Central Petroleum

2025

ANNUAL REPORT

Central Petroleum Limited

ACN 083 254 308

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CHAIR’S LETTER

Dear Shareholders,

I am pleased to present this Annual Report as Chair of Central Petroleum, marking a pivotal year of measurable progress and execution. The past twelve months have provided clear evidence that the deliberate actions taken in recent years are beginning to deliver tangible results for our company and our shareholders.

Operating in the Northern Territory has always required resilience and ingenuity due to its remote location and unique market characteristics. In response to recent challenges—including sporadic closures of the Northern Gas Pipeline—we acted swiftly to secure long-term sales agreements that underpin stable domestic supply and largely mitigate market risks.

The positive impact of these new gas contracts, especially those established with the Northern Territory Government, is already evident across our operations. These agreements have not only strengthened our revenue base and balance sheet but also delivered certainty that enables strategic reinvestment. Our underlying profit of $6.5 million—an impressive turnaround from last year’s $1.4 million underlying loss—reflects the effectiveness of these initiatives as contract deliveries commenced in the second half of the year.

This improved financial position has supported investments in two new production wells at Mereenie and facilitated the extension and restructuring of our debt facility. In addition, we anticipate repaying the full balance of our overlifted gas by May 2026, which will significantly increase cash flow in FY2027 and beyond.

Despite these advances, our improved outlook is not yet fully reflected in our share price. Accordingly, we intend to capitalise on any share price weakness by initiating a share buy-back program, our first shareholder return.

Looking ahead, our production assets are positioned for reliable cash generation through 2027, with firm offtake agreements covering expected output from existing wells. This foundation provides a robust platform for the pursuit of further growth opportunities. While current supply and demand dynamics in the Northern Territory are favourable, we remain vigilant to evolving market conditions, including the potential impact of new gas supply from the Beetaloo Basin and the prospect of domestic gas reservation policies influencing contract durations.

As we assess the optimal path for capital allocation, our strengthened financial footing allows us to consider a broader set of value-creating alternatives —whether through production expansion, targeted exploration, mergers and acquisitions, early debt repayment, or the introduction of sustainable dividends.

Our achievements are the result of the dedicated efforts of Central’s Board, management, and staff, whose commitment to safety and operational excellence has been outstanding. I extend my appreciation to CEO Leon Devaney and the executive team for their leadership, and I acknowledge the ongoing support of our stakeholders, suppliers, local communities, and traditional owners.

I would also like to thank my predecessor Mick McCormack, who retired from the Board this year, for his five years of guidance through a period of significant transition. His solid leadership has positioned Central Petroleum well for continued success.

With renewed momentum and a strong operational and financial foundation, I am confident that we are well-placed to deliver further positive results in the coming year. I look forward to updating you as we build on this progress.

Thank you,

Agu Kantsler, Chair

17 September 2025

CHIEF EXECUTIVE OFFICER'S LETTER

Dear fellow Shareholders,

It is with great satisfaction that I present this year's annual report, with improved results that reflect the strategic groundwork we have laid to position Central Petroleum for long-term growth and resilience.

The catalyst for our transformation has been the successful gas marketing initiatives undertaken in 2024. Our landmark, multi-year gas agreement with the Northern Territory Government, which I previously described as the most transformative in the company's history, is already delivering tangible benefits:

- Significant increases in gas revenues, cash flow, margins, and profits
- Mitigation of risks related to Northern Gas Pipeline closures
- Successful drilling of two new production wells at Mereenie
- Extension and restructuring of our debt facility
- Launch of our inaugural share buy-back program, marking the company's first return to shareholders.

Our new gas agreements enable nearly all anticipated firm gas production from existing wells to be delivered into the Northern Territory market, independent of Northern Gas Pipeline (NGP) availability through 2027. The resulting sales portfolio is now more robust, less vulnerable to pipeline disruptions, and commands a significantly higher average price compared to legacy contracts that expired this year.

The impact of this initiative is directly reflected in our financial performance: revenues increased by 17% year-on-year, underlying EBITDAX rose by 43%, and we achieved an underlying profit of $6.5 million—a significant turnaround from last year's $1.4 million underlying loss. The results achieved are a testament to both our disciplined execution and our commitment to value creation.

The certainty provided by these contracts facilitated our investment in two new production wells at Mereenie, both drilled ahead of schedule, under budget, and exceeding performance expectations.

The Northern Territory gas market remains finely balanced. The NGP was closed for three quarters of the financial year, and Central's Amadeus Basin fields continue to supply approximately half of the NT's gas needs, with the remainder sourced from offshore, including diverted from LNG when necessary.

Looking ahead, supply outlooks for the NT market are evolving. The well-publicised Beetaloo Basin shale gas projects continue to progress and could contribute to supply as early as next year, subject to ongoing appraisal results.

These market dynamics naturally create uncertainty regarding the long-term supply landscape. Central Petroleum is proactively engaging with the market for both short and long-term contracts, including for potential output from future wells at Mereenie and Palm Valley. Whilst we have advanced preparations and approvals for new wells, any future production investments will be contingent on securing suitable long-term offtake agreements.

With higher and more stable cash flows from our producing assets, we remain focused on driving sustainable growth and maximising shareholder value.

The exploration and appraisal of our sub-salt permits—delayed in recent years—hold the potential for significant volumes of helium, hydrogen, and hydrocarbons. We are actively pursuing a restart of sub-salt exploration, with a priority on drilling an appraisal well at Mt Kitty, given its world-class helium and hydrogen concentrations.

Additionally, there is renewed industry interest in conventional exploration across the western Amadeus Basin, specifically targeting our Mamlambo prospect and EP115, which sits on trend with Mereenie and Palm Valley.

Beyond our exploration efforts, we are open to new opportunities that align with our objective of delivering lower-risk, high-impact growth.

Our strengthened financial position is the product not only of the benefits realised from new contracts, but also of prudent financial management over recent years—strategic debt reduction, disciplined cost control, and capital preservation.

At 30 June, we held a net cash position of $3.9 million, with our debt facility structured for full repayment by 2030. This provides us with flexibility to consider a range of capital allocation options, including share buy-backs, investment in new production capacity, early debt repayment, exploration, M&A opportunities, and potential dividend distributions.

Each option offers distinct advantages, and collectively they underscore the substantial transformation our company has achieved in the past five years, providing multiple pathways for near-term value enhancement.

I wish to extend my sincere thanks to Central's Board for their guidance, as well as to our management team and staff for their unwavering commitment—particularly in the successful execution of the Mereenie drilling program.

Central Petroleum is now positioned stronger than ever. We look forward to building on these achievements and delivering further value to our shareholders in the year ahead.

Sincerely,

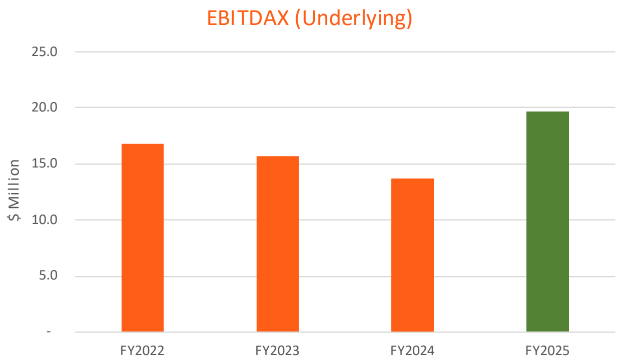
Leon Devaney, CEO

17 September 2025

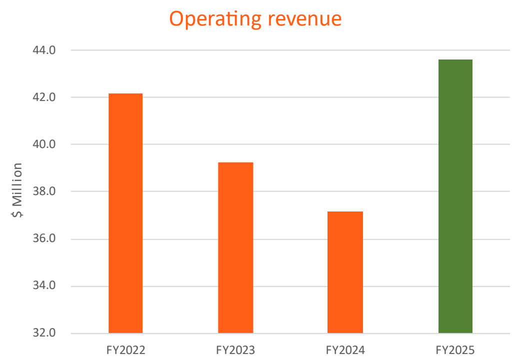
OPERATING AND FINANCIAL REVIEW

OPERATING HIGHLIGHTS

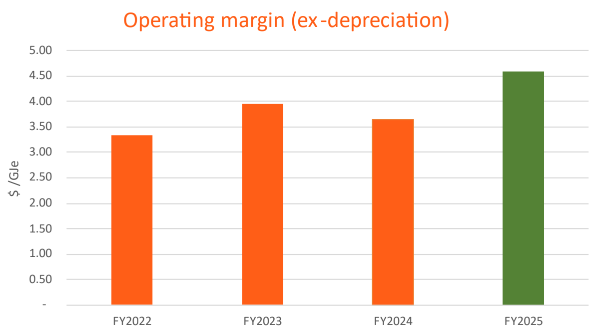
- Central's operational performance in FY2025 was a significant improvement on previous periods:
  - Sales revenue increased 17% to $43.6 million
  - Underlying EBITDAX was 43% higher at $19.6 million
  - Underlying profit of $6.5 million compared to FY2024's $1.4 million loss
  - Positive net cash balance increased from $0.8 million to $3.9 million
- These financial outcomes were a direct result of several key achievements during the year, including:
  - Secured new long-term gas contracts with the Northern Territory Government which resulted in higher, more reliable cash flows for the second half of the year
  - Drilled and commissioned two new production wells at Mereenie (ahead of schedule, under budget and significantly above initial production rate targets)
  - Restructured and extended the group's loan facility for five years, with full amortisation by 2030 (eliminating refinancing risk)
- Announcing Central's first shareholder returns, with an on-market share buy-back to start in September 2025.



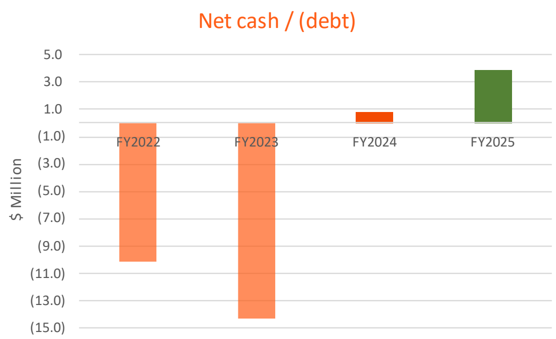
Underlying EBITDAX: Increased 43% to $19.6m in FY2025
(Earnings before interest, tax, depreciation, impairment, exploration costs, and profit on asset disposals)



Operating revenue: Increased 17% to $43.6m in FY2025



Operating margin (excluding depreciation) increased 26% to $4.60/GJe



Net cash: $3.9m at 30 June 2025

OPERATING AND FINANCIAL REVIEW

FINANCIAL REVIEW

The Consolidated Entity had a profit after income tax for the year ended 30 June 2025 of $7.7 million (2024: profit of $12.4 million).

The above result includes a $1.2 million profit on the sale of the land previously held by the Mereenie joint venture partners and was after expensing exploration costs of $1.7 million (2024: $4.0 million). The 2024 profit after tax included a $13.8 million profit on the disposal of the Range CSG interests.

To assist with comparability of this year's result, EBITDAX, EBITDA and EBIT have been reported against the underlying results in FY2024.

The table below shows key metrics for the Group:

Key Metrics	Total 2025	Total 2024	Change	% Change
Net Sales Volumes				
- Natural Gas (TJ)	**4,453**	4,377	76	2%
- Oil & Condensate (bbls)	**30,006**	26,304	3,702	14%
Sales Revenue ($'000)	**43,626**	37,154	6,472	17%
Gross Profit ($'000)	**14,539**	9,789	4,750	49%
Underlying EBITDAX[1] ($'000)	**19,616**	13,751	5,865	43%
Underlying EBITDA[2] ($'000)	**17,938**	9,761	8,177	84%
Underlying EBIT[3] ($'000)	**9,862**	1,973	7,889	400%
Underlying profit/(loss) after tax[4] ($'000)	**6,501**	(1,373)	7,874	573%
Statutory profit after tax ($'000)	**7,734**	12,422	(4,688)	(38)%
Net cashflow from operations[5] ($'000)	**14,304**	6,862	7,442	108%
Capital expenditure[6] ($'000)	**8,544**	2,718	5,826	214%

1 Underlying EBITDAX is Earnings before Interest, Tax, Depreciation, Amortisation, Impairment and Exploration costs and profit on disposal of interests in subsidiaries, exploration permits and land (refer reconciliation below).
2 Underlying EBITDA is Earnings before Interest, Tax, Depreciation, Amortisation, Impairment and profit on disposal of interests in subsidiaries, exploration permits and land.
3 Underlying EBIT is Earnings before Interest, Tax and profit on disposal of interests in subsidiaries, exploration permits and land.
4 Underlying profit / loss after tax is statutory profit after tax, before profit on disposal of interests in subsidiaries, exploration permits and land.
5 Cashflow from operations includes cash outflows associated with exploration activities.
6 Capital expenditure on tangible assets.

Underlying EBITDAX, Underlying EBITDA and Underlying EBIT are non-IFRS measures that are presented to provide an understanding of the underlying performance of the Group. The non-IFRS information is not subject to audit; however the numbers have been extracted from the financial statements which have been subject to review by the Group's auditor. A reconciliation to profit before tax is provided below.

Underlying EBITDAX

Underlying EBITDAX for the year was $19.6 million, up 43% from $13.8 million in 2024, reflecting higher portfolio pricing under new gas sale contracts that came into effect from 1 January 2025.

Underlying EBITDAX are earnings before interest, tax, depreciation, amortisation, impairment, exploration and profit on disposal of interests in subsidiaries, exploration permits and land. Underlying EBITDAX is used by management as an indicative measure of underlying operating profit from operations as it excludes some non-cash items, the costs of finance, expensed exploration costs and significant one-off transactions and is reconciled to statutory profit below.

It should be noted however that Underlying EBITDAX is only an indicative measure of underlying cash profit from operations. There are other significant non-cash items included in Underlying EBITDAX, such as share based payments amounting to $0.6 million this year (2024: $0.7 million). Revenues recognised may also not reflect actual cash receipts, as some gas revenues relate to presold gas for which cash was received in previous periods and amounts received under 'take or pay' gas contracts are not recognised as revenue until the gas is taken or forfeited by the customer.

Reconciliation of statutory profit before tax to Underlying EBITDAX	2025 $'000	2024 $'000
Statutory profit before tax	7,734	12,422
Profit on disposal of land	(1,233)	—
Profit on disposal of interest in Range CSG project	—	(13,795)
Underlying profit/(loss) before tax	**6,501**	(1,373)
Net finance costs	3,361	3,346
Underlying EBIT	**9,862**	1,973
Depreciation, amortisation and impairment	7,397	7,788
Change in fair value of other financial liabilities	679	—
Underlying EBITDA	**17,938**	9,761
Exploration expenses	1,678	3,990
Underlying EBITDAX	**19,616**	13,751

Sales Volumes

Sales volumes were 2% higher than FY2024 at 4.6 PJe. New gas sale contracts came into effect on 1 January 2025, resulting in more consistent, firm sales that reduced the impact of NGP interruptions. Two new development wells were successfully drilled and brought on line in the second half at Mereenie, boosting production. Natural field decline at Palm Valley was partly offset by increased demand for gas from Dingo.

Product	Unit	FY 2025	FY 2024
Gas	PJ	4.5	4.4
Crude and Condensate	bbls	30,006	26,304
Total	**PJe**	**4.6**	**4.5**

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

Sales Revenue

Central recorded sales revenue of $43.6 million, an increase of 17% on FY2024, reflecting the higher volumes and significantly higher portfolio pricing from the new contracts which commenced on 1 January 2025. Average realised prices were up 19% on FY2024 at $9.02/GJe. Total sales revenue included $1.3 million released from deferred take-or-pay balances (2024: $3.0 million).

Gross Profit

Gross profit was $14.5 million, an increase of 49% on FY2024. On a per unit basis this represents a gross profit of $3.14/GJe which is an increase of 45% from $2.16/GJe for FY2024, reflecting the higher average sales price. The unit cost of sales increased by 4%, due to inflation and higher gas transportation costs. Excluding depreciation, the operating margin increased by 26% from $3.65/GJe to $4.60/GJe.

Net Assets/Liabilities

At 30 June 2025, the Group had a net asset position of $40.9 million compared to $32.6 million at 30 June 2024, reflecting the current year profit before share-based payments.

Included in liabilities on the Group's balance sheet are amounts recognised in respect of deferred revenue and associated make-up gas provisions amounting to $10.0 million. These liabilities will be transferred to revenue as gas is supplied to the customer or forfeited to Central under take-or-pay contracts and therefore do not represent a cash liability to the Group. During the year, 0.72 PJ of previously over-lifted gas was repaid to joint venture partners.

Debt

In December 2024 the loan facility was extended, with a new five year term ending 31 December 2029. No principal repayments are required before 31 March 2027 and there are no penalties for early repayment. Interest rates are re-priced quarterly based on fixed spread over the periodic Bank Bill Swap (BBSY) average bid rate.

The Group repaid $1.2 million of loan principal during the year before the revised facility became active. The outstanding balance of the loan facility at 30 June 2025 was $23.4 million. An additional $4.6 million is currently undrawn and available until 31 December 2026, if required, to fund development activity.

At 30 June 2025 the Group was in a positive net cash position of $3.9 million (2024: $ 0.8 million), reflecting stronger cashflows from operations, partly offset by the investment in two new development wells at Mereenie.

The consolidated debt ratio at 30 June 2025 was 0.23 (2024: 0.23). Debt ratio is defined as: Total Debt/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 increased by $2.5 million over the year. Net cash flow from production operations for 2025 was $21.0 million (before CAPEX), compared to $14.1 million for 2024, reflecting higher revenues, partly offset by higher cash production costs including transportation costs and royalties.

OPERATING AND FINANCIAL REVIEW

After net interest payments of $1.1 million, $1.8 million of corporate and staff expenses and $4.1 million for exploration activities (inclusive of rehabilitation costs of $1.7 million), net cash from operating activities was $14.3 million (2024: $6.9 million).

During the year, Central invested $8.5 million in capital projects, including two successful new development wells at Mereenie. Central repaid $1.2 million of debt during the year prior to extending and reshaping the debt facility and lodged $2.5 million as security for the facility.

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.

	2021 $ MILLION	2022 $ MILLION	2023 $ MILLION	2024 $ MILLION	2025 $ MILLION
Financial Data[1]					
Operating revenue	59.83	42.15	39.26	37.15	**43.63**
Exploration expenditure	7.74	21.65	13.09	3.99	**1.68**
Profit/(loss) after income tax	0.25	21.32	(7.96)	12.42	**7.73**
EBITDAX	26.09	53.31	15.96	27.55	**20.17**
Underlying EBITDAX	26.09	16.75	15.75	13.75	**19.62**
Property, plant and equipment[2]	108.28	53.85	60.19	55.58	**57.68**
Cash[2]	37.17	21.65	13.83	24.99	**27.47**
Borrowings	(66.81)	(30.81)	(27.53)	(23.16)	**(23.39)**
Net Assets (Total Equity)	3.69	26.53	19.39	32.56	**40.91**
Net Working Capital (Net current assets/(liabilities))	8.25	22.31	7.11	16.00	**24.40**

[1] In October 2021, Central sold a 50% interest in its producing gas fields
[2] Includes assets classified as held for sale in 2021

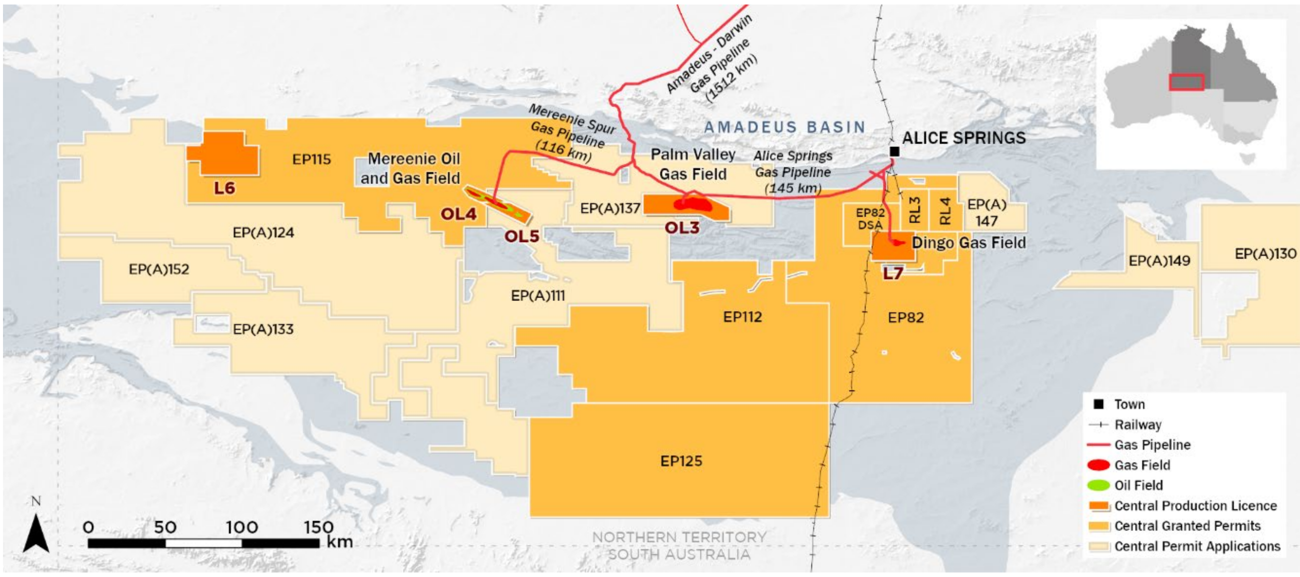
	2021	2022	2023	2024	2025
Operating Data					
Gas Sales (TJ)	9,820	5,993	4,664	4,377	**4,453**
Oil Sales (barrels)	77,255	47,197	30,293	26,304	**30,006**
No. of employees at 30 June	85	88	80	81	**82**

Drilling at Mereenie: WM29

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 onshore producing gas fields in the NT, supplying industrial customers, electricity generators and gas distributors from three producing fields in central Australia.

Producing Assets



Location of Central's producing oil and gas fields

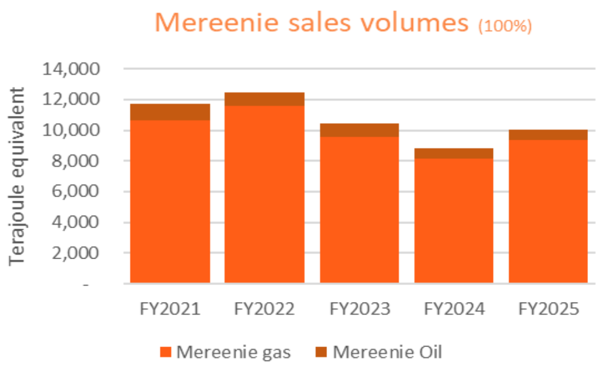
Mereenie Oil and Gas Field (OL4 and OL5)

Ownership interests	
Central Petroleum (operator)	**25.0%**
Echelon Mereenie Pty Ltd	42.5%
Horizon Australia Energy Pty Ltd	25.0%
Cue Mereenie Pty Ltd	7.5%

Reserves & Resources (Central share)[1]	Unit	1P	2P	2C
Gas	PJ	28.9	37.9	45.6
Oil	mmbbl	0.31	0.39	0.05
Total[2]	PJe	30.7	40.2	45.9

1 Reserves and resources are as at 30 June 2025. 2C gas resources include 27 PJ attributable to the Stairway Sandstone.

2 Oil converted at 5.816 PJ/mmbbl



Operations

Central's share of Mereenie gas and oil sales for FY2025 was 2.5 PJe. Full field gas production for the year was 9.5 PJ, averaging 26.1 TJ/d, up from the 8.1 PJ (22.2 TJ/d) produced in FY2024, after the successful drilling and tie-in of two new development wells in the March quarter. The wells were drilled ahead of schedule and under budget and have outperformed pre-drill expectations.

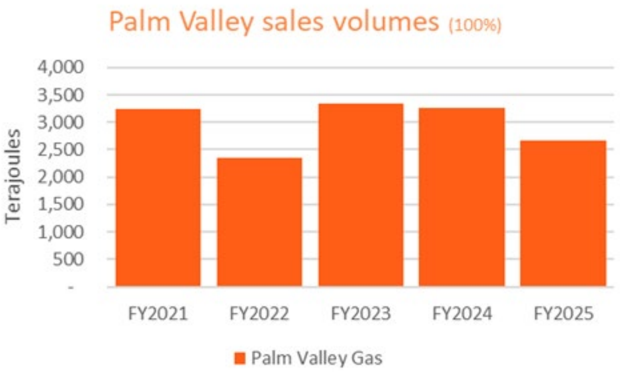
After a review of the performance of the new production wells, proved and probable (2P) gas reserves were revised upwards by 3.3 PJ (net to Central) before production for the year, an increase of 9%.

Mereenie highlights

- Two new production wells successfully drilled and commissioned under budget and ahead of schedule
- 2P gas reserves increased by 3 PJ (8%) before production
- Flare gas compressor commissioned, reducing emissions

OPERATING AND FINANCIAL REVIEW

Palm Valley Gas Field (OL3)



Ownership interests	
Central Petroleum (operator)	**50.0%**
Echelon Palm Valley Pty Ltd	35.0%
Cue Palm Valley Pty Ltd	15.0%

Reserves & Resources (Central share)[1]	Unit	1P	2P	2C
Gas	PJ	9.6	10.3	6.5

[1] Reserves and resources are as at 30 June 2025.

Palm Valley highlights

- Ongoing strong production performance from the most recent production well at Palm Valley

Operations

Central's share of Palm Valley gas sales for FY2025 was 1.3 PJ.

Production from the Palm Valley field averaged 7.3 TJ/d through FY2025 (2024: 8.9 TJ/day), recording an aggregate of 2.7 PJ (2024: 3.3 PJ), reflecting natural field decline.

Planning for new wells at Palm Valley continued during the year, with the environmental management plan lodged and approved by regulators.

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

Ownership interests	
Central Petroleum (operator)	**50.0%**
Echelon Dingo Pty Ltd	35.0%
Cue Dingo Pty Ltd	15.0%

Reserves & Resources (Central share)[1]	Unit	1P	2P	2C
Gas	PJ	19.0	22.6	—

[1] Reserves and resources are as at 30 June 2025.

Dingo highlights

- Record gas production, up 9% on FY2024
- 1P gas reserves increased by 6% before production

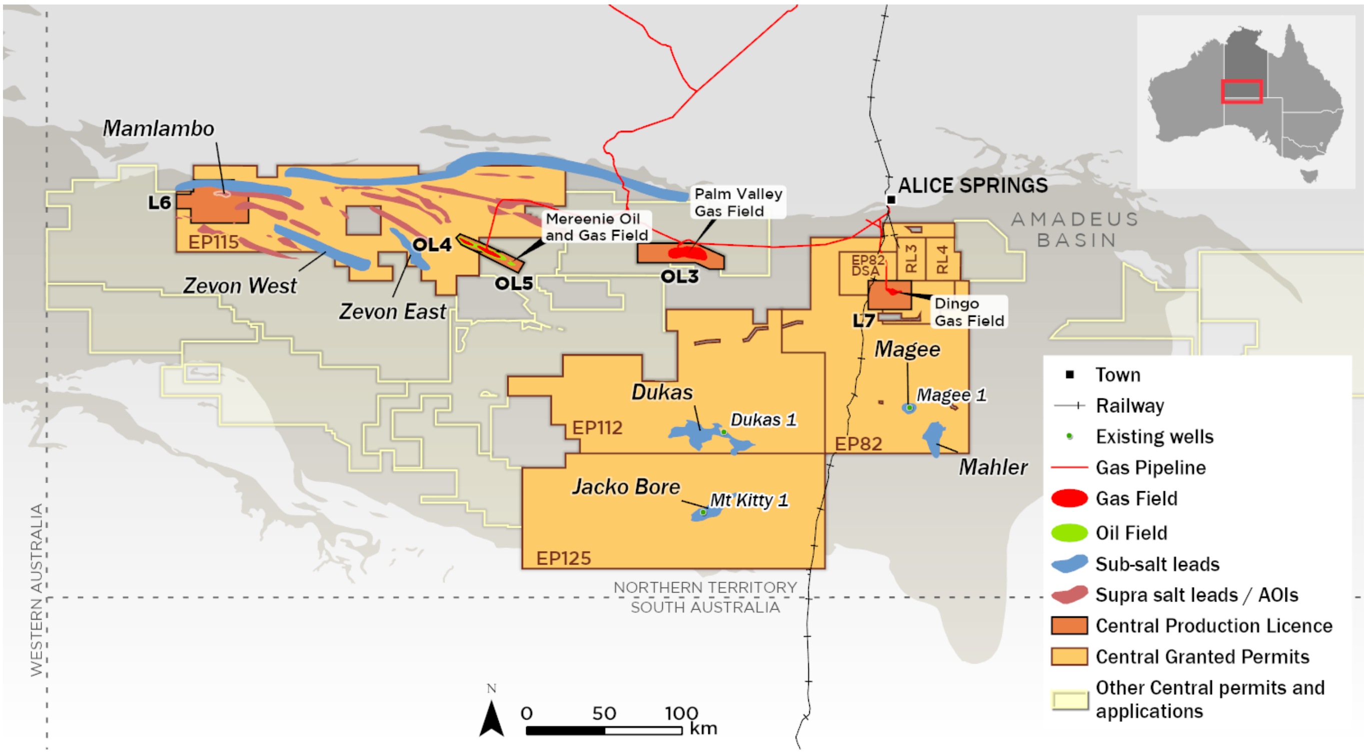
Operations

Sales volumes at Dingo were the highest on record for the second consecutive year, averaging 4.2 TJ/d across the year, an aggregate of 1.5 PJ (Central share 0.8 PJ), up 9% on FY2024. The daily contract volume of 4.4 TJ/d is subject to take-or-pay provisions under which Central will be paid in January 2026 for any gas nomination shortfall by the customer in CY2025.

After a review of field performance and updated modelling, proved (1P) gas reserves were revised upwards by 1.1 PJ (net to Central) before production, an increase of 6%.

Exploration

Central Petroleum holds a significant portfolio of exploration opportunities across the Amadeus, Wiso and Georgina Basins in the Northern Territory. The total area held or applied for by Central for exploration is 159,362 km² (50,393 km² granted and 108,969 km² under application).



Location of exploration targets

Central Petroleum has a significant footprint across the proven Amadeus Basin, which has provided reliable, high-quality oil and gas since the 1980s, yet it is relatively under-explored and has the potential for significant additional gas resources, including helium and naturally-occurring hydrogen, with good prospectivity for oil on the western flank of the basin.

Central and its partners have identified several prospects and leads across the Amadeus Basin as a result of exploration and appraisal activities, including exploration wells and seismic acquisition and seismic re-interpretation.

Exploration strategy

Central is committed to unlocking value from its portfolio of exploration assets through targeted activity, funded where possible through the introduction of new co-venturers.

In-field

Some of the more promising prospects lie within the existing producing fields at Mereenie, Palm Valley and Dingo which are comprised of several stacked layers of producing and prospective oil and gas reservoirs. There are opportunities to target intervals which are not currently the principal production zones in each field. If successful, production wells could be tied into existing facilities relatively quickly and efficiently.

In-field opportunity: Mereenie Sandstone

At Mereenie, 27 PJ of 2C Contingent Resource (Central share) has been attributed to the Stairway Sandstones, which lie above the current production zones and flow gas when drilling through them to lower zones. Successful appraisal drilling could result in a significant boost to production capacity at Mereenie and extend the economic life of the field subject to gas demand and pricing.

Near-field

Central has identified several other promising exploration targets close to producing fields which can be pursued relatively quickly once capital is allocated.

Near field opportunity: Mamlambo

With an estimated mean prospective resource of 18 mmbbl of oil, Mamlambo is a large structure defined on an existing seismic grid, only 8km from the suspended Surprise oil field. An appraisal well could target the Lower Stairway Sandstone and the Pacoota Formation, both of which are proven reservoirs in the Surprise and Mereenie fields.

OPERATING AND FINANCIAL REVIEW

Identified resources – in-field and near-field opportunities

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 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

In addition to hydrocarbons, the presence of radiogenic basement rocks and an evaporitic sealing unit has created the ideal conditions for a helium and hydrogen play in the sub-salt section of the Amadeus Basin.

Helium is contained at low levels in gas flows from Central's Mereenie, Palm Valley and Dingo gas fields, with higher concentrations of helium and hydrogen measured in previous exploration wells at Mt Kitty (Jacko Bore), Magee and Dukas. Drilling activity in all three areas is planned, subject to the introduction of new participants to assist with funding.

Helium in the Amadeus

In the context of helium concentrations of >0.3% being widely considered as helium-rich, a helium concentration of 6% was recorded at the Magee-1 well and gas flows at Mt Kitty-1 (Jacko Bore 1) contained 9% helium.

Central estimates that its share of gas resources across the three prospects (prior to any farmout) are:

Prospects	Jacko Bore (Mt Kitty)	Dukas	Mahler
Resource type	Contingent resource 2C (bcf)	Prospective resource (unrisked best estimate) (bcf)	Prospective resource (unrisked best estimate) (bcf)
Helium*	5.4	51.3	1.3
Hydrogen*	6.6	65.3	1.1
Natural gas	11.7	333.9	6.0

*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 the Dukas, Jacko Bore and Mahler prospects were first reported to ASX on 18 April 2023 and have been adjusted for Central's increased beneficial interests (Jacko Bore was 24%, now 30%), (Dukas was 35%, now 45%) and (Mahler was 29%, now 60%).

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.

COMMERCIAL

New contracts underwrite improved performance

Central’s improved financial position in FY2025 is largely due to the successful gas contracting activities concluded in 2024, which resulted in several new gas sale contracts that have resulted in more reliable cash flows and increased resilience to disruptions to the Northern Gas Pipeline (NGP).

The first half of FY2025 benefitted from as-available contracts with the Northern Territory Government which allowed Central to divert all of its available gas to the Northern Territory (NT), providing relief to gas users throughout the NT from declining supply from offshore fields.

The second half saw new multi-year supply contracts commence, again supplying the NT Government and other NT customers under contracts with pricing that reflected the difficult supply-side dynamics of the NT market.

The increased cash flow certainty provided the confidence to drill two successful production wells at Mereenie during the year, boosting production, revenues and cash flows, supported the extension and restructuring of Central’s debt facility, and allowed the commencement of shareholder returns through the forthcoming share buy-back.

Gas markets

The NGP reopened in April after having been closed more than 12 months, following the commissioning of the new offshore Blacktip well. This enabled supply of gas to Central’s customers in eastern markets.

Temporary NT supply constraints resulted in the NGP being subsequently closed for short periods and consequently, Central alternated gas sales between its existing east coast customers (when the NGP is operational) and NT customers (when the NGP is closed). Central’s NT gas sale agreements (GSAs) have mechanisms that allow east coast sales to be redirected into the NT when the NGP is closed, which minimised the impact of NGP outages on Central’s revenues this year.

Central continues to monitor the NT’s longer-term gas market dynamics, including Blacktip production and progress from the active Beetaloo appraisal projects that are targeting commencement of new gas supply next year. The bulk of Central’s expected firm production from existing wells until the end of 2027 can be delivered into existing contracts. Marketing activities continue, targeting existing and potential gas customers for firm supply in both NT and east coast markets from 2028 to replace volumes previously allocated to Arafura’s rare earths project. The conditional Arafura GSA, for gas supply from 2028, lapsed due to the project not reaching FID in the required timeframe.

Oil constraints

Oil sales from Mereenie in the fourth quarter were partially constrained under oil offtake arrangements which reduced total oil sales volume by approximately 37 bopd (Central share) and reduced gas capacity by approximately 5%. Alternative arrangements are being put in place to reduce the impact on revenues until the offtake constraint is resolved.

Helium Recovery Unit

Activity on the proposed Mereenie Helium Recovery Unit (HRU) project was suspended following a softening in the global helium market as new supply from two major helium producers entered the market, and pending a decision from the Mereenie JV to appraise the Mereenie Stairway formation which, if successful, could have a material impact on the size, scope, design, commercial terms and economics of the HRU project. The project proponents will monitor these factors with the potential to resume HRU project FID activities.

Other activities

In April, Central completed the sale of the non-core Brewer Estate oil terminal property near Alice Springs for $1m (Central share). This transaction removes associated rehabilitation liabilities and has contributed $1.2m to Central’s profit this year.

ESG AND COMMUNITY

Central Petroleum is committed to maintaining the highest environmental, social and governance standards across its operations.

Our core values

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

Environmental

Central is committed to conducting its operations in an environmentally responsible and sustainable manner aligned with regulatory requirements and community, cultural and social expectations. We believe that achieving and maintaining positive environmental outcomes is critical to the success of our business.

We operate under some of the most stringent environmental regulations in Australia. Our operations are conducted under comprehensive government-approved Environmental Management Plans (EMPs) in compliance with all relevant Commonwealth and Northern Territory regulations. The EMPs typically set out detailed requirements for all aspects of environmental protection, including levels for water and waste management, air emissions, land disturbance and rehabilitation, soil and flora/fauna conservation including pest and weed control as well as bushfire prevention.

No fracture stimulation (fracking) activities are conducted in our production or exploration areas.

We have had several visits and inspections during the year by regulatory agencies to monitor environmental conditions associated with our operations. These visits and inspections complement our own internal monitoring and assurance programs. Internal assessments of compliance with our environmental conditions outlined in the various EMPs over the course of the year identified a high level of compliance.

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

Climate change and emissions

Central recognises that climate change is a significant environmental, social, and business issue.

There is widespread acknowledgment that as we transition to a lower-emission energy future, natural gas will play a critical role in providing cleaner, affordable, and reliable energy using existing transmission infrastructure.

We have a social responsibility to contribute towards Australia's energy security by providing energy to businesses and residents across the Northern Territory and eastern states until reliable renewable energy can be introduced cost effectively.

At present, approximately half of the Northern Territory's gas supply comes from Central's gas fields, with residents and businesses of Alice Springs relying on our gas every day to generate electricity which protects them from central Australia's soaring summer temperatures and bitterly cold winter nights. Remote mine sites in the Northern Territory rely on our gas to supply rare minerals to local and worldwide markets.

We report our greenhouse emissions under the National Greenhouse and Energy Reporting Act 2007 (NGER). In the most recent completed reporting period, FY2024, our share of scope 1 and 2 emissions across our operations was consistent with the previous year, at 21,285 tons of CO_2e (21,685 tons in FY2023). On a per unit basis, our emissions intensity increased from 4.48kgCO_2e/GJe in FY2023 to 4.70 KgCO_2e/GJe in FY2024 due to lower gas volumes being produced at Mereenie and Palm Valley in FY2024.

We have invested in several initiatives to reduce our emissions, including the $8 million flare gas compressor at Mereenie, which was commissioned in late FY2024. Its impact on flare gas emissions should be visible in the FY2025 statistics when they become available. As older legacy equipment is replaced, we are installing more efficient appliances which will further reduce Scope 1 emissions across our operations.

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 rare minerals to worldwide markets.

Safety

At Central, the safety of our employees, contractors and the community are paramount. Central is committed to protecting workers and other persons against harm to their health, safety and welfare through the elimination or minimisation of risks arising from our operations.

During the year, over 288,000 hours were worked, with one injury associated with the Mereenie drilling program, resulting in a Total Recordable Injury Frequency Rate (TRIFR) of 4.1 at 30 June 2025.

Community

Central works closely with the communities in which it operates. We rely on their support, as well as that of local landowners and other stakeholders, and we seek to provide employment and business opportunities to our local communities wherever possible.

In the Northern Territory, for example:

- 24% of our staff live locally.
- 20% of our on-site staff are indigenous.
- Central and partners paid over $11.6 million in royalties to the Northern Territory government and Central Land Council for FY2025.
- Central and partners spent over $4.9 million with local contractors and businesses and incurred over $1.6 million in fees and levies payable to the Northern Territory government, in FY2025.

We aim to pay all of our suppliers on time in accordance with the agreed terms, which usually would not exceed 30 days after the end of the month of invoicing.

Many of Central's operations in the Northern Territory are located on or near Indigenous lands and we recognise, embrace, and respect the Indigenous historical, legal and heritage ties to these lands. We are committed to engage openly with the Traditional Owners and provide employment and training opportunities to the Indigenous people. We work closely with the Central Land Council and Aboriginal Areas Protection Authority to ensure our operations do not disturb areas of cultural heritage significance.

Drilling rig at Mereenie

RESERVES AND RESOURCES STATEMENT

Net proved & probable (2P) oil and gas reserves were 73.1 PJe at 30 June 2025.

Aggregate Reserves and Resources

		As at 30/06/2024	01/07/2024 to 30/06/2025 Production	Other adjustments	As at 30/06/2025	Comprising[1] Developed	Undeveloped
Oil							
Proved reserves (1P)	mmbbl	0.30	(0.03)	0.05	**0.31**	0.30	0.01
Proved plus probable reserves (2P)	mmbbl	0.36	(0.03)	0.06	**0.39**	0.36	0.03
Contingent Resources (2C)	mmbbl	0.05	—	—	**0.05**	—	—
Gas							
Proved reserves (1P)	PJ	57.62	(3.77)	3.57	**57.42**	49.12	8.30
Proved plus probable reserves (2P)	PJ	71.17	(3.77)	3.44	**70.84**	57.85	12.99
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 30/06/2024	01/07/2024 to 30/06/2025 Production	Other Adjustments	As at 30/06/2025
Mereenie, oil					
Proved reserves (1P)	mmbbl	0.30	(0.03)	0.05	**0.31**
Proved plus probable reserves (2P)	mmbbl	0.36	(0.03)	0.06	**0.39**
Contingent Resources (2C)	mmbbl	0.05	—	—	**0.05**
Mereenie, gas					
Proved reserves (1P)	PJ	28.06	(1.66)	2.46	**28.86**
Proved plus probable reserves (2P)	PJ	36.64	(1.66)	2.96	**37.94**
Contingent Resources (2C)	PJ	45.60	—	—	**45.60**
Palm Valley					
Proved reserves (1P)	PJ	10.90	(1.33)	0.02	**9.59**
Proved plus probable reserves (2P)	PJ	11.69	(1.33)	(0.02)	**10.34**
Contingent Resources (2C)	PJ	6.50	—	—	**6.50**
Dingo					
Proved reserves (1P)	PJ	18.66	(0.77)	1.09	**18.98**
Proved plus probable reserves (2P)	PJ	22.84	(0.77)	0.50	**22.57**

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.

Climate change concerns are influencing the business landscape, with emerging policies and regulations presenting both risks and opportunities for our existing assets and growth prospects as Australia transitions towards a lower-carbon future. Our risk management framework includes an integrated and coordinated approach to the management of climate change risks across the business.

Principal risks and uncertainties at 30 June 2025

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
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. 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. 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. 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. 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 strategies, and our regulatory compliance framework. We have a robust framework in place to support our regulatory and compliance obligations and we continue to review our regulatory compliance framework. We proactively maintain open dialogue with governments, regulators and stakeholders within jurisdictions in which we operate. 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.

Context	Risk	Mitigation
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. 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. 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.
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 returns.	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. 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. 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. 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.

Context	Risk	Mitigation
Climate Change		
Climate change is impacting the way that the world produces and consumes energy. Oil and gas produced by Central are fossil fuels, the production and consumption of which emit greenhouse gases.	Demand for oil and gas may subside over the longer-term, impacting demand and pricing as lower carbon substitutes take market share. Global climate change policy continues to evolve and has the potential to constrain Central's ability to create and deliver stakeholder value from the commercialisation of hydrocarbons. Introduction of taxes or other charges associated with carbon emissions may have an adverse impact on Central's operations, financial performance and asset values.	Our business is predominantly focused on supplying natural gas, which is widely accepted as a transitional fuel and could experience increased demand in the medium term as part of the transition to a clean energy future. Central has locked-in sales for estimated firm forward production from existing wells until 2027 at fixed pricing on a take-or-pay basis. Central has opportunities to diversify its reliance on hydrocarbons by targeting valuable non-hydrocarbon gases such as helium and naturally occurring hydrogen, which exists in some of our production and exploration permits.
Climate change may result in more extreme weather in the future.	There may be increased frequency of extreme weather events such as severe storms, floods, drought and bushfires which could damage Central's production infrastructure or customers' facilities, having an adverse impact on Central's operations, financial performance and asset values.	Central's production assets are located in arid regions not prone to cyclones, flooding or uncontrolled bushfires. Central maintains insurance to cover weather related risks.
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.
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. Our remuneration policy aims to attract, incentivise and retain experienced personnel. We also proactively engage contractors to supplement any short-term gaps in capability and capacity to support the execution of our business plans.

OPERATING AND FINANCIAL REVIEW

Context	Risk	Mitigation
Environment		
Our environmental performance underpin 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. 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. In recent years Central has been exposed to multiple 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. 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 interruptions to the NGP.
Digital and Cyber Security		
We are reliant upon our systems and infrastructure availability and reliability to support the business operating safely and effectively. 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. 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. We continuously assess and determine access permissions to critical information or data, whilst consolidating, simplifying, and automating security controls. 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.

Context	Risk	Mitigation
Financial		
Our financial strength and performance 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.
Our revenue is from the sale of hydrocarbons. This underpins Central's financial performance.	Central is exposed to gas commodity prices with respect to gas sales, all of which are to the Northern Territory and Australian east coast markets. 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. Central is exposed to USD commodity price variability with respect to crude oil sales which are impacted by broader economic factors beyond our control.	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. 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. Oil revenue represented less than 10% of consolidated sales revenue in FY2025.
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. We are also investigating other new ventures outside of the Amadeus Basin. 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.

DIRECTORS' REPORT

FOR THE YEAR ENDED 30 JUNE 2025

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 2025.

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 Michael (Mick) McCormack (Resigned 30 April 2025)

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 (2024: $Nil). No recommendation for payment of dividends has been made.

OPERATING AND FINANCIAL REVIEW

The operating and financial highlights for the financial year were:

- Operational performance in FY2025 was a significant improvement on previous periods:
    - Sales revenue increased 17% to $43.6 million
    - Underlying EBITDAX was 43% higher at $19.6 million
    - Underlying profit of $6.5 million compared to FY2024's $1.4 million loss
    - Positive net cash balance increased from $0.8 million to $3.9 million
- These financial outcomes were a direct result of several key achievements during the year, including:
    - Securing new long-term gas contracts with the Northern Territory Government which resulted in higher, more reliable cash flows for the second half of the year
    - Drilled and commissioned two new production wells at Mereenie (ahead of schedule, under budget and significantly above initial production rate targets)
    - Restructured and extended the group's loan facility for five years, with full amortisation by 2030 (eliminating refinancing risk)
- Announcing Central's first shareholder returns, with an on-market share buy-back to start in September 2025.

A detailed review of the operating and financial performance for the year ended 30 June 2025, including principal risks is provided on pages 3 to 19 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 2025:

- Securing new long-term gas contracts with the Northern Territory Government which resulted in higher, more reliable cash flows for the second half of the year
- Drilled and commissioned two new production wells at Mereenie which contributed to increased revenues
- Restructured and extended the group's loan facility for five years, with full amortisation by 2030
- Sold surplus land for a profit of $1.2 million.

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

EVENTS SINCE THE END OF THE FINANCIAL YEAR

In August 2025, 6,261,742 vested share rights, being 50% of the unexercised EIP share rights at 30 June were settled for $345,341 cash, 233,016 share rights lapsed and 7,491,308 new ordinary shares were issued upon exercise of vested share rights.

No other significant matters or circumstances have arisen between 30 June 2025 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

Commercial

Demand for gas is expected to remain strong through FY2026, with future firm production from existing wells contracted for the next two years, providing reliable cash flows.

Market conditions will be monitored and gas marketing activities will continue for new long-term gas sale agreements to underpin final investment decisions for new production wells at Mereenie and Palm Valley.

Exploration

Efforts will continue to introduce new partners into key exploration permits to assist with funding exploration and appraisal activity, including drilling in the sub-salt prospects for helium, hydrogen and hydrocarbons and exploration in the western Amadeus Basin for oil and gas.

Capital allocation considerations

Considerations for future capital allocation in the next year will include:

- investment in increased production capacity
- investment in new lower-risk, high-impact production and exploration opportunities
- possible early debt repayments
- commencement of sustainable dividend payments to shareholders.

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.

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 30 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 over 25 years of commercial and finance experience within the Australian oil and gas sector and holds an MBA and BSc (Finance) from the University of Southern California, USA.

He joined Central Petroleum in 2012 and has been responsible for commercial, finance and business development activities in various senior roles. He was instrumental in identifying and negotiating the Mereenie acquisition from Santos in 2015 and the Palm Valley and Dingo Gas Field acquisition from Magellan Petroleum in 2014, as well as structuring the winning application for ATP2031 (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 since July 2018.

Prior to joining Central Petroleum, he worked at QGC and played a pivotal role in its growth from a small cap gas exploration company into a multi-billion-dollar takeover target by the BG Group in 2008. He continued with BG following the QGC takeover, where he served as General Manager, Gas and Power, responsible for the domestic gas and electricity portfolio.

Prior to QGC, Mr Devaney held senior roles at Deloitte in the Corporate Finance Advisory Group where he was active in structuring and implementing commercial and financing transactions for major energy and infrastructure projects throughout 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 the Chair of Powerlink and a board member of Sims Limited and Chief Executive Women.

Ms Hirschfeld has also been a board member 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.

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.

Directorships of other listed companies in the last three years: Director of Sims Limited from 1 September 2023.

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	8	8	—	4	—	4	—	5
Stephen Gardiner	8	8	4	4	4	4	5	5
Katherine Hirschfeld AM	8	8	4	4	4	4	1	5
Agu Kantsler	8	8	1	4	4	4	5	5
Michael McCormack[3]	7	7	3	3	3	3	4	4

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 Michael McCormack resigned as Director effective 30 April 2024.

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 42.

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	
	2025	2024
PwC Australian firm:	**$**	$
Taxation services		
Income tax compliance	17,085	15,300
Other tax related services	5,550	21,581
Total remuneration from non-audit services	**22,635**	36,881

EXECUTIVE SUMMARY – REMUNERATION

Dear Shareholders,

It has been pleasing to see the Company's strategies beginning to bear fruit this year, with a significant improvement in revenues, cash flows and the strongest balance sheet for many years. This flowed from the successful gas contracting activity last year, extension of the debt facility and the well-executed drilling campaign at Mereenie.

The broader economy has remained strong, with a labour market that reflects ever-evolving expectations for work/life balance and a need to offset the increasing cost of living. Attracting and retaining high-performing staff in this environment remains an ongoing challenge.

The Board is committed to ensuring that the Company's remuneration strategy aligns the interests of management and staff with those of our shareholders. This year, we introduced a number of enhancements intended to reward high performance and underpin our share price.

Executive Remuneration

As part of our ongoing efforts to foster accountability and bolster shareholder value, the CEO's remuneration package was restructured to include a greater emphasis on performance-based incentives. Fixed remuneration for the CEO was reduced by 13%, with the balance redirected toward meaningful at-risk rewards, contingent on ambitious share price appreciation targets.

Remuneration for other executives was held at FY2024 levels and a revised incentive plan introduced, with targets consistent with that of the CEO.

Staff Remuneration

For non-executive staff, fixed remuneration increased 4% on average for FY2025, reflecting our commitment to remain competitive in a dynamic labour market and to help offset cost of living pressures. There was also the mandated 0.5% rise in the superannuation guarantee.

Directors' Fees

Directors' Fees have remained unchanged for eight years. Demonstrating their confidence in the Company's future, all non-executive directors voluntarily allocated a portion of their FY2025 fees toward the purchase of Company equity.

Short-Term Incentives

Short-term incentive opportunities for non-executive staff ranged from 10% to 30% of fixed remuneration, depending on role and seniority. Achievement of key milestones—including a successful drilling campaign, robust production volumes, effective cost management, and debt refinancing—resulted in an average award of 82.5% of maximum entitlement. While certain farmout and commercial objectives were not reached, the award this year was higher than previous years, reflecting the much-improved business performance and successful delivery of the Mereenie drilling program.

Executive Incentive Program (EIP)

Following a comprehensive benchmarking review, we launched a revised incentive plan for executives in FY2025. The short-term incentive component, linked to corporate objectives shared by all staff, yielded an award of 84.25% of the maximum available—intended to be distributed as 80% cash and 20% share rights, with deferred vesting.

The long-term component now consists solely of share rights, vesting only upon achievement of ambitious share price appreciation over three years. The plan is structured so that rewards are unlocked only if the share price rises to at least 8 cents per share—an increase of approximately 50% from the 30 June 2024 price of 5.3 cents. At this threshold, the CEO earns a long-term incentive equal to 50% of a reduced FY2025 fixed remuneration (15% of FY2025 fixed remuneration for other executives), scaling up to 218% should the share price more than triple to reach the aspirational target of 16 cents per share (65% for other executives).

Shareholder Returns and Incentive Settlement

In support of our shareholder return strategy, the Board announced an on-market share buyback program commencing mid-September 2025. To mitigate dilution from issuing new shares at prices prevailing at that time, the Board elected to cash-settle both the 20% FY2025 short-term award, which had been intended to be distributed as deferred share rights, and 50% of vested share rights from prior years that would otherwise convert to shares post-30 June 2025.

While this approach adjusts the equity alignment between executives and shareholders, it also ensures consistency with our shareholder return policy, maintains the intent of the EIP to have executives invested in the long-term success of the company, and preserves long-term value for all investors.

Commitment to Performance

In summary, our remuneration outcomes this year are a direct reflection of the Company's improved operating performance and promising outlook. The Board is confident that the balance of fixed and incentive-based remuneration provides a robust framework to attract, reward, and retain the talent necessary for continued growth and shareholder returns.

Agu Kantsler
Remuneration and Nominations Committee Chair

REMUNERATION REPORT

(AUDITED)

This Remuneration Report for the year ended 30 June 2025 (FY2025) 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	Executive Incentive Plan (FY22-FY24 EIP)
I	Realised Remuneration
J	Remuneration Details – Statutory Tables
K	Executive Service Agreements
L	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 Michael (Mick) McCormack	Former Independent Non-executive Chair (resigned 30 April 2025)

Other Key Management Personnel

Mr Ross Evans	Chief Operations Officer
Mr Damian Galvin	Chief Financial Officer
Mr Daniel White	Group General Counsel and Company Secretary

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 2025 Summary of fixed and variable remuneration outcomes	
Fixed remuneration	The CEO's fixed remuneration was reduced for FY2025 and other executives' fixed remuneration was frozen at FY2024 levels. An average 4% pay rise applied to other eligible employees for FY2025 and compulsory superannuation contributions increased from 11% to 11.5%.
Executive Incentive Plan (EIP)	Achievement of Group-wide corporate KPIs resulted in an award of 84.25% with 80% of the awarded value being payable as cash and 20% that would have otherwise been settled as Share Rights settled as cash in August 2025. Refer Section F of this report. One-third of Share Rights issued to the CEO and eligible executives under EIPs for FY2022, FY2023 and FY2024 vested at 30 June 2025. Subsequent to year end, the Company elected to cash-settle 50% of these Share Rights at the share price prevailing in July 2025.
Short Term Incentive Plan (STIP)	Achievement of Group-wide corporate and individual KPIs resulted in payment of an average 82.5% 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 2025 fully vested on 30 June 2025 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 2025, 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 FY2025 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.

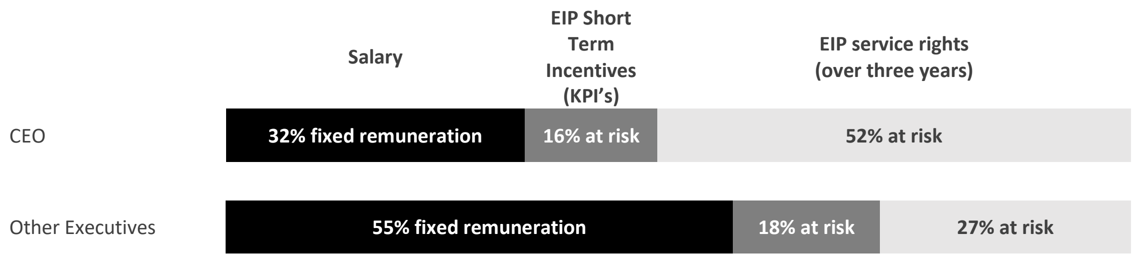
Executives, including executive directors:

1. Annual salary and non-monetary benefits including statutory superannuation; and
2. Participation in the Executive Incentive Plan (EIP), vesting over a 4 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 FY2025.

C. Remuneration Policy (continued)

The balance of fixed and maximum at risk remuneration for executives for FY2025 is summarised as follows:



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:

		FY2021	FY2022	FY2023	FY2024	FY2025
Financial performance[1]						
Operating revenue	$ million	59.8	42.2	39.3	37.2	**43.6**
Profit/(loss) after income tax	$ million	0.2	21.3	(8.0)	12.4	**7.7**
Underlying EBITDAX[2]	$ million	26.1	16.8	15.8	13.8	**19.6**
Net cash/(debt)	$ million	(31.3)	(10.2)	(14.3)	0.8	**3.9**
Shareholder wealth						
Share price at year end	$/share	$0.117	$0.110	$0.053	$0.053	**$0.055**
Incentive awarded						
STIP	% of maximum	67.0%	62.75%	51.0%	54.0%	**82.3%**
LTIP	% of maximum	31.5%	43%	29.9%	N/a	**N/a**
EIP	% of maximum	N/a	62.5%	45.0%	51.0%	**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.

The expansion programs at the Group's Amadeus Basin oil and gas fields, funded by debt, gas presales and gas overlifts enabled increased production into new markets upon the opening of the Northern Gas Pipeline in early 2019, resulting in strong revenues and EBITDAX. The STIP awards in FY2021 reflected these results and were paid as a combination of cash, equity and deferred equity. 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 FY2021, 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 does not appear to have been reflected in the share price at 30 June, and the equity component of the EIP continues to align shareholders' economic outcomes with the value of executives' incentives. With the share price lagging the Company's performance, an on-market share buy-back has been announced to commence in September 2025, and in conjunction with that initiative, 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.

D. Remuneration Consultants

No remuneration consultants were engaged to provide remuneration recommendations in relation to the remuneration of any Key Management Personnel for FY2025.

Guerdon Associates were engaged to provide information relating to Non-executive Director fees (NED fees have not increased since 2017) and market information from peer companies relating to 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)

Following a review of the Company's executive incentive plans, Central established a new EIP for key executives to align performance with the achievement of key objectives and share price hurdles, commencing in FY2025.

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 – 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:

Hurdle Share Price (at 30 June 2027)	Share price increase required to reach Hurdle Share Price (from $0.053 at 30 June 2024)	Value as % of TFR at Hurdle Share Price	
		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.

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.

EIP Long Term Incentive – FY2026

The FY2026 EIP has 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) its ending VWAP Floor price at the end of the Performance Period.

For the FY2026 plan year, the Performance Rights will be subject to exceeding a minimum Share Price Hurdle of $0.08 per share during a three-year period, and meeting the $0.08 per share VWAP Floor price at 30 June 2028. Central's share price would need to increase by 45% from the price at 30 June 2025 over three years 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 30 June 2028. 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 30 June 2028. 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, relative to TFR at the relevant Vesting Target Hurdle Share Price is set out below:

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)	Value as % of TFR at Hurdle Share Price	
			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 ending on 30 June 2028 (for the VWAP Floor price).

For both the FY2025 and FY2026 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.

F. Executive Incentive Plan (continued)

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 the eligible employee's:

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.

FY2025 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, 82.5% of their maximum STIP bonus. The STIP bonuses were paid in August 2025.

The Financial Year 2025 STIP (FY2025 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 %	50.55 %	84.25 % satisfaction of corporate KPIs
Individual KPIs	40 %	32.00 % (avg)	80.00 % satisfaction of individual KPIs
	100 %	82.55 % (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 FY2025 STIP, depending on their participation level.

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

Corporate KPIs for FY2025:

Objective	Weighting	Performance Outcome for FY2025			
		0%	Threshold 25%	Target 100%	Stretch 125%
Production (gas – sales volume) Assessed against budget	16%			●	
Total Cost[1] Total group operating and capital expenditure for agreed scope of works assessed against budget	16%				●
Growth & Development Milestones Development wells – on schedule and within budget	17%			●	
Farmout of exploration permits / helium recovery unit FID	20%	●			
Commercial Funding and re-financing	10%				●
Traditional Owner cultural heritage Assessed against compliance with agreements	3%			●	
Safety Total Recordable Incident Frequency Rate (TRIFR)	5%			●	
Process Safety Unplanned or uncontrolled release of materials from a process (loss of primary containment – LOPC)	5%			●	
Environment Recordable environmental incidents	5%			●	
NT Operations (maintain Indigenous employment)	3%		●		

[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 FY2025 were assessed as achieving an average of 80% (or a weighted average of 32% out of a maximum possible 40%).

H. Executive Incentive Plan (FY22-FY24 EIP)

Participation

The FY22-FY24 EIP for key executives for FY2022, FY2023 and FY2024 aimed to align executive performance with the achievement of key objectives.

Key terms and vesting conditions

The FY22-FY24 EIP was an integrated incentive with both short term and long-term components. The value of the FY22-FY24 EIP award was determined at the end of the 12-month performance period upon measurement of performance against Board established KPI targets for that year.

The incentive awarded was then split into two components:

a) 33% paid in cash at that time (i.e., at the end of the initial 12-month performance period); and
b) The 67% balance of the awarded incentive value was granted as Service Rights that vest over the following three years in equal tranches beginning 12-months after the end of the initial 12-month performance period.

The maximum opportunity for the executive team as a percentage of TFR was:

- CEO: 120%
- Other eligible executives: 80%

Vested Service Rights may be exercised in accordance with the Employee Rights Plan (ERP) Rules. The number of Service Rights awarded for any single Plan Year was 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 period ending 30 June.

H. Executive Incentive Plan (FY22-FY24 EIP) (continued)

The Service Rights are the right to acquire fully paid ordinary shares for no exercise price at the end of the vesting period and can be exercised up to five years from the grant date. 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 equal in value to the dividends paid, or capital returned during the period from grant to exercise.

The Company may elect to cash-settle some, or all, vested Service Rights.

If a Change of Control Event (as defined in the ERP Rules) occurs, the Board has the discretion to determine the appropriate treatment regarding any unvested or unexercised Share 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, having regard for the prevailing facts and circumstances at the time of cessation.

Details of remuneration for the Directors and Key Management Personnel of Central Petroleum Limited and the Consolidated Entity are set out in Sections I and J of this report.

I. Realised remuneration (not audited)

Table 1 identifies the actual remuneration received by Senior Executives in respect of the 2025 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 (2025: 5.5 cents per share, 2024: 5.3 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	**2025**	**596,671**	**367,493**	**8,601**	**116,530**	**1,089,295**
	2024	681,849	139,097	8,839	153,172	982,957
Ross Evans[5]	**2025**	**558,079**	**220,454**	**8,601**	**63,568**	**850,702**
	2024	558,079	156,233	8,839	90,697	813,848
Damian Galvin	**2025**	**357,848**	**145,804**	**8,601**	**42,021**	**554,274**
	2024	369,179	50,208	8,839	58,606	486,832
Daniel White	**2025**	**495,639**	**195,779**	**8,601**	**56,446**	**756,465**
	2024	495,639	67,407	8,839	78,782	650,667
Total Executive KMP	**2025**	**2,008,237**	**929,530**	**34,404**	**278,565**	**3,250,736**
	2024	2,104,746	412,945	35,356	381,257	2,934,304

1 Total Fixed Remuneration includes salaries, fees and superannuation contributions.
2 Includes FY2025 short term incentive and 50% of rights that vested 30 June 2025 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.
5 Ross Evans' STIP/EIP for 2024 Included a key operational employee retention incentive.

J. 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	**2025**	**72,500**	**—**	**—**	**8,338**	**—**	**20,114**	**100,952**	**—**
	2024	72,500	—	—	7,975	—	19,309	99,784	—
Katherine Hirschfeld	**2025**	**78,833**	**—**	**—**	**9,066**	**—**	**8,045**	**95,944**	**—**
	2024	85,000	—	—	9,350	—	—	94,350	—
Agu Kantsler	**2025**	**74,167**	**—**	**—**	**8,529**	**—**	**20,114**	**102,810**	**—**
	2024	62,500	—	—	6,875	—	19,309	88,684	—
Former Non-Executive Directors									
Michael McCormack[5]	**2025**	**101,851**	**—**	**—**	**11,713**	**—**	**26,606**	**140,170**	**—**
	2024	117,500	—	—	12,925	—	35,860	166,285	—
Troy Harry[6]	**2025**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
	2024	47,816	—	—	5,260	—	—	53,076	—
Sub-total	**2025**	**327,351**	**—**	**—**	**37,646**	**—**	**74,879**	**439,876**	**—**
	2024	385,316	—	—	42,385	—	74,478	502,179	—
Executives									
Leon Devaney	**2025**	**590,983**	**200,515**	**8,601**	**29,932**	**11,219**	**271,379**	**1,112,629**	**42%**
	2024	679,448	139,097	8,839	27,399	12,600	216,083	1,083,466	33%
Ross Evans	**2025**	**530,085**	**125,369**	**8,601**	**29,932**	**20,436**	**114,194**	**828,617**	**29%**
	2024	547,708	139,130	8,839	27,399	16,196	126,848	866,120	31%
Damian Galvin	**2025**	**304,640**	**82,934**	**8,601**	**29,932**	**12,426**	**75,515**	**514,048**	**31%**
	2024	331,213	50,208	8,839	27,399	5,509	83,857	507,025	26%
Daniel White	**2025**	**471,972**	**111,342**	**8,601**	**29,932**	**13,094**	**101,409**	**736,350**	**29%**
	2024	471,549	67,407	8,839	27,399	9,253	112,638	697,085	26%
Sub-total	**2025**	**1,897,680**	**520,160**	**34,404**	**119,728**	**57,175**	**562,497**	**3,191,644**	**34%**
	2024	2,029,918	395,842	35,356	109,596	43,558	539,426	3,153,696	30%
Total Remuneration	**2025**	**2,225,031**	**520,160**	**34,404**	**157,374**	**57,175**	**637,376**	**3,631,520**	**32%**
	2024	2,415,234	395,842	35,356	151,981	43,558	613,904	3,655,875	28%

1 Includes movements in annual leave provisions.
2 Short term incentives are unpaid at the end of the financial year. Includes key operational employee retention incentive.
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 Subsequent to year end, in respect of EIP rights that vested 30 June 2025 and any previously vested but unexercised EIP rights, the Board resolved to settle 50% of the outstanding rights in cash during FY2026. The remaining 50% of vested rights remain as equity.
5 Michael McCormack resigned 30 April 2025.
6 Troy Harry resigned 5 February 2024.

J. Remuneration Details – Statutory tables (continued)

Table 3: Short Term Incentives awarded

		Maximum $	Awarded[1] $	Awarded %	Forfeited %
Leon Devaney	**2025**	**297,500**	**250,644**	**84.3%**	**15.7%**
	2024	272,740	139,097	51.0%	49.0%
Ross Evans[2]	**2025**	**186,008**	**156,712**	**84.3%**	**15.7%**
	2024	229,161	156,233	68.2%	31.8%
Damian Galvin	**2025**	**123,047**	**103,667**	**84.3%**	**15.7%**
	2024	98,448	50,208	51.0%	49.0%
Daniel White	**2025**	**165,197**	**139,178**	**84.3%**	**15.7%**
	2024	132,170	67,407	51.0%	49.0%
Total	**2025**	**771,752**	**650,201**	**84.3%**	**15.7%**
	2024	732,519	412,945	56.4%	43.6%

1 In accordance with the FY2025 plan offer, 20% of the short-term incentive was designated as a share-based award having a vesting date of 30 June 2026. In July 2025 the Board resolved to settle this component in cash during FY2026.

2 In 2024 Ross Evans was entitled to a retention incentive of 15% of total fixed remuneration implemented as part of the retention strategy made in connection with the Strategic Review announced in August 2022. The incentive was conditional upon Mr Evans remaining employed by the Company and was payable as soon as practicable after the earlier of completion of a transaction resulting from the Strategic Review and 30 June 2024. An amount of $80,334 is included in the 2024 awarded incentives for this retention incentive.

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	**2025**	**365,703**	**20 Nov 24**	**0.055**	**—**	**30 Jun 29**
	2024	386,182	14 Nov 23	0.050	—	30 Jun 28
Katherine Hirschfeld	**2025**	**146,281**	**20 Nov 24**	**0.055**	**—**	**30 Jun 29**
	2024	—	—	—	—	—
Agu Kantsler	**2025**	**365,703**	**20 Nov 24**	**0.055**	**—**	**30 Jun 29**
	2024	386,182	14 Nov 23	0.050	—	30 Jun 28
Michael McCormack[5]	**2025**	**679,164**	**20 Nov 24**	**0.055**	**—**	**30 Jun 29**
	2024	717,196	14 Nov 23	0.050	—	30 Jun 28
Sub-total	**2025**	**1,556,851**				
	2024	1,489,560				
Executives						
Leon Devaney[4]	**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**
	2024[3]	4,021,260	14 Nov 23	0.050	—	14 Nov 28
Ross Evans	**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**
	2024[3]	2,193,405	14 Sep 23	0.053	—	14 Sep 28
Damian Galvin	**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**
	2024[3]	1,449,525	14 Sep 23	0.053	—	14 Sep 28
Daniel White	**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**
	2024[3]	1,947,534	14 Sep 23	0.053	—	14 Sep 28
Sub-total	**2025**	**27,130,616**				
	2024	9,611,724				
Total	**2025**	**28,687,467**				
	2024	11,101,284				

1 Represents a portion of Directors Fees sacrificed. These Share Rights vested on 30 June – Refer Section L of this report.

2 Represents Shares Rights granted under the FY2025 Executive Incentive Plan which vest 30 June 2027 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.

J. 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 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 – Refer Section L 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, FY2024:

Grant Date	Expiry Date	Fair Value Per Right	Exercise Price	Price of Shares at Grant Date	Estimated Volatility	Risk Free Interest Rate	Dividend Yield
14 Sep 2023[1]	14 Sep 2028	$0.053	Nil	$0.053	N/A	N/A	—
14 Nov 2023[1]	14 Nov 2028	$0.050	Nil	$0.050	N/A	N/A	—
14 Nov 2023[2]	30 Jun 2028	$0.050	Nil	$0.050	N/A	N/A	—

1 EIP Rights for the plan year commencing 1 July 2022.
2 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	STIP Year Commencing 1 July 2019[2]	Number of Rights Vested	Proportion of Rights Vested[1]	Proportion of Rights Forfeited
Leon Devaney	**2025**	**1,843,567**	**1,340,420**	**1,053,451**	—	**4,237,438**	**100%**	**Nil**
	2024	—	1,340,420	1,053,451	496,171	2,890,042	100%	Nil
Ross Evans	**2025**	**1,005,947**	**731,135**	**574,478**	—	**2,311,560**	**100%**	**Nil**
	2024	—	731,135	574,478	405,655	1,711,268	100%	Nil
Damian Galvin	**2025**	**665,451**	**483,175**	**379,405**	—	**1,528,031**	**100%**	**Nil**
	2024	—	483,175	379,405	243,198	1,105,778	100%	Nil
Daniel White	**2025**	**893,397**	**649,178**	**510,000**	—	**2,052,575**	**100%**	**Nil**
	2024	—	649,178	510,000	327,269	1,486,447	100%	Nil
Total	**2024**	**4,408,362**	**3,203,908**	**2,517,334**	—	**10,129,604**	**100%**	**Nil**
	2024	—	3,203,908	2,517,334	1,472,293	7,193,535	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. Subsequent to year end the Board resolved to settle 50% of the rights vested at 30 June 2025 in cash paid in August 2025.
2 The FY2020 STIP was awarded as deferred share rights instead of cash. These rights vested 1 July 2023.

In addition, 1,361,431 Share Rights vested on 30 June 2025 (2024: 1,489,560), 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.

J. 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	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	**2025**	**386,182**	**365,703**	**—**	**(386,182)**	**N/A**	**365,703**	**—**
	2024	379,040	386,182	—	(379,040)	N/A	386,182	—
Katherine Hirschfeld	**2025**	**—**	**146,281**	**—**	**—**	**N/A**	**146,281**	**—**
	2024	86,910	—	—	(86,910)	N/A	—	—
Agu Kantsler	**2025**	**386,182**	**365,703**	**—**	**(386,182)**	**N/A**	**365,703**	**—**
	2024	217,275	386,182	—	(217,275)	N/A	386,182	—
Michael McCormack[1]	**2025**	**717,196**	**679,164**	**(195,420)**	**(717,196)**	**(473,744)**	**N/A**	**N/A**
	2024	403,511	717,196	—	(403,511)	N/A	717,196	—
Sub-total	**2025**	**1,489,560**	**1,556,851**	**(195,420)**	**(1,489,560)**	**(483,744)**	**877,687**	**—**
	2024	1,086,736	1,489,560	—	(1,086,736)	N/A	1,489,560	—
Executives								
Leon Devaney	**2025**	**6,128,162**	**13,655,701**	**—**	**—**	**N/A**	**6,631,309**	**13,152,554**
	2024	4,235,213	4,021,260	—	(2,128,311)	N/A	2,393,871	3,734,291
Ross Evans	**2025**	**3,342,361**	**5,285,041**	**—**	**(1,305,613)**	**N/A**	**2,311,560**	**5,010,229**
	2024	2,129,089	2,193,405	—	(980,133)	N/A	1,305,613	2,036,748
Damian Galvin	**2025**	**2,208,335**	**3,496,146**	**—**	**(862,580)**	**N/A**	**1,528,031**	**3,313,870**
	2024	1,381,413	1,449,525	—	(622,603)	N/A	862,580	1,345,755
Daniel White	**2025**	**2,967,534**	**4,693,728**		**(1,159,178)**	**N/A**	**2,052,575**	**4,449,509**
	2024	3,367,745	1,947,534	(1,058,316)	(1,289,429)	N/A	1,159,178	1,808,356
Sub-total	**2025**	**14,646,392**	**27,130,616**		**(3,327,371)**	**N/A**	**12,523,475**	**25,926,162**
	2024	11,113,460	9,611,724	(1,058,316)	(5,020,476)	N/A	5,721,242	8,925,150
Total	**2025**	**16,135,952**	**28,687,467**	**(195,420)**	**(4,816,931)**	**(483,744)**	**13,401,162**	**25,926,162**
	2024	12,200,196	11,101,284	(1,058,316)	(6,107,212)	N/A	7,210,802	8,925,150

[1] Michael McCormack resigned 30 April 2025.

J. 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 2025	Vesting Period End Date[1]	Maximum value yet to vest[2]
Key Management Personnel					
Leon Devaney	20 Nov 2024	Deferred Share Rights – FY2025 EIP	8,125,000	30 Jun 2027	152,500
	20 Nov 2024	Deferred Share Rights – FY2024 EIP	1,843,567	30 Jun 2027	47,077
	20 Nov 2024	Deferred Share Rights – FY2024 EIP	1,843,567	30 Jun 2026	27,039
	14 Nov 2023	Deferred Share Rights – FY2023 EIP	1,340,420	30 Jun 2026	13,165
Ross Evans	13 Sep 2024	Deferred Share Rights – FY2025 EIP	2,267,200	30 Jun 2027	33,600
	12 Sep 2024	Deferred Share Rights – FY2024 EIP	1,005,947	30 Jun 2027	22,885
	12 Sep 2024	Deferred Share Rights – FY2024 EIP	1,005,947	30 Jun 2026	13,144
	14 Sep 2023	Deferred Share Rights – FY2023 EIP	731,135	30 Jun 2026	7,612
Damian Galvin	13 Sep 2024	Deferred Share Rights – FY2025 EIP	1,499,793	30 Jun 2027	22,228
	12 Sep 2024	Deferred Share Rights – FY2024 EIP	665,451	30 Jun 2027	15,139
	12 Sep 2024	Deferred Share Rights – FY2024 EIP	665,451	30 Jun 2026	8,695
	14 Sep 2023	Deferred Share Rights – FY2023 EIP	483,175	30 Jun 2026	5,030
Daniel White	13 Sep 2024	Deferred Share Rights – FY2025 EIP	2,013,537	30 Jun 2027	29,841
	12 Sep 2024	Deferred Share Rights – FY2024 EIP	893,397	30 Jun 2027	20,325
	12 Sep 2024	Deferred Share Rights – FY2024 EIP	893,397	30 Jun 2026	11,674
	14 Sep 2023	Deferred Share Rights – FY2023 EIP	649,178	30 Jun 2026	6,758
Total			**25,926,162**		**436,712**

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.

The Executive Share Option Plan was a historical plan granting management the right to exercise options at a given price during the period 1 July 2022 until 30 June 2023. No share options were exercised by 30 June 2023 and all options subsequently lapsed on 1 July 2023.

The number of Options to ordinary shares in the Company under the Executive Share Option Plan held during the financial year by Key Management Personnel of the Consolidated Entity, including their personally related parties, are set out below:

Table 8: Options Holdings of Key Management Personnel

Share Options		Number of Options Held at Start of Year	Options Granted as Compensation	Exercise Price	Expiry Date	Cancelled or Expired During the Year	Exercised and Converted to Shares	Number of Options Held at End of Year (Unvested)
Leon Devaney	**2025**	—	—	—	—	—	—	—
	2024	5,105,000	—	$0.20	01 Jul 2023	(5,105,000)	—	—
Ross Evans	**2025**	—	—	—	—	—	—	—
	2024	4,170,025	—	$0.20	01 Jul 2023	(4,170,025)	—	—
Damian Galvin	**2025**	—	—	—	—	—	—	—
	2024	2,750,000	—	$0.20	01 Jul 2023	(2,750,000)	—	—
Total	**2025**	—	—	—	—	—	—	—
	2024	12,025,025	—	$0.20	01 Jul 2023	(12,025,025)	—	—

J. Remuneration Details – Statutory tables (continued)

Table 9: 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	**2025**	**379,040**	**N/A**	**—**	**386,182**	**N/A**	**765,222**
	2024	—	N/A	—	379,040	N/A	379,040
Troy Harry[1]	**2025**	**N/A**	**N/A**	**—**	**—**	**N/A**	**N/A**
	2024	53,340,268	N/A	—	—	(53,340,268)	N/A
Katherine Hirschfeld	**2025**	**912,466**	**N/A**	**—**	**—**	**N/A**	**912,466**
	2024	825,556	N/A	—	86,910	N/A	912,466
Agu Kantsler	**2025**	**379,040**	**N/A**	**—**	**386,182**	**N/A**	**765,222**
	2024	161,765	N/A	—	217,275	N/A	379,040
Michael McCormack[2]	**2025**	**703,931**	**N/A**	**—**	**717,196**	**(1,421,127)**	**N/A**
	2024	300,420	N/A	—	403,511	N/A	703,931
Sub-total	**2025**	**2,374,477**	**—**	**—**	**1,489,560**	**(1,421,127)**	**2,442,910**
	2024	54,628,009	—	—	1,086,736	(53,340,268)	2,374,477
Other Key Management Personnel							
Leon Devaney	**2025**	**4,735,068**	**N/A**	**—**	**—**	**N/A**	**4,735,068**
	2024	2,606,757	N/A	—	2,128,311	N/A	4,735,068
Ross Evans	**2025**	**1,366,317**	**N/A**	**—**	**1,305,613**	**N/A**	**2,671,930**
	2024	386,184	N/A	—	980,133	N/A	1,366,317
Damian Galvin	**2025**	**763,603**	**N/A**	**181,000**	**862,580**	**N/A**	**1,807,183**
	2024	141,000	N/A	—	622,603	N/A	763,603
Daniel White	**2025**	**4,274,849**	**N/A**	**—**	**1,159,178**	**N/A**	**5,434,027**
	2024	2,985,420	N/A	—	1,289,429	N/A	4,274,849
Sub-total	**2025**	**11,139,837**	**—**	**181,000**	**3,327,371**	**—**	**14,648,208**
	2024	6,119,361	—	—	5,020,476	—	11,139,837
Total KMP	**2025**	**13,514,314**	**—**	**181,000**	**4,816,931**	**(1,421,127)**	**17,091,118**
	2024	60,747,370	—	—	6,107,212	(53,340,268)	13,514,314

1 Troy Harry resigned on 5 February 2024.
2 Michael McCormack resigned 30 April 2025.

K. Executive Service Agreements

The details of service agreements of the Key Management Personnel of the Consolidated Entity as of 1 July 2025 are as follows:

Table 10: 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	$612,020	6-months
Ross Evans	Chief Operations Officer	Full time permanent	$574,000	6-months
Damian Galvin	Chief Financial Officer	Full time permanent	$379,430	6-months
Daniel White	Group General Counsel & Company Secretary	Full time permanent	$509,680	3-months

1 Total Annual Fixed Remuneration, effective 1 July 2025 includes compulsory superannuation contributions.
2 In certain exceptional circumstances (such as breach or gross misconduct) a shorter notice period applies.

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).

L. 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 FY2025. 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 2024.

FY2025 Board Fees (per annum)	
Chair	$130,000
Non-Executive Director	$70,000

FY2025 Committee Fees (per annum)		
Audit & Financial Risk	Chair	$10,000
	Member	$5,000
Remuneration & Nominations	Chair	$10,000
	Member	$5,000
Risk & Sustainability	Chair	$10,000
	Member	$5,000

From 1 July 2025, fees for Non-Executive Directors will increase with CPI for the first time since 2017 to $72,000 pa and to $134,000 pa for the Chair of the Board. The Chair of each committee will receive $10,500 pa and committee members' fees will remain unchanged at $5,000. The aggregate fees remain within the shareholder-approved limit of $750,000.

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 2025

Auditor's Independence Declaration

As lead auditor for the audit of Central Petroleum Limited for the year ended 30 June 2025, 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; and

(b) no contraventions of any applicable code of professional conduct in relation to the audit.

This declaration is in respect of Central Petroleum Limited and the entities it controlled during the period.

Marcus Goddard
Partner
PricewaterhouseCoopers

Brisbane
17 September 2025

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FINANCIAL REPORT

CONTENTS

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 19. These pages are not part of these financial statements.

The financial statements were authorised for issue by the Directors on 17 September 2025. The Directors have the power to amend and reissue the financial statements.

Through the use of the internet, we have ensured that our corporate reporting is timely and complete. 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 2025

	NOTE	2025 $'000	2024 $'000
Revenue from contracts with customers – sale of hydrocarbons	2(a)	43,626	37,154
Cost of sales	4(a)	(29,087)	(27,365)
Gross profit		**14,539**	**9,789**
Other income	3	2,491	14,754
Exploration expenditure	4(f)	(1,678)	(3,990)
General and administrative expenses net of recoveries	4(c)	(2,369)	(3,386)
Finance costs	4(d)	(4,524)	(4,293)
Other expenses	4(b)	(725)	(452)
Profit before income tax		**7,734**	**12,422**
Income tax expense	5	—	—
Profit for the year		**7,734**	**12,422**
Other comprehensive profit for the year, net of tax		—	—
Total comprehensive profit for the year		**7,734**	**12,422**
Total comprehensive profit attributable to members of the parent entity		**7,734**	**12,422**
Earnings per share for profit or loss attributable to the ordinary equity holders of the company:			
Basic earnings per share (cents)	23(a)	**1.04**	**1.68**
Diluted earnings per share (cents)	23(b)	**1.01**	**1.64**

The accompanying notes form part of these financial statements.

CONSOLIDATED BALANCE SHEET

AS AT 30 JUNE 2025

	NOTE	2025 $'000	2024 $'000
ASSETS			
Current assets			
Cash and cash equivalents	7	27,471	24,985
Trade and other receivables	8	7,348	5,450
Inventories	9	3,613	3,765
Total current assets		38,432	34,200
Non-current assets			
Property, plant and equipment	10	57,678	55,578
Right of use assets	11(a)	2,617	1,018
Exploration assets	12	7,674	7,674
Other intangible assets	13	242	376
Other financial assets	14	5,416	2,840
Goodwill	15	1,953	1,953
Total non-current assets		75,580	69,439
Total assets		**114,012**	**103,639**
LIABILITIES			
Current liabilities			
Trade and other payables	16	5,175	3,260
Deferred revenue	2(b)	992	1,087
Borrowings	17(a)	7	4,440
Lease liabilities	11(a)	360	624
Provisions	19	7,496	8,794
Total current liabilities		14,030	18,205
Non-current liabilities			
Deferred revenue	2(b)	9,036	10,237
Borrowings	17(b)	23,384	18,723
Lease liabilities	11(a)	2,301	426
Other financial liabilities	18	722	—
Provisions	19	23,634	23,493
Total non-current liabilities		59,077	52,879
Total liabilities		**73,107**	**71,084**
Net assets		**40,905**	**32,555**
EQUITY			
Contributed equity	20 (a)	197,776	197,776
Reserves	21	42,104	41,488
Accumulated losses	22	(198,975)	(206,709)
Total equity		**40,905**	**32,555**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

FOR THE YEAR ENDED 30 JUNE 2025

	Contributed Equity $'000	Share Options Reserve $'000	Accumulated Profits Reserve $'000	Accumulated Losses $'000	Total $'000
Balance at 1 July 2023	**197,776**	**31,433**	**—**	**(209,821)**	**19,388**
Total profit for the year	—	—	—	12,422	12,422
Other comprehensive income	—	—	—	—	—
Total comprehensive profit for the year	—	—	—	12,422	12,422
Transactions with owners in their capacity as owners					
Share based payments	—	749	—	—	749
Share issue costs	—	(4)	—	—	(4)
	—	745	—	—	745
Transfer of retained profits to accumulated profits reserve	—	—	9,310	(9,310)	—
Balance at 30 June 2024	**197,776**	**32,178**	**9,310**	**(206,709)**	**32,555**
Total profit for the year	—	—	—	7,734	7,734
Other comprehensive income	—	—	—	—	—
Total comprehensive profit for the year	—	—	—	7,734	7,734
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	**197,776**	**32,794**	**9,310**	**(198,975)**	**40,905**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED 30 JUNE 2025

	NOTE	2025 $'000	2024 $'000
Cash flows from operating activities			
Receipts from customers		45,398	36,882
Interest received		1,169	912
Other income		273	3
Government grants		—	11
Interest and borrowing costs		(2,256)	(2,893)
Payments for exploration expenditure		(4,101)	(2,614)
Payments to other suppliers and employees		(26,179)	(25,439)
Net cashflow from operating activities	28	14,304	6,862
Cash flows from investing activities			
Payments for property, plant and equipment		(8,522)	(2,939)
Proceeds from sale of producing assets and property, plant and equipment		994	3
Proceeds from sale of subsidiary net of transaction costs and cash disposed	3(a)	—	12,184
Redemption of security deposits and bonds		55	290
Lodgement of security deposits and bonds		(2,641)	(89)
Net cash (outflow)/inflow from investing activities		(10,114)	9,449
Cash flows from financing activities			
Payments for the issue of securities		(3)	(4)
Repayment of borrowings	29(b)	(1,167)	(4,667)
Principal elements of lease payments	29(b)	(534)	(481)
Net cash outflow from financing activities		(1,704)	(5,152)
Net increase in cash and cash equivalents		**2,486**	**11,159**
Cash and cash equivalents at the beginning of the financial year		**24,985**	**13,826**
Cash and cash equivalents at the end of the financial year	7	**27,471**	**24,985**

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.

Central and its joint venturer continue to consider the future structure and timing of the sub-salt exploration activities following the termination of previous farm-out funding arrangements. The Operator is progressing permit renewals and work program discussions with the Northern Territory Government and Central is seeking potential farmin partners to assist with funding permit commitments. Alternatively, the relevant permit 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 2024 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 19.

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. 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 18.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(a) Basis of Preparation (continued)

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 J 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 12.

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 10, 11, 13 and 15. Testing for impairment of goodwill and other non-financial assets in FY2025 was assessed against a recent market transaction adopting the fair value less costs of disposal measurement methodology (refer Note 15).

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.

(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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(b) Principles of Consolidation (continued)

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 34.

(c) Segment Reporting

Operating segments are reported in Note 24 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.

(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).

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(e) Revenue Recognition (continued)

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.

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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(g) Income Tax (continued)

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 11.

(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 33.

(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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(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 8) in the balance sheet. Amounts paid as performance bonds or amounts held as security for bank guarantees are classified as other financial assets (Note 14).

(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.

(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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(o) Property, plant and Equipment – Other than Development and Production Assets (continued)

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. 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 24).

(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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(s) Provisions (continued)

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. 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 claims and 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.

(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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(t) Employee Benefits (continued)

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.

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.

(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.

(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.

(aa) Standards, Amendments and Interpretations

The Group has applied the following standards and amendments for the first time for its annual reporting period commencing 1 July 2024:

- AASB 2020-1 Amendments to Australian Accounting Standards – Classification of Liabilities as Current or Non-current [AASB 101]
- AASB 2022-6 Amendments to Australian Accounting Standards – Non-current Liabilities with Covenants [AASB 101]
- AASB 2022-5 Amendments to Australian Accounting Standards – Lease Liability in a Sale and Leaseback [AASB 16]; and
- AASB 2023-1 Amendments to Australian Accounting Standards – Supplier Finance Arrangements [AASB 7 & AASB 107].

The amendments listed above 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 2025 have not been early adopted. These are:

- AASB 2023-5 Amendments to Australian Accounting Standards – Lack of Exchangeability [AASB 1, AASB 121 & AASB 1060] (effective for reporting period ending 30 June 2026)
- 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. REVENUE FROM CONTRACTS WITH CUSTOMERS

(a) Revenue from contracts with customers

	2025 $'000	2024 $'000
Sale of hydrocarbon products - point in time		
Natural gas	38,944	30,963
Crude oil and condensate	3,407	3,155
Revenue released from Deferred Revenue in respect of take or pay contracts [1]	1,275	3,036
Total revenue from contracts with customers	**43,626**	**37,154**

[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 24(f) – Segment Reporting.

(b) Contract Liabilities

	2025			2024		
	Current $'000	Non-current $'000	Total $'000	Current $'000	Non-current $'000	Total $'000
Deferred Revenue – take-or-pay contracts[1]	992	9,036	10,028	1,087	10,237	11,324
Total contract liabilities	**992**	**9,036**	**10,028**	**1,087**	**10,237**	**11,324**

[1] Refer Note 1(e) (i) and (iii).

Movements in Contract Liabilities	Total $'000
Carrying amount at 1 July 2024	**11,324**
Revenue recognised from the delivery of gas	(128)
Revenue released (forfeited gas)	(1,275)
Gas paid for but not taken during the period	107
Carrying amount at 30 June 2025	**10,028**

3. OTHER INCOME

	2025 $'000	2024 $'000
Interest	1,163	947
Profit on disposal of subsidiary (a)	—	13,795
Profit on disposal of inventory and other assets (b)	1,328	1
Government subsidies	—	11
Total other income	**2,491**	**14,754**

3. OTHER INCOME (CONTINUED)

(a) Profit from disposal of subsidiary

On 30 November 2023, the Group completed the sale of its 50% interest in the Range Gas Project (ATP 2031) in Queensland's Surat Basin by way of the sale of its wholly owned subsidiary, Central Petroleum Eastern Pty Ltd. Details of the disposal were as follows:

	2024 $'000
Cash consideration received net of cash disposed	12,457
Transaction costs	(273)
Net cash received	12,184
Net liabilities of Central Petroleum Eastern Pty Ltd at date of disposal	1,611
Profit on disposal	**13,795**

(b) 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.

4. EXPENSES

(a) Cost of sales includes the following specific expenses

	NOTE	2025 $'000	2024 $'000
Depreciation and amortisation	4(e)	6,732	6,748
Employee and contractor costs		6,522	5,963
Gas purchases		5,266	4,894
Other production costs		4,286	4,672
Royalties		4,309	3,104
Transportation and storage		1,972	1,984
Total cost of sales		**29,087**	**27,365**

(b) Other expenses include the following specific expenses

	2025 $'000	2024 $'000
Change in fair value of other financial liabilities[1]	679	—
Write off, impairment, and disposal of property, plant and equipment	46	442
Other costs	—	10
Total other expenses	**725**	**452**

1 Change in fair value of deferred consideration that may become payable in future years (refer Note 18).

4. EXPENSES (CONTINUED)

(c) General and administrative expenses include the following specific expenses

	NOTE	2025 $'000	2024 $'000
Depreciation and amortisation	4(e)	664	598
Employee and contractor costs		777	1,334
Share based payments		619	749
Other costs		309	705
Total general and administrative expenses		**2,369**	**3,386**

(d) Finance costs include the following specific expenses

Interest and fees on debt facilities		3,273	2,865
Interest on lease liabilities	11(b)	81	43
Amortisation of deferred finance costs		292	291
Accretion charges		878	1,094
Total finance costs		**4,524**	**4,293**

(e) Total depreciation and amortisation

Depreciation			
Buildings	10	175	176
Producing assets	10	3,458	3,485
Plant and equipment	10	3,080	3,100
Leasehold improvements	10	2	10
Right of use assets	11(b)	546	437
Total depreciation		**7,261**	**7,208**
Amortisation			
Other intangible assets - software	13	136	138

(f) Exploration-related impairment expense

In the previous financial year ended 30 June 2024, impairment expenses of $325,000 were recognised for costs carried forward in respect of the Palm Valley Deep prospect.

(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 11(b)).

5. 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.

	2025 $'000	2024 $'000
(a) Income tax expense		
Current tax	—	—
Deferred tax	—	—
Income tax expense	**—**	**—**
(b) Numerical reconciliation of income tax expense and prima facie tax benefit		
Profit before income tax expense	7,734	12,422
Prima facie tax expense at 30%	(2,320)	(3,726)
Tax effect of amounts which are not deductible in calculating taxable income:		
Non-deductible expenses	(9)	(8)
Share based payments	(187)	(225)
Sub-total	(2,516)	(3,959)
Previously unrecognised deferred tax assets	2,516	3,959
Deferred tax assets not recognised	—	—
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	125,857	131,696
Potential tax benefit at 30%	**37,757**	**39,509**

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.

5. INCOME TAX (CONTINUED)

(e) Deferred tax assets and liabilities

	2025 $'000	2024 $'000
Deferred tax assets		
Provisions and accruals	9,411	10,072
Other expenditure	207	294
Borrowing costs	164	78
Unutilised losses	47,017	48,643
Total deferred tax assets before set-offs	56,799	59,087
Set-off of deferred tax liabilities pursuant to set-off provisions	(9,260)	(9,134)
Net deferred tax assets not recognised	**47,539**	**49,953**
Movements in deferred tax assets		
Opening balance at 1 July	9,134	9,296
Charged to the income statement	126	(162)
Closing balance at 30 June	**9,260**	**9,134**
Deferred tax assets to be recovered after more than 12-months	6,817	6,051
Deferred tax assets to be recovered within 12-months	2,443	3,083
	9,260	**9,134**
Deferred tax liabilities		
Capitalised exploration	2,278	2,271
Property, plant and equipment	6,982	6,863
Total deferred tax liabilities before set-offs	9,260	9,134
Set-off of deferred tax assets pursuant to set-off provisions	(9,260)	(9,134)
Net deferred tax liabilities	—	—
Movements in deferred tax liabilities		
Opening balance at 1 July	9,134	9,296
Credited to the income statement	126	(162)
Closing balance at 30 June	**9,260**	**9,134**
Deferred tax liabilities to be recovered after more than 12-months	9,152	8,947
Deferred tax liabilities to be recovered within 12-months	108	187
	9,260	**9,134**

6. REMUNERATION OF AUDITORS

	2025 $	2024 $
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 statements	251,003	234,900
(ii) Taxation services		
Income tax compliance	17,085	15,300
Other tax related services	5,550	21,581
Total taxation services	22,635	36,881
Total remuneration of PwC	**273,638**	**271,781**

7. CASH AND CASH EQUIVALENTS

	2025 $000	2024 $000
Cash and cash equivalents	**27,471**	**24,985**
Made up as follows:		
Corporate cash and bank balances (a)	26,022	14,567
Joint arrangements (b)	1,449	418
Cash on term deposit (c)	—	10,000
Total cash and cash equivalents	**27,471**	**24,985**

(a) Following the extension and restructuring of the loan facility in December 2024, 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 14). At the end of the previous financial year, 30 June 2024, $2,759,000 of the cash balance related to cash held with Macquarie Bank Limited to be used for allowable purposes under the loan facility including, but not limited to, operating costs for the Palm Valley, Dingo and Mereenie fields, taxes, capital expenditure and debt servicing.

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

(c) Cash on 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 33.

8. TRADE AND OTHER RECEIVABLES

	2025 $'000	2024 $'000
Current		
Trade debtors	232	17
Accrued income and recoveries (a)	5,285	3,943
Other receivables	66	1
Prepayments	1,765	1,489
	7,348	**5,450**

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 33(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.

9. INVENTORIES

	2025 $'000	2024 $'000
Crude oil and natural gas	164	132
Spare parts and consumables	1,854	1,744
Drilling materials and supplies at cost	1,595	1,889
	3,613	**3,765**

10. PROPERTY, PLANT AND EQUIPMENT

	Freehold Land and Buildings $'000	Producing Assets $'000	Plant and Equipment $'000	Total $'000
Year ended 30 June 2024				
Opening net book amount	579	38,179	21,434	60,192
Additions	—	353	2,365	2,718
Changes to rehabilitation estimates	—	(110)	(3)	(113)
Disposals and write offs	—	—	(448)	(448)
Depreciation charge	(176)	(3,485)	(3,110)	(6,771)
Closing net book amount	**403**	**34,937**	**20,238**	**55,578**
At 30 June 2024				
Cost	1,952	64,685	49,476	116,113
Accumulated depreciation	(1,549)	(29,748)	(29,238)	(60,535)
Net book amount at 30 June 2024	**403**	**34,937**	**20,238**	**55,578**
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**

At 30 June 2025, $1,043,000 of property plant and equipment balances relates to assets under construction and is not subject to depreciation until complete (2024: $839,000).

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 15).

11. LEASES

(a) Amounts recognised in the Balance Sheet

The Balance Sheet shows the following amounts relating to leases:

	2025 $'000	2024 $'000
Right-of-use assets		
Land & Buildings	2,461	951
Plant & Equipment	156	67
	2,617	**1,018**
Lease Liabilities		
Current	360	624
Non-current	2,301	426
	2,661	**1,050**

Additions to the right-of-use assets during the 2025 financial year were $2,146,000 (2024: $904,000). Disposals and incentive adjustments amounted to $Nil (2024: $Nil).

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

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

	2025 $'000	2024 $'000
Depreciation charge of right-of-use assets		
Land & Buildings	507	368
Plant & Equipment	39	69
Total depreciation of right-of-use assets	**546**	**437**
Interest expense	81	43
Expense related to short term leases included in cost of sales and general and administrative expenses (Note 4(g))	—	—

The total cash outflow for leases in 2025 was $616,000 (2024: $524,000).

(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.

11. 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.

12. EXPLORATION ASSETS

	2025 $'000	2024 $'000
Acquisition costs of right to explore	**7,674**	**7,674**
Movement for the year:		
Balance at the beginning of the year	7,674	7,999
Impairment expense (Note 4(f))	—	(325)
Balance at the end of the year	**7,674**	**7,674**

13. OTHER INTANGIBLE ASSETS

	2025 $'000	2024 $'000
Software		
At the beginning of the year		
Cost	1,050	1,094
Accumulated amortisation	(674)	(762)
Net book value	**376**	**332**
Movements for the year		
Opening net book amount	376	332
Additions	2	182
Amortisation	(136)	(138)
Closing net book amount	**242**	**376**
At the end of the year		
Cost	1,052	1,050
Accumulated amortisation	(810)	(674)
Net book value	**242**	**376**

14. OTHER FINANCIAL ASSETS

	2025 $'000	2024 $'000
Non-Current		
Security bonds over petroleum permits and rental properties [1]	2,916	2,840
Cash on deposit – debt facility[2]	2,500	—
Total other financial assets	**5,416**	**2,840**

[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

15. GOODWILL

	2025 $'000	2024 $'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 February 2024 New Zealand Oil & Gas Limited (now renamed Echelon Resources Limited) and Horizon Oil Limited entered into agreements with Macquarie Mereenie Pty Ltd to acquire the latter's interest in the Mereenie gas field with an effective date of 1 April 2023. The transaction completed on 11 June 2024.

Management and the Board have considered the existence of any other similar market transactions, macro-economic changes, and asset performance since the transaction was completed and have concluded that the transaction above provides evidence to support the fair value of the Mereenie, Palm Valley and Dingo fields which constitute the Amadeus Basin assets ('the Assets') and will therefore adopt the fair value less costs of disposal measurement methodology as at 30 June 2025. This recent market transaction approach has been used as an alternative to the future cash flows method due to the transaction representing a more reliable estimate of the fair value of the Assets.

15. GOODWILL (CONTINUED)

Management and the Board believe the transaction meets the requirements of an orderly transaction where all parties were acting in their own economic best interests and therefore can be relied upon to determine a fair value for the Group's interests in the Assets on a reserves valuation basis. Management have taken the implied 2P reserves multiple from the transaction of $1.14 per GJ (including maximum possible deferred consideration) and applied this across the Group's interest of 2P reserves across the Assets. The Group's 2P reserves of 73.1 PJe attributed to the Assets used to underpin this assessment are obtained from an independent reserves report. From the assessment performed, it was determined that the value of the transaction consideration on 2P Reserves Basis, when applied to Central's 2P gas reserves, exceeds the net carrying value of the Group's interests in the Assets and the associated goodwill.

On this basis Management and the Board have concluded there is no impairment of the carrying value of Goodwill or other producing assets at 30 June 2025.

Fair Value Measurement is governed by AASB 13 which defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. It assumes the asset or liability is exchanged in an orderly transaction between market participants at the measurement date under current market conditions. The fair value measurement of the Assets falls under Level 2 of the fair value hierarchy. This classification is based on observable inputs other than quoted prices in active markets for identical assets or liabilities. The inputs used in the valuation include market multiples derived from comparable transactions, which are observable and verifiable.

16. TRADE AND OTHER PAYABLES

	2025 $'000	2024 $'000
Current		
Trade payables	962	1,133
Other payables	233	—
Accruals	3,980	2,127
	5,175	**3,260**

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 33.

17. BORROWINGS

		2025 $'000	2024 $'000
(a)	Current[1]		
	Debt facilities	7	4,440
(b)	Non-current[1]		
	Debt facilities	23,384	18,723

[1] Details regarding interest bearing liabilities are contained in Note 33(e).

In December 2024 the loan facility was extended with 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.

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.

18. OTHER FINANCIAL LIABILITIES

	2025 $'000	2024 $'000
Non-current		
Deferred consideration payable – at fair value	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 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 $679,000 (Note 4(b)) and accretion charges of $43,000 included in finance charges (Note 4 (d)).

19. PROVISIONS

	2025			2024		
	Current $'000	Non-Current $'000	Total $'000	Current $'000	Non-Current $'000	Total $'000
Employee entitlements (a)	5,969	720	6,689	5,092	708	5,800
Restoration and rehabilitation (b)	874	22,914	23,788	2,831	22,047	24,878
Joint Venture production over-lift (c)	653	—	653	871	738	1,609
	7,496	**23,634**	**31,130**	**8,794**	**23,493**	**32,287**

(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 has previously taken a higher proportion of natural gas produced from the Mereenie joint venture than its joint venture percentage entitlement. A provision has been recognised to reflect the expected additional production costs of rebalancing production entitlements between the joint venture partners from future operations.

Movements in Provisions

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

2025	Employee Entitlements $'000	Restoration & Rehabilitation $'000	Joint Venture Production Over-Lift $'000	Total $'000
Carrying amount at start of year	5,800	24,878	1,609	32,287
Change in provision charged/(credited) to property, plant and equipment	—	637	—	637
Additional provisions charged/(credited) to profit or loss	3,592	(152)	(190)	3,250
Unwinding of discount	—	835	—	835
Disposal of assets (Note 3 (b))	—	(562)	—	(562)
Amounts used during the year	(2,703)	(1,848)	(766)	(5,317)
Carrying amount at end of year	**6,689**	**23,788**	**653**	**31,130**

20. CONTRIBUTED EQUITY

	2025 $'000	2024 $'000
(a) Share capital		
745,258,314 fully paid ordinary shares (2024: 740,147,003)	**197,776**	**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

	2025 Number of Shares	2024 Number of Shares	2025 $'000	2024 $'000
Balance at start of year	740,147,003	729,405,268	197,776	197,776
Shares issued under Employee Incentive Plans	5,111,311	10,741,735	—	—
Balance at end of year	**745,258,314**	**740,147,003**	**197,776**	**197,776**

(b) 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 32 and sections E, F and H 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 2025	1 Jul 2020	111,700	—	(111,700)	—	—
Employee LTIP rights	30 Jun 2026	1 Jul 2021	332,216	16,392	(17,103)	(294,380)	37,125
Employee LTIP rights	30 Jun 2027	1 Jul 2022	448,009	—	(45,963)	—	402,046
Employee LTIP rights	30 Jun 2028	1 Jul 2023	964,550	54,926	(171,783)	—	847,693
Employee LTIP rights	30 Jun 2029	1 Jul 2024	—	1,052,580	(87,715)	—	964,865
Executive Incentive Plan							
EIP Share Rights	19 Sep 2027	1 Jul 2021	2,927,766	—	—	(1,463,883)	1,463,883
EIP Share Rights	10 Nov 2027	1 Jul 2021	2,106,902	—	—	—	2,106,902
EIP Share Rights	14 Sep 2028	1 Jul 2022	5,590,464	—	—	(1,863,488)	3,726,976
EIP Share Rights	14 Nov 2028	1 Jul 2022	4,021,260	—	—	—	4,021,260
EIP Share Rights	12 Sep 2029	1 Jul 2023	—	7,694,385	—	—	7,694,385
EIP Share Rights	21 Nov 2029	1 Jul 2023	—	5,530,701	—	—	5,530,701
EIP Share Rights	30 Jun 2029	1 Jul 2024	—	13,905,530	—	—	13,905,530
Non-Executive Director rights [1]							
Director Share Rights	30 Jun 2028	1 Jul 2023	1,489,560	—	—	(1,489,560)	—
Director Share Rights	30 Jun 2029	1 Jul 2024	—	1,556,851	(195,420)	—	1,361,431
Total			**17,992,427**	**29,811,365**	**(629,684)**	**(5,111,311)**	**42,062,797**

[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.

21. RESERVES

	2025 $'000	2024 $'000
Share options reserve	32,794	32,178
Accumulated profits reserve	9,310	9,310
Total Reserves	**42,104**	**41,488**

Movements	**Share options reserve**	**Accumulated profits reserve**
Balance at 1 July 2023	31,433	—
Share based payments relating to employee incentive plans (a)	749	—
Transaction costs	(4)	—
Transfer of profit during the period from accumulated losses (b)	—	9,310
Balance at 30 June 2024	**32,178**	**9,310**
Share based payments relating to employee incentive plans (a)	619	—
Transaction costs	(3)	—
Transfer of profit during the period from accumulated losses (b)	—	—
Balance at 30 June 2025	**32,794**	**9,310**

(a) Share based payments are provided to employees under the Long Term Incentive Plan and Executive Incentive Plan. Refer to Note 32 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.

22. ACCUMULATED LOSSES

	2025 $'000	2024 $'000
Movements in accumulated losses were as follows:		
Balance at the start of year	(206,709)	(209,821)
Net profit for the year	7,734	12,422
Transfer of profits to accumulated profits reserve	—	(9,310)
Balance at end of year	**(198,975)**	**(206,709)**

23. EARNINGS PER SHARE

		2025	2024
(a)	**Basic earnings per share (cents)**	**1.04**	**1.68**
(b)	**Diluted earnings per share (cents)**	**1.01**	**1.64**
(c)	**Profit used in earnings per share calculation**		
	Profit attributed to ordinary equity holders ($'000)	**7,734**	**12,422**
(d)	**Weighted average number of ordinary shares**		
	Weighted average number of shares used as the denominator in calculating basic earnings per share	**743,955,980**	**737,684,614**
	Adjustments for the calculation of diluted earnings per share:		
	Employee share rights	24,897,192	20,948,527
	Weighted average number of shares used as the denominator in calculating diluted earnings per share	**768,853,172**	**758,633,141**

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.

24. 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.

24. SEGMENT REPORTING (CONTINUED)

(e) Performance monitoring and evaluation (continued)

2025	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	(29,087)	—	—	(29,087)
Gross profit	**14,539**	**—**	**—**	**14,539**
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]	—	—	(2,369)	(2,369)
Statutory profit / (loss) before income tax	**10,848**	**(1,322)**	**(1,792)**	**7,734**
Taxes	—	—	—	—
Statutory profit / (loss) for the year	**10,848**	**(1,322)**	**(1,792)**	**7,734**
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]	**22,538**	**16**	**(1,705)**	**20,849**
Segment assets	**74,901**	**9,051**	**30,060**	**114,012**
Segment liabilities	**(58,234)**	**(3,285)**	**(11,588)**	**(73,107)**
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 3(b)).
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.

24. SEGMENT REPORTING (CONTINUED)

(e) Performance monitoring and evaluation (continued)

2024	Producing Assets 2024 $'000	Exploration Assets 2024 $'000	Unallocated Items 2024 $'000	Consolidation 2024 $'000
Revenue from contracts with customers				
Natural gas	30,963	—	—	30,963
Crude oil and condensate	3,155	—	—	3,155
Forfeited take or pay amounts	3,036	—	—	3,036
Total revenue from contracts with customers	**37,154**	**—**	**—**	**37,154**
Cost of sales	(27,365)	—	—	(27,365)
Gross profit	**9,789**	**—**	**—**	**9,789**
Other income[1]	239	13,798	717	14,754
Other expenses	(452)	—	—	(452)
Exploration expenditure	(169)	(3,821)	—	(3,990)
Finance costs	(3,930)	(96)	(267)	(4,293)
General and administrative expenses[2]	—	—	(3,386)	(3,386)
Statutory profit / (loss) before income tax	**5,477**	**9,881**	**(2,936)**	**12,422**
Taxes	—	—	—	—
Statutory profit / (loss) for the year	**5,477**	**9,881**	**(2,936)**	**12,422**
Add Finance costs net of interest income	3,703	93	(450)	3,346
Add Depreciation, amortisation and impairment	7,190	—	598	7,788
Add Exploration expenditure	169	3,821	—	3,990
EBITDAX[3]	**16,539**	**13,795**	**(2,788)**	**27,546**
Segment assets	**69,754**	**9,169**	**24,716**	**103,639**
Segment liabilities	**(56,377)**	**(5,509)**	**(9,198)**	**(71,084)**
Capital expenditure				
Property, plant and equipment	2,651	—	67	2,718
Intangibles	164	—	18	182
Total capital expenditure	**2,815**	**—**	**85**	**2,900**

1 Other Income attributable to the Exploration Assets segment includes $13,795,000 relating to the sale of the Group's 50% interest in the Range Gas Project (ATP 2031) in Queensland's Surat Basin by way of the sale of its wholly owned subsidiary, Central Petroleum Eastern Pty Ltd. (Refer Note 3(a)).
2 Includes share-based payments of $749,000 which is a non-cash item.
3 EBITDAX is earnings before interest, taxation, depreciation, amortisation, impairment and exploration expense.

	2025 $'000	2024 $'000
Revenue from external customers by geographical location of production:		
Australia	**43,626**	**37,154**
Non-current assets by geographical location:		
Australia	**75,580**	**69,439**

24. SEGMENT REPORTING (CONTINUED)

(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.

	2025 $'000	% of Sales Revenue	2024 $'000	% of Sales Revenue
Largest customer	25,513	58%	22,774	61%
Second largest customer	6,756	15%	4,414	12%

25. PARENT ENTITY INFORMATION

(a) Summary financial information

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

	2025 $'000	2024 $'000
Balance Sheet		
Current assets	33,025	27,182
Non-current assets	19,754	18,011
Total assets	52,779	45,193
Current liabilities	(15,880)	(8,488)
Non-current liabilities	(2,911)	(994)
Total liabilities	(18,791)	(9,482)
Net assets	**33,988**	**35,711**
Shareholders' equity		
Issued capital	197,776	197,776
Reserves	42,104	41,488
Accumulated losses	(205,892)	(203,553)
Total equity	**33,988**	**35,711**
(Loss)/profit for the year	**(2,339)**	**9,310**
Total comprehensive (loss)/profit	**(2,339)**	**9,310**

(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 17).

26. 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	
			2025	2024
Name of Entity	Place of Incorporation	Class of Shares	%	%
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

	2025 $	2024 $
Short-term employee benefits	2,779,595	2,846,432
Post-employment benefits	157,374	151,981
Long-term benefits	57,175	43,558
Share based payments	637,376	613,904
	3,631,520	**3,655,875**

Detailed remuneration disclosures are provided in the Remuneration Report on pages 27 to 41.

27. 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 2025.

	2025 $'000	2024 $'000
Revenue from the sale of goods	19,596	19,670
Cost of sales	(13,263)	(13,502)
Gross profit	6,333	6,168
Other income	1,291	14,716
Other expenses	(679)	(458)
Exploration expenses	(1,628)	(3,505)
Finance costs	(2,587)	(2,346)
General and administrative expenses	(1,857)	(3,376)
Profit before income tax	873	11,199
Income tax credit	2,276	271
Profit for the year	3,149	11,470
Other comprehensive profit/(loss) for the year, net of tax	—	—
Total comprehensive profit for the year	**3,149**	**11,470**
Accumulated losses at the beginning of the financial year	(219,454)	(221,614)
Profit for the year	3,149	11,470
Transfer to Accumulated Profits Reserve	—	(9,310)
Accumulated losses at the end of the financial year	**(216,305)**	**(219,454)**

27. DEED OF CROSS GUARANTEE (CONTINUED)

(b) Consolidated balance sheet

Set out below is a consolidated balance sheet of the closed group as at 30 June.

	2025 $'000	2024 $'000
ASSETS		
Current assets		
Cash and cash equivalents	26,740	24,752
Trade and other receivables	6,673	3,969
Inventories	2,424	2,630
Total current assets	35,837	31,351
Non-current assets		
Property, plant and equipment	23,567	26,111
Right of use assets	2,288	678
Exploration assets	7,674	7,674
Other intangible assets	176	284
Other financial assets	4,596	2,046
Deferred Tax Assets	5,592	5,387
Goodwill	1,953	1,953
Total non-current assets	45,846	44,133
Total assets	**81,683**	**75,484**
LIABILITIES		
Current liabilities		
Trade and other payables	2,018	489
Deferred revenue	992	992
Borrowings	7	4,440
Lease liabilities	351	617
Provisions	6,489	7,658
Total current liabilities	9,857	14,196
Non-current liabilities		
Deferred revenue	9,036	10,237
Borrowings	23,384	18,723
Lease liabilities	1,961	84
Other financial liabilities	722	—
Provisions	13,148	12,434
Total non-current liabilities	48,251	41,478
Total liabilities	**58,108**	**55,674**
Net assets	**23,575**	**19,810**
EQUITY		
Contributed equity	197,776	197,776
Reserves	42,104	41,488
Accumulated losses	(216,305)	(219,454)
Total equity	**23,575**	**19,810**

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

	2025 $'000	2024 $'000
Profit after income tax	**7,734**	**12,422**
Adjustments for:		
Depreciation and amortisation	7,397	7,346
Impairment	—	325
Profit on disposal of subsidiary	—	(13,795)
(Profit)/loss on disposal and write-off of non-current assets	(1,190)	445
Exploration costs funded by Joint Venture partners	—	89
Share-based payments	619	749
Financing costs and interest (non-cash)	2,698	1,398
Changes in assets and liabilities relating to operating activities:		
(Increase)/decrease in trade and other receivables	(1,898)	474
Decrease/(increase) in inventories	151	(215)
Increase in trade and other payables	2,004	1,007
Decrease in deferred revenue	(1,296)	(3,919)
(Decrease)/increase in provisions	(1,915)	536
Net cash flows from operating activities	**14,304**	**6,862**

29. CASH FLOW INFORMATION

(a) Non-cash investing and financing activities

In December 2024 the Group extended and restructured its loan facility. During the half year ended 31 December 2024, interest costs of $494,000 and loan refinancing fees and expenses of $616,000 were added to the loan facility balance.

During the 2024 year, the purchasers of 50% of the Group's interests in the Amadeus Basin producing properties funded $663,000 of the Group's share of costs for the acquisition of property, plant and equipment. This was the balance of the deferred consideration component of the sale proceeds.

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

- Acquisition of right of use assets – Note 11(a); and
- Rights issued to employees under short and long-term incentive plans – Note 32.

(b) Net cash/(debt) 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 cash	2025 $'000	2024 $'000
Cash and cash equivalents	27,471	24,985
Other financial assets – cash on deposit as security for debt facility	2,500	-
Borrowings and leases – repayable within one year	(367)	(5,064)
Borrowings and leases – repayable after one year	(25,685)	(19,149)
Net cash	**3,919**	**772**
Cash	27,471	24,985
Cash on deposit as security for debt facility	2,500	-
Gross Debt – fixed interest rates	(2,660)	(1,050)
Gross debt – variable interest rates	(23,392)	(23,163)
Net cash	**3,919**	**772**

29. CASH FLOW INFORMATION (CONTINUED)

(b) Net 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 debt 1 July 2023	**13,826**	**—**	**(27,526)**	**(627)**	**(14,327)**
Cash flows	11,159	—	4,667	481	16,307
Amortisation of deferred borrowing costs	—	—	(291)	—	(291)
Non-cash adjustments	—	—	(13)	(904)	(917)
Net cash 30 June 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 30 June 2025	**27,471**	**2,500**	**(23,391)**	**(2,661)**	**3,919**

30. CONTINGENCIES

There are no contingent assets or liabilities at 30 June 2025.

31. COMMITMENTS

	2025 $'000	2024 $'000
(a) Capital commitments		
The Consolidated Entity has the following capital expenditure commitments:		
The following amounts are due:		
Within one year	613	378
	613	**378**

(b) Joint Venture exploration commitments

The Consolidated Entity has contingent exploration expenditure commitments on various permit areas held through joint venture arrangements in Australia:

	2025 $'000	2024 $'000
The following amounts are due:		
Within one year	9,150	20,850
Later than one year but not later than three years	—	9,000
	9,150	**29,850**

In April 2025 permit renewal applications were lodged by the Operator of the EP125 and EP82 joint ventures. At 30 June 2025 the NT Government had yet to formally approve the renewal applications and discussions over the work program and timing remain ongoing. The Group's share of proposed commitments included in the renewal applications amounts to $14,145,000 over the proposed five-year renewal terms. Central has no reason to believe the renewal of these permits will not be granted once agreement on the work program for each permit is achieved.

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.

32. SHARE BASED PAYMENTS

(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
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)	—	—
2024							
14 Nov 2023	30 Jun 2024	—	1,489,560	$0.050	—	—	1,489,560
23 Nov 2022	30 Jun 2023	924,971	—	$0.084	(924,971)	—	—
23 Nov 2021	30 Jun 2022	161,765	—	$0.115	(161,765)	—	—

The weighted average remaining contractual life of outstanding Non-Executive Director share rights at the end of the year was 4.0 years (2024: 4.0 years).

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

For plan years ended 30 June 2022, 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 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 hurdle pricing at the time of vesting. The maximum number of Performance Rights were granted during FY2025, 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 30 June 2027.

32. SHARE BASED PAYMENTS (CONTINUED)

The following EIP movements occurred during the year:

(c) Rights to shares — Executive Incentive Plan (EIP) (continued)

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	Balance at End of Year: Vested and Exercisable	Balance at End of Year: Total Yet to Vest
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
2024							
19 Sep 2022	30 Jun 2022	4,653,118	—	$0.096	(1,725,352)	1,463,883	1,463,883
10 Nov 2022	30 Jun 2022	3,160,353	—	$0.083	(1,053,451)	1,053,451	1,053,451
14 Sep 2023	30 Jun 2023	—	5,590,464	$0.053	—	1,863,488	3,726,976
14 Nov 2023	30 Jun 2023	—	4,021,260	$0.050	—	1,340,420	2,680,840
Totals		7,813,471	9,611,724	$0.065	(2,778,803)	5,721,242	8,925,150

The weighted average fair value of share rights issued to key management personnel under the EIP during the financial year was $0.038 (2024: $0.052). The weighted average remaining contractual life of outstanding Executive Incentive Plan share rights at the end of the year was 3.8 years (2024 3.9 years).

Subsequent to year end the Board resolved to settle 50% of vested but unexercised rights at 30 June 2025, in cash rather than shares (refer Note 35).

(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.

In previous financial years prior to FY2022, eligible employees were granted rights based on the maximum long term incentive amount applicable for each employee, being either a fixed dollar amount or a percentage of the employee's base salary, divided by the volume weighted average share price at the start of the plan year. Final vesting percentages at the end of three years were determined by performance hurdles in respect of a combination of absolute total shareholder return and relative total shareholder return compared to a specific group of exploration and production companies.

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:

32. 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
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**

The weighted average fair value of share rights granted under the Long-Term Incentive Plan during the year was $0.054 (2024: $0.051). The weighted average remaining contractual life of outstanding share rights at the end of the year was 3.2 years (2024: 3.2 years).

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 and an agreed comparator group to assess relative total shareholder return. Other share rights are valued at the value of an equivalent ordinary share at the grant date.

Grant Date	Plan Year End	Balance at Start of Year	Granted During the Year	Average Fair Value Per Right	Exercised During the Year	Cancelled or Expired During the Year	Balance at End of Year
2024							
24 Sep 2019	30 Jun 2019	36,738	—	$0.120	(30,615)	(6,123)	—
24 Sep 2019	30 Jun 2019	8,127	—	$0.087	(8,127)	—	—
09 May 2019	30 Jun 2019	28,012	—	$0.101	(28,012)	—	—
23 Aug 2019	30 Jun 2020	23,988	—	$0.190	(22,140)	(1,848)	—
23 Aug 2019	30 Jun 2020	295,045	—	$0.155	(138,996)	(156,049)	—
07 Nov 2019	30 Jun 2019	578,689	—	$0.119	(578,689)	—	—
24 Jul 2020	30 Jun 2021	8,360,299	—	$0.065	(2,402,287)	(5,857,649)	100,363
24 Jul 2020	30 Jun 2021	340,770	—	$0.089	(306,759)	(22,674)	11,337
17 Aug 2021	30 Jun 2022	319,644	—	$0.105	—	(32,784)	286,860
22 Aug 2022	30 Jun 2022	55,257	—	$0.090	—	(9,901)	45,356
22 Aug 2022	30 Jun 2023	507,180	—	$0.090	—	(59,171)	448,009
11 Aug 2023	30 Jun 2024	—	1,019,157	$0.051	—	(86,656)	932,501
13 Sep 2023	30 Jun 2024	—	32,049	$0.059	—	—	32,049
Totals		**10,553,749**	**1,051,206**		**(3,515,625)**	**(6,232,855)**	**1,856,475**

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:

	2025 $	2024 $
Share Rights issued to employees	**618,820**	**749,453**

33. 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.

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 2025 is nil (2024: nil), no loss allowance provision has been recorded at 30 June 2025 (2024: 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	2025 $'000	2024 $'000	2025 $'000	2024 $'000
Current: 0-30 days	**5,517**	3,868	—	—
	5,517	**3,868**	—	—

The trade receivables at 30 June 2025 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 25(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 below) and cash and cash equivalents (Note 7) 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.

33. FINANCIAL RISK MANAGEMENT (CONTINUED)

(b) Liquidity Risk (continued)

The following are the contractual maturities of financial assets and liabilities:

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)**

2024 ($'000)	≤ 6 Months	6–12 Months	1–5 Years	≥ 5 Years	Contractual Cash Flow	Carrying Amount
Financial Assets						
Cash and cash equivalents	24,985	—	—	—	24,985	24,985
Trade and other receivables	3,961	—	—	—	3,961	3,961
Other financial assets	—	—	2,840	—	2,840	2,840
	28,946	**—**	**2,840**	**—**	**31,786**	**31,786**
Financial Liabilities						
Trade and other payables	(3,260)	—	—	—	(3,260)	(3,260)
Interest bearing liabilities	(3,830)	(3,702)	(19,563)	(554)	(27,649)	(24,213)
	(7,090)	**(3,702)**	**(19,563)**	**(554)**	**(30,909)**	**(27,473)**

33. 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	
	2025 %	2024 %	2025 $'000	2024 $'000	2025 $'000	2024 $'000	2025 $'000	2024 $'000	2025 $'000	2024 $'000
Financial Assets:										
Cash and cash equivalents	**3.8**	4.6	**27,471**	14,985	**—**	10,000	**—**	—	**27,471**	24,985
Trade and other receivables	**—**	—	**—**	—	**—**	—	**5,583**	3,961	**5,583**	3,961
Other financial assets	**2.5**	0.9	**—**	—	**3,103**	528	**2,313**	2,312	**5,416**	2,840
Total Financial Assets			**27,471**	14,985	**3,103**	10,528	**7,896**	6,273	**38,470**	31,786
Financial Liabilities:										
Trade and other payables	**—**	—	**—**	—	**—**	—	**(5,175)**	(3,260)	**(5,175)**	(3,260)
Interest bearing liabilities	**11.6**	10.0	**(23,391)**	(23,163)	**(2,661)**	(1,050)	**—**	—	**(26,052)**	(24,213)
Total Financial Liabilities			**(23,391)**	(23,163)	**(2,661)**	(1,050)	**(5,175)**	(3,260)	**(31,227)**	(27,473)
Net Financial Assets / (Liabilities)			**4,080**	(8,178)	**442**	9,478	**2,721**	3,013	**7,243**	4,313

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
2025 ($'000)				
Cash and cash equivalents	133	(133)	—	—
Interest bearing liabilities	(117)	117	—	—
2024 ($'000)				
Cash and cash equivalents	75	(75)	—	—
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.

33. 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.

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 and certain liabilities associated with gas sales agreements with Macquarie.
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:

	2025 $'000	2024 $'000
Trade and other receivables (USD)	—	437
Trade and other payables:		
- USD	(23)	(112)
- 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.

	2025 $'000	2024 $'000
Australian dollar +10% movement in exchange rate	3	(30)
Australian dollar -10% movement in exchange rate	(4)	36

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.

34. INTERESTS IN JOINT ARRANGEMENTS

Details of joint arrangements in which the Consolidated Entity has an interest are as follows:

	Principal Activities	2025 %	2024 %
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	60.00
EP 105[2]	Oil & gas exploration	—	60.00
EP 112[1]	Oil & gas exploration	45.00	45.00
EP 125[1]	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

1 The farmout agreement with Peak Helium (Amadeus Basin) Pty Ltd (Peak) was terminated in September 2023. The relevant subsidiaries have commenced the process to have ownership interests in the permits returned to pre-farmout interest, requiring the following interests to be returned to Central:
(a) 31% in EP82, excluding Dingo Satellite Area (Central's interest to be restored from 29% to 60%);
(b) 10% in EP112 (Central's interest to be restored from 35% to 45%); and
(c) 6% in EP125 (Central's interest to be restored from 24% to 30%).

2 EP105 was surrendered and expired on 27 February 2025.

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.

Other parties' rights to earn and retain participating interests in certain permits is subject to satisfying various obligations in their respective farmout agreements. The participating interests as stated above are beneficial interests and assume such obligations have been met, or otherwise may be subject to change or negotiation.

34. 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:

	2025 $'000	2024 $'000
Current assets		
Cash and cash equivalents	1,449	417
Trade and other receivables	4,932	3,212
Inventory	3,393	3,406
Total current assets	9,774	7,035
Non-current assets		
Property, plant and equipment	50,200	47,543
Right of use assets	376	387
Total non-current assets	50,576	47,930
Current liabilities		
Trade and other payables	3,962	3,038
Lease liabilities	12	10
Deferred revenue	992	1,087
Provision for production over-lift	653	871
Restoration provision	454	299
Total current liabilities	6,073	5,305
Non-current liabilities		
Deferred revenue	9,036	10,237
Lease liabilities	393	396
Provision for production over-lift	—	738
Restoration provision	19,685	19,018
Total non-current liabilities	29,114	30,389
Net assets	**25,163**	**19,271**
Joint arrangement contribution to profit before tax		
Revenue	43,626	37,154
Other income	1,460	77
Expenses	(30,960)	(25,266)
Profit before income tax	**14,126**	**11,965**

35. EVENTS OCCURRING AFTER THE REPORTING PERIOD

In August 2025, 6,261,742 vested share rights, being 50% of the unexercised EIP share rights at 30 June were settled for $345,341 cash, 233,016 share rights lapsed and 7,491,308 new ordinary shares were issued upon exercise of vested share rights.

No other matters or circumstances have arisen between 30 June 2025 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 2025

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[1]	Body corporate	–	100	Australia	Australian
Ordiv Petroleum Pty Ltd[1]	Body corporate	–	100	Australia	Australian
Frontier Oil & Gas Pty Ltd[1]	Body corporate	–	100	Australia	Australian
Central Geothermal Pty Ltd	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	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 44 to 89 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 2025 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 90 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 2025.

3. As at the date of this declaration, there are reasonable grounds to believe that the members of the Closed Group identified in Note 27 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 2025

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 2025 and of its financial performance for the year then ended

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 2025
- 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 2025
- the directors' declaration.

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BRISBANE QLD 4001
T: +61 7 3257 5000, F: +61 7 3257 5999,

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 our audit of the financial report 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.

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 matters to the Audit and Financial Risk Committee.

Key audit matter	How our audit addressed the key audit matter
Valuation of exploration and evaluation assets Refer to Note 1(p) and Note 12 of the financial report 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, and to the success or otherwise of activities undertaken in the area of interest. 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. We considered management's indicator assessment to be a key audit matter given the significance of the assets to the consolidated balance sheet and the uncertainty surrounding the sub-salt exploration program.	To evaluate the Group's assessment of whether any indicators of impairment exist, we performed the following procedures, amongst others: • inquired with key operational and finance staff to develop an understanding of the current status and future intention for each area of interest. • obtained and read relevant support including internal and external documents for current and future intentions for each area of interest. • considered whether areas of interest that remain capitalised are included in future budgets and/or operational plans of the Group. • ascertained 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.

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 2025, 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.

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 2025.

In our opinion, the remuneration report of Central Petroleum Limited for the year ended 30 June 2025 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

Marcus Goddard
Partner

Brisbane
17 September 2025

ASX ADDITIONAL INFORMATION

DETAILS OF QUOTED SECURITIES AS AT 15 SEPTEMBER 2025

Top holders

The 20 largest registered holders of the quoted securities as at 15 September 2025 were:

	NAME	NO. OF SHARES	%
1	Norfolk Enchants Pty Ltd <Trojan Retirement Fund A/c>	48,608,932	6.46
2	Maitri Pty Ltd <Coci Super Fund A/C>	38,269,716	5.08
3	Mr Kenneth John Beer + Mr Alexander Charles Beer <Beer Super Fund A/C>	27,460,215	3.65
4	Moranbah Nominees Pty Ltd <Chris Wallin Super Fund A/C>	19,526,612	2.59
5	Brazil Farming Pty Ltd	17,785,209	2.36
6	Citicorp Nominees Pty Limited	15,303,534	2.03
7	Macquarie Bank Limited <Metals Mining and AG A/C>	14,166,667	1.88
8	JH Nominees Australia Pty Ltd <Harry Family Super Fund A/C>	13,000,000	1.73
9	Mr Philip Gasteen <Thrushton Investment A/C>	12,373,780	1.64
10	Careniup Pty Ltd <Mathis Super Fund A/c>	10,221,888	1.36
11	Chembank Pty Limited <Philandron A/C>	10,000,000	1.33
12	Mr Leon Goss Devaney	8,050,721	1.07
13	Kensington Capital Partners Pty Ltd	8,000,000	1.06
14	ITA Vero Pty Ltd <The Richmond A/c)	7,470,849	0.99
15	BNP Paribas Nominees Pty Ltd <IB AU Noms Retailclient>	7,245,805	0.96
16-17	Garmi Holdings Pty Ltd <Pemco Super Fund A/c>	7,000,000	0.93
16-17	PA and RE Gibson Pty Ltd <PA&RE Gibson Super Fund A/C>	7,000,000	0.93
18	Chembank Pty Limited <CABAC Super Fund A/c>	6,000,000	0.80
19	Mr Donald Leonard Cottee	5,830,594	0.77
20	Mr James Donald Bruce Cochrane + Mrs Joan Elizabeth Cochrane <Bruce & Joan Cochrane A/c)	5,000,001	0.66
	Total	**288,314,523**	**38.30**

DISTRIBUTION SCHEDULE

A distribution schedule of the number of holders in each class of equity securities as at 15 September 2025 was:

SIZE OF HOLDING	LISTED FULLY PAID SHARES	UNLISTED SHARE RIGHTS
1 – 1,000	121	-
1,001 – 5,000	238	-
5,001 – 10,000	448	1
10,001 – 100,000	1,860	57
100,001 – Over	740	6
Total	**3,407**	**64**

UNLISTED SECURITIES

At 15 September 2025, there were 28,188,431 unlisted share rights on issue.

ASX ADDITIONAL INFORMATION

SUBSTANTIAL SHAREHOLDERS

Substantial shareholders as disclosed by notices received by the Company as at 15 September 2025 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 8,197 shares as at 15 September 2025):

HOLDERS	UNITS
463	1,445,175

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 15 September 2025.

ANNUAL GENERAL MEETING

Central Petroleum Limited advises that the Annual General Meeting (AGM) of the Company is scheduled for 20 November 2025. 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 30 September 2025.

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 2025 Corporate Governance Statement reflects the corporate governance practices in place throughout the 2025 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(a)]	Amadeus Basin NT	Santos	29	60	Santos QNT Pty Ltd ("Santos")	40
EP82 Sub-Blocks	Amadeus Basin NT	Central	100	100		
EP112 [1(b)]	Amadeus Basin NT	Santos	35	45	Santos	55
EP115	Amadeus Basin NT	Central	100	100		
EP125[1(c)]	Amadeus Basin NT	Santos	24	30	Santos	70
OL3 (Palm Valley)	Amadeus Basin NT	Central	50	50	Echelon Palm Valley Pty Ltd Cue Palm Valley Pty Ltd	35 15
OL4 (Mereenie)	Amadeus Basin NT	Central	25	25	Echelon Mereenie Pty Ltd Horizon Australia Energy Pty Ltd Cue Mereenie Pty Ltd	42.5 25 7.5
OL5 (Mereenie)	Amadeus Basin NT	Central	25	25	Echelon Mereenie Pty Ltd Horizon Australia Energy Pty Ltd Cue Mereenie Pty Ltd	42.5 25 7.5
L6 (Surprise)	Amadeus Basin NT	Central	100	100		
L7 (Dingo)	Amadeus Basin NT	Central	50	50	Echelon Dingo Pty Ltd Cue Dingo Pty Ltd	35 15
RL3 (Ooraminna)	Amadeus Basin NT	Central	100	100		
RL4 (Ooraminna)	Amadeus Basin NT	Central	100	100		

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	100	50	Santos	50
EPA124 [2]	Amadeus Basin NT	Santos	100	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		

INTERESTS IN PETROLEUM PERMITS AND PIPELINE LICENCES

AT THE DATE OF THIS REPORT

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

Notes:

[1] As announced on 20 September 2023, the farmout agreement with Peak Helium (Amadeus Basin) Pty Ltd (***Peak***) has been terminated . The relevant subsidiaries have commenced the process to have ownership interests in the permits returned to pre-farmout interest, requiring the following interest to be returned to Central:

(a) 31% in EP82, excluding Dingo Satellite Area (Central's interest to be restored from 29% to 60%)

(b) 10% in EP112 (Central's interest to be restored from 35% to 45%); and

(c) 6% in EP125 (Central's interest to be restored from 24% to 30%)

[2] In March 2018 Central received notice from DME that EPA124 had been placed in moratorium on 6 December 2017 for a five year period which ended on 6 December 2022.

GLOSSARY AND ABBREVIATIONS

1P	Proved reserves*
2C	Best estimate contingent resources*
2P	Proved and probable reserves*
Bbl	barrel of oil (unit of measure)
Bcf	billion cubic feet
Bopd	barrel of oil per day
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
ESOP	Executive share option plan
GJ	Gigajoule (1 billion joules) (unit of energy measure)
GJe	Gigajoule equivalent (oil converted at 5.816 GJe / bbl)
GSA	Gas sale agreement
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
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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AUDITORS

PricewaterhouseCoopers
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SHARE REGISTER

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Telephone: 1300 552 270
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STOCK EXCHANGE LISTING

Central Petroleum Limited shares are listed on the Australian Securities Exchange under the code CTP.