenced on the first well, PV14 in late July 2026. The new wells can be quickly connected to existing production infrastructure and the PV14 well is expected to be supplying gas to customers from October 2026. If successful, the two wells could restore Palm Valley's sales capacity to the facility limit of approximately 14 TJ/d (100% JV) and deliver a total of at least 10 PJ of gas (100% JV) over their operating lives. The investment is underpinned by the new Northern Territory Government Gas Supply Agreement and the new wells are expected to boost Central's share of total gas production capacity across its three producing fields by circa 40%.

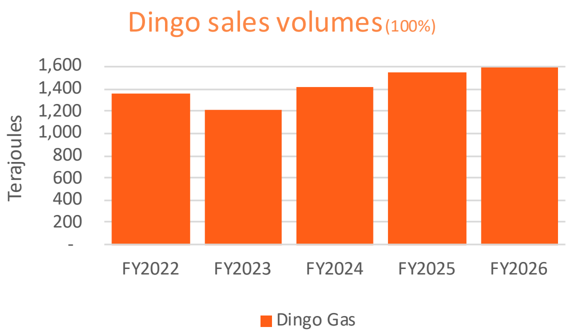

Drilling at the PV14 well (July 2026)

## Dingo Gas Field (L7) and Dingo Pipeline (PL30)

### 50% interest (Operator)

| Reserves & Resources (Central share)[1] | Unit | 1P | 2P | 2C |
|---|---|---|---|---|
| Gas | PJ | 10.2 | 22.0 | - |

[1] Reserves and resources are as at 30 June 2026.




**Operations**

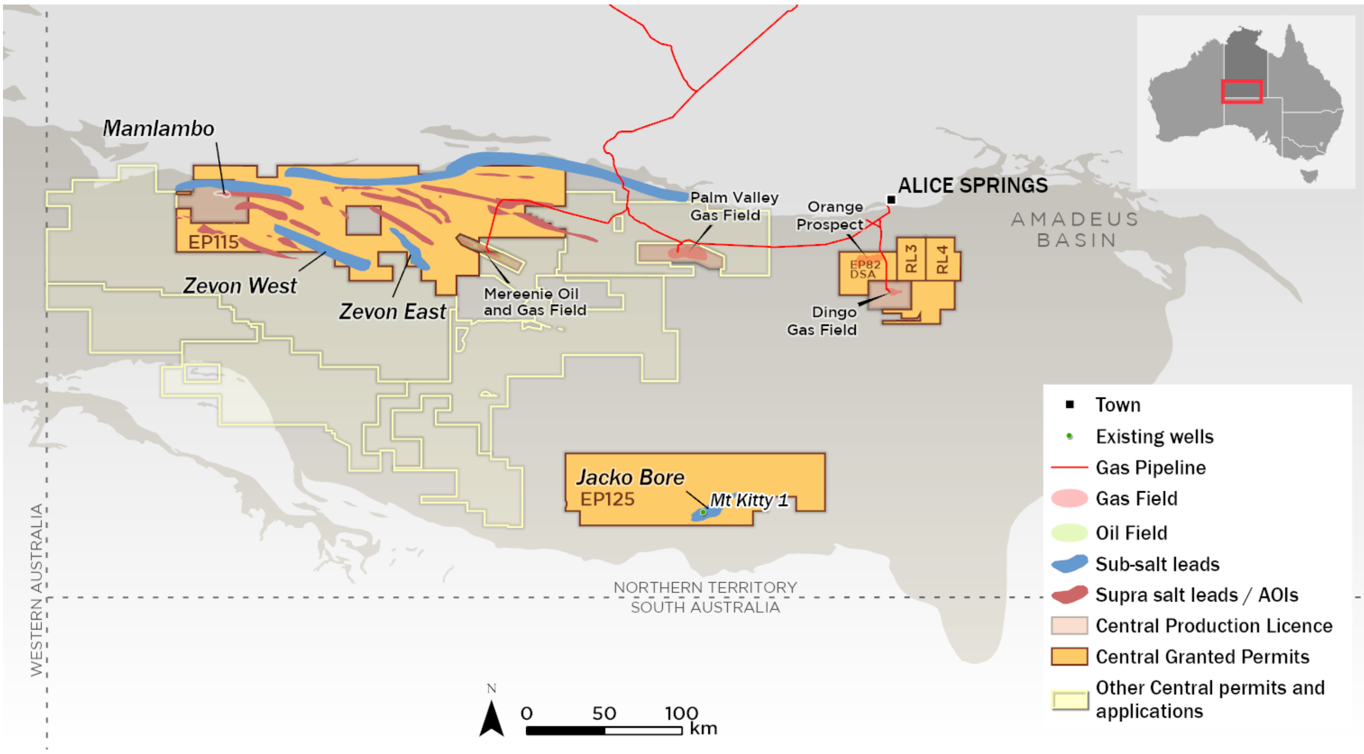
Sales volumes at Dingo were the highest on record for the third consecutive year, averaging 4.4 TJ/d across the year, an aggregate of 1.6 PJ (Central share 0.8 PJ), 3% higher than FY2025.

Proved (1P) gas reserves were revised downwards by 8.0 PJ (net to Central) before production, with classification of that undeveloped gas volume as 1P now contingent on future market conditions supporting further field development. Proved and Probable (2P) gas reserves were revised upwards by 1% before production.

## Exploration

Central Petroleum holds a significant exploration portfolio across proven Australian hydrocarbon provinces, including the Amadeus and Wiso Basins in the Northern Territory, the onshore Otway Basin in Victoria and the Cooper Basin in South Australia. Central holds, or has applied for, 107,214 km$^2$ of exploration acreage, comprising 25,707 km$^2$ granted and 81,507 km$^2$ under application.

### Amadeus Basin, Northern Territory




Location of Amadeus Basin exploration targets

Central Petroleum has a large position in the proven Amadeus Basin, which has produced reliable oil and gas since the 1980s, but remains relatively under-explored. The basin offers further gas potential, including helium and naturally occurring hydrogen, as well as oil prospectivity on its western flank.

Exploration wells, seismic acquisition and re-interpretation have identified multiple Amadeus Basin prospects and leads.

| Infield opportunities | Near-field opportunities |
|---|---|
| Exploration opportunities lie above or below the existing producing horizons at Mereenie, Palm Valley and Dingo. Successful appraisal could allow rapid, efficient tie-in to existing facilities. | Several promising targets have been identified near existing producing fields and could be advanced relatively quickly once capital is allocated. |
| ➢ **Mereenie Stairway**: the Stairway Sandstones lie above current production zones and flow gas while drilling to deeper intervals. Successful appraisal could materially boost production capacity and extend field life.<br>➢ **Dingo Deeps**: the Pioneer and Areyonga formations lie below the Dingo gas field and have flowed gas at the nearby Ooraminna exploration well.<br>➢ **Palm Valley Deeps**: the Arumbera Sandstones lie below the Palm Valley gas field and is the productive interval at Dingo. | ➢ **EP115**: leads between Mereenie and Surprise include Pacoota and Stairway Sandstones and the Horn Valley Siltstone, the source of oil and gas at Mereenie and Palm Valley.<br>➢ **Mamlambo:** 8km from the suspended Surprise oil field, with appraisal potential in the Lower Stairway Sandstone and Pacoota Formation, both proven reservoirs at Surprise and Mereenie.<br>➢ **Orange:** previous wells encountered gas in the shallow Arumbera Sandstone, the productive interval at nearby Dingo. |

Future activity across these prospects will depend on market conditions and capital availability.

### Identified resources – in-field and near-field opportunities (net to Central)

| Lead / Prospect | Unit | Prospective Resource[1] | | Contingent resource |
|---|---|---|---|---|
| | | Best estimate (P50) | Mean | 2C |
| Dingo Deep | PJ | 24.5 | **34.5** | — |
| Palm Valley Deep | PJ | 37.5 | **61.5** | — |
| Mereenie Stairway | PJ | — | **—** | 27.0 |
| Orange | PJ | 284.0 | **401.0** | — |
| **Total gas resource** | **PJ** | **346.0** | **497.0** | **27.0** |
| Mamlambo (oil) | mmbbl | 13.0 | **18.0** | — |

1. **Prospective Resource**: As first reported to ASX on 7 August 2020 for Dingo, Palm Valley and Orange, and 10 February 2022 for Mamlambo. The volumes of gross prospective resources represent the unrisked recoverable volumes derived from Monte Carlo probabilistic volumetric analysis for each prospect. Inputs required for these analyses have been derived from offset wells and fields relevant to each play and field. Recovery factors used have been derived from analogous field production data.

   **Cautionary statement**: the estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially recoverable hydrocarbons.

   Central confirms that it is not aware of any new information or data that materially affects the information included in those announcements and all material assumptions and technical parameters underpinning the estimate continue to apply and have not materially changed.

**Sub-salt targets**

The Amadeus Basin's radiogenic basement rocks and evaporitic seal create favourable conditions for sub-salt helium and hydrogen in addition to hydrocarbons.

Low helium levels occur in gas flows from Mereenie, Palm Valley and Dingo, with higher helium and hydrogen concentrations measured in previous wells at Mt Kitty (Jacko Bore) and Magee.

During the year, Central withdrew from the EP82 and EP112 joint ventures after assessing the expected drilling costs and relative prospectivity of Mahler and Dukas.

Central has retained its interest in the Mt Kitty / Jacko Bore prospect in EP125, where an appraisal well is expected by early 2028. The proposed Jacko Bore 2 well will target helium, naturally-occurring hydrogen and natural gas by re-entering Mt Kitty-1 (Jacko Bore-1) and drilling a deviated/horizontal sidetrack into the fractured basement at about 2,000m. Mt Kitty-1 flowed gas containing 11.5% hydrogen and 9% helium at up to 530,000 scfd. Central is seeking to farm out the prospect.

EP115 also contains a number of potential sub-salt leads.

### Gas resources estimated in EP125

| Mt Kitty / Jacko Bore<br>Central 30% interest | Helium*<br>(bcf) | Hydrogen*<br>(bcf) | Natural gas<br>(bcf) |
|---|---|---|---|
| Contingent Resource (2C) | 5.5 | 6.6 | 11.7 |

*Volume expected to be recovered in association with contingent and prospective hydrocarbon resources stated in the table. While estimated in accordance with the SPE PRMS guidelines, Hydrogen and Helium are not officially classified in this system.

**Additional resources guidance**

The resources for Jacko Bore were first reported to ASX on 18 April 2023 and have been adjusted for Central's increased beneficial interests (was 24%, now 30%).

Central confirms that it is not aware of any new information or data that materially affects the information included in those announcements and all material assumptions and technical parameters underpinning the estimate continue to apply and have not materially changed.

**Cautionary statement**: The estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both a risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially recoverable hydrocarbons/gases.

## Otway Basin, Victoria

### Enterprise North

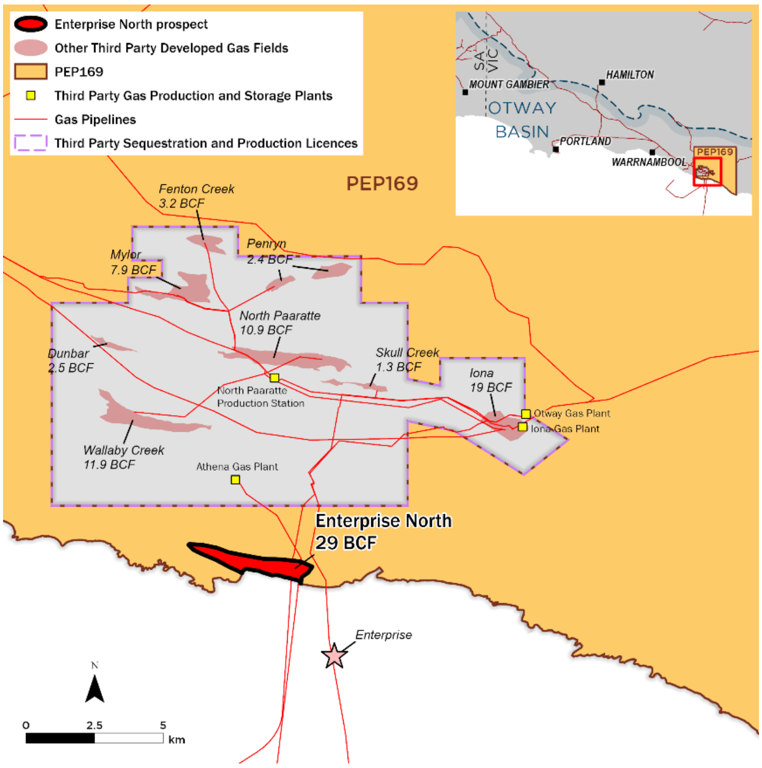
20% interest

Enterprise North is a prospective onshore target 2.5km north of the producing offshore Enterprise gas field, discovered in 2020.

The prospect is well positioned in the high-value Victorian gas market, close to existing pipelines and the Iona, Otway and Athena gas plants.

The Enterprise North well is planned for 2027 in southern PEP169, targeting natural gas in the Waarre C Formation at about 2,000 m. The location is approximately 8.5 km southwest of the Iona Gas Field and 2.5 km north of the offshore Enterprise discovery.

Central estimates up to 79 Bcf of gas in place in the Waarre C Formation at Enterprise North, equivalent to about 16 Bcf, net to Central. Additional prospectivity may exist in the Waarre A and Eumeralla formations, although resource estimates for these secondary targets have not yet been completed.




Location of Enterprise North and PEP169

| Enterprise North (PEL169) | 100% JV | | Central 20% interest | |
|---|---|---|---|---|
| | Gas in place[1] (Bcf) | Prospective Resource[1] (Bcf) | Gas in place[1] (Bcf) | Prospective Resource[1] (Bcf) |
| **High estimate** | 78.9 | 51.3 | 15.8 | 10.3 |
| **Best estimate** | 43.9 | 28.6 | 8.8 | 5.7 |
| **Low estimate** | 5.4 | 3.5 | 1.1 | 0.7 |

Note 1 – Cautionary statement: the estimated quantities of petroleum that may potentially be recovered by the application of a future development Project(s) relate to undiscovered accumulations. These estimates have both a risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially recoverable hydrocarbons. The resources above were first reported to ASX on 27 January 2026. Central is not aware of any new information or data that materially affects the information included in those announcements and all material assumptions and technical parameters underpinning the estimate continue to apply and have not materially changed.

The volumes of prospective resources included above represent unrisked recoverable volumes. No petroleum reserves or contingent resources have been attributed to Enterprise North at this time.

Modelling of a P50 success case indicates Enterprise North could nearly double Central's current gas production rate. The high-permeability target formation may allow more than half of the resource to be produced within the first three years.

If successful, Enterprise North, or other significant gas targets in the permit, could be highly value accretive, with low transport costs into the Victorian gas market and limited upfront infrastructure capital if access to nearby gas plants is secured.

PEP169 also offers further growth potential, with 18 conventional prospects and leads identified, including several amplitude-supported targets close to gas processing and transport infrastructure.

## Cooper Basin, South Australia

### PEL677 and 24 Petroleum Retention Leases

49% interest

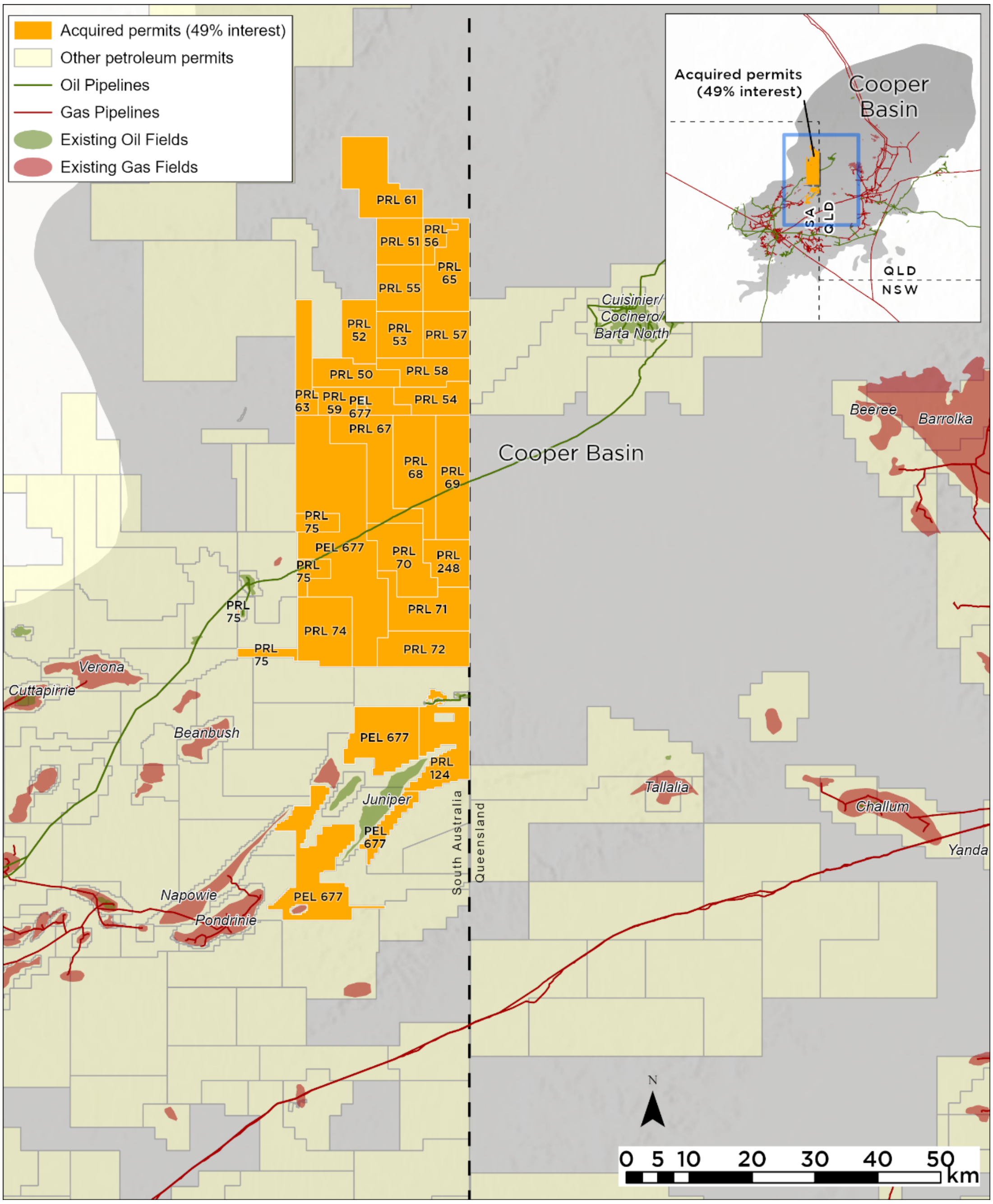
The Cooper Basin is a mature, well-established petroleum province with numerous historic and recent discoveries.

Central's Cooper interests comprise 24 Petroleum Retention Leases and exploration permit PEL677, covering a large, relatively under-explored area close to existing conventional oil and gas discoveries. The retention leases came out of suspension in 2025.

The acreage has good seismic coverage from prior 2D and 3D surveys.

Seventeen prospects and leads have been identified, including at least seven drill-ready prospects. Reprocessed seismic data will guide selection of at least two priority oil and gas targets for planned 2027 drilling.

Cooper Basin discoveries can be brought online quickly through existing gas pipelines to the east coast gas market, and through established oil pipelines and trucking routes to refineries and port facilities.




Location of Cooper Basin exploration targets

# OPERATING AND FINANCIAL REVIEW

## COMMERCIAL

**New gas sale contracts**

Central's successful gas marketing efforts are now reflected in a 14% increase in the average portfolio gas price since FY2025. With Northern Territory gas supply remaining tight, Central supplied approximately 50% of the Territory's gas requirements during the year. As the Territory's only onshore gas supplier with certified reserves during this period, Central secured new multi-year gas sale agreements that are expected to support reliable cash flow in coming years:

- A firm gas sales agreement signed in October to supply 1.3 PJ of gas, net to Central, to McArthur River Mining Pty Ltd in 2026 and 2027.
- Multi-year gas contracts with the Northern Territory Government through to the end of 2034, supporting the final investment decision for two new Palm Valley wells expected to increase gas production by 40% when commissioned in late 2026.

Based on expected production, including anticipated output from the Palm Valley wells now being drilled, Central's gas production is 98% contracted in 2027, 82% contracted over the next three years (2027-2029) and 73% contracted over the next five years (2027-2031).

**Overlifted gas fully repaid**

Central made the final delivery to repay previously overlifted gas in May 2026. Since 2020, Central had delivered 2 TJ per day against this liability, receiving no net revenue for that volume, accounted for as both revenue and operating costs. With the liability now cleared, future cash flows are expected to benefit from reduced operating cash costs of approximately $7 million per year.

**Expansion into Cooper and Otway basins**

Central expanded its exploration footprint into the Cooper and Otway basins, two proven onshore basins offering lower-cost, near-term drilling opportunities, growth potential and access to the east coast gas market. Further detail is provided in the Exploration section of this report.

**Restructure of sub-salt exploration permits**

Central continued to seek new partners to help fund drilling in its sub-salt Amadeus Basin permits. A conditional agreement to sell three sub-salt exploration permits was secured, but later terminated, after the counterparty did not satisfy the conditions precedent by the due date.

Following a review of drilling costs and relative prospectivity, Central withdrew from the EP82 and EP112 joint ventures during the year.

**Loan facility extended**

Central increased its existing loan facility to provide up to $15 million of working capital, if required, to support accelerated drilling at Palm Valley.

**Oil constraints**

Revised oil specification requirements constrained oil and gas production at times during the year. Oil sales were suspended from mid-June 2026, and Central continues to pursue alternative arrangements to commercialise Mereenie oil and condensate production.

## ESG AND COMMUNITY

Central's approach to ESG is grounded in safe operations, responsible environmental management and respectful engagement with the communities and Traditional Owners connected to our activities. We will continue to build on these foundations as we pursue reliable energy production, disciplined growth and long-term value for our stakeholders.

### Environmental

Central conducts its operations in an environmentally responsible and sustainable manner, consistent with regulatory requirements and community, cultural and social expectations. Maintaining positive environmental outcomes is central to the success of our business.

**Our core values**

- We put safety first.
- We respect the environment and the communities we work with.
- We value our people and our stakeholders.

Central operates under comprehensive, government-approved Environmental Management Plans (EMPs) and complies with relevant Commonwealth and Northern Territory regulations. The EMPs set detailed requirements for water and waste management, air emissions, land disturbance and rehabilitation, soil and flora/fauna conservation, pest and weed control and bushfire prevention. No fracture stimulation (fracking) activities are conducted in our production or exploration areas.

Regulatory agencies conducted several visits and inspections during the year to monitor environmental conditions. These inspections complemented Central's internal monitoring and assurance programs, which confirmed a high level of compliance with EMP requirements.

There were no reportable environmental incidents at any Central operated fields during the year.

**Australians rely on natural gas from Central Petroleum**

- Approximately 50% of the Northern Territory's gas supply comes from our gas fields.
- Supplied across the Northern Territory for residents, manufacturers and electricity generation.
- Electricity for Alice Springs residents, businesses, schools and hospitals is generated from gas from our Dingo gas field.
- Remote mine sites in the Northern Territory rely on our gas to supply minerals to worldwide markets.

### Safety

The safety of Central's employees, contractors and communities is paramount. Central is committed to eliminating or minimising health, safety and welfare risks arising from its operations.

During the year, Central had no recordable injuries across more than 230,000 hours worked, resulting in a Total Recordable Injury Frequency Rate (TRIFR) of nil at 30 June 2026.

### Community

Central works closely with local communities, landowners and other stakeholders. We value their support and seek to provide local employment and business opportunities wherever possible.

In the Northern Territory:

- 30% of our staff live locally.
- 18% of our on-site staff are indigenous.
- Central and its partners paid over $12.9 million in royalties to the Northern Territory government and Central Land Council in FY2026.
- Central and its partners spent over $4.9 million with local contractors and businesses and incurred over $2.1 million in fees and levies payable to the Northern Territory government in FY2026.

Central aims to pay suppliers on time and in accordance with agreed terms, typically within 30 days after the end of the month of invoicing.

Many of Central's Northern Territory operations are located on or near Indigenous lands. We recognise and respect Indigenous historical, legal and heritage ties to these lands and are committed to open engagement with Traditional Owners, including through employment and training opportunities for Indigenous people. We work closely with the Central Land Council and Aboriginal Areas Protection Authority to avoid disturbance to areas of cultural heritage significance.

### Sustainability report

For information on Central's emissions and climate-related risks and opportunities, refer to the Sustainability Report on page 22 of this report.

## RESERVES AND RESOURCES STATEMENT

Net proved & probable (2P) oil and gas reserves were 72.4 PJe at 30 June 2026.

### Aggregate Reserves and Resources

| | | As at 30/06/2025 | 01/07/2025 to 30/06/2026 Production | Other adjustments | As at 30/06/2026 | Comprising[1] Developed | Undeveloped |
|---|---|---|---|---|---|---|---|
| **Oil** | | | | | | | |
| Proved reserves (1P) | mmbbl | 0.31 | (0.03) | 0.02 | **0.31** | 0.30 | 0.01 |
| Proved plus probable reserves (2P) | mmbbl | 0.39 | (0.03) | 0.01 | **0.37** | 0.35 | 0.02 |
| Contingent Resources (2C) | mmbbl | 0.05 | – | – | **0.05** | – | – |
| **Gas** | | | | | | | |
| Proved reserves (1P) | PJ | 57.42 | (3.64) | (6.57) | **47.21** | 46.33 | 0.88 |
| Proved plus probable reserves (2P) | PJ | 70.84 | (3.64) | 3.03 | **70.23** | 58.06 | 12.17 |
| Contingent Resources (2C) | PJ | 52.10 | – | – | **52.10** | – | – |

1 All developed and undeveloped 1P and 2P reserves are located in the Amadeus Basin geographical area.

### Reserves and Resources by Field

| | | As at 30/06/2025 | 01/07/2025 to 30/06/2026 Production | Other Adjustments | As at 30/06/2026 |
|---|---|---|---|---|---|
| **Mereenie, oil** | | | | | |
| Proved reserves (1P) | mmbbl | 0.31 | (0.03) | 0.02 | **0.31** |
| Proved plus probable reserves (2P) | mmbbl | 0.39 | (0.03) | 0.01 | **0.37** |
| Contingent Resources (2C) | mmbbl | 0.05 | – | – | **0.05** |
| **Mereenie, gas** | | | | | |
| Proved reserves (1P) | PJ | 28.86 | (1.74) | 1.46 | **28.58** |
| Proved plus probable reserves (2P) | PJ | 37.94 | (1.74) | 2.86 | **39.06** |
| Contingent Resources (2C) | PJ | 45.60 | – | – | **45.60** |
| **Palm Valley** | | | | | |
| Proved reserves (1P) | PJ | 9.59 | (1.10) | (0.04) | **8.45** |
| Proved plus probable reserves (2P) | PJ | 10.34 | (1.10) | (0.04) | **9.20** |
| Contingent Resources (2C) | PJ | 6.50 | – | – | **6.50** |
| **Dingo** | | | | | |
| Proved reserves (1P) | PJ | 18.98 | (0.80) | (8.00) | **10.19** |
| Proved plus probable reserves (2P) | PJ | 22.57 | (0.80) | 0.20 | **21.97** |

Note: Estimates may not arithmetically balance due to rounding.

**Qualified Petroleum Reserves and Resources Evaluator Statement**

The information contained in this Reserves and Resources Statement is based on, and fairly represents, information and supporting documentation prepared by, or under the supervision of Mr. John Hattner who is a full-time employee of Netherland, Sewell & Associates, Inc. ("NSAI") where he holds the position of Senior Vice President. Mr. Hattner is a member in good standing of the Society of Petroleum Engineers, is qualified in accordance with ASX listing rule 5.41. and has consented to the inclusion of this information in the form and context in which it appears.

Central Petroleum Limited is not aware of any new information or data that materially affects the information included in this document and all the material assumptions and technical parameters underpinning the estimates in the relevant market announcement continue to apply and have not materially changed.

Reserves and resources estimates are prepared by suitably qualified personnel in a manner consistent with the Petroleum Resources Management System (PRMS) 2018 published by the Society of Petroleum Engineers (SPE). Reserves and resources estimates are reviewed at least annually or when new technical or commercial information becomes available. Additionally, external certification is conducted periodically.

## RISK MANAGEMENT

Central Petroleum recognises that the effective management of risks inherent to our business is vital to delivering our strategic objectives, continued growth and success. We are committed to managing risks in a proactive, robust, and effective manner, to help achieve our objectives.

Our risk management process is designed to recognise and manage risks that have the potential to materially impact on Central's business objectives. This process is aligned to the international standard ISO31000 for risk management and assesses potential risks across our business. In managing these risks, we consider impacts on the health and safety of our employees, the environment and communities in which we operate, our financial stability, our reputation and legal and compliance obligations.

### Principal risks and uncertainties at 30 June 2026

The principal risks and uncertainties outlined in this section may materialise independently, concurrently or in combination and may impact Central's ability to meet its strategic objectives.

| Context | Risk | Mitigation |
|---|---|---|
| **Financial Strength** | | |
| Our financial strength underpins our strategy and future growth. | Insufficient liquidity to meet financial commitments and fund growth opportunities could have a material adverse effect on our operations and financial performance. | We have a robust expenditure management and forecasting process which is monitored against a Board approved budget to ensure capital is allocated in accordance with the company's strategy. We actively manage debt and other funding sources to ensure the business is appropriately capitalised to sustain ongoing operations and growth plans. We also actively seek partnering opportunities to share risks and assist in funding key activities on a project-by-project basis. |
| **Gas Market** | | |
| Our revenue and cash flows are highly dependent on the ability to sell hydrocarbons profitably, underpinning Central's financial performance and shareholder value. | Central is exposed to regional gas prices – particularly in the Northern Territory and Australian east coast markets.<br>In addition to normal demand and supply forces, gas prices in these markets are subject to risk of Government intervention, including the Australian Domestic Gas Supply Mechanism and Mandatory Code of Conduct.<br>Central's ability to sell sufficient volumes of gas in the future at profitable prices could also be impacted by new supply from emerging Beetaloo Basin production or from LNG gas volumes forced into the market by proposed national gas reservation regulations. | The majority of Central's revenue is from natural gas sales and the short-term uncertainty with this commodity is largely mitigated through medium and long term fixed-price gas sales agreements with 'take-or-pay' provisions.<br>Central receives an automatic exemption from current mandated gas price caps as its level of production falls below eligibility thresholds and its gas supplies are only to domestic markets.<br>Central's established gas reserves and production infrastructure is likely to provide a cost advantage in comparison with new producers. |
| | Central is exposed to USD oil price variability which is impacted by broader economic factors beyond our control. | Oil revenue represented less than 10% of consolidated sales revenue in FY2026. |

| Context | Risk | Mitigation |
|---|---|---|
| **Geographic Concentration** | | |
| We face risks associated with the concentration of our production assets. | Central's revenue is derived from oil and gas production in the Amadeus Basin leaving Central exposed to downsides associated with weather conditions, infrastructure failure and regional market fluctuations. | We ensure that appropriate insurance is in place to mitigate the impact of any extended business interruption.<br>Central has locked in sales for estimated firm forward production from existing and new wells until 2027 at fixed pricing on a take-or-pay basis within the NT.<br>We have recently expanded our exploration footprint to the Cooper and Otway Basins. |
| **Social and Legal License to Operate** | | |
| Our business performance is underpinned by our social license to operate, that requires compliance with legislation and the maintenance of a high standard of ethical behaviour and social responsibility.<br>Our business activities are subject to extensive regulation and increasingly costly government policy and regulatory requirements. Failure to comply may impact our license to operate.<br>Stakeholders have expectations of social responsibility and ethical decision making, which can exceed regulatory requirements. | Failure to meet stakeholder expectations can lead to opposition and a decline in support for both our operational activities and future growth opportunities.<br>A significant or continuous departure from national or local laws, regulations or approvals, or the introduction of new laws and regulations may result in negative social, cultural and reputational impacts and could impact our ability to operate or pursue our growth strategy.<br>Violation of laws and regulations may expose Central to fines, sanctions, and civil suits, and negatively impact our reputation. | Central proactively maintains and builds our social license to operate through the application of our values, effective stakeholder engagement, and our regulatory compliance framework.<br>We have a robust framework in place to support our regulatory and compliance obligations and we continue to review our compliance processes.<br>We proactively maintain open dialogue with governments, regulators and stakeholders within jurisdictions in which we operate.<br>Our governance framework aims to prevent, detect, and respond to unethical behaviour. It incorporates policies, procedures, and training to ensure activities are conducted legally and ethically. |
| **Growth** | | |
| Our future growth depends on our ability to identify, acquire, explore, appraise and develop resources. | The inability to identify and commercialise growth opportunities, or realise their full value, may result in a loss of shareholder value.<br>Unsuccessful exploration and renewal of upstream resources may impede delivery of our strategy to maximise shareholder value. | We engage experienced, skilled personnel to identify and progress a suite of commercially attractive and sustainable opportunities that complement our existing assets, enable portfolio diversity and optimise our commercial position.<br>Exposure to reserve depletion is addressed through our exploration strategy. We continue to analyse existing acreage for exploration drilling prospects and look for joint venture partners to assist with funding and sharing of risk. |
| Our ability to successfully deliver value adding projects is also critical. | Central is exposed to market and industry conditions - some beyond our control, which may impact project delivery and lead to cost overruns or schedule delays when developing and executing our capital projects. | We utilise an established project management framework which is supported by skilled and experienced personnel to govern and deliver major projects. |

| Context | Risk | Mitigation |
|---|---|---|
| **Oil and Gas Reserves** | | |
| Commercialisation of hydrocarbon reserves is a key contributor to our long-term success. | Uncertainty in hydrocarbon reserve estimation and the broad range of possible recovery scenarios from existing resources could have a material adverse effect on our operations and financial performance. | Our reserve and resource estimates are prepared in accordance with the guidelines set forth in the 2018 Petroleum Resources Management System (PRMS). We proactively analyse reservoir performance and undertake comprehensive production and economic modelling to determine the most likely outcomes across our fields. We engage independent experts periodically to update reserve estimates. |
| **Operating** | | |
| The safe and reliable production and delivery of hydrocarbon products is key to our operational and financial performance and directly impacts shareholder value. | Reservoir / field performance is subject to subsurface uncertainty. The actual performance could vary from that forecasted, which may result in diminished production and /or additional development costs.<br>Our facilities are subject to hazards associated with the production of gas and petroleum, including unexpected equipment failure or major accident events, such as spills and leaks, which can result in a loss of hydrocarbon containment, diminished production, additional costs, environmental damage or harm to our people, reputation or brand. | We continually monitor field performance and schedule production optimisation and development activities to extract maximum value from the field and to mitigate any potential reservoir under-performance.<br>Embedded within our operational practices is a framework of controls which enable the management of these risks. We have in place asset integrity management processes, inspections, maintenance procedures and performance standards across all activities and infrastructure to support reliable and safe operations.<br>Central maintains insurance in line with industry practice considered sufficient to cover normal operational risks. However, Central is not insured against all potential risks because not all risks can be insured cost effectively. Insurance coverage is determined by the availability of commercial options and cost/ benefit analysis, considering Central's risk management program. |
| Central's hydrocarbon products must comply with market specifications. | Central's ability to sell its products can be impacted by changing composition of produced gas or liquids. This may require investment in new production infrastructure or lead to increased production costs or reduced revenues, impacting financial performance. | Central constantly monitors the composition of its production and works with customers and infrastructure operators to ensure production meets required specifications. |
| **Climate Change** | | |
| Climate change may result in more extreme weather in the future which could impact Central's operations. Transitional policies could potentially impact Central's business, which is dependent on demand for fossil fuels. | Refer to the Sustainability Report for a comprehensive discussion of climate change related risks and opportunities relevant to Central. | |
| **Community** | | |
| Our proactive engagement and support of local and indigenous communities is at the core of how we operate. | Our interactions with, and decisions involving landholders, traditional owners, suppliers and the community fails to attract and maintain the continued support of the communities in which we operate. | We work in conjunction with our key stakeholders and have established programs to support and assist the communities in which we operate through donations, sponsorships, local procurement, training and providing ongoing local employment and business opportunities. |

| Context | Risk | Mitigation |
|---|---|---|
| **Health and Safety** | | |
| Health and safety are at the heart of all activities and decisions at Central. | Health and safety incidents or accidents may adversely impact our people, the communities in which we operate, our reputation and/or our licence to operate. | Health and safety are key areas of focus for Central and our risk management framework includes audit and verification processes for our critical controls. We also regularly review our operations and processes to ensure we have in place robust, safe systems of work, and an effective health and safety management system. |
| **People and Culture** | | |
| We must have the right capability and capacity within our business through personnel who are engaged and enabled to deliver our current business and future growth opportunities. | Failure to establish and develop sufficient capability and capacity to support our operations may impact achievement of our objectives. | We aim to secure and develop the right people to support the operation and development of our portfolio of assets and opportunities.<br>Our remuneration policy aims to attract, incentivise and retain experienced personnel.<br>We also proactively engage contractors to supplement any short-term gaps in capability and capacity to support the execution of our business plans. |
| **Environment** | | |
| Our environmental performance underpins our licence to operate. | Our operations, by their nature, have the potential to impact air quality, biodiversity, land and water resources and related ecosystems. A failure to manage these could adversely impact not just the environment, but our people, the communities in which we operate, our reputation, licence to operate and financial performance. | Environmental management is a very high priority for Central. We operate under approved Field Environmental Management Plans and have a program of regular environmental inspections and audits in place to ensure compliance. We also continue to assess and develop our standards to prevent, monitor and limit the impact of our operations on the environment.<br>We maintain insurance policies for environmental liability and well control to mitigate financial impacts should an event occur. |
| **Joint Ventures** | | |
| Although we operate most of the tenements we hold, we are dependent on technical and commercial alignment with our joint venture partners. | Misalignment between joint venture partners, or failure to honour financial commitments may impact the prioritisation of exploration, development or production opportunities. This can lead to delayed approvals or forfeited tenure, which may impact Central's financial performance and growth strategy. | We work closely with our new and existing joint venture partners to achieve mutually beneficial outcomes. |
| **Access to Infrastructure** | | |
| Our financial performance and growth strategy are dependent on access to third party owned infrastructure, such as gas pipelines. | Infrastructure failure or closure, increased tariffs, or restricted access to third party owned infrastructure can have adverse impacts on financial performance.<br>In recent years Central has been exposed to pipeline outages which has restricted our access to east coast gas markets. | We seek to work closely with customers and suppliers of infrastructure to mitigate the risk of closure or failure, however we have little or no control over the outcome. We continue to explore alternative routes to market to diversify risk where possible.<br>Central has locked-in sales for estimated firm forward production from existing wells until 2027 at fixed pricing on a take-or-pay basis within the NT, mitigating exposure to pipeline interruptions. |

| Context | Risk | Mitigation |
|---|---|---|
| **Digital and Cyber Security** | | |
| We are reliant upon our systems and infrastructure availability and reliability to support the business operating safely and effectively.<br>Cyber risks continue to evolve with greater levels of sophistication. | Failure to safeguard the confidentiality, integrity, availability and reliability of digital data and intellectual property.<br>Central's information and operational technology systems may be subject to intentional or unintentional disruption (e.g. cyber security attack) which could impact our ability to reliably supply customers. | Digital risks are identified, assessed and managed based on the business criticality of our systems, which may be segregated and isolated if required.<br>We continuously assess and determine access permissions to critical information or data, whilst consolidating, simplifying, and automating security controls.<br>Our exposure to cyber risk is managed by a proactive and continuing focus on system controls such as firewalls, restricted points of entry, multifactor authentication, multiple data back-ups and security monitoring software. We are continuing to embed a cyber-safe culture across Central, including regular staff training. |

# SUSTAINABILITY REPORT

FOR THE YEAR ENDED 30 JUNE 2026

Central Petroleum Limited is pleased to present its Sustainability Report for the year ended 30 June 2026.

**Sustainability Report Contents**



# DIRECTORS' DECLARATION – Sustainability Report

In the Directors' opinion:

Central Petroleum Limited has taken reasonable steps to ensure that the substantive provisions of the Central Petroleum Limited sustainability report for the financial year ended 30 June 2026 set out on pages 23 to 33 are in accordance with the *Corporations Act 2001 (Cth)* ("the Act") including section 296C of the Act (compliance with applicable sustainability standard *AASB S2 Climate-related Disclosures*) and section 296D of the Act (climate statement disclosures).

This declaration is made in accordance with a resolution of the directors of Central Petroleum Limited.

**Agu Kantsler**
**Director**
Brisbane
17 September 2026

# SUSTAINABILITY REPORT

## A Basis of Preparation

This report presents climate-related financial disclosures for Central Petroleum Limited and its subsidiaries (collectively, “Central” or “the Group”) for the year ended 30 June 2026 (“Sustainability Report”).

The Sustainability Report has been prepared in accordance with the *Corporations Act 2001 (Cth)* and *AASB S2 Climate-related Disclosures* (AASB S2), the mandatory Australian Sustainability Reporting Standard issued by the Australian Accounting Standards Board.

Central is a Group 1 Reporting Entity as it is required under the *National Greenhouse and Energy Reporting Act 2007* (NGER) to report 100% of emissions from facilities it operates on behalf of joint venturers.

This report covers the same consolidated reporting entity and reporting period as the Group’s Consolidated Financial Statements (refer to “Note 1(b) Principles of Consolidation” in the Financial Report) and has incorporated climate-related information of the parent company and its subsidiaries.

In the Financial Report, the Group reports only its share of production volumes, reserves, costs and revenues associated with its equity interests in various joint operations. For consistency, the emissions reported in this report are Central’s equity share of emissions from joint operations and will therefore differ from emissions reported as operator under the NGER regulations. Reported emissions include those from the following facilities:

| Facilities | Operational control | Equity interest |
|---|---|---|
| Mereenie<br>Gas and oil production, Northern Territory | Yes | 25% |
| Palm Valley<br>Gas production, Northern Territory | Yes | 50% |
| Dingo<br>Gas production, Northern Territory | Yes | 50% |
| Surprise<br>Oil production (suspended), Northern Territory | Yes | 100% |
| Corporate office<br>Brisbane, Queensland | Yes | 100% |

During the year, Central was also a party to several non-operated exploration joint ventures. There were no field activities in these projects during the year, and these operations are regarded as immaterial for the purposes of the 2026 Climate Report.

Central has reported emissions under NGER since 2014 in accordance with the NGER measurement requirements and has early-adopted the Australian Sustainability Reporting Standards AASB S2025-1 *Amendments to Greenhouse Gas Emissions Disclosures* to utilise the calculation methodology as specified by the NGER Measurement Determination to measure the emissions in this report.

As this is the first year in which the Group has applied AASB S2, the Group has applied transition relief and elected to not disclose comparative information or Scope 3 emissions in this report.

## B Business Overview

**Key business activities**

Central is an established Australian oil and gas producer and is the largest onshore gas operator in the Northern Territory (NT). It supplies gas from the Mereenie, Palm Valley and Dingo gas fields through third-party pipelines to customers across central and northern Australia.

In addition to its established NT production operations, Central also has a pipeline of growth opportunities which include exploration, appraisal and development projects in the Amadeus Basin (NT), Cooper Basin (South Australia) and onshore Otway Basin (Victoria).

**Value chain**

As a producer of natural gas in the Northern Territory, the key components of Central's value chain include:

| | Description | Location |
|---|---|---|
| **Upstream** | | |
| Key suppliers | Equipment, consumables and services for gas field operations | Northern Territory and Australian seaboard |
| Transportation | Remote operations with long supply routes | Northern Territory |
| **Operations** | | |
| Gas wells | Gas flows from wells into gathering pipelines | Northern Territory |
| Gas processing | Gas is processed to remove liquids and impurities, then compressed for pipeline delivery | Northern Territory |
| **Downstream** | | |
| Product delivery | Gas is delivered through third-party pipelines | Northern Territory |
| Customers | Wholesale gas customers, including utilities, power generators, miners and industrial users | Northern Territory and Northern Australia |

## C Climate-related risks and opportunities

**Overview**

Central's gas production facilities operate in arid central Australian conditions and our staff and operations already have a relatively high degree of resilience to high temperatures and long supply chains. Although temperatures have already reportedly increased by almost 1.5ºC from pre-industrial levels, Central has not observed a material operational impact to date. Due to the inherent resilience of the existing operations, Central has not identified any material future impact based on the current forecast increases in the number of hot days or more intense rainfall.

Central's Board and management monitor regulatory changes, market developments and forecasts in its strategic decision making. This includes considering publicly-available information from Australia's most authoritative body on gas and electricity demand, the Australian Energy Market Operator (AEMO), which publishes annual forecasts such as the *Gas Statement of Opportunities* and *Integrated System Plan for the National Electricity Market.*

A decline in gas demand may occur over time, but it is not evident in AEMO's NT gas demand forecasts within Central's planning horizon. Central's expected gas production is already largely contracted through to the end of 2027, with further gas supply contracts extending to 2034. Central also has visibility of ongoing demand from large NT gas users and potential new remote mine sites which will require new supply.

At this time, Central is not subject to any carbon tax or charges and there is no proposed regime in Australia that could impact Central's operations at current or forecast levels. We continue to monitor policy developments.

Based on currently available information and the qualitative assessment performed, Central does not expect climate-related risks or opportunities to materially affect the Group's financial performance or cash flows in the short, medium or long term. Please refer to Note 1 for further details on the assessment performed by Central at this point in time.

The Group has a committed loan facility which is expected to adequately fund short-term requirements and is expected to be fully repaid from expected cash flow by December 2029.

**Time horizons**

The Group considers the possible impact of climate change over the following time horizons:

- Short-term: 1 to 5 years;
- Medium-term: 6 to 10 years; and
- Long-term: greater than 10 years.

These timeframes align with operational budget cycles (typically 1-2 years), corporate cash flow projections (up to 5 years), gas sale agreements (1-5 years), impairment modelling (20 years) and field life expectations (20-40 years).

**Identified climate related risks and opportunities**

Central's identified climate related risks and opportunities that could reasonably be expected to affect it prospects include:

| Climate-related risks | Expected time horizon | Anticipated FY2027 effects | Mitigations and anticipated financial effects over short, medium and long term |
|---|---|---|---|
| **Physical risks** | | | |
| **Extreme weather events**<br><br>Hotter days, increased bush fire risk and more intense rainfall could affect production, costs, site access, customer demand, staff welfare, insurance or financing cost / availability | Long term | None | Central's operations in central Australia already have a relatively high degree of climate resilience as activities are conducted in extreme temperatures, with occasional short-term access restrictions due to flooding. No significant financial impacts have been experienced to date, or are expected over the short, medium or long term[1].<br><br>Mitigations include hot weather workplace procedures, bush fire management plans, on-site fire-fighting equipment, and appropriate cooling systems.<br><br>Based on current predictions of increased days of extreme heat and possible rainfall fluctuations in central Australia, no material financial impact has been identified in the short, medium or long term[1]. |
| **Transition risks** | | | |
| **Introduction of carbon price / tax**<br><br>Any future carbon price / tax could lead to increased operating costs or reduced competitiveness compared to alternative energy sources.<br><br>Impairment of asset carrying values could be required. | Medium Term<br>Long Term | None | Under current regulations, Central is not subject to Australia's Safeguard Mechanism (as none of its facilities exceed the emissions threshold) or carbon price/tax and is not expected to qualify for the scheme based on current production forecasts.<br><br>Central is not aware of any proposed future changes to regulations that would result in its operations becoming subject to a carbon price / tax.<br><br>Existing Gas Sale Agreements allow pass-through of any new carbon tax to customers.<br><br>Based on existing or proposed schemes, no material financial impact has been identified[1]. Central will continue to monitor developments in this area for any anticipated financial impacts that could occur in the future. |
| **Substitution of energy supply**<br><br>Greater renewable energy use could reduce demand or prices for gas in Central's markets.<br><br>Impairment of asset carrying values could be required. | Medium Term<br>Long Term | None | Reduced future demand could impact future revenues, cash flow, growth opportunities and asset values.<br><br>Expected CY2027 production is fully-contracted, and AEMO forecasts do not indicate reduced NT gas demand in the short, medium or long term.<br><br>Based on our existing and expected production and AEMO forecasts, no material financial impact has been identified[1]. Central will continue to monitor demand for gas over the longer term to determine any anticipated financial impacts that could occur in the future. |

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| Climate-related risks | Expected time horizon | Anticipated FY2027 effects | Mitigations and anticipated financial effects over short, medium and long term |
|---|---|---|---|
| **Mandates on, and regulation of existing products**<br>Future Government regulation could reduce demand or prices for gas in Central's markets.<br>Impairment of asset carrying values could be required. | Medium Term<br>Long Term | None | Central is not aware of any proposed future changes to regulations in Central's markets that would result in restrictions on use or supply of gas.<br>AEMO forecasts do not indicate reduced gas demand in the Northern Territory in the future.<br>No material financial impact has been identified[1]. Central will continue to monitor demand for gas over the longer term to determine any anticipated financial impacts that could occur in the future. |
| **Stigmatisation of sector**<br>Could result in reduced gas demand or limit access to, or increase the cost of, insurance or finance. | Medium Term<br>Long Term | None | Gas continues to be recognised as important for industrial use and as a transitional fuel for power generation.<br>There has been no evidence of reduced access to insurance or increased insurance costs.<br>Central's existing finance facility is expected to cover the Group's identified short-term capital requirements and is expected to be fully repaid by December 2029. There is no evidence that funding will not be available in the future.<br>AEMO forecasts do not indicate reduced gas demand in the Northern Territory in the short, medium and long term (Refer Section G).<br>No material financial impact has been identified[1]. Central will continue to monitor any stigmatisation of the sector that could impact anticipated financial impacts in the future. |

Central's operations in FY2026 have not been impacted by any climate-related physical or transition risks.

| Climate-related opportunities | Anticipated financial effects over short, medium and long term |
|---|---|
| **Increases in extreme heat**<br>Higher air-conditioning demand could increase gas-fired power demand. | AEMO forecasts indicate higher medium-term gas demand under an accelerated transition scenario and a more gradual long-term increase under a step change scenario.<br>Because the effect on Central's specific markets and customers remains uncertain, no material financial benefit has been identified[1]. Central will continue to monitor the energy transition and any positive financial benefits this could have for the Group. |
| **Increased / more intense rainfall**<br>Heavier rainfall or extreme weather could reduce renewal generation (less sunshine / usable wind), and increase gas-fired firming demand. | |
| **Increased demand for gas due to its utility as a transitional fuel**<br>Transition to renewable energy sources may require additional supply | |

Note 1: Quantitative information relating to possible financial effects of climate related risks and opportunities.

In ascertaining the possible anticipated future financial effect, reasonable and supportable information available at the reporting date has been considered, utilising an approach commensurate with the skills, capabilities and resources available to Central without undue cost or effort.

Note 1 (continued): Quantitative information relating to possible financial effects of climate related risks and opportunities.

Due to the difficulty of separately identifying the financial impact of each risk / opportunity, the availability of data and the high level of uncertainty of:

- future climate change and its impacts; and
- possible future government policy and regulatory settings,

Central has been unable to quantify the future financial impact and any estimated measurement would be so uncertain that the information would not be useful. The Group will consider introducing quantitative measurements of future financial impacts as available modelling tools and methodologies mature, regulatory settings change and climate-related forecasts become more reliable.

Any impact on gas volumes or gas price would be reflected in the Consolidated Statement of Comprehensive Income in the financial statements on the Revenue line, while any increased costs would be reflected in the Cost of Sales line and the net impact would flow through to the subsequent subtotals: Gross profit; Profit before income tax; Profit for the year; and total comprehensive profit for the year. Any necessary impairment of asset values would be reflected in the relevant Consolidated Balance Sheet lines, which could include Property, plant and equipment, Exploration assets and Goodwill, with the aggregate impact flowing through to the Total non-current assets, Total assets and Net assets subtotals.

Although no material financial impact is expected from the current qualitative assessment of climate-related physical and transition risks over the short, medium or long term, 100% of Central's business activities and assets, with a book value of $75.7 million at 30 June 2026 and revenues of $44.7 million in FY2026 are:

- potentially vulnerable to climate related physical and transition risks; and
- aligned with climate-related opportunities.

## D Effects of climate-related risks and opportunities on strategy and decision-making

Central contributes to Australia's energy security by supplying gas to customers across the Northern Territory and eastern states.

At present, Central's gas fields supply around half of the Northern Territory's gas demand. This gas supports electricity generation for Alice Springs and supplies remote mine sites producing critical and rare minerals for domestic and worldwide markets.

The transition to lower-emission energy sources appears likely to take longer than initially signalled, with natural gas to play a critical role in providing affordable and reliable energy during the extended transition period.

In this context, Central currently has no plans to change its business model. Its strategy is to continue supplying reliable and affordable gas for as long as it is needed, and to invest in capacity where supported by demand. This includes exploring for new oil and gas reserves in the NT and expanding into prospective permits in the Otway Basin (Victoria) and Cooper Basin (South Australia).

In addition to oil and gas, some of Central's NT permits are highly prospective for helium (which is essential for many critical applications and is in short supply, both domestically and globally) and hydrogen (a clean source of alternative energy), providing a potential diversified source of future revenue.

The costs of future exploration activities are expected to be funded from anticipated future free cash flows from the Group's producing gas fields.

Given the current gas demand forecasts, uncertainty over the timing of alternative energy deployment, and its assessment of climate-related risks and opportunities, Central has not committed to a transition plan.

Central is not currently subject to any regulatory emissions charges or reduction targets and continues to evaluate opportunities to reduce emissions where commercially compelling but has not set any emissions targets.

Central continues to monitor market and climate forecasts, regulatory developments and technology changes to identify and assess climate-related physical and transition risks and opportunities.

Climate projections, regulatory settings and market responses become less certain over longer timeframes, limiting their usefulness for medium and long term strategy setting.

## E Governance

Central's Board is responsible for oversight of climate-related risks and opportunities. This is governed through Central's dedicated Board Committees with roles set out in the relevant Board and Committee Charters:

| Board/Committee | Relevant role - as per relevant Committee Charter | Relevant activities |
|---|---|---|
| Board | Oversee the process for identifying significant risks facing the Company.<br>Review and monitor significant risks and oversee how they are managed. | Oversees and reviews the relevant Committee activities. |
| Risk and Sustainability | Review strategic risks relating to health, safety, process safety, asset management, climate change, environment, human rights and other social responsibility matters. | Reviews and assesses physical and transition climate-related risks. |
| Audit and Financial Risk | Review the external financial statements and annual report (including, but not limited to, climate-related financial disclosure). | Reviews preparation of this Sustainability Report. |
| Remuneration and Nominations | Develop a board skills matrix to assist in identifying any gaps in the collective skills of the Board for professional development and succession planning. | Reviews and maintains the Board Skills Matrix, including climate-related skills and experience in strategy, decarbonisation, sustainability, risk management, ESG, capital allocation, stakeholder engagement and legal and compliance matters. |

Through the Remuneration and Nominations Committee, the Directors have assessed the relevant Board skills and determined that the Board has a sufficient experience, diversity and skills to oversee the Company's climate-related risks and opportunities. These attributes are reviewed periodically along with other skills and experience relevant to the Company's business needs.

The Company's Risk & HSE Manager provides reports to the Risk and Sustainability Committee and is responsible for managing the Company's risk management process, including climate-related risks.

The Chief Executive Officer, Chief Operating Officer, Chief Financial Officer and relevant operational managers also play key roles in the risk management process. This is a continuous process, with the Risk and Sustainability Committee meeting several times per year, providing oversight of management's contribution to the risk management process. The Risk and Sustainability Committee reports to the Board after each meeting.

The Board and management team continually assess commercial and business opportunities, including climate-related opportunities, as they are identified in the normal course of business.

Central's experienced environmental personnel manage the measurement and compilation of emissions metrics, utilising external specialists where required.

## F The risk management process

Central considers effective risk management essential to achieving the Group's strategic objectives, growth and success. Its broader risk management approach is described on page 17 of this Annual Report.

For FY2026, a specific exercise was undertaken to identify climate-related risks and opportunities, which have been summarised in Section C of this report.

Identification and monitoring of climate-related risks is integrated into Central's overall risk management processes and handled in the same manner as all other business risks. Climate-related risks are not prioritised over other types of risk.

Central's risk management process is designed to identify and manage risks that could materially affect its business objectives. The process is aligned with international standard ISO31000 for risk management and assesses potential risks across the business.

The Risk & HSE Manager and experienced staff compile, review and regularly update a register of business using input from operational and corporate personnel, Directors and relevant external sources.

Risks are assessed using a risk matrix that considers impact severity across qualitative and quantitative categories, including health and safety, environmental, community, legal, reputational and financial impacts. The impact level is combined with the likelihood of occurrence to determine the intrinsic risk rating. Mitigating factors and controls are then considered to determine the residual risk rating.

The highest rated residual risks are reported to the Risk and Sustainability Committee and reviewed regularly, with ongoing monitoring of the risks and mitigating controls.

Climate-related opportunities are considered by the Board and management as part of the ongoing strategy-setting process to identify business development and commercial opportunities.

## G Climate resilience and scenario analysis

Central has assessed the resilience of its strategy and business to climate-related changes, developments and uncertainties through scenario analysis. Its climate-related risks and opportunities relate to physical and transition matters, each requiring different assumptions.

Central conducted its first climate-related scenario analysis in FY2026. The analysis is qualitative in nature and reflects the Group's exposure to climate-related risks and opportunities using the skills, capabilities and resources available. Central considers this approach appropriate to its circumstances at this point in time.

Central will review and update its scenario analysis approach, inputs and assumptions as required. Scenario analysis is used in periodic reviews of physical and transition risks to assess how different hypothetical climate pathways could affect risks, strategy and financial performance.

Climate scenarios are usually considered as either 'high transition/low physical risk' or 'low transition/high physical risk', as the more aggressive the actions are to reduce emissions, the less warming is likely to occur, and vice versa.

It is widely accepted that average annual temperatures across Australia and the Northern Territory have already increased by around 1.5°C since 1910. Central has not conducted further scenario analysis at this temperature, because its operations have demonstrated resilience to these conditions, with no material operational impact observed.

For future climate scenarios, Central has referenced relevant publicly available authoritative sources for climate related physical and transition risks, as discussed below.

**Physical risks**

| **Physical risk scenarios** | Scenarios | |
|---|---|---|
| Sources | Medium emissions<br>Medium-warming | Higher emissions<br>High-warming |
| • Australian Climate Service: *Australia's National Climate Risk Assessment 2025*[1]<br>• NESP Earth Systems and Climate Change Hub: *Climate Change in the Northern Territory – State of the science and climate change impacts 2020* | RCP 4.5<br>Temperature change from 1986-2005 average in Central NT:<br>2030 0.6°C-1.4°C<br>2050 0.8°C -1.7°C | RCP 8.5<br>Temperature change from 1986-2005 average in Central NT:<br>2030 0.8°C-1.5°C<br>2050 1.5°C-2.6°C |

1 Based on Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report

Scenario analysis is not conducted beyond 2050 because that horizon aligns with projected field life and Paris Agreement timeframes. Projections beyond 2050 are likely to be too uncertain to be useful for Central's strategic considerations at the date of this report.

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In conducting its scenario analysis of physical risks, Central has considered predictions for the Alice Springs region, where Central's revenue-generating operations are concentrated:

| | Medium emissions Medium-warming | | Higher emissions High-warming | |
|---|---|---|---|---|
| | By 2030 | By 2050 | By 2030 | By 2050 |
| **Temperature** Days over 35° expected to increase | 10 – 34 days pa | 13 – 54 days pa | 10 - 40 days pa | 22 - 70 days pa |
| **Rainfall** Change in average rainfall % | From 11% less to 7% more pa | From 12% less to 8% more pa | From 11% less to 8% more pa | From 17% less to 9% more pa |

Climate models indicate that the Northern Territory will continue to get warmer. The hottest days will be hotter and more frequent, warm spells will be longer and frost days will decrease. Both wetter and drier futures are plausible, but for the near future, natural variability is expected to cause greater year-to-year changes in rainfall than the effects of climate change. The uncertainty surrounding rainfall also impacts the likelihood of drought and bushfires. Heavy rainfall events will become more intense, but how much more intense is not clear.

Central's remote operations are already adapted to hot, dry weather conditions and have shown resilience to isolated rainfall events that restrict access for short periods. The scenario analysis of climate-related physical risks conducted in FY2026 did not identify material impacts on Central's operations.

**Transition risks**

| **Transition Risk Scenarios** | | | |
|---|---|---|---|
| AEMO Scenario | IEA Scenario | Scenario | Outcome |
| **Accelerated transition** | Net Zero Emissions by 2050 (NZE) | Reflects decarbonisation to support Australia's contribution to limit global temperature rise to 1.5°C. | Forecast national (NEM) and NT gas demand increases significantly until 2031 and only falls below current levels from around 2037. |
| **Step Change** | Stated Policies Scenario (STEPS) | Reflects a pace of energy transition that supports Australia's contribution to limit global temperature rise to less than 2°C. | Forecast NEM and NT gas demand increases until 2035 and does not fall below current levels.<br>NT gas demand is forecast to remain steady through the forecast horizon (2045) |
| **Slower Growth** | Current Policies Scenario (CPS) | Reflects existing energy-related legislation and regulations. Global temperature rises by 2.9⁰C. | Forecast NEM and NT gas demand increases until 2031 and does not fall below current levels. |
| | | | |
| **Sources** | • Australian Energy Market Operator (AEMO):<br>• *Gas Statement of Opportunities* (2026 GSOO)<br>• *Integrated System Plan for the National Electricity Market* (2026 ISP)<br>• International Energy Agency (IEA) *2025 World Energy Outlook* | | |

AEMO's scenarios align with scenarios from the International Energy Agency's 2025 World Energy Outlook which predict future temperature increases over pre-industrial levels ranging from 1.5⁰C to 2.9⁰C.

The key finding of the 2026 ISP is that "AEMO continues to find that renewable energy connected with transmission and distribution, firmed with storage and backed up by gas is the least-cost way to supply electricity to homes and businesses through to 2050, as coal plants retire and while meeting government policies."

Under AEMO's Gas Statement of Opportunities Accelerated and Step Change scenarios, NT gas demand remains steady. Across the broader National Electricity Market and NT gas-powered generation sector, the Step Change and Slower Growth scenarios forecast a marginal short-term decline in gas demand, before returning to current levels. The 2026 ISP forecasts that "…through to 2050, the gas fleet is projected to supply a similar share of the NEM's annual generation to today's."

The Accelerated Transition scenario shows medium-term gas demand increasing as coal-fired power stations in eastern states are retired earlier. The 2026 ISP assumes "…that more firming solutions would be needed to support the reliability of the power system. Gas-powered generation was assumed to be this firming solution." This could create opportunities for Central to increase gas production to meet demand. Central continues to monitor potential customer requirements.

In summary, Central's FY2026 scenario analysis did not identify material climate-related physical or transition risks. Central will continue to monitor relevant forecasts, policy and market developments and reassess climate-related risks through its periodic risk management processes.

## H Metrics - emissions

Central's equity share of Scope 1 & 2 greenhouse gas emissions is set out in the following table.

| Greenhouse Gas Emissions | FY2026 $CO_2e$ (Tonnes) | | |
|---|---|---|---|
| | Scope 1 | Scope 2 | Total |
| Mereenie | **13,871** | **-** | **13,871** |
| Palm Valley | **6,326** | **-** | **6,326** |
| Dingo | **936** | **20** | **956** |
| Brisbane | **-** | **51** | **51** |
| Other | **-** | **-** | **-** |
| Total | **21,133** | **71** | **21,204** |
| Emissions intensity[1] (Kg $CO_2e$/GJe) | | | **4.88** |

1 Emissions intensity is calculated as the ratio of scope 1 and 2 emissions aggregated from each of the three producing fields (Mereenie, Palm Valley and Dingo) over the aggregate sales volumes.

**Measurement approach**

Central measures its emissions using the equity-share approach under the *Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard (2004)*, applying NGER measurement methods where relevant.

The measurement basis used for the main sources of emissions is set out below:

| Emissions category | % of emissions | Measurement method |
|---|---|---|
| Fuel gas – gas compression / electricity generation | 47% | Fuel gas used for gas compression and electricity generation is captured by facility instrumentation and measured using criterion BBB under the NGER Measurement Determination. Emissions from fuel gas combusted are calculated using energy content, emission factors and methodology set out in the NGER Measurement Determination. |
| Flaring – liquids | 23% | Quantity of flared liquids (comprising of condensates and liquefied petroleum gas) is measured using flow meters and converted to tonnes based on density. Emissions from flared liquids are calculated using energy content, emission factors and methodology set out in the NGER Measurement Determination. |
| Fugitive emissions | 19% | Fugitive emissions (gas vented) are estimated based on annual LDAR surveys performed across production facilities. Surveys are conducted using USEPA Method 21 and emissions are calculated using applicable NGER methodologies, including component-level emission factors and site-specific gas composition data. |
| Flaring – gas | 7% | Quantity of unprocessed gas flared is measured through flow metering systems. Gas volumes are converted to tonnes using facility-specific gas density derived from gas chromatograph analysis before emissions are calculated using energy content, emission factors and methodology set out in the NGER Measurement Determination. |
| Other – Stationary diesel, LPG and lubricants | 4% | Emissions are calculated using relevant methodologies set out in the NGER Measurement Determination. |

**Emission reduction initiatives**

Based on its FY2026 assessment of climate-related physical and transition risks, Central has not established a transition plan or set any emissions reduction targets. It continues to assess commercially viable emissions reduction opportunities, including:

- ongoing replacement of gas instrumentation;
- identification and rectification of fugitive emissions from wellheads and infrastructure;
- installation of solar-powered well skids on new wells;
- consideration of solar and battery solutions to replace or complement existing power generation requirements where supported by an attractive business case; and
- seeking a commercial solution for the offtake of liquids which are currently flared.

In 2024, Central and its partners at the Mereenie gas field commissioned a new compressor to reduce emissions from gas which was previously flared.

Given the low risk ratings for identified climate-related physical and transition risks and the limited near-term opportunities:

- no material capital expenditure, financing or investment has been deployed by Central towards climate related risks and opportunities in FY2026
- no internal carbon prices are applied in decision-making; and
- no component of executive remuneration is linked to climate-related considerations.

## I Judgement and measurement uncertainties

Preparing this climate report required judgement in several areas, including identifying climate-related risks and opportunities and setting materiality thresholds.

The management judgements that could have the most significant effect on this Sustainability Report include:

| Judgement | Description |
|---|---|
| Materiality | Central's risk management process to identify and rank risks includes several impact thresholds which have been selected as appropriate materiality thresholds. Setting these levels required judgement as to what impact could reasonably affect the Group's prospects and influence decisions of users of this information. |
| Identifying climate-related risks and opportunities | Central's risk management processes require judgement in identifying climate-related risks and opportunities that could be reasonably expected to affect the Group's prospects. This includes identifying impacts on third parties which form part of Central's value chain. |
| Selection of appropriate climate-related forecasts and predictions | Several bodies publish authoritative forecasts and predictions on potential future climate impacts, internationally and regionally.<br>Central has selected region-specific sources it considers most relevant to its business and has relied on them to identify climate-related risks and opportunities. |

Central's scenario analysis relies on external projections and forecasts and on internal and external assumptions, including commercial arrangements, investment decision timing, project maturity, technology and market developments, macroeconomic assumptions, government policy and scenario conditions. Changes in these assumptions could affect the analysis and conclusions. Central notes that AEMO and other sources describe their scenarios as potential, not definitive, pathways.

This report uses estimates where amounts cannot be measured directly, forward-looking information relating to possible future events is uncertain, or data is limited. The most significant uncertainties include:

| Amount reported | Sources of uncertainty | Relevant section of this report |
|---|---|---|
| Anticipated effects of climate-related risks and opportunities | Central has relied upon authoritative sources of climate and market forecasts which it believes are most relevant to its business. By their nature, these forward-looking forecasts relate to possible future events with uncertain outcomes.<br>This inherent uncertainty could impact the identification and materiality of climate-related physical and transition risks and opportunities | C, E, F |
| Anticipated effects of climate-related risks and opportunities | Central has estimated the impact of forecast future temperatures and rainfall on its operations and the impact of forecast future demand for gas to identify climate-related physical and transition risks. | C, E, F |
| Emissions | Central measures its emissions in accordance with the GHG Protocol unless otherwise stated as required by AASB S2.<br>Some of the related disclosed metrics are subject to inherent high uncertainties arising from reliance on activity data and emission factors, including those obtained from third parties.<br>Where activity data and emission factors cannot be obtained on time, or are incomplete, estimation is used as permitted by the GHG Protocol and NGERS methodologies. | G |

# Independent Auditor's Review Report on specified Sustainability Disclosures

To the Members of Central Petroleum Limited

## Review Conclusion

We have conducted a review of the following specified Sustainability Disclosures in the Sustainability Report of Central Petroleum Limited (the Company) and its controlled entities (together, the Group) for the year ended 30 June 2026 as required by Australian Standard on Sustainability Assurance ASSA 5010 *Timeline for Audits and Reviews of Information in Sustainability Reports under the Corporations Act 2001* issued by the Auditing and Assurance Standards Board (AUASB):

| **Specified Sustainability Disclosures** | **Reporting requirement of Australian Sustainability Reporting Standard AASB S2 *Climate-related Disclosures* (AASB S2) (including related general disclosures required by Appendix D)** | **Location in Sustainability Report** |
|---|---|---|
| Governance | Paragraph 6 | The governance disclosures presented in Section E: Governance on page 28. |
| Strategy (risks and opportunities) | Subparagraphs 9(a), 10(a) and 10(b) | The climate-related physical risks and climate-related transition risks presented under the 'Climate-related risks' column and the climate-related opportunities under the 'Climate-related opportunities' column in 'Identified climate related risks and opportunities' in Section C: Climate-related risks and opportunities on pages 24 to 27.<br>The information presented in Section F: The risk management process on pages 28 and 29. |
| Scope 1 and 2 emissions | Subparagraphs 29(a)(i)(1) to (2) and 29(a)(ii) to (v) | The following emissions disclosures presented in Section H: Metrics - emissions on page 31:<br>• Scope 1 greenhouse gas emissions – 21,133 $CO_2e$ (Tonnes)<br>• Scope 2 greenhouse gas emissions – 71 $CO_2e$ (Tonnes)<br>The information presented in the 'Measurement Approach' in Section H: Metrics – emissions on page 31. |

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The requirements of AASB S2 identified in the table above form the criteria relevant to the specified Sustainability Disclosures and apply under Division 1 of Part 2M.3 of the *Corporations Act 2001* (the Act).

We have not become aware of any matter in the course of our review that makes us believe that the Sustainability Disclosures specified in the table above do not comply with Division 1 of Part 2M.3 of the *Corporations Act 2001*.

## Basis for Conclusion

Our review has been conducted in accordance with Australian Standard on Sustainability Assurance ASSA 5000 *General Requirements for Sustainability Assurance Engagements* (ASSA 5000) issued by the AUASB. Our review includes obtaining limited assurance about whether the specified Sustainability Disclosures are free from material misstatement.

In applying the relevant criteria, we note that subsection 296C(1) of the Act includes a requirement to comply with AASB S2.

Our conclusion is based on the procedures we have performed and the evidence we have obtained in accordance with ASSA 5000. The procedures in a review vary in nature and timing from, and are less in extent than for, an audit. Consequently, the level of assurance obtained in a review is substantially lower than the assurance that would have been obtained had an audit been performed. See the 'Summary of the Work Performed' section of our report below.

Our responsibilities under ASSA 5000 are further described in the Auditor's Responsibilities section of this report.

We are independent of the Company in accordance with the applicable ethical requirements of APES 110 *Code of Ethics for Professional Accountants (including Independence Standards)* issued by the Accounting Professional & Ethical Standards Board Limited (November 2018 incorporating all amendments to June 2024) (the Code), together with the ethical requirements in the Act, that are relevant to our review of the specified Sustainability Disclosures and public interest entities in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

Our firm applies Australian Standard on Quality Management ASQM 1 *Quality Management for Firms that Perform Audits or Reviews of Financial Reports and Other Financial Information, or Other Assurance or Related Services Engagements*, which requires the firm to design, implement and operate a system of quality management, including policies and procedures regarding compliance with ethical requirements, professional standards, and applicable legal and regulatory requirements.

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

## Other Information

The directors of the Company are responsible for the other information. The other information comprises the information included in the Annual Report for the year ended 30 June 2026, but does not include the specified Sustainability Disclosures and our auditor's report thereon.

Our conclusion on the specified Sustainability Disclosures does not cover the other information and we do not express any form of assurance conclusion thereon. We have issued a separate opinion on the Financial Report, including the Remuneration Report, included in the Annual Report.

In connection with our review of the specified Sustainability Disclosures, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the specified Sustainability Disclosures, or our knowledge obtained when conducting the review, or otherwise appears to be materially misstated. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

## Responsibilities for the specified Sustainability Disclosures

The directors of the Company are responsible for:

The preparation of the specified Sustainability Disclosures in accordance with the Act; and

Designing, implementing and maintaining such internal control necessary to enable the preparation of the specified Sustainability Disclosures, in accordance with the Act that are free from material misstatement, whether due to fraud or error.

## Inherent Limitations in preparing the specified Sustainability Disclosures

Sustainability information may be subject to more inherent limitations than financial information, given both its nature and the methods used for determining, calculating, and estimating such information. Different acceptable methods have varying precision and can affect the comparability of sustainability information across entities and over time.

In addition, greenhouse gas emissions quantification is subject to inherent uncertainty, which arises because of incomplete scientific knowledge used to determine emissions factors and the values needed to combine emissions of different gases.

The specified Sustainability Disclosures in relation to Strategy (risks and opportunities) have been prepared using assumptions about future events, and management's actions, that may not occur.

## Auditor's Responsibilities

Our objectives are to plan and perform the review to obtain limited assurance about whether the specified Sustainability Disclosures are free from material misstatement, whether due to fraud or error, and to issue a review report that includes our conclusion. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence decisions of users taken on the basis of the specified Sustainability Disclosures.

As part of a review in accordance with ASSA 5000, we exercise professional judgement and maintain professional scepticism throughout the engagement. We also:

Perform risk assessment procedures, including obtaining an understanding of internal control relevant to the engagement, to identify and assess the risks of material misstatements, whether due to fraud or error, at the disclosure level but not for the purpose of providing a conclusion on the effectiveness of the entity's internal control.

Design and perform procedures responsive to assessed risks of material misstatement at the disclosure level. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

## Summary of the Work Performed

A review is a limited assurance engagement and involves performing procedures to obtain evidence about the specified Sustainability Disclosures. The nature, timing and extent of procedures selected depend on professional judgement, including the assessed risks of material misstatement at the disclosure level, whether due to fraud or error. In conducting our review, we:

- Inspected the specified Sustainability Disclosures and assessed the completeness and accuracy of these disclosures against the relevant disclosure requirements of AASB S2 and with reference to the knowledge and evidence obtained during the assurance engagement;
- Performed enquiries of management regarding the methodologies, processes and controls for capturing, collating, calculating and reporting the specified Sustainability Disclosures and assessed their alignment with AASB S2 and applicable method and measurement approaches;
- Inspected and assessed, on a sample basis, charters, policies, minutes of meetings regarding the monitoring, management and oversight of climate-related matters, and other underlying evidence supporting the climate-related financial disclosures on governance;
- Performed enquiries of management regarding the approach taken by the Group to:
    - Identify climate-related risks and opportunities;
    - Identify material information for disclosure with regards to the Strategy (risks and opportunities) disclosures;
- Performed enquiries of management and examined underlying evidence to assess the completeness and accuracy of the establishment of the organisational boundary, and sources of emissions, in the context of the specified Sustainability Disclosures.
- Performed enquiries of management regarding the assumptions, conversion factors and greenhouse gas emission factors applied within the calculations of the Scope 1 and 2 emissions;
- Applied analytical procedures to evaluate the Scope 1 and 2 emissions and the underlying activity data, and;

- Performed testing over the calculations of the Scope 1 and 2 emissions, including testing the activity data utilised within the calculations to third-party records, information captured by onsite measurement devices at the facilities within the organisational boundary and other relevant underlying information, on a sample basis.

PricewaterhouseCoopers

Michael Crowe
Partner

Brisbane
17 September 2026

# DIRECTORS' REPORT

FOR THE YEAR ENDED 30 JUNE 2026

Your Directors present their report on the consolidated entity, consisting of Central Petroleum Limited ("the Company", "Central" or "CTP") and the entities it controlled (collectively "the Group" or "the Consolidated Entity") at the end of, or during, the year ended 30 June 2026.

## DIRECTORS

The names of the Directors of the Company in office during the financial year and until the date of this report are set out below. Directors were in office for this entire period unless otherwise stated.

Dr Agu Kantsler (Chair)

Mr Leon Devaney (Managing Director)

Mr Stephen Gardiner

Ms Katherine Hirschfeld AM

Mr Joel Riddle (appointed 12 January 2026, resigned 30 March 2026)

## PRINCIPAL ACTIVITIES

The principal activities of the Consolidated Entity constituting Central Petroleum Limited and the entities it controls consists of development, production, processing and marketing of hydrocarbons and associated exploration.

## DIVIDENDS

No dividends were paid or declared during the financial year (2025: $Nil). No recommendation for payment of dividends has been made.

## OPERATING AND FINANCIAL REVIEW

The operating and financial highlights for the financial year were:

Central delivered a strong underlying operating performance in FY2026:

- Sales revenue increased 3% to $44.7 million.
- Operating margin excluding depreciation increased 5% to $4.96/GJe supported by a 14% increase in the average realised gas price.
- Underlying EBITDAX was $17.0 million.
- Net cashflow from operations was $15.6 million after net interest payments
- Cash balance at 30 June 2026 of $20.41 million, after investing $11.2 million in new exploration acreage.

There were several key achievements during the year, including:

- A new firm gas sales agreement was signed in October to supply 1.3 PJ of gas (net to Central) in 2026 and 2027 providing increased cash flow certainty.
- Secured new multi-year gas contracts with the Northern Territory Government for the sale of gas through to the end of 2034, supporting a final investment decision for two new Palm Valley wells which, if successful, could lift gas production by 40% from late 2026.
- Completed the final delivery to repay previously overlifted gas in May 2026, releasing an expected $7 million per year in future cash flow.
- Increased the existing loan facility by $15 million to provide working capital support for accelerated Palm Valley drilling.
- Expanded into the proven Cooper and onshore Otway basins, acquiring an interest in PEP169 in Victoria and Cooper Basin retention leases and exploration permits, with at least three new exploration wells expected to be drilled in the next 18 months.
- Rationalised the Group's exploration portfolio to reduce costs by exiting two Amadeus Basin exploration permits.
- Implemented the Company's first shareholder returns program through an on-market share buy-back, acquiring and cancelling 2,185,130 shares and cash-settling 8,552,586 employee share rights during the year.

A detailed review of the operating and financial performance for the year ended 30 June 2026, including principal risks is provided on pages 3 to 21 of this Annual Report.

## SIGNIFICANT CHANGES IN THE STATE OF AFFAIRS

The financial position and performance of the Group was particularly affected by the following events and transactions during the year ended 30 June 2026:

- Secured new multi-year contracts for the sale of gas through to the end of 2034, underwriting a final investment decision for two new wells at Palm Valley which, if successful, could boost gas production by 40% when commissioned in late 2026.
- The final delivery to repay previously overlifted gas was made in May 2026. Future cash flows are expected to benefit by approximately $7 million per year.
- In a strategic expansion into two of Australia's proven onshore basins, Central acquired an interest in various Cooper Basin retention leases and exploration permits and in PEP 169 located in the onshore Otway Basin in Victoria, with at least three new exploration wells expected to be drilled in the next 18 months.
- Rationalisation of the Group's exploration portfolio, resulting in exiting from two Amadeus Basin exploration permits.

Following a review of costs allocated to operated joint ventures in previous periods, the Company has adjusted the allocation of staff costs to joint ventures. To correct the over-recovery of costs in prior periods, a provision of $1.5 million has been recognised for the expected net joint venture reimbursements required, and the affected financial statement line items have been corrected by restating each of the affected financial statement line items for the relevant prior periods.

There were no other significant events that are not detailed elsewhere in this Annual Report.

## EVENTS SINCE THE END OF THE FINANCIAL YEAR

No significant matters or circumstances have arisen between 30 June 2026 and the date of this report that will affect the Group's operations, result or state of affairs, or may do so in future years.

## LIKELY DEVELOPMENTS AND EXPECTED RESULTS OF OPERATIONS

Operating profits and cashflows in FY2027 are expected to benefit from:

- Two new wells at Palm Valley, expected to be drilled and commissioned in the first half of FY2027, which if successful, could boost Central's aggregate gas production by up to 40%; and
- Repayment of the gas overlift liability - cash flows and margins are expected to benefit by up to $7 million pa from FY2027 following the final repayment of previously overlifted gas in May 2026.

New exploration wells are planned to be drilled in 2027 in Central's recently-acquired exploration permits in the Otway and Cooper Basins.

Further information on these activities is included from pages 1 to 21 of this Annual Report.

As permitted by sections 299(3) and 299A(3) of the *Corporations Act 2001*, certain information has been omitted from the Operating and Financial Review of this report relating to the Company's business strategy, future prospects, likely developments in operations, and the expected results of those operations in future financial years on the basis that such information, if disclosed, would be likely to result in an unreasonable prejudice to Central (for example, because the information is premature, commercially sensitive, confidential or could give a commercial advantage to a third party). The omitted information relates to internal budgets, estimates and forecasts, contractual pricing, and business strategy.

# DIRECTORS' REPORT

## INFORMATION ON DIRECTORS

### Dr Agu Kantsler PhD, BSc (Hons), FTSE, GAICD

**Independent Non-executive Chair**

Dr Kantsler has been a director of Central Petroleum Limited since 15 June 2020 and has been the Chair since April 2025. He has over 45 years of experience in the international and Australian upstream oil and gas industry and has spent over 20 years in senior leadership positions and 15 years serving on the boards of several listed and private companies.

He is a former Director of Oil Search Limited, a former President of the Chamber of Commerce and Industry Western Australia, a former Director of the Australian Chamber of Commerce and Industry and a former Chairman and Director of the Australian Petroleum Production and Exploration Association (APPEA) which has since become Australian Energy Producers (AEP).

Dr Kantsler spent 15 years working for Shell International Petroleum in various international exploration assignments and his final position was Exploration Manager for the Shell Group of Companies in Indonesia. He then spent 13 years as Executive Vice President for Exploration and New Ventures with Woodside Petroleum Limited where he led teams credited with numerous oil and gas discoveries including the giant Pluto and Calliance gas fields. He then spent two years as the Executive Vice President for Health, Safety and Security at Woodside where he restructured the team of HSS professionals providing management advice on safety, welfare and security for over 16,000 construction workers in Southeast Asia and Australia as well as operations at Woodside's nine major production facilities.

Dr Kantsler was awarded APPEA's Reg Sprigg gold medal for service to the industry in 2005 and in 2006 was elected to Fellowship of the Australian Academy of Technological Sciences and Engineering.

Directorships of other listed companies in the last three years: Director of Suvo Strategic Minerals Ltd from 5 September 2023 until 13 June 2024.

### Mr Leon Devaney BSc, MBA

**Managing Director and Chief Executive Officer**

Mr Devaney has more than 25 years of commercial and finance experience in the Australian oil and gas sector. He holds an MBA and a BSc in Finance from the University of Southern California, USA.

Since joining Central Petroleum in 2012, Mr Devaney held senior roles across commercial, finance and business development. He was instrumental in identifying and negotiating the Palm Valley and Dingo Gas Field acquisition from Magellan Petroleum in 2014 and the Mereenie acquisition from Santos in 2015. He also structured the successful ATP2031 application for the Range Gas Project in 2018, which was sold in 2023 for a book profit of $13.8 million. Mr Devaney has been a director since 14 November 2018 and was appointed Chief Executive Officer, effective February 2019, after serving as Acting CEO from July 2018.

Before joining Central Petroleum, Mr Devaney worked at QGC, where he played a pivotal role in its growth from a small-cap gas exploration company into a multi-billion-dollar takeover target for BG Group in 2008. He remained with BG following the takeover, serving as General Manager, Gas and Power, with responsibility for the domestic gas and electricity portfolio.

Earlier in his career, Mr Devaney held senior roles in Deloitte's Corporate Finance Advisory Group, where he structured and implemented commercial and financing transactions for major energy and infrastructure projects across Australia.

## INFORMATION ON DIRECTORS (CONTINUED)

### Mr Stephen Gardiner BEc (Hons), Fellow of CPA Australia

**Independent Non-executive Director**

Mr Gardiner has been a director of Central Petroleum Limited since 1 July 2021. He has over forty years of corporate finance experience at major companies listed on the ASX, culminating in 17 years at Oil Search Limited, including eight years as Chief Financial Officer.

While at Oil Search, Mr Gardiner covered a range of executive responsibilities including corporate finance and control, treasury, tax, audit and assurance, risk management, investor relations and communications, ICT and sustainability. He also served as Group Secretary for ten years while performing his finance roles.

Prior to Oil Search, Mr Gardiner held senior corporate finance roles at major multinational companies including CSR Limited and Pioneer International Limited. Mr Gardiner has particular strength in capital management and funding, both debt and equity, having raised many billions of dollars, including via structured financings such as working on the US$15 billion PNG LNG Project financing, the largest such financing ever undertaken at the time.

Directorships of other listed companies in the last three years: ioneer Ltd from 25 August 2022 until 5 May 2025.

### Ms Katherine Hirschfeld AM BE(Chem) HonDEng UQ, HonFIEAust, FTSE, FIChemE, FAICD

**Independent Non-executive Director**

Ms Hirschfeld was appointed as a director on 7 December 2018 and is a highly regarded non-executive director, having served on company boards listed on the ASX, NZX and NYSE, as well as government and private company boards. She is currently a board member of Sims Limited.

Ms Hirschfeld has also been the Chair of Powerlink and President of UN Women National Committee Australia and non-executive director of Spark Infrastructure RE Limited, Energy Queensland, Tox Free Solutions, InterOil Corporation, Broadspectrum, Snowy Hydro and Queensland Urban Utilities. She was a member of the Senate of the University of Queensland for 10 years.

Previously she had leadership roles with BP in oil refining, logistics, exploration and production located in Australia, UK and Turkey.

Ms Hirschfeld was recognised in the AFR/Westpac 100 Women of Influence 2015, by Engineers Australia as one of Australia's Top 100 Most Influential Engineers 2015 and as an Honorary Fellow in 2014. She is a Fellow of the Australian Institute of Company Directors and the Academy of Engineering and Technology.

In 2019 Ms Hirschfeld was appointed a Member of the Order of Australia (AM) for significant service to engineering, to women, and to business.

## COMPANY SECRETARY

### Mr Daniel White LLB, BCom, LLM

Mr White is an experienced oil and gas lawyer in corporate finance transactions, mergers and acquisitions, equity and debt capital raisings, joint venture, farmout and partnering arrangements and dispute resolution. He has previously held senior international based positions with Kuwait Energy Company and Clough Limited.

## DIRECTORS' MEETINGS

The numbers of meetings of the Company's board of directors and of each board committee held during the financial year, and the numbers of meetings attended by each Director were:

| | Full Meeting of Directors | | Audit & Financial Risk Committee | | Risk & Sustainability Committee | | Remuneration & Nominations Committee | |
|---|---|---|---|---|---|---|---|---|
| Director | Eligible[1] | Attended | Eligible[1] | Attended[2] | Eligible[1] | Attended[2] | Eligible[1] | Attended[2] |
| Leon Devaney | 13 | 13 | – | 4 | – | 4 | – | 5 |
| Stephen Gardiner | 13 | 13 | 4 | 4 | 4 | 4 | 5 | 5 |
| Katherine Hirschfeld AM | 13 | 13 | 4 | 4 | 4 | 4 | 5 | 5 |
| Agu Kantsler | 13 | 13 | 4 | 4 | 4 | 4 | 5 | 5 |
| Joel Riddle[3] | 2 | 2 | – | 1 | – | 1 | – | 1 |

1 Number of meetings held during the time the director held office or was a member of the committee during the year.
2 The number of meetings attended includes those attended by invitation.
3 Joel Riddle was appointed as a director from 12 January 2026 and resigned 30 March 2026.

## SHARES UNDER OPTION

(a) There were no options granted during or since the end of the financial year to directors and the five most highly remunerated officers of the Company.
(b) There were no unissued ordinary shares of Central Petroleum Limited or interests under option at the date of this report.
(c) No shares were issued by Central Petroleum Limited during or since the end of the year on the exercise of options.

## ENVIRONMENTAL REGULATION

The Consolidated Entity is subject to significant environmental regulation.

The Consolidated Entity aims to ensure the appropriate standard of environmental care is achieved and, in doing so, that it is aware of and is in compliance with all environmental legislation. Internal reviews of compliance with the environmental conditions outlined in applicable Environmental Management Plans over the course of the year identified a high level of compliance.

## INSURANCE OF DIRECTORS AND OFFICERS

During the financial year, the Group paid premiums to insure Directors and officers of the Group. The contracts include a prohibition on disclosure of the premium paid and nature of the liabilities covered under the policy.

## AUDITOR'S INDEPENDENCE

A copy of the Auditor's Independence Declaration as required under section 307C of the *Corporations Act 2001* is set out on page 62.

## ROUNDING OF AMOUNTS

The company is of a kind referred to in ASIC Legislative Instrument 2016/191, relating to the 'rounding off' of amounts in the directors' report. Amounts in the directors' report have been rounded off in accordance with the instrument to the nearest thousand dollars, or in certain cases, to the nearest dollar.

## NON-AUDIT SERVICES

During the year the Company engaged the auditor, PricewaterhouseCoopers (PwC), on assignments additional to its statutory audit duties where the auditor's expertise and experience with the Company and/or the Consolidated Entity was important.

Details of amounts paid or payable to the auditor (PwC) for non-audit services provided during the year are set out below.

The Board of Directors is satisfied that the provision of the non-audit services is compatible with the general standard of independence for auditors imposed by the *Corporations Act 2001*. The Directors are satisfied that the provision of non-audit services by the auditor, as set out below, did not compromise the auditor independence requirements of the *Corporations Act 2001* and did not compromise the general principles relating to auditor independence in accordance with APES 110 Code of Ethics for Professional Accountants set by the Accounting Professional and Ethical Standards Board.

| | Consolidated | |
|---|---|---|
| | 2026 | 2025 |
| **PwC Australian firm:** | **$** | $ |
| Taxation services | | |
| Income tax compliance | 17,942 | 17,085 |
| Other tax related services | 78,434 | 5,550 |
| **Total remuneration from non-audit services** | **96,376** | 22,635 |

# EXECUTIVE SUMMARY – REMUNERATION

Dear Shareholders,

Whilst regulatory uncertainty has added new challenges to the Australian gas markets this year, and our access to eastern gas markets via the Northern Gas Pipeline has remained suspended, it was pleasing that Central's successful gas contracting strategy was able to lift revenues in FY2026 and provide a pathway to increasing cash flows.

We now have over 80% of our expected gas production over the next three years contracted at fixed CPI-linked pricing, and our investment in new wells at Palm Valley, if successful, could increase aggregate group gas sales by circa 40%.

Our expansion into the east coast market will see us participate in as many as three exploration wells in the Otway and Cooper Basins in 2027. Success at any of these wells could provide a significant lift in Central's growth prospects.

We have seen another year of cost pressures, both regulatory and commercial, and while we have improved our margins, there is also an expectation from the labour market for remuneration increases to offset the increased cost of living. Attracting and retaining high-performing staff in this environment, without eroding margins, remains critical to our growth aspirations.

The Board is committed to ensuring that the Company's remuneration strategy aligns the interests of management and staff with those of our shareholders. After making changes to our remuneration structure in recent years, we have retained a similar mix of fixed and incentive-based components this year.

To address shareholder concerns around the dilutionary impact of equity-based incentives, we established an Employee Share Trust (ESS) this year. The ESS purchased shares on market, to be utilised to satisfy vesting share rights and reduce the number of new shares that are required to be issued to settle those incentives.

## Fixed Remuneration

Staff salaries and Director fees increased by an average 3% in FY2026, broadly reflecting CPI levels in mid-2025 to counter cost of living pressures for staff. This followed the restructure of the CEO's remuneration package and a salary freeze for executives the previous year. The increase in Director fees was the first since 2017.

There was also a mandated 0.5% rise in the superannuation guarantee for all staff.

## Incentives

Achievement of key milestones including: increased revenues, new gas contracts, effective cost management, FID on new Palm Valley wells and an excellent safety and environmental record, resulted in an average award of 75% of the maximum entitlement. Certain production, farmout and commercial targets were not achieved.

The executives' short term incentive award was paid 80% as cash and 20% as share rights that will vest after 12 months. The long term incentive scheme for executives was extended for another year on similar terms to last year, rewarding share price growth over a three year period.

As in previous years, Non-executive Directors sacrificed up to 25% of their base fees to purchase share rights.

We believe that the current remuneration settings, including tailored short-term and longer-term equity-based incentives for staff and executives, will drive performance consistent with our operational and growth strategies and will deliver an increase in shareholder value in due course.

**Agu Kantsler**
Remuneration and Nominations Committee Chair

# REMUNERATION REPORT

(AUDITED)

This Remuneration Report for the year ended 30 June 2026 (FY2026) outlines the remuneration arrangements of the Group in accordance with the requirements of the *Corporations Act 2001* (Cth)*, as amended (the Act).* This information has been audited as required by section 308(3C) of the Act.

The Remuneration Report is presented under the following sections:

| | |
|---|---|
| A | Directors and Key Management Personnel (KMP) |
| B | Remuneration Overview |
| C | Remuneration Policy |
| D | Remuneration Consultants |
| E | Long Term Incentive Plan – Employee Rights Plan (LTIP) |
| F | Executive Incentive Plan (EIP) |
| G | Short Term Incentive Plan (STIP) |
| H | Realised Remuneration |
| I | Remuneration Details – Statutory Tables |
| J | Executive Service Agreements |
| K | Non-Executive Director Fee Arrangements |

## A. Directors and Key Management Personnel (KMP)

The Directors and key management personnel of the Consolidated Entity during the year and up to signing date of the Annual Report were:

Directors

| | |
|---|---|
| Dr Agu Kantsler | Independent Non-executive Chair |
| Mr Leon Devaney | Managing Director and Chief Executive Officer |
| Mr Stephen Gardiner | Independent Non-executive Director |
| Ms Katherine Hirschfeld AM | Independent Non-executive Director |
| Mr Joel Riddle | Independent Non-executive Director (appointed 12 January 2026, resigned 30 March 2026) |

Other Key Management Personnel

| | |
|---|---|
| Mr Ross Evans | Chief Operations Officer |
| Mr Damian Galvin[1] | Chief Financial Officer |
| Mr Daniel White | Group General Counsel and Company Secretary |

[1] Damian Galvin has provided notice of his intention to retire in November 2026.

## B. Remuneration Overview

Central's remuneration strategy is designed to attract, motivate and retain high performing individuals and is linked to the Group's objectives to build long-term shareholder value. In doing so, Central adopts a pay for performance culture which is balanced by a fair and equitable approach to the retention and motivation of its team. The current remuneration strategy incorporates the following features:

a. Linking internal strategies to improved shareholder value through achievement of appropriate KPIs.
b. Group-wide performance incentives to drive high performance.
c. Providing key executives with incentives which provide rewards for achievement of annual KPI targets, payable through a combination of cash and deferred equity to provide longer-term alignment with shareholders.
d. Adjusting to remuneration best practice and movements in relevant labour markets.

## B. Remuneration Overview (continued)

| Financial Year 2026<br>Summary of fixed and variable remuneration outcomes | |
|---|---|
| **Fixed remuneration** | An average 3% pay rise applied to other eligible employees for FY2026 and compulsory superannuation contributions increased from 11.5% to 12%.<br>Base fees for Non-executive Directors increased by 3% in FY2026, the first increase since 2017, and the fees for the Chair of each of the Board Committees increased by $500pa. |
| **Executive Incentive Plan (EIP)** | Achievement of Group-wide corporate KPIs resulted in an average award of 74.2% with 80% of the awarded value being payable as cash and 20% as Share Rights. Refer Section F of this report.<br>One-third of Share Rights issued to the CEO and eligible executives under EIPs for FY2023 and FY2024 vested at 30 June 2026. |
| **Short Term Incentive Plan (STIP)** | Achievement of Group-wide corporate and individual KPIs resulted in payment of an average 75% of the maximum STIP to eligible employees. Refer Section G of this report. |
| **Vesting of Share Rights previously granted under the Long-Term Incentive Plan (LTIP)** | The Share Rights issued to participating employees under the Long-Term Incentive Plan ($1,000 Exempt Plan) for the three year period ending 30 June 2026 fully vested on 30 June 2026 for those employees meeting the relevant service requirements. Refer Section E of this report. |

## C. Remuneration Policy

The remuneration policy of the Group is to pay its directors and executives amounts in line with employment market conditions relevant to the oil and gas industry whilst reflecting Central's specific circumstances. The Group's remuneration practices and, in particular, its short-term and long-term incentive plans are focussed on creating strong linkages between shareholder value as measured by shareholder returns and executive remuneration.

The Executive Incentive Plan (EIP) was revised from FY2025 to include both short-term annual KPIs, which have a deferred equity component, and a longer term component linked to share price performance over three years (refer Section F of this report).

Other personnel participate in a Short-Term Incentive Plan (STIP), which provides an incentive linked to achievement of corporate and personal KPIs (Section G), and are also eligible for an annual grant of equities to a value of $1,000 with a three year vesting period (refer Section E of this report).

For periods up to and ending on 30 June 2026, the remuneration of directors and executives consisted of the following key elements:

**Non-executive directors:**

1. Fees including statutory superannuation;
2. Up to 25% sacrifice of FY2026 base fees (inclusive of superannuation but excluding committee fees) in order to receive an equivalent value in the form of Share Rights issued under the Group's Employee Rights Plan; and
3. No participation in short or long term incentive schemes.

**Executives, including executive directors:**

1. Annual salary and non-monetary benefits including statutory superannuation; and
2. Participation in the Executive Incentive Plan (EIP), vesting over a four year period.

In previous years, executives have participated in various long term incentive plans, with the vesting periods for some of these plans extending through FY2026.

## C. Remuneration Policy (continued)

The balance of fixed and maximum at risk remuneration for executives for FY2026 is summarised as follows:

| | Salary | EIP Short Term Incentives (KPI's) | EIP service rights (over three years) |
|---|---|---|---|
| CEO | 40% fixed remuneration | 20% at risk | 40% at risk |
| Other Executives | 55% fixed remuneration | 18% at risk | 27% at risk |

The following table summarises the key performance and shareholder wealth metrics in relation to the outcomes of the STIP, LTIP and EIP over the last five years:

| | | FY2022 | FY2023 | FY2024 | FY2025 | FY2026 |
|---|---|---|---|---|---|---|
| **Financial performance**[1] | | | | | | |
| Operating revenue | $ million | 42.2 | 39.3 | 37.2 | 43.6 | **44.7** |
| Profit/(loss) after income tax | $ million | 21.3 | (8.0) | 11.9 | 6.7 | **(4.9)** |
| Underlying EBITDAX[2] | $ million | 16.8 | 15.8 | 13.3 | 18.6 | **17.0** |
| Net cash/(debt) | $ million | (10.2) | (14.3) | 0.8 | 3.9 | **(5.0)** |
| **Shareholder wealth** | | | | | | |
| Share price at year end | $/share | $0.110 | $0.053 | $0.053 | $0.055 | **$0.061** |
| **Incentive awarded** | | | | | | |
| **STIP** | % of maximum | 62.75% | 51.0% | 54.0% | 82.3% | **75.0%** |
| LTIP | % of maximum | 43% | 29.9% | N/a | N/a | **N/a** |
| **EIP** | % of maximum | 62.5% | 45.0% | 51.0% | N/a | **N/a** |

[1] Central sold a 50% interest in its producing gas fields on 31 October 2021.

[2] Underlying EBITDAX is underlying Earnings before Interest, Tax, Depreciation, Amortisation, Impairment and Exploration costs and profit on disposal of interests in producing properties and exploration permits. Refer to the Operating and Financial Review for further information.

In FY2022, the partial sale of the Company's producing oil and gas assets was completed, recognising a $36.6 million profit on the sale and providing funds to pay-down debt and fund new exploration and development activity.

STIP and EIP awards were lower in FY2023 and FY2024, with a relatively strong operating performance from the smaller asset base offset by slow progress on commercial initiatives and delays and cost overruns to the Company's exploration and development programs.

Results and cash flows in FY2025 improved significantly as a result of successful gas marketing, field development and refinancing activities, leading to a higher STIP award.

The LTIP awards up to FY2023 were linked to the Group's three-year share price performance. Volatile equity and energy markets in FY2022 and FY2023 saw a decline in share price in absolute terms, but Central's shares performed relatively well against those of its peers, resulting in a partial vesting of LTIPs for participants in those years.

The Company's improved performance in FY2025 was reflected in the higher STIP award, and although the share price had not responded by 30 June2025, the equity component of the EIP continues to align shareholders' economic outcomes with the value of executives' incentives. To reduce shareholder dilution from the conversion of Share Rights into issued shares, 50% of vested EIP Share Rights at 30 June 2025 were cash-settled in August 2025.

Central's FY2026 results were affected by impairment write-downs following a rationalization of the Group's exploration permits. The share price had tracked higher during FY2026 than in recent years, reflecting increasing revenues, strong EBITDAX and the strategic acquisition of interests in new exploration permits in the Otway and Cooper Basins.

## D. Remuneration Consultants

No remuneration consultants were engaged to provide remuneration recommendations in relation to the remuneration of any Key Management Personnel for FY2026.

Guerdon Associates were engaged to provide market information from peer companies relating to fixed and variable remuneration for Key Management Personnel for FY2026. The reports did not provide any specific remuneration recommendations.

## E. Long Term Incentive Plan – Employee Rights Plan (LTIP)

All eligible employees (other than key management personnel) may participate in the Central Petroleum $1,000 Exempt Plan which operates to align the interests of employees and shareholders by providing employees with opportunity to earn equity in the Company over a three year period.

No performance conditions apply, other than continuing employment with the Company at the end of a three-year service period.

## F. Executive Incentive Plan (EIP)

Commencing in FY2025, Central established a new EIP for key executives to align performance with the achievement of key objectives and share price hurdles.

The EIP has two components:

a) short-term incentive based on achieving annual KPIs, with both cash and deferred equity components; and
b) long term incentive, with share-price based performance hurdles over a three year performance period.

**EIP Short Term Incentive**

The value of the short-term incentive award is determined annually at the end of a one year performance period upon measurement of performance against Board established KPI targets for that year. The short-term incentive award is split into two parts:

a) 80% is paid at the end of the one year performance period; and
b) 20% is granted as Service Rights that vest at the end of the year following the initial one year performance period (Retention Period), or alternatively, can be cash-settled at the discretion of the Company.

The short-term incentive's maximum opportunity for the executive team as a percentage of Total Fixed Remuneration (TFR) is:

- CEO: 50% at Target (maximum stretch achievement at 62.5% of TFR);
- Other eligible executives: 33.33% at Target (maximum stretch achievement at 41.67% of TFR).

The number of Service Rights awarded under the short-term incentive is determined by reference to Central's volume weighted average share price over the 20-trading days ending on 30 June at the end of the performance period.

The Service Rights are the right to acquire fully paid ordinary shares for no exercise price at the end of the Retention Period and can be exercised from the completion of the Retention Period to the Expiry Date (five years from the beginning of the Retention Period). To maintain alignment with shareholders, the Service Rights have a dividend and return of capital entitlement whereby the Service Rights convert to one share plus an additional number of shares calculated on the basis of the dividends or return of capital that would have been paid in respect of the Share being reinvested over the Retention Period to exercise.

Service Rights do not automatically vest on change of control, but vest as a function of the service period and the circumstances of the change in control, subject to discretion of the Board.

The Board can elect to cash-settle some, or all, of the Service Rights.

Upon cessation of employment the Service Rights remain on foot to be tested in the normal course with the Board having the discretion to forfeit some, none, or all the Service Rights, having regard for the prevailing facts and circumstances at the time of cessation.

**EIP Long Term Incentive**

As a long term incentive, eligible executives are granted Performance Rights that vest if the Company's share price exceeds specified Share Price Hurdles at the end of a three year performance period. The number of Performance Rights available under the long-term incentive plan are based on pricing at the time of vesting, such that executives don't benefit from the current low share price conditions.

## F. Executive Incentive Plan (continued)

**EIP Long Term Incentive – FY2026 and FY2027**

The FY2026 and FY2027 EIP have two vesting conditions. The VWAP of Central's shares:

1. exceeds the relevant Vesting Target Hurdle at any time during the Performance Period; and
2. is at (or above) it's ending VWAP Floor price at the end of the Performance Period, which is to 30 June 2028 for the FY2026 EIP and 30 June 2029 for the FY2027 EIP.

The Performance Rights will be subject to exceeding a minimum Share Price Hurdle of $0.08 per share during the three-year Performance Period and meeting the $0.08 per share VWAP Floor price at the end of the Performance Period. Central's share price would need to increase by 45% over three years from the price at 30 June 2025, or 31% from 30 June 2026 for the FY2026 and FY2027 EIP respectively, to attain this minimum threshold. At this minimum vesting share price, 33% of the Performance Rights will vest. An additional 33% of the Performance Rights will vest if the share price exceeds $0.09 per share during the three year period and meets the $0.08 per share VWAP Floor price at the end of the Performance Period. All the Performance Rights will vest if the share price exceeds $0.10 during the three years and meets a $0.09 per share VWAP Floor price at the end of the Performance Period. Vesting will occur on a linear scale where maximum share prices fall between the three Hurdle Share Prices.

The value of the long-term incentive for FY2027 and FY2026, relative to TFR at the relevant Vesting Target Hurdle Share Price is set out below:

| FY2027 EIP | | | Value as % of TFR at Hurdle Share Price | |
|---|---|---|---|---|
| Vesting Target Hurdle Share Price (at any time up to 30 June 2029) | Ending VWAP Floor (at 30 June 2029) | Share price increase required to reach Vesting Target Hurdle Share Price (from $0.061 at 30 June 2026) | CEO | Other eligible executives |
| Exceeds: $0.08 | $0.08 | 31% | 27% | 13% |
| Exceeds: $0.09 | $0.08 | 48% | 60% | 30% |
| Exceeds: $0.10 | $0.09 | 64% | 100% | 50% |

| FY2026 EIP | | | Value as % of TFR at Hurdle Share Price | |
|---|---|---|---|---|
| Vesting Target Hurdle Share Price (at any time up to 30 June 2028) | Ending VWAP Floor (at 30 June 2028) | Share price increase required to reach Vesting Target Hurdle Share Price (from $0.055 at 30 June 2025) | CEO | Other eligible executives |
| Exceeds: $0.08 | $0.08 | 45% | 27% | 13% |
| Exceeds: $0.09 | $0.08 | 64% | 60% | 30% |
| Exceeds: $0.10 | $0.09 | 82% | 100% | 50% |

The Performance Rights will only vest if the Vesting Target Hurdle Share Price and Ending VWAP Floor price are achieved.

The number of Performance Rights which vest at the end of the Performance Period is determined by reference to Central's volume weighted average share price over 20-trading days during the Performance Period (for the Hurdle Share Price) or at the end of the Performance Period (for the VWAP Floor price).

**EIP Long Term Incentive – FY2025**

For the FY2025 plan year, the Performance Rights are subject to achieving a minimum Share Price Hurdle of $0.08 per share over a three year period, requiring a 51% increase from Central's share price at 30 June 2024. At this threshold share price, approximately 46% of the Performance Rights will vest, increasing to a maximum of 100% if the share price reaches $0.16, more than triple the Company's 2024 share price. The value of the long-term incentive, relative to TFR at the relevant Hurdle Share Price is set out below:

| | | Value as % of TFR at Hurdle Share Price | |
|---|---|---|---|
| Hurdle Share Price (at 30 June 2027) | Share price increase required to reach Hurdle Share Price (from $0.053 at 30 June 2024) | CEO | Other eligible executives |
| Min: $0.08 | 51% | 50% | 15% |
| Max: $0.16 | 202% | 218% | 65% |

The Performance Rights will only vest if the Share Price Hurdles are achieved.

## F. Executive Incentive Plan (continued)

The $0.08 Share Price Hurdle is a binary, all-or nothing minimum hurdle at which 46% of Performance Rights will vest. The remaining 54% of Performance Rights will vest pro-rata on a straight-line basis between the $0.08 and $0.16 Share Price Hurdles. The number of Performance Rights which vest at the end of the Performance Period is determined by reference to Central's volume weighted average share price (VWAP) over the 20-trading days ending on 30 June 2027.

For the FY2025, FY2026 and FY2027 plan years, vesting is subject to the executive's on-going employment with the Company in accordance with the Plan Rules and the Share Rights Offer. Upon cessation of employment, the Performance Rights remain on foot to be tested in the normal course, with the Board having the discretion to forfeit some, none or all of the Performance Rights, having regard for the prevailing facts and circumstances at the time of cessation.

Vested Performance Rights may be exercised in accordance with the Employee Rights Plan Rules. The Board may convert vested Share Rights into either Shares or cash or a combination thereof.

The Performance Rights are the right to acquire fully paid ordinary shares for no exercise price at the end of the Performance Period and can be exercised up to five years from the commencement of the Performance Period. To maintain alignment with shareholders, the Performance Rights have a dividend and return of capital entitlement whereby the Performance Rights convert to one share plus an additional number of shares calculated on the basis of the dividends or return of capital that would have been paid in respect of the Share being reinvested from the commencement of the Performance Period to exercise. The Hurdle Share Prices and Ending VWAP Floor prices will be adjusted for any dividends or return of capital paid during the Performance Period.

Performance Rights do not automatically vest on change of control, but vest as a function of the service period and the circumstances of the change in control, subject to discretion of the Board.

## G. Short Term Incentive Plan (STIP)

The STIP is a performance-based plan comprising a matrix of corporate and individual Key Performance Indicators (KPIs) for eligible employees.

The Company's Board sets the maximum award achievable in any year under the STIP (normally expressed as a percentage of Total Fixed Remuneration (TFR)), which is contingent on the achievement of the KPIs. The KPIs are set at the beginning of each year to incentivise staff to achieve the goals that the Board consider are key to Central's near-term performance and longer-term strategic direction. Neither the Board nor the Company guarantee any payment from the STIP, nor do they guarantee any performance level of the Company in future years.

**Participation**

The STIP operates with three levels of participation for eligible employees, each with a different level of maximum reward:

| STIP participation level | Maximum % of TFR |
|---|---|
| 1 | 30 % |
| 2 | 20 % |
| 3 | 10 % |

At the start of each performance period, the CEO nominates a level of participation for each eligible employee after considering factors such as:

a) Role and responsibilities;
b) Involvement in strategic and operational aspects of management;
c) Ability to be a key driver of the operational parts of the Group's business; and
d) Ability to influence the Group's performance.

The CEO and executives who participate in the EIP are not eligible to participate in the STIP (refer Section F of this report).

At the Board's discretion the STIP award may be paid through a combination of cash and/or Company securities.

**FY2026 Performance**

After assessment of the achievement of the corporate KPIs below, achievement of individual KPIs and the Group's performance during the year, eligible employees were entitled to receive, on average, 75% of their maximum STIP bonus. The STIP bonuses were paid in August 2026.

## G. Short Term Incentive Plan (STIP) (continued)

The Financial Year 2026 STIP (FY2026 STIP) was designed to recognise and reward individual effort by connecting individual KPIs and corporate KPIs:

| KPI Category | Percent Allocation of STIP | | |
|---|---|---|---|
| | Maximum | Actual | Achievement |
| Corporate KPIs | 60 % | 45 % | 75 % satisfaction of corporate KPIs |
| Individual KPIs | 40 % | 30 % (avg) | 75 % satisfaction of individual KPIs |
| | 100 % | 75 % (avg) | |

The majority of employees could earn a maximum of 10% of TFR, whilst more senior employees could earn either a maximum of 20% or 30% of TFR from the FY2026 STIP, depending on their participation level.

**Corporate KPIs for FY2026:**

| Objective | Weighting | Performance Outcomes for FY2026 | | | |
|---|---|---|---|---|---|
| | | 0% | Threshold 25% | Target 100% | Stretch 125% |
| **Production** (gas – sales volume)<br>Assessed against budget | 15% | | ● | | |
| **Total Cost**[1]<br>Total group operating and capital expenditure for agreed scope of works assessed against budget | 15% | | | ● | |
| **Growth & Value Accretive Milestones**<br>• FID for new wells at Palm Valley and Mereenie<br>• Farmout of exploration permits | 15% | | | ● | |
| **Commercial**<br>• Gas revenues assessed against budget | 15% | | | ● 10 % | |
| • New gas sale agreements | 15% | | ● | | |
| **Safety**<br>Total Recordable Incident Frequency Rate (TRIFR) | 10% | | | | ● |
| **Process Safety**<br>Unplanned or uncontrolled release of materials from a process (loss of primary containment – LOPC) | 10% | | | ● | |
| **Environment and Cultural Heritage**<br>• Recordable environmental incidents<br>• Indigenous employment targets | 5% | | | ● | |

[1] Not rewarded for works that were essential but not completed, e.g. capital project delay or deferral. Excludes exploration and specific recompletions / development activity which are assessed as a separate KPIs.

**Individual KPIs**

Individual KPIs provide significant relevance to each role in each department, and for FY2026 were assessed as achieving an average of 75% (or a weighted average of 30% out of a maximum possible 40%).

## H. Realised remuneration (not audited)

Table 1 identifies the actual remuneration received by Senior Executives in respect of the 2026 financial year. Realised Remuneration reflects the pre-tax take home remuneration of the Executive and includes:

- Total fixed remuneration inclusive of company superannuation contributions;
- Any Short-Term or Long-Term incentive awarded as cash for the financial year but paid after the end of the financial year; and
- The value of share rights vesting (if any) on 30 June, valued at the year-end share price (2026: 6.1 cents per share, 2025: 5.5 cents per share).

The table below has been provided to assist shareholders to understand the remuneration received in respect of each financial year ending 30 June. The table is a voluntary disclosure and as such has not been prepared in accordance with the disclosure requirements of the Accounting Standards or Corporations Act 2001. See Table 2 for Executive KMP remuneration in accordance with these requirements.

Table 1: Realised remuneration of Key Management Personnel

| | Year | Total Fixed Remuneration[1] $ | STIP / EIP[2] $ | Other Benefits[3] $ | Shares[4] $ | Total $ |
|---|---|---|---|---|---|---|
| **Executive KMP** | | | | | | |
| Leon Devaney | **2026** | **613,691** | **182,185** | **8,257** | **194,223** | **998,356** |
| | 2025 | 596,671 | 367,493 | 8,601 | 116,530 | 1,089,295 |
| Ross Evans | **2026** | **574,000** | **113,899** | **8,257** | **105,962** | **802,118** |
| | 2025 | 558,079 | 220,454 | 8,601 | 63,568 | 850,702 |
| Damian Galvin | **2026** | **361,959** | **70,231** | **8,257** | **70,066** | **510,513** |
| | 2025 | 357,848 | 145,804 | 8,601 | 42,021 | 554,274 |
| Daniel White | **2026** | **509,680** | **101,139** | **8,257** | **94,097** | **713,173** |
| | 2025 | 495,639 | 195,779 | 8,601 | 56,446 | 756,465 |
| **Total Executive KMP** | **2026** | **2,059,330** | **467,454** | **33,028** | **464,348** | **3,024,160** |
| | 2025 | 2,008,237 | 929,530 | 34,404 | 278,565 | 3,250,736 |

1 Total Fixed Remuneration includes salaries, fees and superannuation contributions.
2 Includes current year short term incentive and, in respect of 2025, 50% of rights that vested on 30 June 2025 and settled as cash after year end.
3 Includes car parking and other fringe benefits.
4 Shares comprise any share rights to vest from the EIP from prior years where the performance period ended on 30 June of the relevant year and are valued at that date. The value of any vested rights that were subsequently cash-settled are included in STIP/EIP amounts.

## I. Remuneration Details – Statutory tables

### Table 2: Remuneration of Directors and Key Management Personnel

| | | Short-Term | | | Post-employment | Long-term benefits | Share-based payments | | Variable remuneration |
|---|---|---|---|---|---|---|---|---|---|
| | | Salary/ Fees[1] $ | STI[2] $ | Non-Monetary Benefits $ | Superannuation Contributions $ | LSL (Accrued) $ | Rights[3,4] $ | Total $ | Percent of Remuneration % |
| **Non-Executive Directors** | | | | | | | | | |
| Stephen Gardiner | **2026** | **74,500** | – | – | **8,940** | – | **20,195** | **103,635** | – |
| | 2025 | 72,500 | – | – | 8,338 | – | 20,114 | 100,952 | – |
| Katherine Hirschfeld | **2026** | **74,500** | – | – | **8,940** | – | **20,195** | **103,635** | – |
| | 2025 | 78,833 | – | – | 9,066 | – | 8,045 | 95,944 | – |
| Agu Kantsler | **2026** | **121,000** | – | – | **14,520** | – | **37,585** | **173,105** | – |
| | 2025 | 74,167 | – | – | 8,529 | – | 20,114 | 102,810 | – |
| **Former Non-Executive Directors** | | | | | | | | | |
| Michael McCormack[6] | **2026** | – | – | – | – | – | – | – | – |
| | 2025 | 101,851 | – | – | 11,713 | – | 26,606 | 140,170 | – |
| Joel Riddle[5] | **2026** | **15,871** | – | – | **1,905** | – | – | **17,766** | – |
| | 2025 | – | – | – | – | – | – | – | – |
| **Sub-total** | **2026** | **285,871** | – | – | **34,305** | – | **77,975** | **398,151** | – |
| | 2025 | 327,351 | – | – | 37,646 | – | 74,879 | 439,876 | – |
| **Executives** | | | | | | | | | |
| Leon Devaney | **2026** | **539,715** | **207,324** | **8,257** | **30,000** | **18,235** | **250,315** | **1,053,846** | **43%** |
| | 2025 | 590,983 | 200,515 | 8,601 | 29,932 | 11,219 | 271,379 | 1,112,629 | 42% |
| Ross Evans | **2026** | **549,600** | **129,617** | **8,257** | **30,000** | **11,927** | **103,139** | **832,540** | **28%** |
| | 2025 | 530,085 | 125,369 | 8,601 | 29,932 | 20,436 | 114,194 | 828,617 | 29% |
| Damian Galvin | **2026** | **341,299** | **80,628** | **8,257** | **30,000** | **12,603** | **67,568** | **540,355** | **27%** |
| | 2025 | 304,640 | 82,934 | 8,601 | 29,932 | 12,426 | 75,515 | 514,048 | 31% |
| Daniel White | **2026** | **502,346** | **115,098** | **8,257** | **30,000** | **11,902** | **91,590** | **759,193** | **27%** |
| | 2025 | 471,972 | 111,342 | 8,601 | 29,932 | 13,094 | 101,409 | 736,350 | 29% |
| **Sub-total** | **2026** | **1,932,960** | **532,667** | **33,028** | **120,000** | **54,667** | **512,612** | **3,185,934** | **33%** |
| | 2025 | 1,897,680 | 520,160 | 34,404 | 119,728 | 57,175 | 562,497 | 3,191,644 | 34% |
| **Total Remuneration** | **2026** | **2,218,831** | **532,667** | **33,028** | **154,305** | **54,667** | **590,587** | **3,584,085** | **31%** |
| | 2025 | 2,225,031 | 520,160 | 34,404 | 157,374 | 57,175 | 637,376 | 3,631,520 | 32% |

1 Includes movements in annual leave provisions.
2 Short term incentives are unpaid at the end of the financial year.
3 Rights granted under the EIP at valued at market value on the grant date and, where applicable, take into account market performance hurdles using a Black Scholes valuation model and Monte Carlo simulations. The values are allocated to each reporting period based upon the service periods over which rights to shares will vest. In the event that rights are cancelled for failure to meet the required service period or are not retained on termination of employment, any amounts previously expensed as share based payments are reversed as negative amounts. Non-executive directors had the discretion to sacrifice up to 25% of their Base Fees to earn share rights which automatically vested on 30 June.
4 In respect of FY 2025, subsequent to year end, the Board resolved to settle 50% of EIP rights that vested 30 June 2025 and 50% of any previously vested but unexercised EIP rights in cash during FY2026. The remaining 50% of vested rights remained as equity.
5 Joel Riddle was appointed 12 January 2026 and resigned 30 March 2026.
6 Michael McCormack resigned 30 April 2025.

## I. Remuneration Details – Statutory tables (continued)

### Table 3: Short Term Incentives awarded

| | | Maximum $ | Awarded[1] $ | Awarded % | Forfeited % |
|---|---|---|---|---|---|
| Leon Devaney | **2026** | **306,010** | **229,508** | **75.0%** | **25.0%** |
| | 2025 | 297,500 | 250,644 | 84.3% | 15.7% |
| Ross Evans | **2026** | **191,333** | **143,486** | **75.0%** | **25.0%** |
| | 2025 | 186,008 | 156,712 | 84.3% | 15.7% |
| Damian Galvin | **2026** | **126,477** | **88,525** | **70.0%** | **30.0%** |
| | 2025 | 123,047 | 103,667 | 84.3% | 15.7% |
| Daniel White | **2026** | **169,893** | **127,407** | **75.0%** | **25.0%** |
| | 2025 | 165,197 | 139,178 | 84.3% | 15.7% |
| **Total** | **2026** | **793,713** | **588,926** | **74.2%** | **25.8%** |
| | 2025 | 771,752 | 650,201 | 84.3% | 15.7% |

1 In accordance with the FY2026 plan offer, 20% of the short-term incentive was designated as a share-based award having a vesting date of 30 June 2027. In respect of FY2025, the Board resolved to settle the 20% equity component in cash during FY2026.

### Table 4: Share based compensation – Share Rights granted to Key Management Personnel during the year

| | | Number of Rights Granted | Grant Date | Average Fair Value at Grant Date | Average Exercise Price Per Right | Expiry Date |
|---|---|---|---|---|---|---|
| **Non-Executive Directors[1,4]** | | | | | | |
| Stephen Gardiner | **2026** | **325,729** | **20 Nov 25** | **0.062** | **–** | **30 Jun 30** |
| | 2025 | 365,703 | 20 Nov 24 | 0.055 | – | 30 Jun 29 |
| Katherine Hirschfeld | **2026** | **325,729** | **20 Nov 25** | **0.062** | **–** | **30 Jun 30** |
| | 2025 | 146,281 | 20 Nov 24 | 0.055 | – | 30 Jun 29 |
| Agu Kantsler | **2026** | **606,217** | **20 Noc 25** | **0.062** | **–** | **30 Jun 30** |
| | 2025 | 365,703 | 20 Nov 24 | 0.055 | – | 30 Jun 29 |
| **Former Non-Executive Directors** | | | | | | |
| Michael McCormack[5] | **2026** | **–** | **–** | **–** | **–** | **–** |
| | 2025 | 679,164 | 20 Nov 24 | 0.055 | – | 30 Jun 29 |
| **Sub-total** | **2026** | **1,257,675** | | | | |
| | 2025 | 1,556,851 | | | | |
| **Executives** | | | | | | |
| Leon Devaney[4] | **2026[2]** | **6,120,198** | **20 Nov 25** | **0.038** | **–** | **30 Jun 30** |
| | 2025[2] | 8,125,000 | 20 Nov 24 | 0.028 | – | 30 Jun 29 |
| | 2025[3] | 5,530,701 | 20 Nov 24 | 0.055 | – | 21 Nov 29 |
| Ross Evans | **2026[2]** | **2,869,998** | **16 Sep 25** | **0.036** | **–** | **30 Jun 30** |
| | 2025[2] | 2,267,200 | 13 Sep 24 | 0.022 | – | 30 Jun 29 |
| | 2025[3] | 3,017,841 | 12 Sep 24 | 0.049 | – | 12 Sep 29 |
| Damian Galvin | **2026[2]** | **1,897,149** | **16 Sep 25** | **0.036** | **–** | **30 Jun 30** |
| | 2025[2] | 1,499,793 | 13 Sep 24 | 0.022 | – | 30 Jun 29 |
| | 2025[3] | 1,996,353 | 12 Sep 24 | 0.049 | – | 12 Sep 29 |
| Daniel White | **2026[2]** | **2,548,398** | **16 Sep 25** | **0.036** | **–** | **30 Jun 30** |
| | 2025[2] | 2,013,537 | 13 Sep 24 | 0.022 | – | 30 Jun 29 |
| | 2025[3] | 2,680,191 | 12 Sep 24 | 0.049 | - | 12 Sep 29 |
| **Sub-total** | **2026** | **13,435,743** | | | | |
| | 2025 | 27,130,616 | | | | |
| **Total** | **2026** | **14,693,418** | | | | |
| | 2025 | 28,687,467 | | | | |

1 Represents a portion of Directors Fees sacrificed. These Share Rights vested on 30 June – Refer Section K of this report.
2 Represents Shares Rights granted under the Executive Incentive Plan which vest over three years on 30 June of the current and two subsequent financial years subject to share price hurdles.
3 Represents Share Rights awarded under the previous year's Executive Incentive Plan which vest over three years on 30 June of the current and two subsequent financial years.
4 Share Rights were issued to Directors in accordance with approvals obtained under ASX Listing Rule 10.14.
5 Michael McCormack resigned 30 April 2025. 195,420 of these Share Rights were cancelled in accordance with the Plan Rules.

## I. Remuneration Details – Statutory tables (continued)

The following factors and assumptions were used in determining the fair value of rights granted to Key Management Personnel during FY2026:

| Grant Date | Expiry Date | Fair Value Per Right | Exercise Price | Price of Shares at Grant Date | Estimated Volatility | Risk Free Interest Rate | Dividend Yield |
|---|---|---|---|---|---|---|---|
| 16 Sep 2025[1] | 30 Jun 2030 | $0.0367 | Nil | $0.059 | 61.6% | 3.40% | – |
| 16 Sep 2025[1] | 30 Jun 2030 | $0.0365 | Nil | $0.059 | 61.6% | 3.40% | – |
| 16 Sep 2025[1] | 30 Jun 2030 | $0.0339 | Nil | $0.059 | 61.6% | 3.40% | – |
| 20 Nov 2025[2] | 30 Jun 2030 | $0.0620 | Nil | $0.062 | N/A | N/A | – |
| 20 Nov 2025[1] | 30 Jun 2030 | $0.0387 | Nil | $0.062 | 61.9% | 3.74% | – |
| 20 Nov 2025[1] | 30 Jun 2030 | $0.0385 | Nil | $0.062 | 61.9% | 3.74% | – |
| 20 Nov 2025[1] | 30 Jun 2030 | $0.0356 | Nil | $0.062 | 61.9% | 3.74% | – |

[1] EIP Rights for the plan year commencing 1 July 2025.
[2] Share Rights granted to Non-Executive Directors. The fair value reflects the value of Director Fees sacrificed– Refer Section K of this report.

The following factors and assumptions were used in determining the fair value of rights granted to Key Management Personnel during the previous financial year, FY2025:

| Grant Date | Expiry Date | Fair Value Per Right | Exercise Price | Price of Shares at Grant Date | Estimated Volatility | Risk Free Interest Rate | Dividend Yield |
|---|---|---|---|---|---|---|---|
| 12 Sep 2024[1] | 12 Sep 2029 | $0.049 | Nil | $0.049 | N/A | N/A | – |
| 13 Sep 2024[2] | 30 Jun 2029 | $0.026 | Nil | $0.048 | 62.5% | 3.44% | – |
| 13 Sep 2024[2] | 30 Jun 2029 | $0.019 | Nil | $0.048 | 62.5% | 3.44% | – |
| 20 Nov 2024[1] | 21 Nov 2029 | $0.055 | Nil | $0.055 | N/A | N/A | – |
| 20 Nov 2024[3] | 30 Jun 2029 | $0.055 | Nil | $0.055 | N/A | N/A | – |
| 20 Nov 2024[2] | 30 Jun 2029 | $0.033 | Nil | $0.055 | 62.1% | 4.08% | – |
| 20 Nov 2024[2] | 30 Jun 2029 | $0.024 | Nil | $0.055 | 62.1% | 4.08% | – |

[1] EIP Rights for the plan year commencing 1 July 2023.
[2] EIP Rights for the plan year commencing 1 July 2024.
[3] Share Rights granted to Non-Executive Directors. The fair value reflects the value of Director Fees sacrificed.

### Table 5: Share based compensation – Share Rights vested to Key Management Personnel during the year

| | | Maximum number of rights eligible for vesting | | | | | |
|---|---|---|---|---|---|---|---|
| | | EIP Commencing 1 July 2023 | EIP Commencing 1 July 2022 | EIP Commencing 1 July 2021 | Number of Rights Vested | Proportion of Rights Vested[1] | Proportion of Rights Forfeited |
| Leon Devaney | **2026** | **1,843,567** | **1,340,420** | **–** | **3,183,987** | **100%** | **Nil** |
| | 2025 | 1,843,567 | 1,340,420 | 1,053,451 | 4,237,438 | 100% | Nil |
| Ross Evans | **2026** | **1,005,947** | **731,135** | **–** | **1,737,082** | **100%** | **Nil** |
| | 2025 | 1,005,947 | 731,135 | 574,478 | 2,311,560 | 100% | Nil |
| Damian Galvin | **2026** | **665,451** | **483,175** | **–** | **1,148,626** | **100%** | **Nil** |
| | 2025 | 665,451 | 483,175 | 379,405 | 1,528,031 | 100% | Nil |
| Daniel White | **2026** | **893,397** | **649,178** | **–** | **1,542,575** | **100%** | **Nil** |
| | 2025 | 893,397 | 649,178 | 510,000 | 2,052,575 | 100% | Nil |
| **Total** | **2026** | **4,408,362** | **3,203,908** | **–** | **7,612,270** | **100%** | **Nil** |
| | 2025 | 4,408,362 | 3,203,908 | 2,517,334 | 10,129,604 | 100% | Nil |

[1] The proportion of Rights vested represents the proportion of the maximum number of Rights that were eligible for vesting during the financial year. In respect of FY2025, subsequent to year end the Board resolved to settle 50% of the rights vested at 30 June 2025 in cash paid in August 2025.

In addition, 1,257,675 Share Rights vested on 30 June 2026 (2025: 1,361,431), representing 100% of Share Rights granted during the year to Non-Executive Directors adjusted for any cancellations due to resignation. These Share Rights were granted in return for the sacrifice of Directors' fees – refer Table 4 above.

## I. Remuneration Details – Statutory tables (continued)

### Share, Rights and Option Holdings of Key Management Personnel

Key Management Personnel may receive Service Rights to shares of the Company under the Executive Incentive Plan.

Non-Executive Directors were entitled to sacrifice up to 25% of their Base Fee to earn Share Rights which vested on 30 June.

Share Rights issued to Directors, and subsequent conversion to Ordinary Shares, are in accordance with approvals obtained under ASX Listing Rule 10.14.

The maximum number of rights to ordinary shares in the Company under the long term incentive plan held during the financial year by other Key Management Personnel of the Consolidated Entity, including their personally related parties, are set out below:

Table 6: Share Rights held by Key Management Personnel

| Share Rights | | Number of Rights Held at Start of Year | Maximum Number Granted as Compensation | Cancelled/ Forfeited During the Year[2] | Converted to Shares | Retained on Departure | Number of Rights Held at End of Year (Vested) | Number of Rights Held at End of Year (Unvested) |
|---|---|---|---|---|---|---|---|---|
| **Non-executive Directors** | | | | | | | | |
| Stephen Gardiner | **2026** | **365,703** | **325,729** | **—** | **—** | **N/A** | **691,432** | **—** |
| | 2025 | 386,182 | 365,703 | — | (386,182) | N/A | 365,703 | — |
| Katherine Hirschfeld | **2026** | **146,281** | **325,729** | **—** | **—** | **N/A** | **472,010** | **—** |
| | 2025 | — | 146,281 | — | — | N/A | 146,281 | — |
| Agu Kantsler | **2026** | **365,703** | **606,217** | **—** | **(365,703)** | **N/A** | **606,217** | **—** |
| | 2025 | 386,182 | 365,703 | — | (386,182) | N/A | 365,703 | — |
| **Former Non-executive Directors** | | | | | | | | |
| Michael McCormack[1] | **2026** | **N/A** | **N/A** | **N/A** | **N/A** | **N/A** | **N/A** | **N/A** |
| | 2025 | 717,196 | 679,164 | (195,420) | (717,196) | (483,744) | N/A | N/A |
| **Sub-total** | **2026** | **877,687** | **1,257,675** | **—** | **(365,703)** | **N/A** | **1,769,659** | **—** |
| | 2025 | 1,489,560 | 1,556,851 | (195,420) | (1,489,560) | (483,744) | 877,687 | — |
| **Executives** | | | | | | | | |
| Leon Devaney | **2026** | **19,783,863** | **6,120,198** | **(3,315,656)** | **(3,315,653)** | **N/A** | **3,183,987** | **16,088,765** |
| | 2025 | 6,128,162 | 13,655,701 | — | — | N/A | 6,631,309 | 13,152,554 |
| Ross Evans | **2026** | **7,321,789** | **2,869,998** | **(1,155,781)** | **(1,155,779)** | **N/A** | **1,737,082** | **6,143,145** |
| | 2025 | 3,342,361 | 5,285,041 | — | (1,305,613) | N/A | 2,311,560 | 5,010,229 |
| Damian Galvin[3] | **2026** | **4,841,901** | **1,897,149** | **(764,017)** | **(764,014)** | **N/A** | **1,148,626** | **4,062,393** |
| | 2025 | 2,208,335 | 3,496,146 | — | (862,580) | N/A | 1,528,031 | 3,313,870 |
| Daniel White | **2026** | **6,502,084** | **2,548,398** | **(1,026,288)** | **(1,026,287)** | **N/A** | **1,542,575** | **5,455,332** |
| | 2025 | 2,967,534 | 4,693,728 | — | (1,159,178) | N/A | 2,052,575 | 4,449,509 |
| **Sub-total** | **2026** | **38,449,637** | **13,435,743** | **(6,261,742)** | **(6,261,733)** | **N/A** | **7,612,270** | **31,749,635** |
| | 2025 | 14,646,392 | 27,130,616 | — | (3,327,371) | N/A | 12,523,475 | 25,926,162 |
| **Total** | **2026** | **39,327,324** | **14,693,418** | **(6,261,742)** | **(6,627,436)** | **N/A** | **9,381,929** | **31,749,635** |
| | 2025 | 16,135,952 | 28,687,467 | (195,420) | (4,816,931) | (483,744) | 13,401,162 | 25,926,162 |

1 Michael McCormack resigned 30 April 2025.

2 Executive share rights cancelled during FY2026 were cash-settled.

3 Damian Galvin has provided notice of his intention to retire in November 2026. The Board is yet to determine the number of unvested share rights to be retained and/or forfeited.

## I. Remuneration Details – Statutory tables (continued)

### Table 7: Vesting profile of Share Rights held by Key Management Personnel

| | Grant Date | Type | Maximum Number of Unvested Rights at 30 June 2026 | Vesting Period End Date[1] | Maximum value yet to vest[2] |
|---|---|---|---|---|---|
| **Key Management Personnel** | | | | | |
| Leon Devaney | 20 Nov 2025 | Deferred Share Rights – FY2026 EIP | 6,120,198 | 30 Jun 2028 | 153,413 |
| | 20 Nov 2024 | Deferred Share Rights – FY2025 EIP | 8,125,000 | 30 Jun 2027 | 76,250 |
| | 20 Nov 2024 | Deferred Share Rights – FY2024 EIP | 1,843,567 | 30 Jun 2027 | 19,917 |
| Ross Evans | 16 Sep 2025 | Deferred Share Rights – FY2026 EIP | 2,869,998 | 30 Jun 2028 | 68,306 |
| | 13 Sep 2024 | Deferred Share Rights – FY2025 EIP | 2,267,200 | 30 Jun 2027 | 16,801 |
| | 12 Sep 2024 | Deferred Share Rights – FY2024 EIP | 1,005,947 | 30 Jun 2027 | 9,682 |
| Damian Galvin[3] | 16 Sep 2025 | Deferred Share Rights – FY2026 EIP | 1,897,149 | 30 Jun 2028 | 45,152 |
| | 13 Sep 2024 | Deferred Share Rights – FY2025 EIP | 1,499,793 | 30 Jun 2027 | 11,114 |
| | 12 Sep 2024 | Deferred Share Rights – FY2024 EIP | 665,451 | 30 Jun 2027 | 6,405 |
| Daniel White | 16 Sep 2025 | Deferred Share Rights – FY2026 EIP | 2,548,398 | 30 Jun 2028 | 60,652 |
| | 13 Sep 2024 | Deferred Share Rights – FY2025 EIP | 2,013,537 | 30 Jun 2027 | 14,921 |
| | 12 Sep 2024 | Deferred Share Rights – FY2024 EIP | 893,397 | 30 Jun 2027 | 8,599 |
| **Total** | | | **31,749,635** | | **491,212** |

1 Vesting Period End Date is the end of the service period at which an entitlement to vesting is determined. The actual vesting date may be a later date.
2 The maximum value of the share rights yet to vest has been determined as the amount of the grant date fair value of the rights that is yet to be expensed.
3 Damian Galvin has provided notice of his intention to retire in November 2026. The Board is yet to determine the number of unvested share rights to be retained and/or forfeited.

## I. Remuneration Details – Statutory tables (continued)

Table 8: Shareholdings Of Key Management Personnel

| Ordinary Shares | | Held at Beginning of Year | Held at Date of Appointment | Other Purchases | Exercise of Rights | Held at Date of Departure | Held at End of Year |
|---|---|---|---|---|---|---|---|
| **Non-Executive Directors** | | | | | | | |
| Stephen Gardiner | **2026** | **765,222** | **N/A** | **—** | **—** | **N/A** | **765,222** |
| | 2025 | 379,040 | N/A | — | 386,182 | N/A | 765,222 |
| Katherine Hirschfeld | **2026** | **912,466** | **N/A** | **—** | **—** | **N/A** | **912,466** |
| | 2025 | 912,466 | N/A | — | — | N/A | 912,466 |
| Agu Kantsler | **2026** | **765,222** | **N/A** | **—** | **365,703** | **N/A** | **1,130,925** |
| | 2025 | 379,040 | N/A | — | 386,182 | N/A | 765,222 |
| **Former Non-Executive Directors** | | | | | | | |
| Michael McCormack[1] | **2026** | **N/A** | **N/A** | **N/A** | **N/A** | **N/A** | **N/A** |
| | 2025 | 703,931 | N/A | — | 717,196 | (1,421,127) | N/A |
| **Sub-total** | **2026** | **2,442,910** | **—** | **—** | **365,703** | **N/A** | **2,808,613** |
| | 2025 | 2,374,477 | — | — | 1,489,560 | (1,421,127) | 2,442,910 |
| **Other Key Management Personnel** | | | | | | | |
| Leon Devaney | **2026** | **4,735,068** | **N/A** | **—** | **3,315,653** | **N/A** | **8,050,721** |
| | 2025 | 4,735,068 | N/A | — | — | N/A | 4,735,068 |
| Ross Evans | **2026** | **2,671,930** | **N/A** | **—** | **1,155,779** | **N/A** | **3,827,709** |
| | 2025 | 1,366,317 | N/A | — | 1,305,613 | N/A | 2,671,930 |
| Damian Galvin | **2026** | **1,807,183** | **N/A** | **—** | **764,014** | **N/A** | **2,571,197** |
| | 2025 | 763,603 | N/A | 181,000 | 862,580 | N/A | 1,807,183 |
| Daniel White | **2026** | **5,434,027** | **N/A** | **—** | **1,026,287** | **N/A** | **6,460,314** |
| | 2025 | 4,274,849 | N/A | — | 1,159,178 | N/A | 5,434,027 |
| **Sub-total** | **2026** | **14,648,208** | **—** | **—** | **6,261,733** | **—** | **20,909,941** |
| | 2025 | 11,139,837 | — | 181,000 | 3,327,371 | — | 14,648,208 |
| **Total KMP** | **2026** | **17,091,118** | **—** | **—** | **6,627,436** | **N/A** | **23,718,554** |
| | 2025 | 13,514,314 | — | 181,000 | 4,816,931 | (1,421,127) | 17,091,118 |

1 Michael McCormack resigned 30 April 2025.

## J. Executive Service Agreements

The details of service agreements of the Key Management Personnel of the Consolidated Entity as of 1 July 2026 are as follows:

Table 9: Key Management Personnel Service Agreements

| Name | Position | Term of agreement expires | Total Annual Fixed Remuneration[1] | Notice period [2] |
|---|---|---|---|---|
| Leon Devaney | Managing Director & Chief Executive Officer | Full time permanent | $640,720 | 6-months |
| Ross Evans | Chief Operations Officer | Full time permanent | $600,990 | 6-months |
| Damian Galvin[3] | Chief Financial Officer | Full time permanent | $397,660 | 6-months |
| Daniel White | Group General Counsel & Company Secretary | Full time permanent | $533,770 | 3-months |

1 Total Annual Fixed Remuneration, effective 1 July 2026 includes compulsory superannuation contributions.
2 In certain exceptional circumstances (such as breach or gross misconduct) a shorter notice period applies.
3 Damian Galvin has provided notice of his intention to retire in November 2026

If the employment of a member of Key Management Personnel listed above is terminated within 12 months of a change of control event, the executive is entitled to a termination payment equivalent to 12 months TFR (reduced by any redundancy entitlement received).

## K. Non-Executive Director Fee Arrangements

The Company has engaged all Directors pursuant to written service agreements. The terms of appointment are subject to the Company's constitution. The Company maintains an appropriate level of Directors' and Officers' Liability Insurance and provides rights relating to indemnity, insurance, and access to documents.

The table below summarises the Non-Executive Director fees for FY2026. Directors had the discretion to sacrifice up to 25% of their Base Fee to earn Share Rights. The issue of Share Rights to Directors was approved under ASX Listing Rule 10.14 at the Company's Annual General Meeting held on 20 November 2025.

| FY2026 Board Fees (per annum) | |
|---|---|
| Chair | $134,000 |
| Non-Executive Director | $72,000 |

| FY2026 Committee Fees (per annum) | | |
|---|---|---|
| Audit & Financial Risk | Chair | $10,500 |
| | Member | $5,000 |
| Remuneration & Nominations | Chair | $10,500 |
| | Member | $5,000 |
| Risk & Sustainability | Chair | $10,500 |
| | Member | $5,000 |

The Directors also receive superannuation benefits in accordance with legislative requirements. There are no loans issued to key management personnel and no related party transactions with directors during the year.

**Signed in accordance with a resolution of the directors:**

**Agu Kantsler**
Chair

17 September 2026

## Auditor's Independence Declaration

As lead auditor of Central Petroleum Limited's financial report and specified sustainability disclosures within the sustainability report for the year ended 30 June 2026, I declare that, to the best of my knowledge and belief, there have been:

a) no contraventions of the auditor independence requirements of the *Corporations Act 2001* in relation to the audit of the financial report or the review of the specified sustainability disclosures; and

b) no contraventions of any applicable code of professional conduct in relation to the audit of the financial report or the review of the specified sustainability disclosures.

Michael Crowe
Partner
PricewaterhouseCoopers

Brisbane
17 September 2026

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# FINANCIAL REPORT

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These Financial Statements are the consolidated financial statements of the Group, consisting of Central Petroleum Limited and its subsidiaries.

The Financial Statements are presented in Australian currency.

Central Petroleum Limited is a company limited by shares, incorporated and domiciled in Australia. Its registered office and principal place of business is:

Level 7, 369 Ann Street
Brisbane, Queensland 4000

A description of the nature of the Consolidated Entity's operations and its principal activities is included in the operating and financial review on pages 3 to 21. These pages are not part of these financial statements.

The financial statements were authorised for issue by the Directors on 17 September 2026. The Directors have the power to amend and reissue the financial statements.

ASX releases, financial reports and other information are available via the links on our website: www.centralpetroleum.com.au.

# CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

FOR THE YEAR ENDED 30 JUNE 2026

| | NOTE | 2026<br>$'000 | 2025<br>Restated*<br>$'000 |
|---|---|---|---|
| Revenue from contracts with customers – sale of hydrocarbons | 3(a) | 44,747 | 43,626 |
| Cost of sales | 5(a) | (29,716) | (28,583) |
| **Gross profit** | | **15,031** | **15,043** |
| Other income | 4 | 1,045 | 2,491 |
| Exploration expenditure | 5(f) | (11,570) | (1,678) |
| General and administrative expenses net of recoveries | 5(b) | (5,124) | (3,874) |
| Finance costs | 5(c) | (4,234) | (4,524) |
| Other expenses | 5(d) | (66) | (725) |
| **(Loss)/Profit before income tax** | | **(4,918)** | **6,733** |
| Income tax expense | 6(a) | – | – |
| **(Loss)/Profit for the year** | | **(4,918)** | **6,733** |
| Other comprehensive profit for the year, net of tax | | – | – |
| **Total comprehensive (loss)/ profit for the year** | | **(4,918)** | **6,733** |
| **Total comprehensive (loss)/profit attributable to members of the parent entity** | | **(4,918)** | **6,733** |
| **(Loss)/earnings per share for profit or loss attributable to the ordinary equity holders of the company:** | | | |
| Basic (loss)/earnings per share (cents) | 25(a) | **(0.66)** | **0.91** |
| Diluted (loss)/earnings per share (cents) | 25(b) | **(0.66)** | **0.88** |

* See Note 2 for details regarding the restatement of prior year comparatives.

The accompanying notes form part of these financial statements.

# CONSOLIDATED BALANCE SHEET
AS AT 30 JUNE 2026

| | NOTE | 2026 $'000 | 2025 Restated* $'000 |
|---|---|---|---|
| **ASSETS** | | | |
| **Current assets** | | | |
| Cash and cash equivalents | 8 | 20,410 | 27,471 |
| Trade and other receivables | 9 | 7,541 | 7,348 |
| Inventories | 10 | 4,708 | 3,613 |
| Other current assets | 11 | 300 | – |
| Total current assets | | 32,959 | 38,432 |
| **Non-current assets** | | | |
| Property, plant and equipment | 12 | 60,875 | 57,678 |
| Right of use assets | 13(a) | 1,943 | 2,617 |
| Exploration assets | 14 | 13,841 | 7,674 |
| Other intangible assets | 15 | 192 | 242 |
| Other financial assets | 16 | 5,926 | 5,416 |
| Goodwill | 17 | 1,953 | 1,953 |
| Total non-current assets | | 84,730 | 75,580 |
| **Total assets** | | **117,689** | **114,012** |
| **LIABILITIES** | | | |
| **Current liabilities** | | | |
| Trade and other payables | 18 | 6,086 | 5,175 |
| Deferred revenue | 3(b) | 1,363 | 992 |
| Borrowings | 19(a) | 3,839 | 7 |
| Lease liabilities | 13(a) | 410 | 360 |
| Other financial liabilities | 20 | 356 | – |
| Provisions | 21 | 8,618 | 8,973 |
| Total current liabilities | | 20,672 | 15,507 |
| **Non-current liabilities** | | | |
| Deferred revenue | 3(b) | 8,317 | 9,036 |
| Borrowings | 19(b) | 21,702 | 23,384 |
| Lease liabilities | 13(a) | 1,969 | 2,301 |
| Other financial liabilities | 20 | 532 | 722 |
| Provisions | 21 | 30,301 | 23,634 |
| Total non-current liabilities | | 62,821 | 59,077 |
| **Total liabilities** | | **83,493** | **74,584** |
| **Net assets** | | **34,196** | **39,428** |
| **EQUITY** | | | |
| Share Capital | 22 (a) | 197,638 | 197,776 |
| Treasury shares | 22 (b) | (400) | – |
| Reserves | 23 | 41,398 | 41,174 |
| Accumulated losses | 24 | (204,440) | (199,522) |
| **Total equity** | | **34,196** | **39,428** |

* See Note 2 for details regarding the restatement of prior year comparatives.

The accompanying notes form part of these financial statements.

# CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

FOR THE YEAR ENDED 30 JUNE 2026

| | Contributed Equity $'000 | Treasury shares $'000 | Share Options Reserve $'000 | Accumulated Profits Reserve $'000 | Accumulated Losses $'000 | Total $'000 |
|---|---|---|---|---|---|---|
| **Balance at 1 July 2024 Restated*** | **197,776** | **–** | **32,178** | **8,380** | **(206,255)** | **32,079** |
| Total profit for the year | – | – | – | – | 6,733 | 6,733 |
| Other comprehensive income | – | – | – | – | – | – |
| Total comprehensive profit for the year | – | – | – | – | 6,733 | 6,733 |
| *Transactions with owners in their capacity as owners* | | | | | | |
| Share based payments | – | – | 619 | – | – | 619 |
| Share issue costs | – | – | (3) | – | – | (3) |
| | – | – | 616 | – | – | 616 |
| **Balance at 30 June 2025 Restated*** | **197,776** | **–** | **32,794** | **8,380** | **(199,522)** | **39,428** |
| Total loss for the year | – | – | – | – | (4,918) | (4,918) |
| Other comprehensive income | – | – | – | – | – | – |
| Total comprehensive loss for the year | **–** | **–** | **–** | **–** | **(4,918)** | **(4,918)** |
| *Transactions with owners in their capacity as owners* | | | | | | |
| Buy back of shares | (138) | – | – | – | – | (138) |
| Acquisition of Treasury Shares | – | (400) | – | – | – | (400) |
| Cash settlement of Rights | – | – | (393) | – | – | (393) |
| Share based payments | – | – | 621 | – | – | 621 |
| Share issue costs | – | – | (4) | – | – | (4) |
| | (138) | (400) | 224 | – | – | (314) |
| **Balance at 30 June 2026** | **197,638** | **(400)** | **33,018** | **8,380** | **(204,440)** | **34,196** |

* See Note 2 for details regarding the restatement of prior year comparatives.

The accompanying notes form part of these financial statements.

# CONSOLIDATED STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED 30 JUNE 2026

| | NOTE | 2026<br>$'000 | 2025<br>$'000 |
|---|---|---|---|
| **Cash flows from operating activities** | | | |
| Receipts from customers | | 49,078 | 45,398 |
| Interest received | | 873 | 1,169 |
| Other income | | 2 | 273 |
| Government grants | | 9 | – |
| Interest and borrowing costs | | (961) | (2,256) |
| Payments for exploration expenditure | | (5,254) | (4,101) |
| Payments to other suppliers and employees | | (33,403) | (26,179) |
| Net cashflow from operating activities | 30 | 10,344 | 14,304 |
| **Cash flows from investing activities** | | | |
| Payments for property, plant and equipment | | (4,473) | (8,522) |
| Payments for the acquisition of interests in exploration tenements | | (11,216) | – |
| Proceeds from sale of producing assets and property, plant and equipment | | 1 | 994 |
| Redemption of security deposits and bonds | | 35 | 55 |
| Lodgement of security deposits and bonds | | (545) | (2,641) |
| Net cash outflow from investing activities | | (16,198) | (10,114) |
| **Cash flows from financing activities** | | | |
| Payments for the issue of securities | | (4) | (3) |
| Payment for the on-market buy back of shares | | (138) | – |
| Payments for the acquisition of shares by the Employee Share Trust | | (400) | – |
| Transaction costs related to finance facility | | (300) | – |
| Repayment of borrowings | 31(b) | – | (1,167) |
| Principal elements of lease payments | 31(b) | (365) | (534) |
| Net cash outflow from financing activities | | (1,207) | (1,704) |
| **Net (decrease)/increase in cash and cash equivalents** | | **(7,061)** | **2,486** |
| **Cash and cash equivalents at the beginning of the financial year** | | **27,471** | **24,985** |
| **Cash and cash equivalents at the end of the financial year** | 8 | **20,410** | **27,471** |

The accompanying notes form part of these financial statements.

# 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The principal accounting policies adopted in the preparation of these consolidated financial statements are set out below. These policies have been consistently applied to all the years presented, unless otherwise stated. The financial statements are for the consolidated entity consisting of Central Petroleum Limited ("the Company") and its subsidiaries (collectively "the Group" or "the Consolidated Entity").

## (a) Basis of Preparation

These general-purpose financial statements have been prepared in accordance with Australian Accounting Standards and Interpretations issued by the Australian Accounting Standards Board and the *Corporations Act 2001*. They present reclassified comparative information where required for consistency with the current year's presentation or where otherwise stated. Central Petroleum Limited is a for-profit entity for the purpose of preparing the financial statements.

*Rounding of Amounts*

The company is of a kind referred to in ASIC Legislative Instrument 2016/191, relating to the 'rounding off' of amounts in the financial statements. Amounts in the financial statements have been rounded off in accordance with the instrument to the nearest thousand dollars, or in certain cases, the nearest dollar.

### (i) Going Concern

The Directors have prepared the financial statements on a going concern basis which contemplates continuity of normal business activities and the realisation of assets and settlement of liabilities in the normal course of business.

The Group has interests in various exploration permits with multi-year work program commitments which require expenditure on agreed future exploration activity to maintain the permits in good standing. Central intends to fund its future commitments from a combination of existing cash resources, cash inflows from production operations and through introduction of new partners to assist with funding work obligations. Alternatively, individual permits may be relinquished if funds are not available to satisfy specific permit commitments. Any relinquishment of interests would potentially impact the carrying value of relevant Exploration Assets.

### (ii) Compliance with IFRS

The consolidated financial statements of the Central Petroleum Limited Group also comply with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board.

### (iii) Early Adoption of Standards

The Group has not applied any pronouncements to the annual reporting period beginning on 1 July 2025 where such application would result in them being applied prior to them becoming mandatory.

### (iv) Historical Cost Convention

These financial statements have been prepared under the historical cost convention.

### (v) Critical Accounting Judgements and Key Sources of Estimate Uncertainty

In the application of the Group's accounting policies, management is required to make judgements, estimates and assumptions regarding carrying values of assets and liabilities that are not readily apparent from other sources. The estimates and assumptions are based on historical experience and various other factors that are believed to be reasonable under the circumstances, the results of which form the basis of making the judgements. Actual results may differ from these estimates. Key judgements in applying the entity's accounting policies are required in the following areas:

*Rehabilitation Obligations*

The Group recognises any obligations for removal and restoration that are incurred during a particular period as a consequence of having undertaken exploration and development activity. The Group makes provision for future restoration expenditure relating to work previously undertaken based on management's estimation of the work required and by obtaining cost estimates from relevant experts. Further information on the nature and carrying amount of restoration and rehabilitation obligations can be found in Note 21.

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

## (a) Basis of Preparation (continued)

*Other financial liabilities at fair value*

The Group has recognised an estimate of the fair value of deferred consideration payable in relation to a business acquisition in a previous period. The estimate of fair value is determined using a discounted cashflow model that involves judgements of future production volumes, sales prices and discount rates. Changes in expected future market conditions, field production and gas sales agreements are reassessed at each reporting date. Further information can be found in Note 20.

*Share-based Payments*

The Group is required to use assumptions in respect of its fair value models, and the variable elements in these models, used in attributing a value to share based payments. The Directors have used a model to value options and rights, which requires estimates and judgements to quantify the inputs used by the model. Further information on the assumptions used in determining the fair value of rights and options granted during the year can be found in Section I of the Remuneration Report.

*Capitalised Exploration and Evaluation Expenditure*

The future recoverability of capitalised exploration and evaluation expenditure is dependent on a number of factors, including whether the Group decides to exploit the lease itself or, if not, whether it successfully recovers the related exploration and evaluation expenditure through sale. Factors that impact recoverability may include, but are not limited to, the level of resources and reserves, the expected cost of production, regulatory changes and expected future commodity prices. Ongoing exploration and evaluation expenditure is expensed as incurred. Acquisition expenditure is capitalised if activities in the area of interest have not yet reached a stage that permits a reasonable assessment of the existence or otherwise of economically recoverable reserves. To the extent that the capitalised acquisition expenditure is determined not to be recoverable in future, profits and net assets will be reduced in the period in which this determination is made. Further information on the carrying value of capitalised exploration and evaluation expenditure can be found in Note 14.

*Other Non-financial Assets*

Property, plant and equipment and other non-financial assets are written down immediately to their recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount. Goodwill is tested for impairment annually or whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows which are largely independent of the cash inflows from other assets or groups of assets (cash-generating units). Where discounted cash flows are used to assess recoverability of non-financial assets, the Group is required to use assumptions in respect of future commodity prices, foreign exchange rates, interest rates and operating costs, along with the possible impact of climate-related and other emerging business risks in determining expected future cash flows from operations. Further information on the nature and carrying value of other non-financial assets can be found in Notes 12, 13, 14, 15 and 17. Testing for impairment of goodwill and other non-financial assets is described in Note 17.

*Taxation*

The Group's accounting policy for taxation requires management's judgement in relation to the types of arrangements considered to be a tax on income in contrast to an operating cost. Judgement is also made in assessing whether deferred tax assets and certain deferred tax liabilities are recognised on the Consolidated Balance Sheet. Deferred tax assets, including those arising from un-recouped tax losses and capital losses, are recognised only where it is considered more likely than not they will be recovered, which is dependent on the generation of sufficient future taxable profits.

Judgements are also required about the application of income tax legislation. These judgements and assumptions are subject to risk and uncertainty, hence there is a possibility changes in circumstances will alter expectation, which may impact the amount of deferred tax assets and deferred tax liabilities recognised on the Consolidated Balance Sheet and the amount of other tax losses and temporary differences not yet recognised. In such circumstances, some or all of the carrying amounts of recognised deferred tax assets and liabilities may require adjustment, resulting in a corresponding credit or charge to the Consolidated Statement of Comprehensive Income.

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

## (b) Principles of Consolidation

### (i) Subsidiaries

The consolidated financial statements incorporate the assets and liabilities of all subsidiaries of Central Petroleum Limited ("the Company" or "Parent Entity") as at 30 June and the results of all subsidiaries for the year then ended. Central Petroleum Limited and its subsidiaries together are referred to in this financial report as "the Group" or "the Consolidated Entity".

Subsidiaries are all entities (including structured entities) over which the Group has control. The Group controls an entity when the Group is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power to direct the activities of the entity. Subsidiaries are fully consolidated from the date on which control is transferred to the Group. They are deconsolidated from the date that control ceases. The acquisition method is used to account for business combinations by the Group.

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

Non-controlling interests (if applicable) in the results and equity of subsidiaries are shown separately in the Consolidated Statement of Comprehensive Income, Statement of Changes in Equity and balance sheet respectively.

### (ii) Joint Arrangements

The Group's investments in joint arrangements are classified as either joint operations or joint ventures; depending on the contractual rights and obligations each investor has, rather than the legal structure of the joint arrangement.

The Group's exploration and production activities are conducted through joint arrangements governed by joint operating agreements or similar contractual relationships.

A joint operation involves the joint control, and often the joint ownership, of one or more assets contributed to, or acquired for the purpose of, the joint operation and dedicated to the purposes of the joint operation. The assets are used to obtain benefits for the parties to the joint operation. Each party may take a share of the output from the assets and each bears an agreed share of expenses incurred. Each party has control over its share of future economic benefits through its share of the joint operation. The interests of the Group in joint operations are brought to account by recognising in the financial statements the Group's share of jointly controlled assets, share of expenses and liabilities incurred, and the income from the sale or use of its share of the production of the joint operation in accordance with the revenue policy in Note 1(e). Details of the joint operations are set out in Note 36.

## (c) Segment Reporting

Operating segments are reported in Note 26 in a manner consistent with the internal reporting provided to the chief operating decision makers. The chief operating decision makers, who are responsible for allocating resources and assessing performance of the operating segments, have been identified as the Executive Management Team.

## (d) Foreign Currency Translation

### (i) Functional and Presentation Currency

Items included in the financial statements of each of the Group's entities are measured using the currency of the primary economic environment in which the entity operates (the "functional currency"). The consolidated financial statements are presented in Australian dollars, which is Central Petroleum Limited's functional currency and presentation currency.

### (ii) Transactions and Balances

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognised in profit or loss, except when they are deferred in equity as qualifying cash flow hedges and qualifying net investment hedges or are attributable to part of the net investment in a foreign operation.

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

### (e) Revenue Recognition

Revenue from contracts with customers is recognised in the income statement when or as the Group transfers control of goods or services to a customer at the amount to which the Group expects to be entitled. If the consideration promised includes a variable amount, the Group estimates the amount of consideration to which it will be entitled.

#### (i) Revenue from the sale of hydrocarbons

Revenue from the sale of hydrocarbons is recognised based on volumes sold under contracts with customers, at the point in time where performance obligations are considered met. Generally, regarding the sale of hydrocarbon products, the performance obligation will be met when the product is delivered to the specified measurement point (gas) or the point of load-out from third party storage facilities (liquids).

Take or pay proceeds received are taken to revenue at the earlier of physical delivery of the product to the customer; upon forfeiture of the right to take product under the contract; or when it is considered that the customer will not be able to take physical delivery of the product during the remaining term of the contract.

#### (ii) Farmouts and terminations

Farmouts outside the exploration phase are accounted for by derecognition of the proportion of the asset disposed of, and recognition of the consideration received or receivable from the farminee. A gain or loss is recognised for the difference between the net disposal proceeds and the carrying value of the asset disposed. Consideration is initially recognised at fair value or the cash price equivalent where payment is deferred. Interest revenue is recognised for the difference between the nominal amount of the consideration and the cash price equivalent.

Any cash consideration received directly from a farminee in respect of the farmout of an exploration asset is credited against costs previously capitalised, if applicable, with any excess accounted for as a gain on disposal.

#### (iii) Contract Liabilities

A contract liability (deferred revenue) is recorded for obligations under sales contracts to deliver natural gas in future periods for which payment has already been received (including “take-or-pay” arrangements). The Group applies the practical expedient in paragraph 121 of AASB 15 and does not disclose information on the transaction price allocated to performance obligations that are unsatisfied.

#### (iv) Interest Income

Interest income is recognised on a time proportionate basis that takes into account the effective yield on the financial assets.

### (f) Government Grants

Cash grants from the government are recognised at their fair value where there is a reasonable assurance that the grant or refund will be received, and the Group has or will comply with any conditions attaching to the grant or refund. Grants in the form of wages subsidies are credited against employee costs. Non-monetary grants are recognised at a nominal amount.

### (g) Income Tax

Central Petroleum Limited and its wholly owned Australian controlled entities have implemented the tax consolidation legislation. The head entity is Central Petroleum Limited. As a consequence, these entities are taxed as a single entity. The Company and the other entities in the tax-consolidated group have entered into tax funding and tax sharing agreements.

The Group accounts for income taxes in accordance with UIG 1052 adopting the “Separate Taxpayer within Group Approach”.

The income tax expense or revenue for the period is the tax payable on the current period’s taxable income based on the applicable income tax rate adjusted by changes in deferred tax assets and liabilities attributable to temporary differences. The current income tax charge is calculated on the basis of the tax laws enacted or substantially enacted at the end of the reporting period in the countries where entities in the Group generate taxable income.

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

### (g) Income Tax (continued)

Each individual entity recognises deferred tax assets and deferred tax liabilities arising from temporary differences on the basis that the entity is subject to tax as part of the tax-consolidated group. Deferred tax assets are recognised for deductible temporary differences and unused tax losses only if it is probable that future taxable amounts will be available to utilise those temporary differences and losses. Each entity assesses the recovery of its unused tax losses and tax credits only in the period in which they arise and before assumption by the head entity, applied in the context of the Group whether as a reduction of current tax of other entities in the group or as a deferred tax asset of the head entity. The aggregate amount of losses or credits utilised or recognised as a deferred tax asset by the head entity is apportioned on a systematic and reasonable basis.

Deferred tax liabilities are not recognised if they arise from the initial recognition of goodwill. Deferred tax is also not accounted for if it arises from initial recognition of an asset or liability in a transaction other than a business combination that, at the time of the transaction, affects neither accounting nor taxable profit or loss. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantially enacted by the end of the reporting period and are expected to apply when the related deferred income tax asset is realised, or the deferred income tax liability is settled.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to offset current tax assets and liabilities and when the deferred tax balances relate to the same taxation authority. Current tax assets and tax liabilities are offset where the entity has a legally enforceable right to offset and intends either to settle on a net basis, or to realise the asset and settle the liability simultaneously.

### (h) Leases

The Group's accounting policy for leases where the Group is lessee is described in Note 13.

### (i) Impairment of Assets

Goodwill and intangible assets that have an indefinite useful life are not subject to amortisation and are tested annually for impairment, or more frequently if events or changes in circumstances indicate that they might be impaired. Other assets are tested for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognised for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value less costs to sell and value in use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows which are largely independent of the cash inflows from other assets or groups of assets (cash-generating units). Non-financial assets other than goodwill that have had historical impairments are reviewed for possible reversal of the impairment at the end of each reporting period.

### (j) Cash and Cash Equivalents

For the purpose of presentation in the statement of cash flows, cash and cash equivalents includes cash on hand, deposits held at call with financial institutions, other short-term, highly liquid investments with original maturities of 3-months or less that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value, and bank overdrafts. Bank overdrafts (if applicable) are shown within borrowings in current liabilities in the balance sheet.

### (k) Trade Receivables

Trade receivables are recognised initially at the amount of consideration that is unconditional unless they contain significant financing components, when they are recognised at fair value. The Group holds the trade receivables with the objective to collect the contractual cash flows and therefore measures them subsequently at amortised cost using the effective interest method.

The Group considers an allowance for expected credit losses (ECLs) for all receivables. The Group applies a simplified approach in calculating ECLs which is based on an assessment on its historical credit loss experience, adjusted for factors specific to the debtors and the economic environment. This includes, but is not limited to, financial difficulties of the debtor, probability that the debtor will enter bankruptcy or financial reorganisation and delinquency in payments. Information about the impairment of trade receivables and the Group's exposure to credit risk, foreign currency risk and interest rate risk can be found in Note 35.

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

### (l) Inventories

Inventories comprise hydrocarbon stocks, drilling materials and spare parts and are valued at the lower of cost and net realisable value. Costs are assigned to individual items of inventory on a first in first out or weighted average cost basis. Cost of inventory includes the purchase price after deducting any rebates and discounts, as well as any associated freight charges.

Net realisable value is the estimated selling price in the ordinary course of business less the estimated costs necessary to make the sale.

### (m) Other Financial Assets

#### (i) Classification

The Group's financial assets consist of receivables and security deposits. These are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. They are included in current assets, except for those with maturities greater than 12-months after the reporting period which are classified as non-current assets. Receivables are included in trade and other receivables (Note 9) in the balance sheet. Amounts paid as performance bonds or amounts held as security for bank guarantees are classified as other financial assets (Note 16).

#### (ii) Measurement

At initial recognition, the Group measures a financial asset at its fair value plus, in the case of a financial asset not at fair value through profit or loss, transaction costs that are directly attributable to the acquisition of the financial asset. Transaction costs of financial assets carried at fair value through profit or loss are expensed in profit or loss. Financial assets carried at fair value through profit or loss are revalued to fair value at the end of the reporting period. Loans and receivables are subsequently carried at amortised cost using the effective interest method.

The Group considers an allowance for expected credit losses (ECLs) for its financial assets. The Group applies a simplified approach in calculating ECLs which is based on an assessment on its historical credit loss experience, adjusted for factors specific to the counterparty and the economic environment.

### (n) Property, Plant and Equipment – Development and Production Assets

#### (i) Assets in Development

The costs of oil and gas properties in the development phase are separately accounted for and include costs transferred from exploration and evaluation assets once technical feasibility and commercial viability of an area of interest are demonstrable. When production commences, the accumulated costs are transferred to producing areas of interest except for land and buildings and surface plant and equipment associated with development assets which are recorded in the land and buildings and plant and equipment categories respectively. Amortisation is not charged on costs carried forward in respect of areas of interest in the development phase until production commences.

#### (ii) Producing Assets

The costs of oil and gas properties in production are separately accounted for and include costs transferred from exploration and evaluation assets, transferred development assets and the ongoing costs of continuing to develop reserves for production including an estimate of the future costs to restore the site. Land and buildings and surface plant and equipment associated with producing areas of interest are recorded in the land and buildings and plant and equipment categories respectively.

Depreciation of producing assets is calculated for an asset or group of assets from the date of commencement of production. Depletion charges are calculated using the units of production method which will amortise the cost of carried forward exploration, evaluation and subsurface development expenditure (subsurface assets) and capitalised restoration costs over the life of the estimated Proven plus Probable (2P) hydrocarbon reserves for an asset or group of assets, together with estimated future costs necessary to develop the hydrocarbon reserves included in the calculation.

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

### (o) Property, Plant and Equipment – Other than Development and Production Assets

All property, plant and equipment is stated at historical cost less depreciation. Historical cost includes expenditure that is directly attributable to the acquisition of the items. Cost may also include transfers from equity of any gains or losses on qualifying cash flow hedges of foreign currency purchases of property, plant and equipment.

Subsequent costs are included in the asset's carrying amount or recognised as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably. The carrying amount of any component accounted for as a separate asset is derecognised when replaced. All other repairs and maintenance costs are charged to profit or loss during the reporting period in which they are incurred.

Land is not depreciated. Depreciation of plant and equipment is calculated on a reducing balance basis so as to write off the net costs of each asset over the expected useful life. The assets' residual values and useful lives are reviewed, and adjusted if appropriate, at each balance date.

An asset's carrying amount is written down immediately to its recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount. Gains and losses on disposals are determined by comparing proceeds with the carrying amount. These are included in the profit or loss.

The expected useful life for each class of depreciable assets is:

| Class of Fixed Asset | Expected Useful Life |
|---|---|
| Buildings | 10 – 40 years |
| Leasehold Improvements | 4 – 10 years |
| Plant and Equipment | 2 – 30 years |
| Motor Vehicles | 4 – 12 years |

### (p) Exploration Expenditure

Exploration and evaluation costs are expensed as incurred. Acquisition costs of rights to explore are capitalised in respect of each separate area of interest and carried forward where: right of tenure of the area of interest is current; these costs are expected to be recouped through sale or successful development and exploitation of the area of interest; or where exploration and evaluation activities in the area of interest have not yet reached a stage that permits reasonable assessment of the existence of economically recoverable reserves.

Consideration payable in respect of an acquisition of exploration rights that is contingent upon future exploration success is not recognised until the outcome is known and it can be reliably measured. No amortisation is charged on acquisition costs capitalised under this policy.

The Group assesses the recoverability of the carrying value of capitalised exploration and evaluation assets at each reporting date (or during the year should the need arise). In completing this assessment, regard is given to the currency of the right of tenure over the area of interest, the Group's intentions with respect to proposed future exploration and development plans for the area of interest, to the success or otherwise of activities undertaken in the area of interest, and to any potential plans for divestment. Exploration and evaluation activities that have not yet reached a stage that permits reasonable assessment of the existence of economically recoverable reserves may be subject to impairment in the future.

### (q) Goodwill

Goodwill arising on the acquisition of subsidiaries is not amortised, but it is tested for impairment annually, or more frequently if events or changes in circumstances indicate a potential impairment. Goodwill is carried at cost less accumulated impairment losses.

Goodwill is allocated to cash generating units for the purpose of impairment testing. The allocation is made to those cash-generating units or groups of cash-generating units that are expected to benefit from the business combination in which the goodwill arose. The units or groups of units are identified at the lowest level at which goodwill is monitored for internal management purposes, being the producing assets segments (Note 26).

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

## (r) Trade and Other Payables

These amounts represent liabilities for goods and services provided to the Group prior to the end of financial year which are unpaid. The amounts are unsecured and are usually paid within 30 days of recognition, except contributions to Joint Arrangements that are settled in line with the Joint Operating Agreements. Trade and other payables are presented as current liabilities unless payment is not due within 12-months from the reporting date. They are recognised initially at their fair value and subsequently measured at amortised cost using the effective interest method.

## (s) Provisions

### (i) Restoration and Rehabilitation

The Group records the present value of the estimated cost of legal and constructive obligations to restore operating locations in the period in which the obligation arises. The nature of restoration activities includes the removal of facilities, abandonment of wells and restoration of affected areas.

A restoration provision is recognised and updated at different stages of the development and construction of a facility and then reviewed on an annual basis. When the liability is initially recorded, the present value of the estimated future cost is capitalised by increasing the carrying amount of the related property, plant and equipment. Provisions in respect of exploration assets are taken directly to profit and loss unless recognised upon the initial acquisition of a tenement. Over time, the liability is increased for the change in the present value based on a pre-tax discount rate appropriate to the risks inherent in the liability. The unwinding of the discount is recorded as an accretion charge within finance costs.

The carrying amount capitalised in property, plant and equipment is depreciated over the useful life of the related producing asset (refer to Note 1(n)).

Costs incurred that relate to an existing condition caused by past operations and do not have a future economic benefit are expensed.

### (ii) Onerous Contracts

An Onerous Contracts provision is recognised where the unavoidable costs of meeting obligations under the contract exceeds the value of the economic benefits expected to be received under the contract.

### (iii) Other

Provisions for legal and joint venture related claims and other make good obligations are recognised when the Group has a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation and the amount has been reliably estimated. Provisions are not recognised for future operating losses.

Where there are a number of similar obligations, the likelihood that an outflow will be required in settlement is determined by considering the class of obligations as a whole. A provision is recognised even if the likelihood of an outflow with respect to any one item included in the same class of obligations may be small.

Provisions are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the end of the reporting period. The discount rate used to determine the present value is a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognised as accretion expense within finance costs.

## (t) Employee Benefits

### (i) Short-term Obligations

Liabilities for wages and salaries, including non-monetary benefits, annual leave and long service leave expected to be settled within 12-months after the end of the period in which the employees render the related service are recognised in respect of employees' services up to the end of the reporting period and are measured at the amounts expected to be paid when the liabilities are settled. The liability for annual leave and long service leave is recognised in the provision for employee benefits. All other short-term employee benefit obligations are presented as payables.

# 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

## (t) Employee Benefits (continued)

### (ii) Long-term Employee Benefit Obligations

The liability for long service leave which is not expected to be settled within 12-months after the end of the period in which the employees render the related service is recognised in the provision for employee benefits and measured as the present value of expected future payments to be made in respect of services provided by employees up to the end of the reporting period. Consideration is given to expected future wage and salary levels, experience of employee departures and periods of service. Expected future payments are discounted using market yields at the end of the reporting period with terms to maturity and currency that match, as closely as possible, the estimated future cash outflows.

### (iii) Share-based Payments

Share-based compensation benefits are provided to employees and directors by Central Petroleum Limited.

The fair value of options or rights granted is recognised as an employee benefits expense with a corresponding increase in equity. The total amount to be expensed is determined by reference to the fair value of the rights or options granted, which includes any market performance conditions and the impact of any non-vesting conditions but excludes the impact of any service and non-market performance vesting conditions.

Non-market vesting conditions are included in assumptions about the number of rights or options that are expected to vest. The total expense is recognised over the vesting period, which is the period over which all of the specified vesting conditions are to be satisfied. At the end of each period, the entity revises its estimates of the number of rights or options that are expected to vest based on the non-market vesting conditions. It recognises the impact of the revision to original estimates, if any, in profit or loss, with a corresponding adjustment to equity.

Equity grants subsequently settled in cash are accounted for as a reduction from equity. In the case of the settlement having a higher fair value at the date of settlement, any excess value will be recorded as an expense.

### (iv) Termination Benefits

The Group recognises termination benefits at the earlier of the following dates: (a) when the Group can no longer withdraw the offer of those benefits; and (b) when the entity recognises costs for a restructuring that is within the scope of AASB 137 and involves the payment of termination benefits. In the case of an offer made to encourage voluntary redundancy, the termination benefits are measured based on the number of employees expected to accept the offer. Benefits falling due more than 12-months after the end of the reporting period are discounted to present value.

## (u) Contributed Equity

Ordinary shares are classified as equity. Incremental costs directly attributable to the issue of new shares or options are shown in equity as a deduction from the proceeds, net of tax. Shares acquired on-market pursuant to a buy back scheme and Treasury Shares held for the purposes of operating employee plans are recognised as a reduction from equity.

## (v) Dividends

Provision is made for the amount of any dividend declared, being appropriately authorised and no longer at the discretion of the entity, on or before the end of the reporting period but not distributed at the end of the reporting period.

## (w) Earnings Per Share

### (i) Basic Earnings Per Share

Basic earnings per share is calculated by dividing the profit attributable to owners of the Company, excluding any costs of servicing equity other than ordinary shares, by the weighted average number of ordinary shares outstanding during the financial year.

# 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

## (w) Earnings Per Share (continued)

### (ii) Diluted Earnings Per Share

Diluted earnings per share adjusts the figures used in the determination of basic earnings per share to take into account the after income tax effect of interest and other financing costs associated with dilutive potential ordinary shares and the weighted average number of additional ordinary shares that would have been outstanding assuming the exercise of all dilutive potential ordinary shares.

## (x) Goods and Services Tax (GST)

Revenues, expenses and assets are recognised net of the amount of GST, unless the GST incurred is not recoverable from the taxation authority. In this case it is recognised as part of the cost of acquisition of the asset or as part of the expense. Receivables and payables are stated inclusive of the amount of GST receivable or payable. The net amount of GST recoverable from, or payable to, the taxation authority is included with other receivables or payables in the balance sheet.

Cash flows are presented on a gross basis. The GST components of cash flows arising from investing or financing activities which are recoverable from, or payable to the taxation authority, are presented as operating cash flows.

## (y) Parent Entity Financial Information

The financial information for the Parent Entity, Central Petroleum Limited, disclosed in Note 25, has been prepared on the same basis as the consolidated financial statements except for investments in subsidiaries, associates and joint venture entities which are accounted for at cost in the financial statements of Central Petroleum Limited.

## (z) Business Combinations

The acquisition method of accounting is used to account for all business combinations, regardless of whether equity instruments or other assets are acquired. The consideration transferred for the acquisition of a subsidiary comprises the:

- fair values of the assets transferred;
- liabilities incurred to the former owners of the acquired business;
- equity interests issued by the Group;
- fair value of any asset or liability resulting from a contingent consideration arrangement; and
- fair value of any pre-existing equity interest in the subsidiary.

Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are, with limited exceptions, measured initially at their fair values at the acquisition date. The Group recognises any non-controlling interest in the acquired entity on an acquisition-by-acquisition basis either at fair value or at the non-controlling interest's proportionate share of the acquired entity's net identifiable assets. Acquisition related costs are expensed as incurred.

The excess of the:

- consideration transferred;
- amount of any non-controlling interest in the acquired entity; and
- acquisition-date fair value of any previous equity interest in the acquired entity

over the fair value of the net identifiable assets acquired is recorded as goodwill. If those amounts are less than the fair value of the net identifiable assets of the business acquired, the difference is recognised directly in profit or loss as a bargain purchase.

Where settlement of any part of cash consideration is deferred, the amounts payable in the future are discounted to their present value as at the date of exchange. The discount rate used is the entity's incremental borrowing rate, being the rate at which a similar borrowing could be obtained from an independent financier under comparable terms and conditions.

Contingent consideration is classified either as equity or a financial liability. Amounts classified as a financial liability are subsequently remeasured to fair value with changes in fair value recognised in profit or loss.

If the business combination is achieved in stages, the acquisition date carrying value of the acquirer's previously held equity interest in the acquiree is remeasured to fair value at the acquisition date. Any gains or losses arising from such remeasurement are recognised in profit or loss.

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

### (aa) Standards, Amendments and Interpretations

The Group has applied AASB 2023-5 Amendments to Australian Accounting Standards – Lack of Exchangeability [AASB 1, AASB 121 & AASB 1060] for the first time for its annual reporting period commencing 1 July 2025. The amendment did not have any impact on the amounts recognised in prior periods and are not expected to significantly affect the current or future periods.

New standards and amendments to existing standards that are not mandatory for 30 June 2026 have not been early adopted. These are:

- AASB 2024-2 Amendments to Australian Accounting Standards – Classification and Measurement of Financial Instruments [AASB 7 & AASB 9] (effective for reporting period ending 30 June 2027); and
- AASB 18 Presentation and Disclosure in Financial Statements (effective for reporting period ending 30 June 2028).

None of these are expected to have any impact on the recognition or measurement of items in the financial statements. AASB 18 will replace AASB 101 Presentation of financial statements, introducing new requirements that will help to achieve comparability of the financial performance of similar entities and provide more relevant information and transparency to users. Even though AASB 18 will not impact the recognition or measurement of items in the financial statements, Management is yet to assess the detailed implications of applying the new Standard especially with respect to providing management-defined performance measures within the financial statements.

## 2. PRIOR PERIOD RESTATEMENTS

After reviewing costs allocated to operated joint ventures in previous periods, the Company has corrected its allocation of staff costs. The over-recovery of costs in prior periods has resulted in an understatement of general and administrative expenses relating to employee costs and an over-statement of production costs.

A provision of $1,477,000 has been recognised for the expected joint venture reimbursements required in respect of FY2024 and FY2025, and the affected financial statement line items have been corrected by restating each of the affected financial statement line items for the prior periods as follows:

**Consolidated Balance Sheet (extract of affected line items)**

| | 2025 | | | 2024 | | |
|---|---|---|---|---|---|---|
| | **30 June 2025 $'000** | **Increase/ (Decrease) $'000** | **30 June 2025 (Restated) $'000** | **30 June 2024 $'000** | **Increase/ (Decrease) $'000** | **1 July 2024 (Restated) $'000** |
| Provisions - current | 7,496 | 1,477 | 8,973 | 8,794 | 476 | 9,270 |
| Total current liabilities | 14,030 | 1,477 | 15,507 | 18,205 | 476 | 18,681 |
| **Total liabilities** | **73,107** | **1,477** | **74,584** | **71,084** | **476** | **71,560** |
| **Net Assets** | **40,905** | **(1,477)** | **39,428** | **32,555** | **(476)** | **32,079** |
| Reserves | 42,104 | (930) | 41,174 | 41,488 | (930) | 40,558 |
| Accumulated Losses | (198,975) | (547) | (199,522) | (206,709) | 454 | (206,255) |
| **Total equity** | **40,905** | **(1,477)** | **39,428** | **32,555** | **(476)** | **32,079** |

**Consolidated Statement of Comprehensive Income (extract of affected line items)**

| | **2025 $'000** | **Profit Increase/ (Decrease) $'000** | **2025 (Restated) $'000** |
|---|---|---|---|
| Cost of Sales | (29,087) | 504 | (28,583) |
| **Gross Profit** | **14,539** | **504** | **15,043** |
| General and administrative expenses net of recoveries | (2,369) | (1,505) | (3,874) |
| **Profit before income tax** | **7,734** | **(1,001)** | **6,733** |
| **Profit for the year** | **7,734** | **(1,001)** | **6,733** |
| **Total comprehensive profit for the year** | **7,734** | **(1,001)** | **6,733** |
| **Total comprehensive profit attributable to members of the parent entity** | **7,734** | **(1,001)** | **6,733** |

Basic and diluted earnings per share for the prior year have also been restated. The amount of the correction for basic and diluted earnings per share was a decrease of 0.13 cents per share.

## 3. REVENUE FROM CONTRACTS WITH CUSTOMERS

### (a) Revenue from contracts with customers

| | 2026 $'000 | 2025 $'000 |
|---|---|---|
| **Sale of hydrocarbon products - point in time** | | |
| Natural gas | 42,456 | 38,944 |
| Crude oil and condensate | 1,446 | 3,407 |
| Revenue released from Deferred Revenue in respect of take or pay contracts [1] | 845 | 1,275 |
| **Total revenue from contracts with customers** | **44,747** | **43,626** |

[1] Represents amounts paid for gas under contracts for which the customer will no longer be able to take physical delivery of the gas due to time and maximum daily quantity limits under the contract.

Revenue relating to contracts with major customers is disclosed in Note 26(f) – Segment Reporting.

### (b) Contract Liabilities

| | 2026 | | | 2025 | | |
|---|---|---|---|---|---|---|
| | Current $'000 | Non-current $'000 | Total $'000 | Current $'000 | Non-current $'000 | Total $'000 |
| Deferred Revenue – take-or-pay contracts[1] | 1,363 | 8,317 | 9,680 | 992 | 9,036 | 10,028 |
| **Total contract liabilities** | **1,363** | **8,317** | **9,680** | **992** | **9,036** | **10,028** |

[1] Refer Note 1(e) (i) and (iii) for details of the relevant accounting policies.

| **Movements in Contract Liabilities** | Total $'000 |
|---|---|
| **Carrying amount at 1 July 2025** | **10,028** |
| Revenue recognised from the delivery of gas | (337) |
| Revenue released (forfeited gas) | (845) |
| Gas paid for but not taken during the period | 834 |
| **Carrying amount at 30 June 2026** | **9,680** |

## 4. OTHER INCOME

| | 2026 $'000 | 2025 $'000 |
|---|---|---|
| Interest | 1,041 | 1,163 |
| Profit on disposal of inventory and other assets (a) | 4 | 1,328 |
| **Total other income** | **1,045** | **2,491** |

### (a) Profit from disposal of inventory and other assets

In 2025, profit on disposal of assets includes a $1,233,000 profit on the disposal of the Group's interest in land held by the Mereenie joint venture. The book profit includes derecognition of associated rehabilitation liabilities of $562,000 and is net of associated costs of disposal.

## 5. EXPENSES

| | NOTE | 2026<br>$'000 | 2025*<br>Restated<br>$'000 |
|---|---|---|---|
| **(a) Cost of sales includes the following specific expenses** | | | |
| Depreciation and amortisation | 5(e) | 6,517 | 6,732 |
| Employee and contractor costs | | 6,155 | 6,018 |
| Gas purchases | | 6,196 | 5,266 |
| Other production costs | | 4,921 | 4,286 |
| Royalties | | 4,741 | 4,309 |
| Transportation and storage | | 1,186 | 1,972 |
| **Total cost of sales** | | **29,716** | **28,583** |

* See Note 2 for details regarding the restatement of prior year comparatives.

### (b) General and administrative expenses include the following specific expenses

| | | | |
|---|---|---|---|
| Depreciation and amortisation | 5(e) | 572 | 664 |
| Employee and contractor costs | | 2,749 | 2,282 |
| Share based payments | | 621 | 619 |
| Business development costs | | 874 | 45 |
| Other costs | | 308 | 264 |
| **Total general and administrative expenses** | | **5,124** | **3,874** |

* See Note 2 for details regarding the restatement of prior year comparatives.

### (c) Finance costs include the following specific expenses

| | | | |
|---|---|---|---|
| Interest and fees on debt facilities | | 2,944 | 3,273 |
| Interest on lease liabilities | 13(b) | 274 | 81 |
| Amortisation of deferred finance costs | | – | 292 |
| Accretion charges relating to provisions and other financial liabilities | | 1,016 | 878 |
| **Total finance costs** | | **4,234** | **4,524** |

### (d) Other expenses include the following specific expenses

| | | | |
|---|---|---|---|
| Change in fair value of other financial liabilities[1] | 20 | 64 | 679 |
| Write off, impairment, and disposal of property, plant and equipment | | 2 | 46 |
| **Total other expenses** | | **66** | **725** |

[1] Change in fair value of deferred consideration that may become payable in future years (refer Note 20).

# 5. EXPENSES (CONTINUED)

| | NOTE | 2026 $'000 | 2025 $'000 |
|---|---|---|---|
| **(e) Total depreciation and amortisation** | | | |
| **Depreciation** | | | |
| Buildings | 12 | 33 | 175 |
| Producing assets | 12 | 3,430 | 3,458 |
| Plant and equipment | 12 | 3,028 | 3,080 |
| Leasehold improvements | 12 | 31 | 2 |
| Right of use assets | 13(b) | 457 | 546 |
| **Total depreciation** | | **6,979** | **7,261** |
| **Amortisation** | | | |
| Other intangible assets - software | 15 | 110 | 136 |

### (f) Exploration expenditure

| | | 2026 $'000 | 2025 $'000 |
|---|---|---|---|
| Exploration costs | | 5,701 | 1,678 |
| Impairment of exploration assets[1] | | 5,869 | – |
| **Total exploration expenditure** | | **11,570** | **1,678** |

[1] During the current year the Group withdrew from the EP82 and EP112 Joint Ventures. As a result, an impairment expense was recognised.

### (g) Leases not on the balance sheet

There were no rental expenses relating to operating leases that are not on the Balance Sheet during the current or prior financial year (Note 13(b)).

## 6. INCOME TAX

This note provides an analysis of the Group's income tax expense, shows what amounts are recognised directly in equity and how the tax credit is affected by non-assessable and non-deductible items. It also explains significant estimates made in relation to the Group's tax position.

| | 2026 $'000 | 2025 Restated* $'000 |
|---|---|---|
| **(a) Income tax expense** | | |
| Current tax | – | – |
| Deferred tax | – | – |
| **Income tax expense** | **–** | **–** |
| **(b) Numerical reconciliation of income tax expense and prima facie tax benefit** | | |
| (Loss)/profit before income tax expense | (4,918) | 6,733 |
| Prima facie tax benefit/(expense) at 30% | 1,475 | (2,020) |
| Tax effect of amounts which are not deductible in calculating taxable income: | | |
| Non-deductible expenses | (10) | (9) |
| Share based payments | (186) | (187) |
| Sub-total | 1,279 | (2,216) |
| Previously unrecognised deferred tax assets | – | 2,216 |
| Deferred tax assets not recognised | (1,279) | – |
| **Income tax expense** | **–** | **–** |
| **(c) Amounts recognised directly in equity** | | |
| Aggregate deferred tax arising in the reporting period and not recognised in net profit or loss or other comprehensive income but directly debited or credited to equity: | | |
| Net deferred tax – debited directly to equity | 1 | 1 |
| Deferred tax assets not recognised | (1) | (1) |
| **Net amounts recognised directly in equity** | **–** | **–** |
| **(d) Tax Losses** | | |
| Unutilised tax losses for which no deferred tax asset has been recognised | 122,590 | 125,857 |
| **Potential tax benefit at 30%** | **36,777** | **37,757** |

Unutilised tax losses are available for use in Australia and are available to offset future taxable profits of the income tax consolidated group, subject to the relevant tax loss recoupment requirements being met.

## 6. INCOME TAX (CONTINUED)

| | 2026 $'000 | 2025 Restated* $'000 |
|---|---|---|
| **(e) Deferred tax assets and liabilities** | | |
| **Deferred tax assets** | | |
| Provisions and accruals | 12,021 | 9,854 |
| Other expenditure | 337 | 207 |
| Borrowing costs | 127 | 164 |
| Unutilised losses | 45,675 | 47,017 |
| Total deferred tax assets before set-offs | 58,160 | 57,242 |
| Set-off of deferred tax liabilities pursuant to set-off provisions | (8,898) | (9,260) |
| **Net deferred tax assets not recognised** | **49,262** | **47,982** |
| ***Movements in deferred tax assets*** | | |
| Opening balance at 1 July | 9,260 | 9,134 |
| (Credited)/charged to the income statement | (362) | 126 |
| **Closing balance at 30 June** | **8,898** | **9,260** |
| Deferred tax assets to be recovered after more than 12-months | 5,664 | 6,817 |
| Deferred tax assets to be recovered within 12-months | 3,234 | 2,443 |
| | **8,898** | **9,260** |
| **Deferred tax liabilities** | | |
| Capitalised exploration | 896 | 2,278 |
| Deferred expenditure | 6 | – |
| Property, plant and equipment | 7,996 | 6,982 |
| Total deferred tax liabilities before set-offs | 8,898 | 9,260 |
| Set-off of deferred tax assets pursuant to set-off provisions | (8,898) | (9,260) |
| **Net deferred tax liabilities** | **–** | **–** |
| ***Movements in deferred tax liabilities*** | | |
| Opening balance at 1 July | 9,260 | 9,134 |
| (Charged)/credited to the income statement | (362) | 126 |
| **Closing balance at 30 June** | **8,898** | **9,260** |
| Deferred tax liabilities to be recovered after more than 12-months | 8,780 | 9,152 |
| Deferred tax liabilities to be recovered within 12-months | 118 | 108 |
| | **8,898** | **9,260** |

* See Note 2 for details regarding the restatement of prior year comparatives.

## 7. REMUNERATION OF AUDITORS

| | 2026 $ | 2025 $ |
|---|---|---|
| The following fees were paid or payable for services provided by PwC Australia, the auditor of the Company, its related practices and non-related audit firms: | | |
| *(i) Audit and other assurance services* | | |
| Audit and review of Group financial reports | 289,476 | 253,303 |
| Other statutory assurance services – sustainability report | 71,400 | – |
| Total audit and other assurance services | 360,876 | 253,303 |
| *(ii) Taxation services* | | |
| Income tax compliance | 17,942 | 17,085 |
| Other tax related services | 78,434 | 5,550 |
| Total taxation services | 96,376 | 22,635 |
| **Total remuneration of PwC** | **457,252** | **275,938** |

## 8. CASH AND CASH EQUIVALENTS

| | 2026 $000 | 2025 $000 |
|---|---|---|
| **Cash and cash equivalents** | **20,410** | **27,471** |
| Made up as follows: | | |
| Corporate cash and bank balances (a) | 11,161 | 26,022 |
| Joint arrangements (b) | 1,249 | 1,449 |
| Cash on term deposit (c) | 8,000 | — |
| **Total cash and cash equivalents** | **20,410** | **27,471** |

(a) There are no restrictions on cash balances. In addition to the cash balances above, a separate fixed deposit of $2,500,000 has been provided for the duration of the loan facility and is disclosed in the Balance Sheet as a non-current Other Financial Asset (Note 16).

(b) This balance relates to the Group's share of cash balances held under Joint Venture Arrangements.

(c) Cash on 3 month term deposit held to meet short term cash needs and there is no significant risk of a change in value as a result of early withdrawal.

### (i) Risk exposure

The Group's exposure to credit and interest rate risk is discussed in Note 35.

## 9. TRADE AND OTHER RECEIVABLES

| | 2026 $'000 | 2025 $'000 |
|---|---|---|
| **Current** | | |
| Trade debtors | 7 | 232 |
| Accrued income and recoveries (a) | 5,377 | 5,285 |
| Other receivables | 280 | 66 |
| Prepayments | 1,877 | 1,765 |
| | **7,541** | **7,348** |

Due to the nature of the Group's receivables, their carrying values are considered to approximate their fair values. The Group applies the simplified approach to providing for expected credit losses (refer Note 35(a)).

(a) Accrued income and recoveries includes revenue recognised from hydrocarbon volumes delivered to respective customers but not yet invoiced and accrued costs recoverable under Joint Arrangements.

## 10. INVENTORIES

| | 2026 $'000 | 2025 $'000 |
|---|---|---|
| Crude oil and natural gas | 69 | 164 |
| Spare parts and consumables | 2,008 | 1,854 |
| Drilling materials and supplies at cost | 2,631 | 1,595 |
| | **4,708** | **3,613** |

## 11. OTHER CURRENT ASSETS

| | | |
|---|---|---|
| Deferred financing costs | 300 | – |
| | **300** | **–** |

## 12. PROPERTY, PLANT AND EQUIPMENT

| | Freehold Land and Buildings $'000 | Producing Assets $'000 | Plant and Equipment $'000 | Total $'000 |
|---|---|---|---|---|
| **Year ended 30 June 2025** | | | | |
| Opening net book amount | 403 | 34,937 | 20,238 | 55,578 |
| Additions | — | 6,056 | 2,488 | 8,544 |
| Changes to rehabilitation estimates | — | 621 | 16 | 637 |
| Disposals and write offs | (38) | (282) | (46) | (366) |
| Depreciation charge | (175) | (3,458) | (3,082) | (6,715) |
| **Closing net book amount** | **190** | **37,874** | **19,614** | **57,678** |
| **At 30 June 2025** | | | | |
| Cost | 1,904 | 70,903 | 51,928 | 124,735 |
| Accumulated depreciation | (1,714) | (33,029) | (32,314) | (67,057) |
| **Net book amount at 30 June 2025** | **190** | **37,874** | **19,614** | **57,678** |
| **Year ended 30 June 2026** | | | | |
| Opening net book amount | 190 | 37,874 | 19,614 | 57,678 |
| Additions | 143 | 366 | 5,002 | 5,511 |
| Changes to rehabilitation estimates | – | 4,689 | (5) | 4,684 |
| Disposals and write offs | – | – | (26) | (26) |
| Third party contributions | – | (450) | – | (450) |
| Depreciation charge | (33) | (3,430) | (3,059) | (6,522) |
| **Closing net book amount** | **300** | **39,049** | **21,526** | **60,875** |
| **At 30 June 2026** | | | | |
| Cost | 2,047 | 75,508 | 56,495 | 134,050 |
| Accumulated depreciation | (1,747) | (36,459) | (34,969) | (73,175) |
| **Net book amount at 30 June 2026** | **300** | **39,049** | **21,526** | **60,875** |

At 30 June 2026, $3,039,000 of property plant and equipment balances relates to assets under construction and is not subject to depreciation until complete (2025: $1,043,000).

In assessing the appropriateness of the recoverability of property, plant and equipment balances, the net book amounts above have been tested for impairment as described in the Goodwill impairment assessment (Note 17).

## 13. LEASES

### (a) Amounts recognised in the Balance Sheet

The Balance Sheet shows the following amounts relating to leases:

| | 2026 $'000 | 2025 $'000 |
|---|---|---|
| **Right-of-use assets** | | |
| Land & Buildings | 1,775 | 2,461 |
| Plant & Equipment | 168 | 156 |
| | **1,943** | **2,617** |
| **Lease Liabilities** | | |
| Current | 410 | 360 |
| Non-current | 1,969 | 2,301 |
| | **2,379** | **2,661** |

Additions to the right-of-use assets during the 2026 financial year were $84,000 (2025: $2,146,000). Incentive adjustments amounted to $300,000 (2025: $Nil), and there were $Nil disposals (2025: Nil).

### (b) Amounts recognised in the statement of profit or loss

The statement of profit or loss shows the following amounts relating to leases:

| | 2026 $'000 | 2025 $'000 |
|---|---|---|
| **Depreciation charge of right-of-use assets** | | |
| Land & Buildings | 403 | 507 |
| Plant & Equipment | 54 | 39 |
| **Total depreciation of right-of-use assets** | **457** | **546** |
| Interest expense | 274 | 81 |
| Expense related to short term leases included in cost of sales and general and administrative expenses (Note 5(g)) | – | – |

The total cash outflow for leases in 2026 was $639,000 (2025: $616,000).

### (c) The Group's leasing activities and how they are accounted for

The Group leases office space, property easements, equipment and vehicles. Rental contracts are typically made for fixed periods of 3 to 5 years but may have extension options as described below. Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions. The lease agreements do not impose any covenants other than the security interests in the leased assets that are held by the lessor and a bank guarantee held in respect of the Brisbane office lease. Leased assets may not be used as security for borrowing purposes.

Contracts may contain both lease and non-lease components. The Group has elected not to separate lease and non-lease components and instead accounts for these as a single lease component.

Leases are recognised as a right-of-use asset and a corresponding liability at the date at which the leased asset is available for use by the Group. Each lease payment is allocated between the liability and finance cost. The finance cost is charged to profit or loss over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period.

Assets and liabilities arising from a lease are initially measured on a present value basis. Lease liabilities include the net present value of the following lease payments:

- fixed payments (including in-substance fixed payments), less any lease incentives receivable;
- variable lease payment that are based on an index or a rate;
- amounts expected to be payable by the lessee under residual value guarantees;
- the exercise price of a purchase option if the lessee is reasonably certain to exercise that option; and
- payments of penalties for terminating the lease, if the lease term reflects the lessee exercising that option.

## 13. LEASES (CONTINUED)

### (c) The Group's leasing activities and how they are accounted for (continued)

Extension and termination options are included in some leases across the Group. These are used to maximise operational flexibility in terms of managing the assets used in the Group's operations. The extension and termination options held are exercisable only by the Group and not by the respective lessor. Lease payments to be made under reasonably certain extension options are also included in the measurement of the liability.

The lease payments are discounted using the interest rate implicit in the lease. If that rate cannot be determined, the lessee's incremental borrowing rate is used, being the rate that the lessee would have to pay to borrow the funds necessary to obtain an asset of similar value in a similar economic environment with similar terms, security and conditions.

To determine the incremental borrowing rate, the Group:

- where possible, uses recent third-party financing received by the individual lessee as a starting point, adjusted to reflect changes in financing conditions since third party financing was received;
- uses a build-up approach that starts with a risk-free interest rate adjusted for credit risk for leases held by Central Petroleum Limited, which does not have recent third-party financing; and
- makes adjustments specific to the lease, e.g. term, country, currency and security.

The Group is exposed to potential future increases in variable lease payments based on an index or rate, which are not included in the lease liability until they take effect. When adjustments to lease payments based on an index or rate take effect, the lease liability is reassessed and adjusted against the right-of-use asset.

Right-of-use assets are measured at cost comprising the following:

- the amount of the initial measurement of lease liability;
- any lease payments made at or before the commencement date less any lease incentives received;
- any initial direct costs; and
- the present value of estimated future restoration costs.

Right-of-use assets are generally depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis. If the Group is reasonably certain to exercise a purchase option, the right-of-use asset is depreciated over the underlying asset's useful life.

Payments associated with short-term leases and leases of low-value assets are recognised on a straight-line basis as an expense in profit or loss. Short-term leases are leases with a lease term of 12-months or less.

If there is a modification to a lease arrangement, a determination of whether the modification results in a separate lease arrangement being recognised needs to be made. Where the modification does result in a separate lease arrangement needing to be recognised, due to an increase in scope of a lease through additional underlying leased assets and a commensurate increase in lease payments, the measurement requirements as described above need to be applied.

Where the modification does not result in a separate lease arrangement, from the effective date of the modification, the Group will remeasure the lease liability using the redetermined lease term, lease payments and applicable discount rate. A corresponding adjustment will be made to the carrying amount of the associated right-of-use asset. Additionally, where there has been a partial or full termination of a lease, the Group will recognise any resulting gain or loss in the income statement.

## 14. EXPLORATION ASSETS

| | 2026<br>$'000 | 2025<br>$'000 |
|---|---|---|
| Acquisition costs of right to explore | **13,841** | **7,674** |
| *Movement for the year:* | | |
| Balance at the beginning of the year | 7,674 | 7,674 |
| Acquisition costs | 12,036 | – |
| Impairment expense (Note 5(f)) | (5,869) | – |
| **Balance at the end of the year** | **13,841** | **7,674** |

## 15. OTHER INTANGIBLE ASSETS

| | 2026 $'000 | 2025 $'000 |
|---|---|---|
| **Software** | | |
| ***At the beginning of the year*** | | |
| Cost | 1,052 | 1,050 |
| Accumulated amortisation | (810) | (674) |
| Net book value | **242** | **376** |
| ***Movements for the year*** | | |
| Opening net book amount | 242 | 376 |
| Additions | 60 | 2 |
| Amortisation | (110) | (136) |
| Closing net book amount | **192** | **242** |
| ***At the end of the year*** | | |
| Cost | 1,112 | 1,052 |
| Accumulated amortisation | (920) | (810) |
| **Net book value** | **192** | **242** |

## 16. OTHER FINANCIAL ASSETS

| | 2026 | 2025 |
|---|---|---|
| **Non-Current** | | |
| Security bonds over petroleum permits and rental properties [1] | 3,426 | 2,916 |
| Cash on deposit – debt facility[2] | 2,500 | 2,500 |
| **Total other financial assets** | **5,926** | **5,416** |

[1] Security bonds are provided to State or Territory governments in respect of certain performance obligations arising from awarded petroleum and mineral tenements. These bonds are typically provided as cash or as bank guarantees in favour of the State or Territory government. Bank guarantees covering these bonds and rental properties are secured by term deposits with the financial institution providing the bank guarantee. Amounts refundable on condition of meeting performance obligations are measured at amortised cost.

[2] Cash on deposit as security for the debt facility

## 17. GOODWILL

| | 2026 $'000 | 2025 $'000 |
|---|---|---|
| Goodwill arising from business combinations | **1,953** | **1,953** |

*Impairment tests for goodwill and property, plant and equipment*

Goodwill is monitored by management at the level of the operating segments and has been allocated to the gas producing assets cash generating unit. There has been no impairment of amounts previously recognised as goodwill. Goodwill is tested for impairment where an indicator of impairment exists, and at least on an annual basis.

In determining impairment indicators for the current year, an assessment of the fair value less cost of disposal was made by estimating future cash flows from available 2P gas and oil reserves over a 20-year period from balance date, being the period over which the value of existing reserves is expected to be substantially realised. Cash flows include estimated capital expenditure to enhance production. The future cash flows are discounted to their present value using a post-tax discount rate, which includes an assessment of asset specific risks and the time value of money. The calculations require significant management judgement and are subject to risk and uncertainty, and broader economic conditions.

## 17. GOODWILL (CONTINUED)

The following table sets out the key assumptions used in assessing the fair value less cost to sell of producing assets:

| 2026 | Producing Assets |
|---|---|
| Sales volumes | 2P Reserves |
| Sales price (% annual growth rate) | 2.5 – 4.2% |
| Operating costs (% annual growth rate) | 2.5 – 4.2% |
| Post-tax discount rate (%) | 13.25% |

Management has determined the values assigned to each of the above key assumptions as follows:

| Assumption | Approach used to determine values |
|---|---|
| Sales volume | Natural gas sales are based on both Annual Contract Quantities for existing contracts which continue at projected nominations and uncontracted volumes taking into account firm plant capacity, and limited to 2P reserve volumes. Gas, crude and condensate volumes are based on projected field production, taking into account historical production and forecast reservoir decline. |
| Sales price | Existing contracts are based on current contracted prices escalated for forecast CPI increases as per the contract terms. Some contracts contain minimum and maximum increases. Uncontracted gas sales are based on estimated attainable gas prices taking into account indicative customer proposals. Crude and condensate pricing is based on a mid-point of independent analyst forecasts of crude prices and a long-term forecast average USD exchange rate and considers any expected offtake constraints. |
| Operating costs | Current budgeted operating costs are based on past performance and expectations for the future. Forecasts are inflated beyond the budget year using inflationary estimates. Other known factors are included where applicable. |
| Capital expenditure | Where further field capital expenditure is required in order to meet contracted and projected sales volumes, the expected future cash costs are taken into account. |
| Annual growth rate | This is the average growth rate used to extrapolate cash flows beyond the budget period. Management considers forecast inflation rates and industry trends if applicable. |
| Post-tax discount rate | This rate reflects risks relating to the segment which includes the impact of sustainability and climate-change related factors if appropriate. Post-tax discount rates have been applied to discount the forecast future post-tax cash flows. |

The directors and management have concluded the recoverable amount of the producing assets exceeded the carrying amount at the end of the reporting period and no impairment write-down was required.

## 18. TRADE AND OTHER PAYABLES

| | 2026<br>$'000 | 2025<br>$'000 |
|---|---|---|
| **Current** | | |
| Trade payables | 1,509 | 962 |
| Other payables | 198 | 233 |
| Accruals | 4,379 | 3,980 |
| | **6,086** | **5,175** |

Trade payables are usually non-interest bearing, provided payment is made within the terms of credit. The Consolidated Entity's exposure to liquidity and currency risks related to trade and other payables is disclosed in Note 35.

## 19. BORROWINGS

| | | 2026 $'000 | 2025 $'000 |
|---|---|---|---|
| (a) | **Current**[1] | | |
| | Debt facilities | 3,839 | 7 |
| (b) | **Non-current**[1] | | |
| | Debt facilities | 21,702 | 23,384 |

[1] Details regarding interest bearing liabilities are contained in Note 35(e).

No principal repayments are required before 31 March 2027. There are no penalties for early repayment. Interest rates are re-priced quarterly based on fixed spreads over the periodic Bank Bill Swap (BBSY) average bid rate. During the year, interest payments of $2,148,000 (2025: $494,000) were capitalised into the loan balance. The Group does not have any interest rate hedging arrangements in place.

Under the terms of the Facility, the Group is required to comply with the following key financial covenants:

1. The Group current ratio is at least 1:1, excluding amounts payable under the debt facility.
2. The Net Present Value with a 10% discount rate (NPV10) of forecasted net cash flow from the Palm Valley, Dingo and Mereenie gas fields limited by the sales of only Proved Developed Producing reserves, divided by the outstanding loan amount must be greater than 1.3:1.

The Group remains compliant with these and all other financial covenants under the facility.

## 20. OTHER FINANCIAL LIABILITIES

| | 2026 $'000 | 2025 $'000 |
|---|---|---|
| **Current** | | |
| Deferred consideration payable – at fair value | 356 | – |
| **Non-current** | | |
| Deferred consideration payable – at fair value | 532 | 722 |

In 2014 the Group acquired an interest in the Palm Valley gas field. The purchase terms included a deferred consideration component which requires the Group to make additional payments where the weighted average price of gas sold from the Palm Valley gas field during a contract year exceeds certain gas price hurdles during a period of 15 years following the purchase transaction (terminates 31 December 2028).

The weighted average price of gas sold from the Palm Valley gas field has not exceeded the gas price hurdle for completed contract years to date, but with recent increases in market prices it is now expected that payments may be required in future periods. A liability has been recognised at the estimated fair value of future payments.

The fair value estimate takes into account expected future CPI indexation, field production capacity and expected mix of contracts to be delivered from the Palm Valley field until 31 December 2028. Movement for the year comprises changes in fair value recognised in other expenses of $64,000 (2025: $679,000) (Note 5(d)) and accretion charges of $101,000 (2025: $43,000) included in finance charges (Note 5 (c)).

## 21. PROVISIONS

| | 2026 | | | 2025 Restated* | | |
|---|---|---|---|---|---|---|
| | Current $'000 | Non-Current $'000 | Total $'000 | Current $'000 | Non-Current $'000 | Total $'000 |
| Employee entitlements (a) | 6,074 | 714 | 6,788 | 5,969 | 720 | 6,689 |
| Restoration and rehabilitation (b) | 1,067 | 29,587 | 30,654 | 874 | 22,914 | 23,788 |
| Joint Venture production over-lift (c) | – | – | – | 653 | – | 653 |
| Other Provisions (d) | 1,477 | – | 1,477 | 1,477 | – | 1,477 |
| | **8,618** | **30,301** | **38,919** | **8,973** | **23,634** | **32,607** |

* See Note 2 for details regarding the restatement of prior year comparatives.

(a) The current provision for employee entitlements includes accrued short term incentive plans, severance entitlements, accrued annual leave and the unconditional entitlements to long service leave where employees have completed the required period of service.

(b) Provisions for future removal and restoration costs are recognised where there is a present obligation and it is probable that an outflow of economic benefits will be required to settle the obligation. The estimated future obligations include the costs of removing facilities, abandoning wells and restoring the affected areas.

(c) Under an Interim Gas Balancing Agreement with its joint venture partners, the Group had previously taken a higher proportion of natural gas produced from the Mereenie joint venture than its joint venture percentage entitlement. A provision had been recognised to reflect the expected additional production costs of rebalancing production entitlements between the joint venture partners from future operations. During FY 2026 the gas imbalance was fully repaid.

(d) Other Provisions relate to the correction of recoveries from operated joint ventures in prior periods (refer also Note 2)

### Movements in Provisions

Movements in each class of provision during the financial year are set out below:

| 2026 | Employee Entitlements $'000 | Restoration & Rehabilitation $'000 | Joint Venture Production Over-Lift $'000 | Other Provisions $'000 | Total $'000 |
|---|---|---|---|---|---|
| Carrying amount at start of year (Restated)* | 6,689 | 23,788 | 653 | 1,477 | 32,607 |
| Amounts recognised on acquisition of interests in exploration tenements | – | 923 | – | – | 923 |
| Change in provision charged to property, plant and equipment | – | 4,684 | – | – | 4,684 |
| Additional provisions charged to profit or loss | 3,755 | 798 | 25 | – | 4,578 |
| Unwinding of discount | – | 915 | – | – | 915 |
| Amounts used during the year | (3,656) | (454) | (678) | – | (4,788) |
| **Carrying amount at end of year** | **6,788** | **30,654** | **–** | **1,477** | **38,919** |

* See Note 2 for details regarding the restatement of prior year comparatives.

## 22. CONTRIBUTED EQUITY

### (a) Share capital

| | 2026 $'000 | 2025 $'000 |
|---|---|---|
| **750,578,825 fully paid ordinary shares (2025: 745,258,314)** | **197,638** | **197,776** |

Ordinary shares have no par value, and the Company does not have a limited amount of authorised capital.

On a show of hands, every holder of ordinary shares present at a meeting in person or by proxy, is entitled to one vote, and upon a poll each share is entitled to one vote.

#### Movements in ordinary share capital

| | 2026 Number of Shares | 2025 Number of Shares | 2026 $'000 | 2025 $'000 |
|---|---|---|---|---|
| Balance at start of year | 745,258,314 | 740,147,003 | 197,776 | 197,776 |
| Shares issued under Employee Incentive Plans | 7,505,641 | 5,111,311 | – | – |
| On-market share buy-backs | (2,185,130) | – | (138) | – |
| **Balance at end of year** | **750,578,825** | **745,258,314** | **197,638** | **197,776** |

### (b) Treasury shares

Treasury shares are ordinary shares in Central Petroleum Limited that are held by the CTP Employee Share Trust for the purpose of operating Employee Rights Plans that are made available by the Group to employees and other persons from time to time, including acquiring, holding and transferring shares for the benefit of employees in connection with Employee Rights Plans.

| | 2026 $'000 | 2025 $'000 |
|---|---|---|
| **6,076,280 fully paid ordinary shares (2025: NIL)** | **(400)** | **–** |

#### Movements in Treasury shares

| | 2026 Number of Shares | 2025 Number of Shares | 2026 $'000 | 2025 $'000 |
|---|---|---|---|---|
| Balance at start of year | – | – | – | – |
| Acquisition of shares (average price 6.58 cents per share) | (6,076,280) | – | (400) | – |
| **Balance at end of year** | **(6,076,280)** | **–** | **(400)** | **–** |

## 22. CONTRIBUTED EQUITY (CONTINUED)

### (c) Share rights

Under the Group's Employee Rights Plan, eligible employees may receive rights to shares in Central Petroleum Limited. Details of the terms and conditions of the various share rights issued pursuant to the Employee Rights Plan are set out in Note 34 and sections E and F of the Remuneration Report.

The table below sets out the maximum number of share rights outstanding at year end and movements for the year.

| Class | Expiry Date | Plan Year Commencing | Balance at Start of Year | Issued During the Year | Cancelled or Lapsed During the Year | Exercised During the Year | Balance at the End of the Year |
|---|---|---|---|---|---|---|---|
| **Long Term Incentive Plans** | | | | | | | |
| Employee LTIP rights | 30 Jun 2026 | 1 Jul 2021 | 37,125 | — | (20,733) | (16,392) | — |
| Employee LTIP rights | 30 Jun 2027 | 1 Jul 2022 | 402,046 | 6,137 | (16,906) | (378,069) | 13,208 |
| Employee LTIP rights | 30 Jun 2028 | 1 Jul 2023 | 847,693 | — | (107,037) | — | 740,656 |
| Employee LTIP rights | 30 Jun 2029 | 1 Jul 2024 | 964,865 | 45,610 | (61,568) | — | 948,907 |
| Employee LTIP rights | 30 Jun 2030 | 1 Jul 2025 | — | 1,092,192 | (32,464) | — | 1,059,728 |
| **Executive Incentive Plan** | | | | | | | |
| EIP Share Rights | 19 Sep 2027 | 1 Jul 2021 | 1,463,883 | — | (731,942) | (731,941) | — |
| EIP Share Rights | 10 Nov 2027 | 1 Jul 2021 | 2,106,902 | — | (1,053,452) | (1,053,450) | — |
| EIP Share Rights | 14 Sep 2028 | 1 Jul 2022 | 3,726,976 | — | (931,745) | (931,743) | 1,863,488 |
| EIP Share Rights | 14 Nov 2028 | 1 Jul 2022 | 4,021,260 | — | (1,340,420) | (1,340,420) | 1,340,420 |
| EIP Share Rights | 12 Sep 2029 | 1 Jul 2023 | 7,694,385 | — | (1,282,399) | (1,282,396) | 5,129,590 |
| EIP Share Rights | 21 Nov 2029 | 1 Jul 2023 | 5,530,701 | — | (921,784) | (921,783) | 3,687,134 |
| EIP Share Rights | 30 Jun 2029 | 1 Jul 2024 | 13,905,530 | — | — | — | 13,905,530 |
| EIP Share Rights | 30 Jun 2030 | 1 Jul 2025 | — | 13,435,743 | — | — | 13,435,743 |
| **Non-Executive Director rights** [1] | | | | | | | |
| Director Share Rights | 30 Jun 2029 | 1 Jul 2024 | 1,361,431 | — | — | (849,447) | 511,984 |
| Director Share Rights | 30 Jun 2030 | 1 Jul 2025 | — | 1,257,675 | — | — | 1,257,675 |
| **Total** | | | **42,062,797** | **15,837,357** | **(6,500,450)** | **(7,505,641)** | **43,894,063** |

[1] Directors had the discretion to sacrifice up to 25% of their Base Directors Fees to earn share rights. These rights vested on 30 June of the Plan Year and may be exercised any time prior to the expiry date.

The rights do not entitle the holders to participate in any share issue of the Company or any other entity.

## 23. RESERVES

| | 2026 $'000 | 2025 Restated* $'000 |
|---|---|---|
| Share options reserve | 33,018 | 32,794 |
| Accumulated profits reserve | 8,380 | 8,380 |
| **Total Reserves** | **41,398** | **41,174** |

* See Note 2 for details regarding the restatement of prior year comparatives.

## 23. RESERVES (CONTINUED)

| MOVEMENTS | Share options reserve | Accumulated profits reserve [b] |
|---|---|---|
| | $'000 | $'000 |
| Balance at 1 July 2024 (Restated*) | 32,178 | 8,380 |
| Share based payments relating to employee incentive plans [a] | 619 | – |
| Transaction costs | (3) | – |
| **Balance at 30 June 2025 (Restated*)** | **32,794** | **8,380** |
| Share based payments relating to employee incentive plans [a] | 621 | – |
| Transaction costs | (4) | – |
| Cash settled employee rights | (393) | – |
| **Balance at 30 June 2026** | **33,018** | **8,380** |

* See Note 2 for details regarding the restatement of prior year comparatives.

(a) Share based payments are provided to employees under the Long Term Incentive Plan and Executive Incentive Plan. Refer to Note 34 and sections E, F and H of the Remuneration Report for further details of share-based payments.

(b) The accumulated profits reserve acts to quarantine profits of the Company generated in the current or prior periods.

## 24. ACCUMULATED LOSSES

| | 2026 $'000 | 2025 Restated* $'000 |
|---|---|---|
| Movements in accumulated losses were as follows: | | |
| Balance at the start of year | (199,522) | (206,255) |
| Net (loss)/profit for the year | (4,918) | 6,733 |
| Transfer of profits to accumulated profits reserve | – | – |
| **Balance at end of year** | **(204,440)** | **(199,522)** |

* See Note 2 for details regarding the restatement as a result of an error.

## 25. EARNINGS PER SHARE

| | | 2026 | 2025 Restated* |
|---|---|---|---|
| **(a)** | **Basic (loss)/earnings per share (cents)** | **(0.66)** | **0.91** |
| **(b)** | **Diluted (loss)/earnings per share (cents)** | **(0.66)** | **0.88** |
| **(c)** | **(Loss)/Profit used in earnings per share calculation** | | |
| | (Loss)/Profit attributed to ordinary equity holders ($'000) | **(4,918)** | **6,733** |
| **(d)** | **Weighted average number of ordinary shares** | | |
| | Weighted average number of shares used as the denominator in calculating basic (loss)/earnings per share | 750,280,703 | 743,955,980 |
| | Adjustments for the calculation of diluted (loss)/earnings per share: | | |
| | Employee share rights | – | 24,897,192 |
| | Weighted average number of shares used as the denominator in calculating diluted (loss)/earnings per share | **750,280,703** | **768,853,172** |

* See Note 2 for details regarding the restatement of prior year comparatives.

Rights on issue are considered to be potential ordinary shares and have not been included in the calculation of basic (loss)/earnings per share. In accordance with AASB 133, they are also excluded from the diluted loss per share calculation.

## 26. SEGMENT REPORTING

The Group has identified its operating segments based on the internal reports that are reviewed and used by the executive management team (the chief operating decision makers) in assessing performance and in determining the allocation of resources. The following operating segments are identified by management based on the nature of the business or venture.

### (a) Producing assets

Production and sale of crude oil, natural gas and associated petroleum products from fields that are in the production phase.

### (b) Development assets

Fields under development in preparation for the sale of petroleum products. There were no fields under development during the current or prior financial year.

### (c) Exploration assets

Exploration and evaluation of permit areas.

### (d) Unallocated items

Unallocated items comprise non-segmental items of revenue and expenses and associated assets and liabilities not allocated to operating segments as they are not considered part of the core operations of any segment.

### (e) Performance monitoring and evaluation

Management monitors the operating results of the operating segments separately for the purpose of making decisions about resource allocation and performance assessment. Non IFRS measures such as Earnings before interest, depreciation, amortisation and impairment (EBITDA) are also used by management. Refer to the following tables and reconciliations.

The Consolidated Entity's operations are wholly in one geographical location, being Australia.

## 26. SEGMENT REPORTING (CONTINUED)

### (e) Performance monitoring and evaluation (continued)

| **2026** | Producing Assets 2026 $'000 | Exploration Assets 2026 $'000 | Unallocated Items 2026 $'000 | Consolidation 2026 $'000 |
|---|---|---|---|---|
| **Revenue from contracts with customers** | | | | |
| Natural gas | 42,456 | – | – | 42,456 |
| Crude oil and condensate | 1,446 | – | – | 1,446 |
| Forfeited take or pay amounts | 845 | – | – | 845 |
| **Total revenue from contracts with customers** | **44,747** | – | – | **44,747** |
| Cost of sales | (29,716) | – | – | (29,716) |
| **Gross profit** | **15,031** | – | – | **15,031** |
| Other income | 173 | | 872 | 1,045 |
| Other expenses | (64) | – | (2) | (66) |
| Exploration expenditure | (2,693) | (8,877) | – | (11,570) |
| Finance costs | (3,640) | – | (594) | (4,234) |
| General and administrative expenses[1] | – | – | (5,124) | (5,124) |
| **Statutory profit / (loss) before income tax** | 8,807 | (8,877) | **(4,848)** | **(4,918)** |
| Taxes | – | – | – | – |
| **Statutory profit / (loss) for the year** | **8,807** | **(8,877)** | **(4,848)** | **(4,918)** |
| Add finance costs net of interest income | 3,467 | – | (274) | 3,193 |
| Add depreciation, amortisation and impairment | 6,517 | – | 572 | 7,089 |
| Add change in fair value of other financial liabilities | 64 | – | – | 64 |
| Add exploration expenditure | 2,693 | 8,877 | – | 11,570 |
| **EBITDAX[2]** | **21,548** | **–** | **(4,550)** | **16,998** |
| **Segment assets** | **78,304** | **15,730** | **23,655** | **117,689** |
| **Segment liabilities** | **(65,382)** | **(5,054)** | **(13,057)** | **(83,493)** |
| **Capital expenditure** | | | | |
| Property, plant and equipment | 5,132 | — | 379 | 5,511 |
| Intangibles | 60 | — | — | 60 |
| **Total capital expenditure** | **5,192** | **—** | **379** | **5,571** |

1 Includes share-based payments of $621,000 which is a non-cash item.
2 EBITDAX is earnings before interest, taxation, depreciation, amortisation, impairment and exploration expense.

## 26. SEGMENT REPORTING (CONTINUED)

| 2025 (Restated*) | Producing Assets 2025* $'000 | Exploration Assets 2025 $'000 | Unallocated Items 2025* $'000 | Consolidation 2025* $'000 |
|---|---|---|---|---|
| **Revenue from contracts with customers** | | | | |
| Natural gas | 38,944 | – | – | 38,944 |
| Crude oil and condensate | 3,407 | – | – | 3,407 |
| Forfeited take or pay amounts | 1,275 | – | – | 1,275 |
| **Total revenue from contracts with customers** | **43,626** | – | – | **43,626** |
| Cost of sales | (28,583) | – | – | (28,583) |
| **Gross profit** | **15,043** | – | – | **15,043** |
| Other income[1] | 1,549 | 16 | 926 | 2,491 |
| Other expenses | (725) | – | – | (725) |
| Exploration expenditure | (340) | (1,338) | – | (1,678) |
| Finance costs | (4,175) | – | (349) | (4,524) |
| General and administrative expenses[2] | – | – | (3,874) | (3,874) |
| **Statutory profit / (loss) before income tax** | **11,352** | **(1,322)** | **(3,297)** | **6,733** |
| Taxes | – | – | – | – |
| **Statutory profit / (loss) for the year** | **11,352** | **(1,322)** | **(3,297)** | **6,733** |
| Add finance costs net of interest income | 3,938 | – | (577) | 3,361 |
| Add depreciation, amortisation and impairment | 6,733 | – | 664 | 7,397 |
| Add change in fair value of other financial liabilities | 679 | – | – | 679 |
| Add exploration expenditure | 340 | 1,338 | – | 1,678 |
| **EBITDAX[3]** | **23,042** | **16** | **(3,210)** | **19,848** |
| **Segment assets** | **74,901** | **9,051** | **30,060** | **114,012** |
| **Segment liabilities** | **(58,234)** | **(3,285)** | **(13,065)** | **(74,584)** |
| **Capital expenditure** | | | | |
| Property, plant and equipment | 8,484 | – | 60 | 8,544 |
| Intangibles | 2 | – | – | 2 |
| **Total capital expenditure** | **8,486** | – | **60** | **8,546** |

1 Other Income attributable to the Producing Assets segment includes $1,233,000 relating to the sale of the Group's interest in land previously held by the Mereenie joint venture partners. (Refer Note 4(a)).
2 Includes share-based payments of $619,000 which is a non-cash item.
3 EBITDAX is earnings before interest, taxation, depreciation, amortisation, impairment and exploration expense.

* See Note 2 for details regarding the restatement of prior year comparatives.

## 26. SEGMENT REPORTING (CONTINUED)

| | 2026 $'000 | 2025 $'000 |
|---|---|---|
| Revenue from external customers by geographical location of production: | | |
| Australia | **44,747** | **43,626** |
| Non-current assets by geographical location: | | |
| Australia | **84,730** | **75,580** |

### (f) Major Customers

Customers with revenue exceeding 10% of the Group's total hydrocarbon sales revenue are shown below. Revenues from these customers are reported in the Producing Assets segment.

| | 2026 $'000 | % of Sales Revenue | 2025 $'000 | % of Sales Revenue |
|---|---|---|---|---|
| Largest customer | 32,807 | 73% | 25,513 | 58% |
| Second largest customer | 8,516 | 19% | 6,756 | 15% |

## 27. PARENT ENTITY INFORMATION

### (a) Summary financial information

The individual financial summary statements for the Parent Entity show the following aggregate amounts:

| | 2026 $'000 | 2025 Restated* $'000 |
|---|---|---|
| **Balance Sheet** | | |
| Current assets | 24,805 | 33,025 |
| Non-current assets | 13,751 | 19,754 |
| Total assets | 38,556 | 52,779 |
| Current liabilities | (24,691) | (18,315) |
| Non-current liabilities | (2,591) | (2,911) |
| Total liabilities | (27,282) | (21,226) |
| **Net assets** | **11,274** | **31,553** |
| ***Shareholders' equity*** | | |
| Issued capital | 197,638 | 197,776 |
| Treasury shares | (400) | – |
| Reserves | 41,398 | 41,174 |
| Accumulated losses | (227,362) | (207,397) |
| **Total equity** | **11,274** | **31,553** |
| **Loss for the year** | **(19,965)** | **(3,844)** |
| **Total comprehensive loss** | **(19,965)** | **(3,844)** |

* See Note 2 for details regarding the restatement of prior year comparatives.

## 27. PARENT ENTITY INFORMATION (CONTINUED)

### (b) Guarantees entered into by the Parent Entity

Guarantees have been provided by the Parent Entity to subsidiaries arising out of the course of ordinary operations.

A loan facility exists under which the Parent Entity and non-borrowing subsidiaries have provided guarantees to a financier in relation to the repayment of monies owing and other performance related obligations of the borrowing subsidiaries typical for a loan facility of this nature (Refer Note 19).

## 28. RELATED PARTY TRANSACTIONS

### (a) Parent Entity

The Parent Entity is Central Petroleum Limited.

### (b) Subsidiaries

The consolidated financial statements include the financial statements of Central Petroleum Limited and the subsidiaries listed in the following table:

| | | | Equity Holding | |
|---|---|---|---|---|
| Name of Entity | Place of Incorporation | Class of Shares | 2026 % | 2025 % |
| Merlin Energy Pty Ltd | Western Australia | Ordinary | 100 | 100 |
| Central Petroleum Projects Pty Ltd | Western Australia | Ordinary | 100 | 100 |
| Helium Australia Pty Ltd | Victoria | Ordinary | 100 | 100 |
| Ordiv Petroleum Pty Ltd | Western Australia | Ordinary | 100 | 100 |
| Frontier Oil & Gas Pty Ltd | Western Australia | Ordinary | 100 | 100 |
| Central Geothermal Pty Ltd | Western Australia | Ordinary | 100 | 100 |
| Central Petroleum Services Pty Ltd | Western Australia | Ordinary | 100 | 100 |
| Central Petroleum PVD Pty Ltd | Queensland | Ordinary | 100 | 100 |
| Central Petroleum (NT) Pty Ltd | Queensland | Ordinary | 100 | 100 |
| Jarl Pty Ltd | Queensland | Ordinary | 100 | 100 |
| Central Petroleum Mereenie Pty Ltd | Queensland | Ordinary | 100 | 100 |
| Central Petroleum Mereenie Unit Trust | N/A | Units | 100 | 100 |
| Central Petroleum WS (NO 1) Pty Ltd | Queensland | Ordinary | 100 | 100 |
| Central Petroleum WS (NO 2) Pty Ltd | Queensland | Ordinary | 100 | 100 |

### (c) Key management personnel compensation

| | 2026 $ | 2025 $ |
|---|---|---|
| Short-term employee benefits | 2,784,526 | 2,779,595 |
| Post-employment benefits | 154,305 | 157,374 |
| Long-term benefits | 54,667 | 57,175 |
| Share based payments | 590,587 | 637,376 |
| | **3,584,085** | **3,631,520** |

Detailed remuneration disclosures are provided in the Remuneration Report on pages 47 to 61.

## 29. DEED OF CROSS GUARANTEE

Central Petroleum Limited and its wholly owned subsidiary companies are parties to a deed of cross guarantee under which each company guarantees the debts of the others. By entering into the deed, the wholly-owned entities have been relieved from the requirement to prepare a financial report and Directors' Report under *ASIC Corporations (Wholly-owned Companies) Instrument 2016/785*.

The parties to the deed of cross guarantee are:

- Central Petroleum Limited
- Central Petroleum Projects Pty Ltd
- Ordiv Petroleum Pty Ltd
- Central Petroleum Services Pty Ltd
- Central Petroleum (NT) Pty Ltd
- Central Petroleum Mereenie Pty Ltd
- Central Petroleum WS (NO 2) Pty Ltd
- Merlin Energy Pty Ltd
- Helium Australia Pty Ltd
- Frontier Oil & Gas Pty Ltd
- Central Geothermal Pty Ltd
- Central Petroleum PVD Pty Ltd
- Jarl Pty Ltd
- Central Petroleum WS (NO 1) Pty Ltd

The above companies represent a 'closed group' for the purposes of the instrument, and as there are no other parties to the deed of cross guarantee that are controlled by Central Petroleum Limited, they also represent the 'extended closed group'.

### (a) Consolidated statement of comprehensive income and summary of movements in consolidated retained earnings

Set out below is a consolidated statement of profit or loss, a consolidated statement of comprehensive income and a summary of movements in consolidated retained earnings of the closed group for the year ended 30 June 2026.

| | 2026<br>$'000 | 2025<br>Restated*<br>$'000 |
|---|---|---|
| Revenue from the sale of goods | 20,418 | 19,596 |
| Cost of sales | (13,381) | (13,008) |
| Gross profit | 7,037 | 6,588 |
| Other income | 1,010 | 1,291 |
| Other expenses | (66) | (679) |
| Exploration expenses | (11,565) | (1,628) |
| Finance costs | (2,565) | (2,587) |
| General and administrative expenses | (4,636) | (3,362) |
| Loss before income tax | (10,785) | (377) |
| Income tax credit | 2,543 | 2,276 |
| (Loss)/profit for the year | (8,242) | 1,899 |
| Other comprehensive (loss)/profit for the year, net of tax | – | – |
| **Total comprehensive (loss)/profit for the year** | **(8,242)** | **1,899** |
| Accumulated losses at the beginning of the financial year | (217,324) | (219,223) |
| (Loss)/ profit for the year | (8,242) | 1,899 |
| **Accumulated losses at the end of the financial year** | **(225,566)** | **(217,324)** |

* See Note 2 for details regarding the restatement of prior year comparatives.

## 29. DEED OF CROSS GUARANTEE (CONTINUED)

### (b) Consolidated balance sheet of the closed group

| | 2026 $'000 | 2025 Restated* $'000 |
|---|---|---|
| **ASSETS** | | |
| **Current assets** | | |
| Cash and cash equivalents | 20,201 | 26,740 |
| Trade and other receivables | 5,620 | 6,201 |
| Inventories | 3,535 | 2,424 |
| Other current assets | 300 | – |
| Total current assets | 29,656 | 35,365 |
| **Non-current assets** | | |
| Property, plant and equipment | 26,188 | 23,567 |
| Right of use assets | 1,627 | 2,288 |
| Exploration assets | 13,841 | 7,674 |
| Other intangible assets | 134 | 176 |
| Other financial assets | 5,073 | 4,596 |
| Deferred Tax Assets | 6,320 | 5,592 |
| Goodwill | 1,953 | 1,953 |
| Total non-current assets | 55,136 | 45,846 |
| **Total assets** | **84,792** | **81,211** |
| **LIABILITIES** | | |
| **Current liabilities** | | |
| Trade and other payables | 9,184 | 2,018 |
| Deferred revenue | 992 | 992 |
| Borrowings | 3,839 | 7 |
| Lease liabilities | 401 | 351 |
| Other financial liabilities | 356 | – |
| Provisions | 8,354 | 7,966 |
| Total current liabilities | 23,126 | 11,334 |
| **Non-current liabilities** | | |
| Deferred revenue | 8,317 | 9,036 |
| Borrowings | 21,703 | 23,384 |
| Lease liabilities | 1,634 | 1,961 |
| Other financial liabilities | 532 | 722 |
| Provisions | 16,410 | 13,148 |
| Total non-current liabilities | 48,596 | 48,251 |
| **Total liabilities** | **71,722** | **59,585** |
| **Net assets** | **13,070** | **21,626** |
| **EQUITY** | | |
| Contributed equity | 197,638 | 197,776 |
| Treasury shares | (400) | – |
| Reserves | 41,398 | 41,174 |
| Accumulated losses | (225,566) | (217,324) |
| **Total equity** | **13,070** | **21,626** |

* See Note 2 for details regarding the restatement of prior year comparatives.

## 30. RECONCILIATION OF PROFIT AFTER INCOME TAX TO NET CASH FLOWS FROM OPERATING ACTIVITIES

| | 2026 $'000 | 2025 Restated* $'000 |
|---|---|---|
| **(Loss)/profit after income tax** | **(4,918)** | **6,733** |
| *Adjustments for:* | | |
| Depreciation and amortisation | 7,089 | 7,397 |
| Impairment | 5,869 | – |
| Loss/(profit) on disposal and write-off of non-current assets | 26 | (1,190) |
| Share-based payments | 621 | 619 |
| Cash settled share rights | (393) | – |
| Financing costs and interest (non-cash) | 4,028 | 2,698 |
| *Changes in assets and liabilities relating to operating activities:* | | |
| Increase in trade and other receivables | (66) | (1,898) |
| (Increase)/decrease in inventories | (1,095) | 151 |
| Increase in trade and other payables | 538 | 2,004 |
| Decrease in deferred revenue | (348) | (1,296) |
| Decrease in provisions | (1,007) | (914) |
| **Net cash flows from operating activities** | **10,344** | **14,304** |

* See Note 2 for details regarding the restatement of prior year comparatives.

## 31. CASH FLOW INFORMATION

### (a) Non-cash investing and financing activities

During the current year $2,148,000 of interest was added to the loan facility balance. During the prior year interest costs of $494,000 along with loan refinancing fees and expenses of $616,000 were added to the loan facility balance.

Non-cash investing and financing activities disclosed in other notes are:

- Acquisition of right of use assets – Note 13(a); and
- Rights issued to employees under short and long-term incentive plans – Note 34.

### (b) Net (debt)/cash reconciliation

This section provides an analysis of those liabilities for which cash flows have been or will be classified as financing activities in the Statement of Cash Flows. Cash balances included as current assets on the balance sheet are included as the Group considers these to form part of its net debt.

| Net (debt)/cash | 2026 $'000 | 2025 $'000 |
|---|---|---|
| Cash and cash equivalents | 20,410 | 27,471 |
| Other financial assets – cash on deposit as security for debt facility | 2,500 | 2,500 |
| Borrowings and leases – repayable within one year | (4,249) | (367) |
| Borrowings and leases – repayable after one year | (23,671) | (25,685) |
| **Net (debt)/cash** | **(5,010)** | **3,919** |
| Cash | 20,410 | 27,471 |
| Cash on deposit as security for debt facility | 2,500 | 2,500 |
| Gross Debt – fixed interest rates | (2,379) | (2,660) |
| Gross debt – variable interest rates | (25,541) | (23,392) |
| **Net (debt)/cash** | **(5,010)** | **3,919** |

## 31. CASH FLOW INFORMATION (CONTINUED)

### (b) Net (debt)/cash reconciliation (continued)

Movement in net cash

| | Other assets | | Liabilities from financing activities | | |
|---|---|---|---|---|---|
| | Cash $'000 | Cash on deposit $'000 | Borrowings $'000 | Leases $'000 | Total $'000 |
| **Net cash/(debt) 1 July 2024** | **24,985** | – | **(23,163)** | **(1,050)** | **772** |
| Cash flows | 2,486 | 2,500 | 1,180 | 534 | 6,700 |
| Amortisation of deferred borrowing costs | – | – | (292) | – | (292) |
| Non-cash adjustments | – | – | (1,116) | (2,145) | (3,261) |
| **Net cash/(debt) 30 June 2025** | **27,471** | **2,500** | **(23,391)** | **(2,661)** | **3,919** |
| Cash flows | (7,061) | – | – | 365 | (6,696) |
| Non-cash adjustments | – | – | (2,150) | (83) | (2,233) |
| **Net (debt)/cash 30 June 2026** | **20,410** | **2,500** | **(25,541)** | **(2,379)** | **(5,010)** |

## 32. CONTINGENCIES

**Acquisition of interests in exploration tenements**

In January 2026 Central acquired a 20% interest in PEP 169 in the Otway Basin. Under the terms of the acquisition the Group is required to make a contingent payment of $3,900,000 if a commercial discovery is made and notified by the Operator.

In January 2026 Central acquired a 49% in certain Retention Leases (PRLs) along with Exploration Permit PEL 677 in the Cooper Basin. Under the terms of the acquisition the Group is required to make a monthly royalty payment of 5% of the well head value of petroleum produced from the permit areas.

In accordance with the Group's accounting policy (Refer Note 1(p)) no liability is recognised until the outcome of exploration activities is known and the liability can be reliably measured.

## 33. COMMITMENTS

| | 2026 $'000 | 2025 $'000 |
|---|---|---|
| **(a) Capital commitments** | | |
| The Consolidated Entity has the following capital expenditure commitments: | | |
| The following amounts are due: | | |
| Within one year | 1,827 | 613 |
| | **1,827** | **613** |

| | 2026 $'000 | 2025 $'000 |
|---|---|---|
| **(b) Joint Venture exploration commitments** | | |
| The Consolidated Entity has contingent exploration expenditure commitments on various permit areas held through joint venture arrangements in Australia: | | |
| The following amounts are due: | | |
| Within one year | 21,435 | 9,150 |
| Later than one year but not later than three years | 8,568 | – |
| Later than three years but not later than five years | 650 | – |
| | **30,653** | **9,150** |

The value and timing of these commitments may be varied in the future as a result of renegotiations of the terms of exploration permits. In the petroleum industry it is common practice for entities to farm-out, transfer or sell a portion of their rights to third parties or relinquish (whole or part of the permit) and, as a result, obligations may be reduced or extinguished.

## 34. SHARE BASED PAYMENTS

The fair values of deferred share rights granted are valued using methodology that takes into account market and performance hurdles if applicable. The value of share rights with performance hurdles are calculated at the date of grant using a Black Scholes valuation model and Monte Carlo simulations. Other share rights are valued at the value of an equivalent ordinary share at the grant date.

### (a) Rights to shares — Short Term Incentive Plan

Under the Group's Short Term Incentive Plan, the Board may issue share rights in lieu of cash payments. No share rights were issued in respect of the Short Term Incentive Plan during the current or prior financial year.

### (b) Rights to shares — Non-Executive Directors Offer

Under the Non-Executive Director offers, Directors could agree to receive a maximum of 25% of their Base Fee in the form of Share Rights. By agreeing to the offer, the Directors agreed to waive any entitlement to receive cash fees to the extent of the value of the Share Rights granted. The Share Rights automatically vested on 30 June of the financial year. The following Non-Executive Director Share Rights movements occurred during the year:

| Grant Date | Plan Year End | Balance at Start of Year | Number of Rights Granted During the Year | Average Fair Value Per Right Granted | Exercised During the Year | Cancelled or Forfeited During the Year | Vested and exercisable at End of Year |
|---|---|---|---|---|---|---|---|
| **2026** | | | | | | | |
| 20 Nov 2025 | 30 Jun 2026 | — | 1,257,675 | $0.062 | — | — | 1,257,675 |
| 20 Nov 2024 | 30 Jun 2025 | 1,361,431 | — | $0.055 | (849,447) | — | 511,984 |
| 2025 | | | | | | | |
| 20 Nov 2024 | 30 Jun 2025 | — | 1,556,851 | $0.055 | — | (195,420) | 1,361,431 |
| 14 Nov 2023 | 30 Jun 2024 | 1,489,560 | — | $0.050 | (1,489,560) | — | — |

The weighted average remaining contractual life of outstanding Non-Executive Director share rights at the end of the year was 3.7 years (2025: 4.0 years).

### (c) Rights to shares — Executive Incentive Plans (EIP)

For plan years ended 30 June 2023 and 2024, Key Management Personnel were eligible to participate in the EIP, an integrated incentive plan with both short term and long term components. The value of the EIP that is awarded is determined at the end of the first 12-month performance period upon measurement of performance against Board established KPI targets for that year. The incentive awarded is then split into two components:

i) 33% is paid at that time (i.e. at the end of the initial 12-month performance period); and

ii) The 67% balance of the awarded incentive value is granted as Service Rights that vest over the next three years in equal tranches beginning 12-months after the end of the initial 12-month performance period.

The number of Service Rights awarded for any single Plan Year were determined by reference to Central's volume weighted average share price for the 20 trading days immediately following the release of Central's Quarterly Activity Statement for the performance period ending 30 June.

The EIP for FY2025 and FY2026 is made up of two components:

i) 20% is a short-term incentive based on achieving KPI targets during the initial 12 month performance period ending 30 June. Can be paid as cash or as Service Rights that vest at the end of the year following the initial performance period; and

ii) 80% is a long-term incentive with share-price based performance hurdles over a three-year performance period awarded as Performance Rights that only vest if the hurdles are achieved and subject to on-going employment.

The number of Service Rights awarded under the short-term incentive is determined by reference to Central's volume weighted average share price over the 20 trading days ending on 30 June at the end of the performance period.

The maximum number of Performance Rights available under the long-term incentive is based on the share price performance hurdles. The maximum number of Performance Rights were granted up front, but will only vest if share price performance hurdles are achieved, based on Central's volume weighted average share price over the 20 trading days ending on the last day of the three year performance period.

## 34. SHARE BASED PAYMENTS (CONTINUED)

### (c) Rights to shares — Executive Incentive Plan (EIP) (continued)

The following EIP movements occurred during the year:

| Grant Date | Plan Year End | Balance at Start of Year | Number of Rights Granted During the Year | Average Fair Value Per Right | Exercised During the Year | Cancelled | Balance at End of Year Vested and Exercisable | Total Yet to Vest |
|---|---|---|---|---|---|---|---|---|
| **2026** | | | | | | | | |
| 19 Sep 2022 | 30 Jun 2022 | 1,463,883 | – | $0.096 | (731,941) | (731,942) | – | – |
| 10 Nov 2022 | 30 Jun 2022 | 2,106,902 | – | $0.083 | (1,053,450) | (1,053,452) | – | – |
| 14 Sep 2023 | 30 Jun 2023 | 3,726,976 | – | $0.053 | (931,743) | (931,745) | 1,863,488 | – |
| 14 Nov 2023 | 30 Jun 2023 | 4,021,260 | – | $0.050 | (1,340,420) | (1,340,420) | 1,340,420 | – |
| 12 Sep 2024 | 30 Jun 2024 | 7,694,385 | – | $0.049 | (1,282,396) | (1,282,399) | 2,564,795 | 2,564,795 |
| 21 Nov 2024 | 30 Jun 2024 | 5,530,701 | – | $0.055 | (921,783) | (921,784) | 1,843,567 | 1,843,567 |
| 13 Sep 2024 | 30 Jun 2025 | 5,780,530 | – | $0.022 | – | – | – | 5,780,530 |
| 20 Nov 2024 | 30 Jun 2025 | 8,125,000 | – | $0.028 | – | – | – | 8,125,000 |
| 16 Sep 2025 | 30 Jun 2026 | – | 7,315,545 | $0.036 | – | – | – | 7,315,545 |
| 20 Nov 2025 | 30 Jun 2026 | – | 6,120,198 | $0.038 | – | – | – | 6,120,198 |
| Totals | | 38,449,637 | 13,435,743 | $0.046 | (6,261,733) | (6,261,742) | 7,612,270 | 31,749,635 |
| **2025** | | | | | | | | |
| 19 Sep 2022 | 30 Jun 2022 | 2,927,766 | – | $0.096 | (1,463,883) | – | 1,463,883 | – |
| 10 Nov 2022 | 30 Jun 2022 | 2,106,902 | – | $0.083 | – | – | 2,106,902 | – |
| 14 Sep 2023 | 30 Jun 2023 | 5,590,464 | – | $0.053 | (1,863,488) | – | 1,863,488 | 1,863,488 |
| 14 Nov 2023 | 30 Jun 2023 | 4,021,260 | – | $0.050 | – | – | 2,680,840 | 1,340,420 |
| 12 Sep 2024 | 30 Jun 2024 | – | 7,694,385 | $0.049 | – | – | 2,564,795 | 5,129,590 |
| 21 Nov 2024 | 30 Jun 2024 | – | 5,530,701 | $0.055 | – | – | 1,843,567 | 3,687,134 |
| 13 Sep 2024 | 30 Jun 2025 | – | 5,780,530 | $0.022 | – | – | – | 5,780,530 |
| 20 Nov 2024 | 30 Jun 2025 | – | 8,125,000 | $0.028 | – | – | – | 8,125,000 |
| Totals | | 14,646,392 | 27,130,616 | $0.046 | (3,327,371) | – | 12,523,475 | 25,926,162 |

The weighted average fair value of share rights issued to key management personnel under the EIP during the financial year was $0.037 (2025: $0.038). The weighted average remaining contractual life of outstanding Executive Incentive Plan share rights at the end of the year was 3.0 years (2025 3.8 years).

### (d) Rights to shares — Long Term Incentive Plans

Under the Group's Employee Rights Plan, eligible employees may receive rights to shares of Central Petroleum Limited. The rights are granted in respect of a plan year which commences 1 July each year. The share rights remain unvested for three years commencing from the start of each plan year. Except in limited circumstances, eligible employees must still be in the employment of Central Petroleum Limited as at the vesting date for the rights to vest.

Rights for participants in the fixed $1,000 Exempt Plan vest at the end of the three year service period.

Share based payment expense for the year includes amounts expensed in respect of the following number of rights either granted or expected to be granted:

## 34. SHARE BASED PAYMENTS (CONTINUED)

### (d) Rights to shares — Long-Term Incentive Plans (continued)

| Grant Date | Plan Year End | Balance at Start of Year | Issued During the Year | Average Fair Value Per Right | Exercised During the Year | Cancelled or Expired During the Year | Balance at End of Year |
|---|---|---|---|---|---|---|---|
| **2026** | | | | | | | |
| 17 Aug 2021 | 30 Jun 2022 | 24,588 | – | $0.105 | (16,392) | (8,196) | – |
| 22 Aug 2022 | 30 Jun 2022 | 12,537 | – | $0.090 | – | (12,537) | – |
| 22 Aug 2022 | 30 Jun 2023 | 402,046 | - | $0.090 | (371,932) | (16,906) | 13,208 |
| 11 Aug 2023 | 30 Jun 2023 | – | 6,137 | $0.051 | (6,137) | – | – |
| 11 Aug 2023 | 30 Jun 2024 | 800,390 | – | $0.051 | – | (107,037) | 693,353 |
| 19 Aug 2024 | 30 Jun 2024 | 47,303 | – | $0.054 | – | – | 47,303 |
| 19 Aug 2024 | 30 Jun 2025 | 964,865 | – | $0.054 | – | (61,568) | 903,297 |
| 12 Aug 2025 | 30 Jun 2025 | – | 45,610 | $0.062 | – | – | 45,610 |
| 12 Aug 2025 | 30 Jun 2026 | – | 1,092,192 | $0.062 | – | (32,464) | 1,059,728 |
| **Totals** | | **2,251,729** | **1,143,939** | | **(394,461)** | **(238,708)** | **2,762,499** |

The weighted average fair value of share rights granted under the Long-Term Incentive Plan during the year was $0.062 (2025: $0.054). The weighted average remaining contractual life of outstanding share rights at the end of the year was 3.1 years (2025: 3.2 years).

| Grant Date | Plan Year End | Balance at Start of Year | Issued During the Year | Average Fair Value Per Right | Exercised During the Year | Cancelled or Expired During the Year | Balance at End of Year |
|---|---|---|---|---|---|---|---|
| **2025** | | | | | | | |
| 24 Jul 2020 | 30 Jun 2021 | 100,363 | – | $0.065 | – | (100,363) | – |
| 24 Jul 2020 | 30 Jun 2021 | 11,337 | – | $0.089 | – | (11,337) | – |
| 17 Aug 2021 | 30 Jun 2022 | 286,860 | 16,392 | $0.105 | (270,468) | (8,196) | 24,588 |
| 22 Aug 2022 | 30 Jun 2022 | 45,356 | – | $0.090 | (23,912) | (8,907) | 12,537 |
| 22 Aug 2022 | 30 Jun 2023 | 448,009 | – | $0.090 | – | (45,963) | 402,046 |
| 11 Aug 2023 | 30 Jun 2024 | 932,501 | – | $0.051 | – | (132,111) | 800,390 |
| 13 Sep 2023 | 30 Jun 2024 | 32,049 | – | $0.059 | – | (32,049) | – |
| 19 Aug 2024 | 30 Jun 2024 | – | 54,926 | $0.054 | – | (7,623) | 47,303 |
| 19 Aug 2024 | 30 Jun 2025 | – | 1,052,580 | $0.054 | – | (87,715) | 964,865 |
| **Totals** | | **1,856,475** | **1,123,898** | | **(294,380)** | **(434,264)** | **2,251,729** |

No rights were granted to key management personnel under the Long-Term Incentive Plan during the current or prior financial year.

### (e) Expenses arising from share-based payment transactions

Total expenses arising from share-based transactions recognised during the year were:

| | 2026 $ | 2025 $ |
|---|---|---|
| Share Rights issued to employees | **621,489** | **618,820** |

## 35. FINANCIAL RISK MANAGEMENT

The Consolidated Entity's principal financial instruments are cash and short-term deposits. The Consolidated Entity also has other financial assets and liabilities such as trade receivables, trade payables and borrowings, which arise directly from its operations. The Consolidated Entity's risk management objective with regard to financial instruments and other financial assets include gaining interest income and the policy is to do so with a minimum of risk.

## 35. FINANCIAL RISK MANAGEMENT (CONTINUED)

The Group manages its exposure to key financial risks primarily through supervision by the Audit and Financial Risk Committee. One of the primary functions of this Committee is to assist the Board to fulfil its responsibility to exercise due care, diligence and skill with respect to the oversight and integrity of the management of financial risks and internal controls.

### (a) Credit Risk

The credit risk on financial assets of the Consolidated Entity which have been recognised in the balance sheet is generally the carrying amount, net of any provision for expected credit losses. The Group applies the simplified approach to providing for expected credit losses prescribed by AASB 9, which permits the use of the lifetime expected loss provision for all trade receivables. Under this method, determination of the loss allowance provision and expected loss rate incorporates past experience and forward-looking information, including the outlook for market demand, the current economic environment, and forward-looking interest rates. As the expected loss rate at 30 June 2026 is nil (2025: nil), no loss allowance provision has been recorded at 30 June 2026 (2025: nil).

The Consolidated Entity trades only with recognised banks and large customers where the credit risk is considered minimal.

Customer credit risk is managed in accordance with the Group's established policy, procedures and controls. Outstanding customer receivables are regularly monitored and relate to the Groups' customers for which there is no history of credit risk or overdue payments. An impairment analysis is performed at each reporting date on an individual basis for the major customers.

The aging of the Consolidated Entity's trade receivables at reporting date was:

| | Gross | | Expected Credit Loss Provision | |
|---|---|---|---|---|
| **TRADE RECEIVABLES** | 2026 $'000 | 2025 $'000 | 2026 $'000 | 2025 $'000 |
| Current: 0-30 days | 5,384 | 5,517 | – | – |
| | **5,384** | **5,517** | **–** | **–** |

The trade receivables at 30 June 2026 relate predominantly to oil and gas sales which have all been received subsequent to year end.

Credit risk also arises in relation to financial guarantees given by the Parent Entity and other non-borrowing Group entities to certain parties in respect of borrowings by other Group entities (refer Note 27(b)). Such guarantees are only provided in exceptional circumstances and are subject to specific Board approval.

### (b) Liquidity Risk

Prudent liquidity risk management implies maintaining sufficient cash, marketable securities and funding facilities. Management monitors rolling forecasts of the Group's liquidity reserve (comprising the undrawn borrowing facilities – Note 35(a)) and cash and cash equivalents (Note 8) based on expected cash flows. This is carried out at the Group level in accordance with practice and limits set by the Board of Directors. The Group's objective when managing capital is to safeguard the ability to continue as a going concern to ultimately add value for shareholders through the exploitation and production of hydrocarbon resources.

In addition, the Group's liquidity management policy involves projecting cash flows, monitoring balance sheet liquidity ratios and maintaining debt financing plans. In order to satisfy the capital requirements of the Group, the Company may issue new shares or other equity instruments.

## 35. FINANCIAL RISK MANAGEMENT (CONTINUED)

### (b) Liquidity Risk (continued)

The following are the contractual maturities of financial assets and liabilities:

| **2026 ($'000)** | ≤ 6 Months | 6–12 Months | 1–5 Years | ≥ 5 Years | Contractual Cash Flow | Carrying Amount |
|---|---|---|---|---|---|---|
| **Financial Assets** | | | | | | |
| Cash and cash equivalents | 20,410 | – | – | – | 20,410 | 20,410 |
| Trade and other receivables | 5,664 | – | – | – | 5,664 | 5,664 |
| Other financial assets | – | – | 5,926 | – | 5,926 | 5,926 |
| | **26,074** | **–** | **5,926** | **–** | **32,000** | **32,000** |
| **Financial Liabilities** | | | | | | |
| Trade and other payables | (6,086) | – | – | – | (6,086) | (6,086) |
| Interest bearing liabilities | (1,989) | (5,753) | (29,808) | (495) | (38,045) | (27,920) |
| Other financial liabilities | – | – | (1,058) | – | (1,058) | (888) |
| | **(8,075)** | **(5,753)** | **(30,866)** | **(495)** | **(45,189)** | **(34,894)** |

| 2025 ($'000) | ≤ 6 Months | 6–12 Months | 1–5 Years | ≥ 5 Years | Contractual Cash Flow | Carrying Amount |
|---|---|---|---|---|---|---|
| **Financial Assets** | | | | | | |
| Cash and cash equivalents | 27,471 | – | – | – | 27,471 | 27,471 |
| Trade and other receivables | 5,583 | – | – | – | 5,583 | 5,583 |
| Other financial assets | — | – | 5,416 | – | 5,416 | 5,416 |
| | **33,054** | **–** | **5,416** | **–** | **38,470** | **38,470** |
| **Financial Liabilities** | | | | | | |
| Trade and other payables | (5,175) | – | – | – | (5,175) | (5,175) |
| Interest bearing liabilities | (1,728) | (1,690) | (34,502) | (621) | (38,541) | (26,052) |
| Other financial liabilities | – | – | (980) | – | (980) | (722) |
| | (6,903) | (1,690) | (35,482) | (621) | (44,696) | (31,949) |

## 35. FINANCIAL RISK MANAGEMENT (CONTINUED)

### (c) Interest Rate Risk

The Consolidated Entity's exposure to interest rate risk, which is the risk that a financial instrument's value will fluctuate as a result of changes in market interest rates and the effective weighted average interest rates on classes of financial assets and financial liabilities, is as follows:

| | Weighted Average Effective Interest Rate | | Floating Interest Rate | | Fixed Interest | | Non-Interest-Bearing | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2026 % | 2025 % | 2026 $'000 | 2025 $'000 | 2026 $'000 | 2025 $'000 | 2026 $'000 | 2025 $'000 | 2026 $'000 | 2025 $'000 |
| **Financial Assets:** | | | | | | | | | | |
| Cash and cash equivalents | **4.4** | 3.8 | **12,410** | 27,471 | **8,000** | – | **–** | – | **20,410** | 27,471 |
| Trade and other receivables | **–** | – | **–** | – | **–** | – | **5,664** | 5,583 | **5,664** | 5,583 |
| Other financial assets | **2.1** | 2.5 | **–** | – | **3,100** | 3,103 | **2,826** | 2,313 | **5,926** | 5,416 |
| **Total Financial Assets** | | | **12,410** | 27,471 | **11,100** | 3,103 | **8,490** | 7,896 | **32,000** | 38,470 |
| **Financial Liabilities:** | | | | | | | | | | |
| Trade and other payables | **–** | – | **–** | – | **–** | – | **(6,086)** | (5,175) | **(6,086)** | (5,175) |
| Interest bearing liabilities | **12.4** | 11.6 | **(25,541)** | (23,391) | **(2,379)** | (2,661) | **–** | – | **(27,920)** | (26,052) |
| Other financial liabilities | – | – | – | – | – | – | **(888)** | (722) | **(888)** | (722) |
| **Total Financial Liabilities** | | | **(25,541)** | (23,391) | **(2,379)** | (2,661) | **(6,974)** | (5,897) | **(34,894)** | (31,949) |
| **Net Financial Assets / (Liabilities)** | | | **(13,131)** | 4,080 | **8,721** | 442 | **1,516** | 1,999 | **(2,894)** | 6,521 |

*Interest Rate Sensitivity*

A sensitivity of 50 basis points (0.5% pa) has been selected as this is considered a reasonable, scalable benchmark given the current level and volatility of both short term and long term interest rates. A movement in interest rates of 0.5% pa at the reporting date would have increased/(decreased) equity and profit and loss by the amounts shown below based on the average balance of interest-bearing financial instruments held. This analysis assumes that all other variables remain constant.

The analysis is performed only on those financial assets and liabilities with floating interest rates.

| | Profit or Loss | | Equity | |
|---|---|---|---|---|
| | 50 basis points increase in interest rates | 50 basis points decrease in interest rates | 50 basis points increase in interest rates | 50 basis points decrease in interest rates |
| **2026 ($'000)** | | | | |
| Cash and cash equivalents | 102 | (102) | — | — |
| Interest bearing liabilities | (128) | 128 | — | — |
| 2025 ($'000) | | | | |
| Cash and cash equivalents | 133 | (133) | — | — |
| Interest bearing liabilities | (117) | 117 | — | — |

These movements would not have any impact on equity other than retained earnings.

### (d) Commodity Risk

The majority of gas sales are made under long term contracts and as such do not contain any commodity risk for the duration of the contract. The Consolidated Entity is exposed to commodity price fluctuations in respect of recorded crude oil sales and gas sales which are not subject to long term fixed price contracts. The effect of potential fluctuations is not considered material to balances recorded in these financial statements. The Board's current policy is not to hedge crude oil sales. The Board will continue to monitor commodity price risk and take action to mitigate that risk if it is considered necessary in light of the Group's overall product sales mix and forecast cash flows.

## 35. FINANCIAL RISK MANAGEMENT (CONTINUED)

### (e) Financing Facilities

The Group has a loan facility agreement (Facility) with Macquarie Bank Limited (Macquarie).

The facility structured as a partially amortising term loan and has a maturity date of 31 December 2029. No principal repayments are required before 31 March 2027. There are no penalties for early repayment. Interest rates are re-priced quarterly based on fixed spreads over the periodic Bank Bill Swap (BBSY) average bid rate. The Group does not have any interest rate hedging arrangements in place.

An additional $17.5 million is undrawn at 30 June 2026 and is available until 31 December 2026, if required to fund development activity.

Under the terms of the Facility, the Group is required to comply with the following two key financial covenants:

1. The Group Current Ratio is at least 1:1, excluding amounts payable under the Facility.
2. The Net Present Value with a 10% discount rate (NPV10) of forecasted net cash flow from the Palm Valley, Dingo and Mereenie gas fields, limited to the sales of only Proved Developed Producing reserves, divided by the outstanding loan amount, must be greater than 1.3:1.

The Group remains compliant with these and all other financial covenants under the Facility.

### (f) Currency Risk

The Consolidated Entity's exposure to currency risk is limited due to its ongoing operations being in Australia and most associated contracts completed in Australian dollars. A foreign exchange risk arises from oil sales denominated in US dollars and from liabilities denominated in a currency other than Australian dollars. The Group generally does not undertake any hedging or forward contract transactions as the exposure is considered immaterial, however, individual transactions are reviewed for any potential currency risk exposure.

At reporting date, the Group had the following exposure to foreign currency risk for balances denominated in foreign currencies from its continuing operations, which are disclosed in Australian dollars:

| | 2026<br>$'000 | 2025<br>$'000 |
|---|---|---|
| Trade and other receivables (USD) | – | – |
| Trade and other payables: | | |
| - USD | (206) | (23) |
| - EUR | – | (9) |

The following table details the Group's Profit or Loss sensitivity to a 10% increase or decrease in the Australian dollar against the foreign currency, with all other variables held constant. The sensitivity analysis is based on the foreign currency risk exposure at the reporting date.

| | 2026<br>$'000 | 2025<br>$'000 |
|---|---|---|
| Australian dollar +10% movement in exchange rate | 19 | 3 |
| Australian dollar -10% movement in exchange rate | (23) | (4) |

These movements would not have any impact on equity other than retained earnings.

### (g) Fair Values

The carrying amounts of cash, cash equivalents, financial assets and financial liabilities, approximate their fair values. Borrowings are carried at amortised cost, but fair value is not deemed to be materially different from the carrying amount, as interest payable on the financing facilities reflects current market rates.

## 36. INTERESTS IN JOINT ARRANGEMENTS

Details of joint arrangements in which the Consolidated Entity has an interest are as follows:

| | Principal Activities | 2026 % | 2025 % |
|---|---|---|---|
| OL4, OL5 and PL2 - Mereenie | Oil & gas production | 25.00 | 25.00 |
| OL3 - Palm Valley | Gas production | 50.00 | 50.00 |
| L7 and PL30 - Dingo | Gas production | 50.00 | 50.00 |
| EP 82[1] | Oil & gas exploration | – | 60.00 |
| EP 112[2] | Oil & gas exploration | – | 45.00 |
| EP 125 | Oil & gas exploration | 30.00 | 30.00 |
| EPA 111 | Oil & gas exploration – application | 50.00 | 50.00 |
| EPA 124 | Oil & gas exploration – application | 50.00 | 50.00 |
| PEP 169[3] | Oil & gas exploration | 20.00 | – |
| PEL 677[3] and various PRL's[3,4] | Oil & gas exploration | 49.00 | – |

1 Central withdrew from the EP82 Joint Venture on 19 December 2025
2 Central withdrew from the EP112 joint venture on 6 May 2026
3 Effective from 23 January 2026
4 PRLs 50-59,61,63,65-72,74,75,124 and 248 in the South Australia Cooper Basin

Accounting for the Joint Arrangements is based on contributions made to the Joint Operated Arrangements on an accruals basis. The principal place of business is Australia.

## 36. INTERESTS IN JOINT ARRANGEMENTS (CONTINUED)

The share in the assets and liabilities of the joint arrangements where less than 100% interest is held by the Company are included in the Consolidated Entity's balance sheet in accordance with the accounting policy described in Note 1(b)(ii) under the following classifications:

| | 2026<br>$'000 | 2025<br>$'000 |
|---|---|---|
| **Current assets** | | |
| Cash and cash equivalents | 1,249 | 1,449 |
| Trade and other receivables | 4,288 | 4,932 |
| Inventory | 4,488 | 3,393 |
| Total current assets | 10,025 | 9,774 |
| **Non-current assets** | | |
| Property, plant and equipment | 53,641 | 50,200 |
| Right of use assets | 317 | 376 |
| Total non-current assets | 53,958 | 50,576 |
| **Current liabilities** | | |
| Trade and other payables | 3,956 | 3,962 |
| Lease liabilities | 13 | 12 |
| Deferred revenue | 1,362 | 992 |
| Provision for production over-lift | – | 653 |
| Restoration provision | 404 | 454 |
| Total current liabilities | 5,735 | 6,073 |
| **Non-current liabilities** | | |
| Deferred revenue | 8,317 | 9,036 |
| Lease liabilities | 387 | 393 |
| Restoration provision | 26,185 | 19,685 |
| Total non-current liabilities | 34,889 | 29,114 |
| **Net assets** | **23,359** | **25,163** |
| **Joint arrangement contribution to profit before tax** | | |
| Revenue | 44,747 | 43,626 |
| Other income | 79 | 1,460 |
| Expenses | (34,727) | (30,960) |
| **Profit before income tax** | **10,099** | **14,126** |

## 37. EVENTS OCCURRING AFTER THE REPORTING PERIOD

No other matters or circumstances have arisen between 30 June 2026 and the date of this report that will affect the Group's operations, result or state of affairs, or may do so in future years.

# CONSOLIDATED ENTITY DISCLOSURE STATEMENT

## AS AT 30 JUNE 2026

This consolidated entity disclosure statement (CEDS) has been prepared in accordance with the Corporations Act 2001 and includes information for each entity that was part of the consolidated entity as at the end of the financial year in accordance with AASB 10 Consolidated Financial Statements

| NAME OF ENTITY | TYPE OF ENTITY | TRUSTEE, PARTNER OR PARTICIPANT IN JV | % OF SHARE CAPITAL | PLACE OF BUSINESS / COUNTRY OF INCORPORATION | AUSTRALIAN RESIDENT OR FOREIGN RESIDENT |
|---|---|---|---|---|---|
| Central Petroleum Limited | Body corporate | – | 100 | Australia | Australian |
| Merlin Energy Pty Ltd[1] | Body corporate | – | 100 | Australia | Australian |
| Central Petroleum Projects Pty Ltd | Body corporate | – | 100 | Australia | Australian |
| Helium Australia Pty Ltd | Body corporate | – | 100 | Australia | Australian |
| Ordiv Petroleum Pty Ltd[1] | Body corporate | – | 100 | Australia | Australian |
| Frontier Oil & Gas Pty Ltd | Body corporate | – | 100 | Australia | Australian |
| Central Geothermal Pty Ltd[1] | Body corporate | – | 100 | Australia | Australian |
| Central Petroleum Services Pty Ltd | Body corporate | – | 100 | Australia | Australian |
| Central Petroleum PVD Pty Ltd | Body corporate | – | 100 | Australia | Australian |
| Central Petroleum (NT) Pty Ltd[1] | Body corporate | – | 100 | Australia | Australian |
| Jarl Pty Ltd | Body corporate | – | 100 | Australia | Australian |
| Central Petroleum Mereenie Pty Ltd | Body corporate | Trustee | 100 | Australia | Australian |
| Central Petroleum Mereenie Unit Trust[1] | Trust | – | 100 | Australia | Australian |
| Central Petroleum WS (NO 1) Pty Ltd | Body corporate | – | 100 | Australia | Australian |
| Central Petroleum WS (NO 2) Pty Ltd[1] | Body corporate | – | 100 | Australia | Australian |

[1] These entities are participants in unincorporated joint ventures with third parties not included within the consolidated entity.

# DIRECTORS' DECLARATION

1. In the Directors' opinion:

   a) the financial statements and notes set out on pages 64 to 114 of the Consolidated Entity are in accordance with the *Corporations Act 2001* (Cth), including:

      (i) complying with Accounting Standards, the *Corporations Regulations 2001* (Cth) and other mandatory professional reporting requirements, and

      (ii) giving a true and fair view of the Consolidated Entity's financial position as at 30 June 2026 and of its performance for the financial year ended on that date;

   b) there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable;

   c) the consolidated entity disclosure statement on page 115 is true and correct; and

   d) the financial statements comply with the International Financial Reporting Standards as issued by the International Accounting Standards Board as disclosed in Note 1(a).

2. This declaration has been made after receiving the declarations required to be made to the Directors in accordance with section 295A of the *Corporations Act 2001* (Cth) for the financial year ended 30 June 2026.

3. As at the date of this declaration, there are reasonable grounds to believe that the members of the Closed Group identified in Note 29 will be able to meet any obligations or liabilities to which they are or may become subject by virtue of the Deed of Cross Guarantee between the Company and those members of the Closed Group pursuant to ASIC Corporations (Wholly owned Companies) Instrument 2016/785.

This declaration is made in accordance with a resolution of the Directors of Central Petroleum Limited:

**Agu Kantsler**
Director
Brisbane

17 September 2026

# Independent auditor's report

To the members of Central Petroleum Limited

## Report on the audit of the financial report

### Our opinion

In our opinion, the accompanying financial report of Central Petroleum Limited (the Company) and its controlled entities (together the Group) is in accordance with the *Corporations Act 2001*, including:

a) giving a true and fair view of the Group's financial position as at 30 June 2026 and of its financial performance for the year then ended; and

b) complying with Australian Accounting Standards and the *Corporations Regulations 2001*.

**What we have audited**

The financial report comprises:

- the consolidated balance sheet as at 30 June 2026;
- the consolidated statement of comprehensive income for the year then ended;
- the consolidated statement of changes in equity for the year then ended;
- the consolidated statement of cash flows for the year then ended;
- the notes to the consolidated financial statements, including material accounting policy information and other explanatory information;
- the consolidated entity disclosure statement as at 30 June 2026; and
- the directors' declaration.

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## Basis for opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial report* section of our report.

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

### Independence

We are independent of the Group in accordance with the auditor independence requirements of the *Corporations Act 2001* and the ethical requirements of the Accounting Professional & Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants (including Independence Standards)* (the Code) that are relevant to audits of the financial report of public interest entities in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

## Our audit approach

An audit is designed to provide reasonable assurance about whether the financial report is free from material misstatement. Misstatements may arise due to fraud or error. They are considered material if individually or in aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial report.

We tailored the scope of our audit to ensure that we performed enough work to be able to give an opinion on the financial report as a whole, taking into account the geographic and management structure of the Group, its accounting processes and controls and the industry in which it operates.

### Audit Scope

Our audit focused on where the Group made subjective judgements; for example, significant accounting estimates involving assumptions and inherently uncertain future events.

In establishing the overall approach to the group audit, we determined the type of work that needed to be performed by us, as the group auditor.

pwc

**Key audit matters**

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial report for the current period. The key audit matters were addressed in the context of our audit of the financial report as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters. Further, any commentary on the outcomes of a particular audit procedure is made in that context. We communicated the key audit matter to the Audit and Financial Risk Committee.

| Key audit matter | How our audit addressed the key audit matter |
|---|---|
| **Carrying value of exploration assets**<br>Refer to Note 1(p) and Note 14 of the financial report<br><br>The Group assesses the recoverability of the carrying value of capitalised exploration and evaluation assets at each reporting date (or during the year should the need arise).<br><br>In completing this assessment, regard is given to the currency of the right of tenure over the area of interest, the Group's intentions with respect to proposed future exploration and development plans for the area of interest, and to the success or otherwise of activities undertaken in the area of interest.<br><br>Exploration and evaluation activities that have not yet reached a stage that permits reasonable assessment of the existence of economically recoverable reserves may be subject to impairment in the future.<br><br>We considered management's indicator assessment to be a key audit matter given:<br>• the significance of the exploration and evaluation assets to the consolidated balance sheet;<br>• the judgement involved in accounting for the $5.9m impairment on withdrawal from two joint venture permits; and<br>• the $12m capitalised on the acquisition of two new permits during the year. | We performed the following procedures, amongst others:<br>• inquired with key operational and finance staff to develop an understanding of the current status and future intention for each area of interest;<br>• obtained and read relevant support including internal and external documents for current and future intentions for each area of interest;<br>• considered whether areas of interest that remain capitalised are included in future budgets and/or operational plans of the Group;<br>• obtained licence expiry dates of the areas of interest to assess whether there were any areas where the Group's right to explore are under renewal or either at, or close to, expiry;<br>• inspected the signed notices of withdrawal and the operator's acceptance for the permits from which the Group withdrew as a joint venture party, and assessed the basis for the resulting $5.9m impairment;<br>• for newly acquired permits, agreed the amounts capitalised to the underlying sale and purchase agreements and supporting documentation, and also assessed the accounting for the deferred / contingent consideration; and<br>• evaluated the reasonableness of the disclosures made in the notes to the consolidated financial statements in light of the requirements of Australian Accounting Standards. |

## Other information

The directors are responsible for the other information. The other information comprises the information included in the annual report for the year ended 30 June 2026, but does not include the financial report and our auditor's report thereon.

Our opinion on the financial report does not cover the other information and accordingly we do not express any form of assurance conclusion thereon through our opinion on the financial report. We have issued a separate opinion on the remuneration report. We have issued a separate review conclusion on specified Sustainability Disclosures within the Sustainability Report, in accordance with the scope of Australian Standard on Sustainability Assurance ASSA 5010 *Timeline for Audits and Reviews of Information in Sustainability Reports under the Corporations Act 2001*.

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

If, based on the work we have performed on the other information that we obtained prior to the date of this auditor's report, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

## Responsibilities of the directors for the financial report

The directors of the Company are responsible for the preparation of the financial report in accordance with Australian Accounting Standards and the *Corporations Act 2001*, including giving a true and fair view, and for such internal control as the directors determine is necessary to enable the preparation of the financial report that is free from material misstatement, whether due to fraud or error.

In preparing the financial report, the directors are responsible for assessing the ability of the Group to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the Group or to cease operations, or have no realistic alternative but to do so.

## Auditor's responsibilities for the audit of the financial report

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

A further description of our responsibilities for the audit of the financial report is located at the Auditing and Assurance Standards Board website at: https://auasb.gov.au/media/bwvjcgre/ar1_2024.pdf. This description forms part of our auditor's report.

## Report on the remuneration report

### Our opinion on the remuneration report

We have audited the remuneration report included in the directors' report for the year ended 30 June 2026.

In our opinion, the remuneration report of Central Petroleum Limited for the year ended 30 June 2026 complies with section 300A of the *Corporations Act 2001*.

### Responsibilities

The directors of the Company are responsible for the preparation and presentation of the remuneration report in accordance with section 300A of the *Corporations Act 2001*. Our responsibility is to express an opinion on the remuneration report, based on our audit conducted in accordance with Australian Auditing Standards.

PricewaterhouseCoopers

PricewaterhouseCoopers

Michael Crowe

Michael Crowe
Partner

Brisbane
17 September 2026

# ASX ADDITIONAL INFORMATION

## DETAILS OF QUOTED SECURITIES AS AT 14 SEPTEMBER 2026

### Top holders

The 20 largest registered holders of the quoted securities as at 14 September 2026 were:

| | NAME | NO. OF SHARES | % |
|---|---|---|---|
| 1 | Norfolk Enchants Pty Ltd <Trojan Retirement Fund A/c> | 48,608,932 | 6.48 |
| 2 | Maitri Pty Ltd <Coci Super Fund A/C> | 43,992,654 | 5.86 |
| 3 | Mr Kenneth John Beer + Mr Alexander Charles Beer <Beer Super Fund A/C> | 27,798,066 | 3.70 |
| 4 | Brazil Farming Pty Ltd | 17,785,209 | 2.37 |
| 5 | BNP Paribas Nominees Pty Ltd <IB AU Noms Retailclient> | 16,675,810 | 2.22 |
| 6 | Moranbah Nominees Pty Ltd <Chris Wallin Super Fund A/C> | 14,830,642 | 1.98 |
| 7 | Macquarie Bank Limited <Metals Mining and AG A/C> | 14,166,667 | 1.89 |
| 8 | JH Nominees Australia Pty Ltd <Harry Family Super Fund A/C> | 13,000,000 | 1.73 |
| 9 | Careniup Pty Ltd <Mathis Super Fund A/c> | 12,778,223 | 1.70 |
| 10 | Citicorp Nominees Pty Limited | 12,473,820 | 1.66 |
| 11 | Mr Philip Gasteen <Thrushton Investment A/C> | 12,373,780 | 1.65 |
| 12 | Mr Leon Goss Devaney | 8,050,721 | 1.07 |
| 13 | Kensington Capital Partners Pty Ltd | 8,000,000 | 1.07 |
| 14 | ITA Vero Pty Ltd <The Richmond A/c) | 7,470,849 | 1.00 |
| 15-16 | Garmi Holdings Pty Ltd <Pemco Super Fund A/c> | 7,000,000 | 0.93 |
| 15-16 | PA and RE Gibson Pty Ltd <PA&RE Gibson Super Fund A/C> | 7,000,000 | 0.93 |
| 17 | CPU Share Plans <CTP Est Unallocated A/C> | 6,076,280 | 0.81 |
| 18 | Chembank Pty Limited <CABAC Super Fund A/c> | 6,000,000 | 0.80 |
| 19 | Mr Donald Leonard Cottee | 5,830,594 | 0.78 |
| 20 | T H XX Holdings Pty Ltd <Hutton Super Fund A/c> | 5,413,458 | 0.72 |
| | **Total** | **295,325,705** | **39.35** |

## DISTRIBUTION SCHEDULE

A distribution schedule of the number of holders in each class of equity securities as at 14 September 2026 was:

| SIZE OF HOLDING | LISTED FULLY PAID SHARES | UNLISTED SHARE RIGHTS |
|---|---|---|
| **1 – 1,000** | 128 | - |
| **1,001 – 5,000** | 225 | - |
| **5,001 – 10,000** | 476 | 1 |
| **10,001 – 100,000** | 1,838 | 55 |
| **100,001 – Over** | 726 | 6 |
| **Total** | **3,393** | **62** |

## UNLISTED SECURITIES

At 14 September 2026, there were 28,116,040 unlisted share rights on issue.

## SUBSTANTIAL SHAREHOLDERS

Substantial shareholders as disclosed by notices received by the Company as at 14 September 2026 with holdings of 5% or more of the total votes attached to the voting shares or interests in the Entity:

| HOLDER | UNITS |
|---|---|
| **Troy Harry** | 66,736,902 |
| **Maitri Pty Ltd <Coci Super Fund A/c>** | 37,745,627 |

## UNMARKETABLE PARCELS

Holdings less than a marketable parcel of ordinary shares (being 7,693 shares as at 14 September 2026):

| HOLDERS | UNITS |
|---|---|
| **479** | 1,505,841 |

## VOTING RIGHTS

Subject to any rights or restrictions for the time being attached to any class or classes of shares, at meetings of shareholders or classes of shareholders:

- each shareholder entitled to vote may vote in person or by proxy, attorney or representative of a shareholder;
- on a show of hands, every person present who is a shareholder or a proxy, attorney or representative of a shareholder has one vote; and
- on a poll, every person present who is a shareholder shall, in respect of each fully paid share held by him, or in respect of which he is appointed a proxy, attorney or representative, have one vote for their share, but in respect of partly paid shares, shall have such number of votes being equivalent to the proportion which the amount paid (not credited) is of the total amounts paid and payable in respect of those shares (excluding amounts credited).

## ON-MARKET BUY-BACK

An on-market buy-back of the Company's securities commenced on 17 November 2025 and is proposed to end on 13 November 2026.

## ANNUAL GENERAL MEETING

Central Petroleum Limited advises that the Annual General Meeting (AGM) of the Company is scheduled for 19 November 2026. Details of the meeting will be provided at a later date. Further to Listing Rule 3.13.1, Listing Rule 14.3 and the Company's Constitution, nomination for election of directors at the AGM must be received not less than 35 business days before the meeting, being not later than 29 September 2026.

# CORPORATE GOVERNANCE STATEMENT

Central Petroleum Limited and its Board are committed to achieving and demonstrating high standards of corporate governance. The Company has reviewed its corporate governance practices against the Corporate Governance Principles and Recommendations (4th edition) published by the ASX Corporate Governance Council.

The 2026 Corporate Governance Statement reflects the corporate governance practices in place throughout the 2026 financial year. The Company's Corporate Governance Statement undergoes periodic review by the Board. A description of the Group's current corporate governance practices is set out in the Group's Corporate Governance Statement which can be viewed at www.centralpetroleum.com.au/about/corporate-governance/.

# INTERESTS IN PETROLEUM PERMITS AND PIPELINE LICENCES

AT THE DATE OF THIS REPORT

## PERMITS AND LICENCES GRANTED

| | | | CTP Consolidated Entity | | Other JV Participants | |
|---|---|---|---|---|---|---|
| Tenement | Location | Operator | Registered Interest (%) | Beneficial Interest (%) | Participant Name | Beneficial Interest (%) |
| EP82 (excl. EP82 Sub-Blocks) [1] | Amadeus Basin NT | Santos | 60 | 0 | Santos QNT Pty Ltd ("Santos") | 100 |
| EP82 Sub-Blocks | Amadeus Basin NT | Central | 0 | 100 | | |
| EP112 [2] | Amadeus Basin NT | Santos | 45 | 0 | Santos | 100 |
| EP115 | Amadeus Basin NT | Central | 100 | 100 | | |
| EP125 | Amadeus Basin NT | Santos | 30 | 30 | Santos | 70 |
| OL3 (Palm Valley) | Amadeus Basin NT | Central | 50 | 50 | Echelon Palm Valley Pty Ltd<br>Cue Palm Valley Pty Ltd | 35<br>15 |
| OL4 (Mereenie) | Amadeus Basin NT | Central | 25 | 25 | Echelon Mereenie Pty Ltd<br>Horizon Australia Energy Pty Ltd<br>Cue Mereenie Pty Ltd | 42.5<br>25<br>7.5 |
| OL5 (Mereenie) | Amadeus Basin NT | Central | 25 | 25 | Echelon Mereenie Pty Ltd<br>Horizon Australia Energy Pty Ltd<br>Cue Mereenie Pty Ltd | 42.5<br>25<br>7.5 |
| L6 (Surprise) | Amadeus Basin NT | Central | 100 | 100 | | |
| L7 (Dingo) | Amadeus Basin NT | Central | 50 | 50 | Echelon Dingo Pty Ltd<br>Cue Dingo Pty Ltd | 35<br>15 |
| RL3 (Ooraminna) | Amadeus Basin NT | Central | 100 | 100 | | |
| RL4 (Ooraminna) | Amadeus Basin NT | Central | 100 | 100 | | |
| PEP 169[3] | Otway Basin | ADZ Energy (Victoria) Pty Ltd | 20 | 20 | ADZ Energy (Victoria) Pty Ltd | 80 |
| PEL 677[3] | Cooper Basin SA | Cordillo Energy Pty Ltd ("Cordillo") | 0 | 49 | Cordillo | 51 |
| PRLs 50-59,61,63,65-72,74,75,124,248[3] | Cooper Basin SA | Cordillo Energy Pty Ltd ("Cordillo") | 0 | 49 | Cordillo | 51 |

## PERMITS AND LICENCES UNDER APPLICATION

| | | | CTP Consolidated Entity | | Other JV Participants | |
|---|---|---|---|---|---|---|
| Tenement | Location | Operator | Registered Interest (%) | Beneficial Interest (%) | Participant Name | Beneficial Interest (%) |
| EPA92 | Wiso Basin NT | Central | 100 | 100 | | |
| EPA111 | Amadeus Basin NT | Santos | 50 | 50 | Santos | 50 |
| EPA124 | Amadeus Basin NT | Santos | 50 | 50 | Santos | 50 |
| EPA129 | Wiso Basin NT | Central | 100 | 100 | | |
| EPA130 | Pedirka Basin NT | Central | 100 | 100 | | |
| EPA132 | Georgina Basin NT | Central | 100 | 100 | | |
| EPA133 | Amadeus Basin NT | Central | 100 | 100 | | |
| EPA137 | Amadeus Basin NT | Central | 100 | 100 | | |
| EPA147 | Amadeus Basin NT | Central | 100 | 100 | | |
| EPA149 | Amadeus Basin NT | Central | 100 | 100 | | |
| EPA152 | Amadeus Basin NT | Central | 100 | 100 | | |
| EPA160 | Wiso Basin NT | Central | 100 | 100 | | |
| EPA296 | Wiso Basin NT | Central | 100 | 100 | | |

Notes:

[1] As announced on 19 December 2025, Central provided notice of its withdrawal from the EP82 Joint Venture with Santos

[2] As announced on 6 May 2026, Central provided notice of its withdrawal from the EP112 Joint Venture with Santos

[3] As announced on 27 January 2026, Central completed the acquisition of interests in exploration permits in the onshore Otway Basin (PEP 169) from ADZ Energy (Victoria) Pty Ltd and Cooper Basin (PRLs 50 - 59, 61, 63, 65 - 72, 74, 75, 124, 248, and PEL 677) from Cordillo Energy Pty Ltd (both subsidiaries of ADZ Energy Pty Ltd). Central is progressing the approval and registration process to have legal interests in the Cooper Basin permits transferred.

## PIPELINE LICENCES

| Pipeline Licence | Location | Operator | CTP Consolidated Entity | | Other JV Participants | |
|---|---|---|---|---|---|---|
| | | | Registered Interest (%) | Beneficial Interest (%) | Participant Name | Beneficial Interest (%) |
| PL2 | Amadeus Basin NT | Central | 25 | 25 | Echelon Mereenie Pty Ltd | 42.5 |
| | | | | | Horizon Australia Energy Pty Ltd | 25.0 |
| | | | | | Cue Mereenie Pty Ltd | 7.5 |
| PL30 | Amadeus Basin NT | Central | 50 | 50 | Echelon Dingo Pty Ltd | 35 |
| | | | | | Cue Dingo Pty Ltd | 15 |

# GLOSSARY AND ABBREVIATIONS

| | |
|---|---|
| 1P | Proved reserves* |
| 2C | Best estimate contingent resources* |
| 2P | Proved and probable reserves* |
| AEMO | Australian Energy Market Operator |
| Bbl | barrel of oil (unit of measure) |
| Bcf | billion cubic feet |
| Bopd | barrel of oil per day |
| $CO_2e$ | Carbon dioxide equivalent |
| CPI | Consumer Price Index |
| EBIT | Earnings before interest and tax |
| EBITDA | Earnings before interest, tax, depreciation, amortisation and impairment |
| EBITDAX | Earnings before interest, tax, depreciation, amortisation and exploration costs |
| EIP | Executive incentive plan |
| GJ | Gigajoule (1 billion joules) (unit of energy measure) |
| GJe | Gigajoule equivalent (oil converted at 5.816 GJe / bbl) |
| GSA | Gas sale agreement |
| IAE | International Energy Agency |
| IFRS | International Financial Reporting Standards |
| KMP | Key management personnel |
| KPI | Key performance indicator |
| LTIP | Long term incentive plan |
| Mcfd | Thousand cubic feet per day |
| mmbbl | Million barrels |
| NGER | National Greenhouse and Energy Reporting Scheme |
| NGP | Northern Gas Pipeline |
| NT | Northern Territory |
| PJ | Petajoules (1,000 TJ) (unit of energy measure) |
| PJe | Petajoule equivalent (oil converted at 5.816 PJe / mmbbl) |
| scfd | Standard cubic feet per day |
| STIP | Short term incentive plan |
| TFR | Total fixed remuneration |
| TJ | Terajoule (1,000 GJ) (unit of energy measure) |
| TJ/d | Terajoules per day |
| Tcf | Trillion cubic feet (unit of measure) |

* As defined by Petroleum Resources Management System (PRMS) 2018 published by the Society of Petroleum Engineers.

# CORPORATE DIRECTORY

## CENTRAL PETROLEUM LIMITED

ABN 72 083 254 308

### DIRECTORS

Dr Agu Kantsler PhD, BSc (Hons), FTSE, GAICD, Independent Non-Executive Director, Chair
Mr Leon Devaney BSc MBA, Managing Director and Chief Executive Officer
Mr Stephen Gardiner BEc (Hons), Fellow - CPA Australia, Independent Non-Executive Director
Ms Katherine Hirschfeld AM, BE(Chem) HonDEng UQ, HonFIEAust, FTSE, FIChemE, FAICD, Independent Non-Executive Director

### GROUP GENERAL COUNSEL AND COMPANY SECRETARY

Mr Daniel White LLB, BCom, LLM

### REGISTERED OFFICE

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### STOCK EXCHANGE LISTING

Central Petroleum Limited shares are listed on the Australian Securities Exchange under the code CTP.