Central Petroleum

2024

ANNUAL REPORT

Central Petroleum Limited

ACN 083 254 308

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Forward-looking statements:

This document contains forward-looking statements, including (without limitation) statements of current intention, opinion, predictions and expectations regarding Central's present and future operations, possible future events and future financial prospects. Such statements are not statements of fact, are not certain and are susceptible to change and may be affected by a variety of known and unknown risks, variables and changes in underlying assumptions or strategy that could cause Central's actual results or performance to differ materially from the results or performance expressed or implied by such statements. There can be no certainty of outcome in relation to the matters to which the statements relate. Central makes no representation, assurance or guarantee as to the accuracy or likelihood of fulfilment of any forward-looking statement (whether express or implied) or any outcomes expressed or implied in any forward-looking statement. The forward-looking statements in this document reflect expectations held at the date of this document. Except as required by applicable law or the Australian Securities Exchange (ASX) Listing Rules, Central disclaims any obligation or undertaking to publicly update any forward-looking statements.

CHAIR'S LETTER

Dear Shareholders,

This is my fourth annual letter to Central Petroleum's shareholders, and I have a sense that Central's outlook is more positive than ever before. Over the last decade, your company has been through a number of transformations, with the most significant being the substantial investment in upgrading production capacity leading up to the opening of the Northern Gas Pipeline in 2019.

Since then, the company has prioritised repayment of the various forms of debt that were necessarily raised to fund the expansion programs. This year we have seen three important developments which should result in sustainable positive cash flows and, ultimately, returns to shareholders.

Firstly, we have seen a shift in gas markets, particularly in the Northern Territory where a supply-side shortage has seen Central's onshore gas fields now more critical than ever to the region's energy balance, supplying about half of the Northern Territory's gas demand.

Central's proven reserves and history of reliable production resulted in a successful marketing campaign that will see all of our firm gas production sold at attractive pricing into the Northern Territory from 2025 through to the end of 2030. The importance of these new contracts cannot be understated, with a step change in pricing from maturing legacy gas contracts promising increased free cash flow. The contracts greatly reduce our exposure to pipeline outage risks which impacted our results this year and clouded our future.

Secondly, our decision to exit from the Range gas project in Queensland has reduced our future capital commitments and consequentially has strengthened our balance sheet, with $12.5 million in cash proceeds reducing our net debt. At the end of the year we were in a positive net cash position – for the first time in a decade!

And lastly, we have fully repaid one of our layers of 'debt', the pre-sold gas which was used to fund new production wells three years ago. We are now selling this gas volume, previously dedicated to repaying the debt, into the stronger market, giving us a boost in free cash flow. A further cash flow boost will arrive in just over 18 months, when we will have fully delivered all of our overlifted gas liability.

Our stronger balance sheet, when combined with the contractual certainty from the new multi-year, Northern Territory-focused gas contracts and stronger market pricing, gives us increasing confidence to fund new development wells, underwrites debt restructuring and provides the opportunity for the board to consider returns to shareholders. We are hopeful this will occur in the near term.

The value of Central's producing assets is becoming more obvious in the gas-short market, and the recent transaction, which saw New Zealand Oil & Gas (now Echelon Resources) and Horizon Oil purchase Macquarie's 50% interest in the Mereenie gas field, confirms the value that we see in these assets.

While our producing assets look set to contribute increasing free cash flows in coming years, we are also working to realise value from our extensive exploration holdings. The helium, hydrogen and natural gas potential of the sub-salt prospects could be company-changing, and the potential value of these prospects is too great to ignore. Our strategy is to fund programs from farmouts where possible to spread the risk and costs while preserving some upside for our shareholders.

The underlying financial results for the year unfortunately reflected the pipeline-induced disruptions to production, which were both unexpected and outside of Central's control. However, the new gas sales contracts mentioned earlier will largely neutralise that risk in the foreseeable future.

With our strategic review completed and outcomes being actioned, we farewelled Director Troy Harry from the Board and I thank him for his significant contribution and welcome his ongoing support as Central's largest shareholder.

I also thank our CEO Leon Devaney, together with his management team and staff, for their contributions in safely and efficiently operating our three gas fields. We also greatly appreciate the continuing support and cooperation of the people, suppliers, local communities and traditional owners of the land on which we operate. Their combined efforts allow us to continue to provide a reliable and affordable supply of energy to the businesses and residents of the Northern Territory.

On a closing note, we have responded to the 2023 AGM shareholder vote against our remuneration report by making significant changes to the remuneration structure of our executive team for FY2025 and beyond. The CEO's remuneration package has been re-weighted, with lower fixed remuneration and new at-risk incentives with higher share price appreciation hurdles. The pay of other executives has been frozen at the 2024 level, and we have retained a smaller executive team (four rather than six) and Board (four Non-executive Directors, down from five) than we have in the past. Short and long-term incentives have been revised, including an equity-linked component that now only rewards a significant increase in share price over three years, requiring a circa 50% increase in share price to 8 cents per share over three years to reach the minimum threshold, and only reaching the maximum award if the share price more than triples to 16 cents over three years.

In conclusion, we are already seeing some positive outcomes from our extensive strategic review process concluded earlier this year, and we look forward to sharing news of more success as the next year unfolds.

Thank you,

Mick McCormack, Chair
18 September 2024

CHIEF EXECUTIVE OFFICER'S LETTER

Dear fellow Shareholders,

As we reflect on the past year, I am very proud of how our company has navigated an exceptionally challenging period.

Central, and many of our peers in the gas industry, continued to face stiff headwinds in the form of ill-conceived gas market interventions, constricting regulations and determined opposition from ill-informed, single-interest climate groups.

The reality however, is that gas will play a crucial role in any affordable transition to cleaner energy. This means that the demand for gas will continue to be strong for an extended period, and new gas supply that can be brought to market will be rewarded. This is what Central is positioned to do.

We also faced the unexpected scenario that shortfalls by other gas suppliers in the Northern Territory resulted in the Northern Gas Pipeline, a $1 billion piece of infrastructure linking Northern Territory gas suppliers to east coast gas customers, experiencing extended outages over the past two years. Unfortunately, it has been unavailable for most of this year, and it continues to remain offline for the foreseeable future. This has had a visible impact on our FY2024 results and introduced an entirely unexpected risk to our revenue forecasts.

All of these challenges have put downward pressure on our share price and have been formidable tests of our resilience and strategy. Nonetheless, we have emerged stronger and well positioned to benefit from what we see as tightening gas markets.

Over the last year we sold our Range project for a profit of $13.8 million (cash proceeds of $12.5 million), providing a significant boost to our cash balance. We announced a forward strategy focussed on maximising free cash flow, with exploration prioritised to activities funded through farmouts. We continued to pay down our liabilities and have made further cuts to corporate and administrative costs, including maintaining our executive headcount at four, down from the six executives Central has had historically.

Most significant, however, was the successful conclusion of our gas sale Expression of Interest process which resulted in a new major gas sale agreement with the Northern Territory Government. We have now contracted all of our firm gas production for the next six years, underwritten two new development wells at Mereenie, and mitigated our exposure to the Northern Gas Pipeline. I believe this is the most transformative gas sale agreement that Central has ever executed, with an increase in our historical average portfolio contract price and an anticipated increase in Mereenie production becoming visible early next year.

By exercising rigorous financial discipline and executing robust commercial strategies, we have the financial strength to both capitalise on the opportunities ahead and consider returns to shareholders in the near term.

Accordingly, I am very pleased to report that Central concluded fiscal year 2024 with a number of highlights, including:

- Strong safety record, maintaining a nil TRIFR for more than 18 months,
- Positive net cash position of almost $1m, compared to net debt of $14.3m just a year ago,
- Cost of servicing liabilities is down 60% from just five years ago,
- Net profit of $12.4m with underlying EBITDAX of $13.8m,
- Contracted all existing firm gas for six years into a strong market,
- Mitigated risks associated with the Northern Gas Pipeline, and
- Launched a fully funded two-well drilling program at Mereenie.

Our progress to return to company-changing exploration has also been encouraging. We have advanced farmout discussions for our sub-salt prospects targeting helium and hydrocarbons. We have also engaged with our joint venture partners in respect of lower-risk appraisal and exploration within our existing producing fields, such as new wells at Palm Valley and testing of the Stairway formation at Mereenie, where any new reserves would greatly benefit from prevailing gas markets and brownfield economics.

Our narrower exploration activity is strategically focussed on high-potential, lower risk areas that can be funded through farmouts or infield opportunities with compelling risk / reward metrics. This more affordable and focused exploration activity supports our strategy to maximise cash flow, whilst retaining exposure to growth opportunities that can deliver significant near-term value to our shareholders.

The next 12 months will be a pivotal period for the Company. The Northern Territory gas market will soon witness drilling results at the Blacktip field and in the Beetaloo Basin, with the potential for a shortage in the Northern Territory gas market emerging within the next six months. We are confident that the actions we have taken over the past year have solidified shareholder value within this uncertain landscape and set the foundation for Central to further leverage changing market dynamics.

We have done the hard work and are now turning the corner on what has been a challenging period in the Company's history. I look forward to our much stronger future becoming more visible to shareholders over the next year.

Thank you for your continued trust and support. I am confident that Central can navigate the future successfully and build on this year's strong result to deliver shareholder returns into the future.

Sincerely,

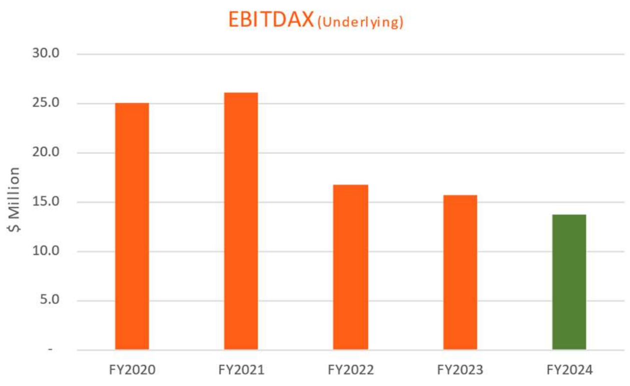
Leon Devaney, CEO

18 September 2024

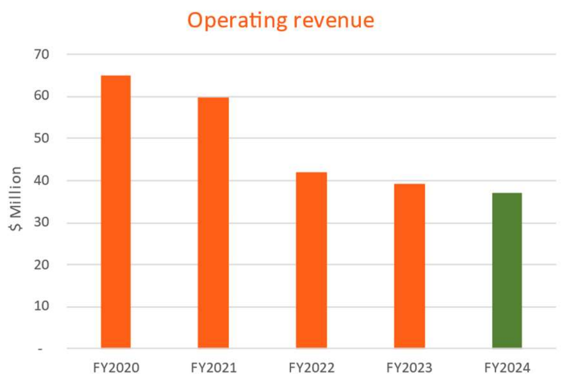
OPERATING AND FINANCIAL REVIEW

OPERATING HIGHLIGHTS

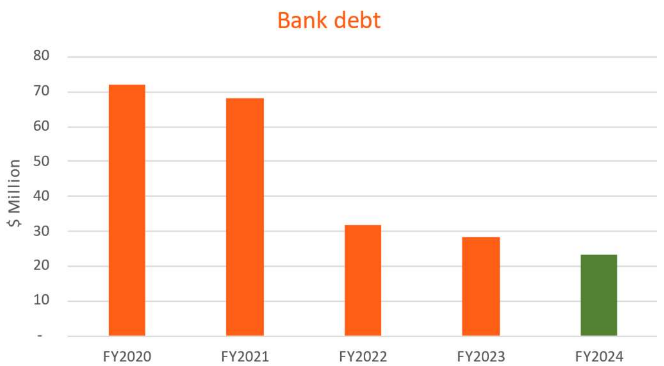
- Central sold its 50% interest in the Range CSG Project (ATP2031) for $12.5 million, releasing capital and realising a book profit of $13.8 million.
- Terminated the farmout of interests in three Northern Territory exploration permits following default by the counterparty, leading to the deferral of a planned three well exploration program.
- New gas sales agreements (GSAs) were secured during and subsequent to the end of the financial year, and are expected to provide higher, more reliable cash flows for Central for several years, benefitting from higher average gas prices and more consistent, firm sales that will not be affected by any Northern Gas Pipeline (NGP) interruptions, should they occur. The new GSAs included the sale of (Central share):
    - up to 2.1 PJ to Power & Water Corporation in the NT until the end of 2024 on an as available basis;
    - up to 12 PJ of gas to the Northern Territory Government for six years from 2025 to 2030; and
    - up to 4.1 PJ of gas to Arafura's Nolan's rare earth project over three years from 2028, subject to project FID by 31 December 2024.
- Gas which was pre-sold in 2020 was fully delivered by December 2023, releasing additional gas volumes for sale on usual cash terms and boosting cash flows from January 2024 onwards.
- Agreement was reached to progress a helium recovery unit at Mereenie, demonstrating the potential of the Amadeus Basin as a world-class helium resource. Work continues with parties that include a major helium distributor, with the scope now expanded to consider a helium liquefaction unit.



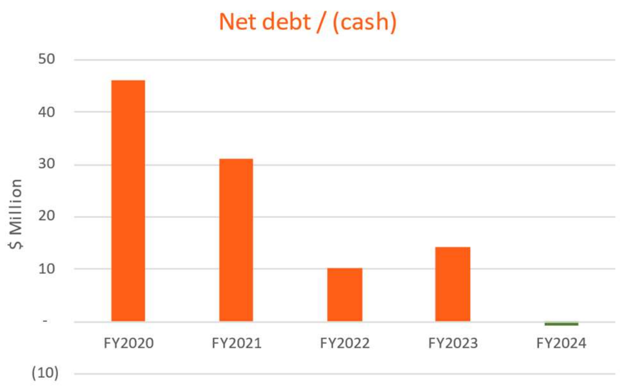
Underlying EBITDAX: Decreased 13% to $13.8m in FY2024
(Earnings before interest, tax, depreciation, impairment, exploration costs, and profit on asset disposals)



Operating revenue: Decreased 5% to $37.2m in FY2024



Bank debt decreased 18% to $23.2m in FY2024.



Net cash: $0.8m at 30 June 2024

OPERATING AND FINANCIAL REVIEW

FINANCIAL REVIEW

The Consolidated Entity had a profit after income tax for the year ended 30 June 2024 of $12.4 million (2023: loss of $8.0 million).

The above result includes a $13.8 million profit on the sale of the Range CSG interests (ATP 2031) and was after expensing exploration costs of $4.0 million (2023: $13.1 million). The Group's policy is to expense all exploration costs as incurred.

To assist with comparability of this year's result, EBITDAX, EBITDA and EBIT have been reported against the underlying results in FY2023.

The table below shows key metrics for the Group:

Key Metrics	Total 2024	Total 2023	Change	% Change
Net Sales Volumes				
- Natural Gas (TJ)	**4,377**	**4,664**	(287)	(6)%
- Oil & Condensate (bbls)	**26,304**	**30,293**	(3,989)	(13)%
Sales Revenue ($'000)	**37,154**	**39,255**	(2,101)	(5)%
Gross Profit ($'000)	**9,789**	**12,847**	(3,058)	(24)%
Underlying EBITDAX[1] ($'000)	**13,751**	**15,749**	(1,998)	(13)%
Underlying EBITDA[2] ($'000)	**9,761**	**2,656**	7,105	268 %
Underlying EBIT[3] ($'000)	**1,973**	**(4,210)**	6,183	147 %
Underlying loss after tax[4] ($'000)	**(1,373)**	**(8,170)**	6,797	83 %
Statutory profit/(loss) after tax ($'000)	**12,422**	**(7,960)**	20,382	256 %
Net cash inflow/(outflow) from Operations[5] ($'000)	**6,862**	**(2,056)**	8,918	434 %
Capital expenditure[6] ($'000)	**2,718**	**12,815**	(10,097)	(79)%

1 Underlying EBITDAX is Earnings before Interest, Tax, Depreciation, Amortisation, Impairment and Exploration costs and profit on disposal of interests in subsidiaries and exploration permits (refer reconciliation below).
2 Underlying EBITDA is Earnings before Interest, Tax, Depreciation, Amortisation, Impairment and profit on disposal of interests in subsidiaries and exploration permits.
3 Underlying EBIT is Earnings before Interest, Tax and profit on disposal of interests in subsidiaries and exploration permits.
4 Underlying profit / loss after tax is statutory profit after tax, before profit on disposal of interests in subsidiaries and exploration permits.
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 review, 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.

EBITDAX

Underlying EBITDAX for the year was $13.8 million, down 13% from $15.7 million in 2023 reflecting lower sales volumes due to intermittent interruptions to the Northern Gas Pipeline during the year. Further discussion on revenues and gross profit are included below.

Underlying EBITDAX are earnings before interest, tax, depreciation, amortisation, impairment, exploration and profit on disposal of interests in subsidiaries or exploration permits. Underlying EBITDAX is used by management as an indicative measure of underlying operating profit from operations as it excludes non-cash items, the costs of finance and expensed exploration costs 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 $0.7 million this year (2023: $0.8 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	2024 $'000	2023 $'000
Statutory profit/(loss) before tax	12,422	(7,960)
Impact of farmout to Peak Helium net of impairment costs	—	(210)
Profit on disposal of interest in Range CSG project	(13,795)	—
Underlying loss before tax	**(1,373)**	**(8,170)**
Net finance costs and restatement of financial assets	3,346	3,960
Underlying EBIT	**1,973**	**(4,210)**
Depreciation, amortisation and impairment	7,788	6,866
Underlying EBITDA	**9,761**	**2,656**
Exploration expenses	3,990	13,093
Underlying EBITDAX	**13,751**	**15,749**

Sales Volumes

Sales volumes were 7% lower than FY2023 at 4.5 PJe, largely due to outages on the Northern Gas Pipeline (NGP) interrupting deliveries to customers in eastern states (oil converted at 5.816 GJ/bbl). The new sale contracts for the balance of CY2024, and with the NT Government starting 2025 are expected to provide result in more consistent, firm sales that will not be affected by NGP interruptions.

Product	Unit	FY 2024	FY 2023
Gas	PJ	4.4	4.7
Crude and Condensate	bbls	26,304	30,293
Total	**PJe**	**4.5**	**4.8**

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

Sales Revenue

Central recorded sales revenue of $37.2 million, down 5% on FY2023, reflecting the lower volumes and restricted access to higher-priced contracts/markets due to the NGP interruptions. Average realised prices were down 4% on FY2023 at $7.56/GJe. Total sales revenue included $3.0 million released from deferred take-or-pay balances (2023: $1.0 million).

Gross Profit

Gross profit was $9.8 million, a decrease of 24% on FY2023. On a per unit basis this represents a gross profit of $2.16/GJe which is a decrease of 18% from $2.65/GJe for FY2023, reflecting the lower average sales price and higher per-unit cost of sales. The unit cost of sales increased by 11%, reflecting fixed costs spread over lower volumes, a 13% increase in royalty expenses on a per unit basis following the introduction of the new NT royalty regime, and additional environmental regulatory and compliance costs.

Net Assets/Liabilities

At 30 June 2024, the Group had a net asset position of $32.6 million compared to $19.4 million at 30 June 2023, 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 associated make-up gas provisions amounting to $11.3 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, 0.73 PJ of previously over-lifted gas was repaid to joint venture partners and the remaining 0.44 PJ of pre-sold gas was fully delivered.

Debt

The Group repaid $4.7 million of loan principal during the year. The outstanding balance of the loan facility at 30 June 2024 was $23.1 million with $4.7 million due for repayment in FY2025. An additional $5.0 million is currently undrawn and available until 30 September 2024.

At 30 June 2024 the Group was in a net cash position of $0.8 million compared to a net debt position of $14.3 million at 30 June 2023, reflecting the cash received on disposal of the Range CSG project and ongoing cashflow from operations.

The consolidated debt ratio at 30 June 2024 was 0.23 (2023: 0.29). 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 $11.2 million over the year. Net cash flow from production operations for 2024 was $14.1 million (before CAPEX), compared to $13.8 million for 2023, with lower sales volumes offset by higher pricing, lower cash production costs and the benefit of additional cash flows following the end of pre-sold gas deliveries in December 2023.

After net interest payments of $2.0 million, $2.6 million of corporate and staff expenses and $2.6 million for exploration activities, net cash from operating activities was $6.9 million (2023: $2.1 million outflow).

OPERATING AND FINANCIAL REVIEW

During the year, Central invested $2.9 million in capital projects, including installation of a compressor to recover flare gas at Mereenie and other sustaining capital expenditure at the three producing fields. Central repaid $4.7 million of debt during the year.

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 years then ended.

	2020 $ MILLION	2021 $ MILLION	2022 $ MILLION	2023 $ MILLION	**2024 $ MILLION**
Financial Data[1]					
Operating revenue	65.05	59.83	42.15	39.26	**37.15**
Exploration expenditure	5.28	7.74	21.65	13.09	**3.99**
Profit/(loss) after income tax	5.41	0.25	21.32	(7.96)	**12.42**
EBITDAX	33.40	26.09	53.31	**15.96**	**27.55**
Underlying EBITDAX	25.01	26.09	16.75	**15.75**	**13.75**
Equity issued during year	—	—	—	—	—
Property, plant and equipment[2]	107.85	108.28	53.85	60.19	**55.58**
Cash[2]	25.92	37.17	21.65	13.83	**24.99**
Borrowings	(70.77)	(66.81)	(30.81)	(27.53)	**(23.16)**
Net Assets (Total Equity)	1.58	3.69	26.53	19.39	**32.56**
Net Working Capital (Net current assets/(liabilities))	6.75	8.25	22.31	7.11	**16.00**

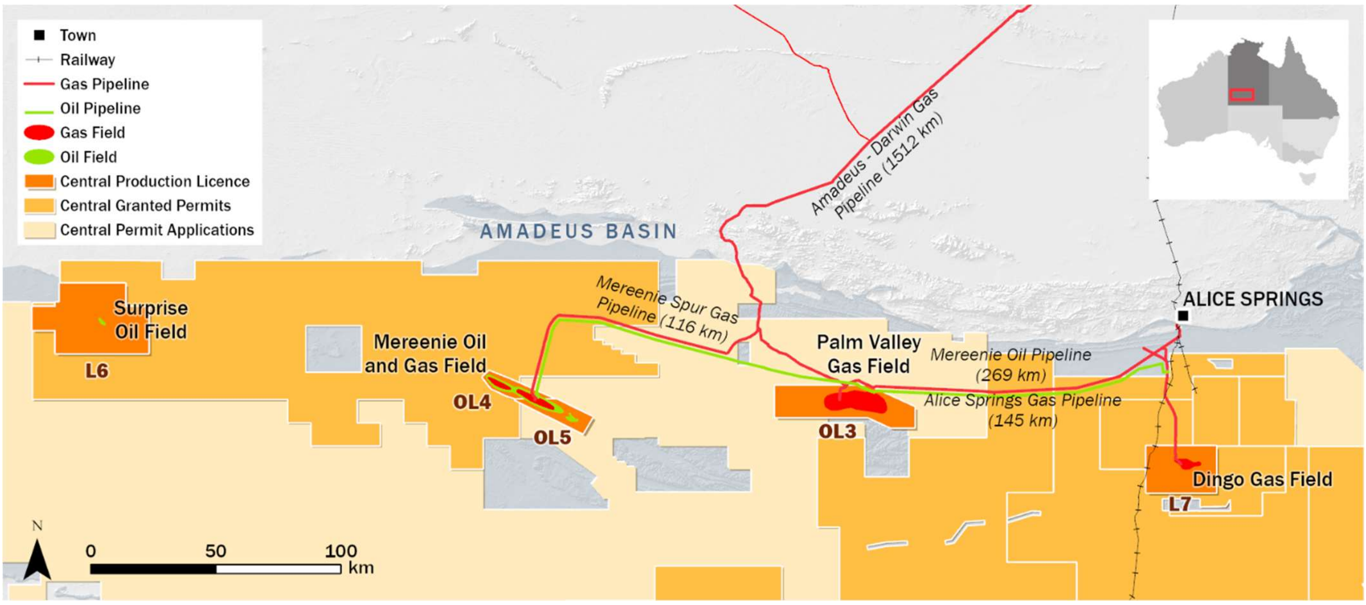
[1] In October 2021, Central sold a 50% interest in its producing gas fields
[2] Includes assets classified as held for sale.

	2020	2021	2022	2023	**2024**
Operating Data					
Gas Sales (TJ)	11,822	9,820	5,993	**4,664**	**4,377**
Oil Sales (barrels)	89,016	77,255	47,197	**30,293**	**26,304**
No. of employees at 30 June	92	85	88	**80**	**81**

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 gas producing fields in the NT, supplying industrial customers, electricity generators and gas distributors from three producing fields near Alice Springs.

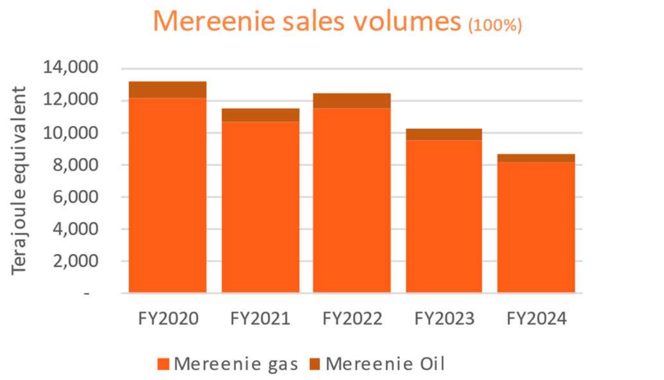
Producing Assets



Location of Central's producing oil and gas fields

Mereenie Oil and Gas Field (OL4 and OL5)

Northern Territory



Ownership interests	
Central Petroleum (operator)	**25.0%**
Echelon Mereenie Pty Ltd[1]	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	28.1	36.6	45.6
Oil	mmbbl	0.30	0.36	0.05
Total[2]	PJe	29.8	38.7	45.9

1 Formerly NZOG Mereenie Pty Ltd

2 Reserves and resources are as at 30 June 2024. 2C gas resources include 27 PJ attributable to the Stairway Sandstone.

3 Oil converted at 5.816 PJ/mmbbl

Mereenie highlights

- Flare gas compressor commissioned, reducing emissions by up to 33%.
- Planning progressing for construction of a helium recovery and liquefaction unit.
- Two new production wells to be drilled in early 2025

Operations

Central's share of Mereenie gas and oil production for FY2024 was 2.2 PJe.

Full field gas production for the year was 8.1 PJ, averaging 22.2 TJ/d, down from the 9.5 PJ (26.2 TJ/d) produced in FY2023, impacted by several temporary shutdowns to the Northern Gas Pipeline during the year. Consequently, oil production was also lower at 294 bbl/d.

A new compressor was commissioned to capture low pressure waste gas and convert it to sales gas, thereby increasing sales and reducing annual Mereenie CO_2 emissions by approximately one-third. The flare gas recovery compressor is intended to increase sales capacity by 0.5 TJ/d and reduce emissions by 13.2 kt CO_2-e per year (gross JV).

Future plans

New Mereenie wells

In response to strong market signals arising from Central's gas marketing campaign, the Mereenie joint venture has reached a final investment decision (FID) for two new Mereenie development wells which are forecast to return field production capacity back above 30 TJ/d (100% JV) and produce at least 25 PJ of gas (100% JV) over their lifetime. Gas from the new wells can be sold into the new contract with the Northern Territory Government, which can be expanded by up to 6 TJ/d following successful completion of the wells.

The wells are expected to be drilled in early 2025 and will target the crest of the Pacoota 3 reservoir (at depths of around 1,500m) to optimise productivity and gas recovery from the field. Project economics are compelling, benefitting from new gas contracts and low incremental production costs through the use of existing surface infrastructure.

Helium recovery and liquefaction

Central and its Mereenie joint venturers continue to work with a major global helium supplier to progress a helium recovery and liquefaction unit at Mereenie to extract helium from the existing Mereenie gas stream, which typically contains circa 0.2% helium.

OPERATING AND FINANCIAL REVIEW

Mereenie appraisal plans

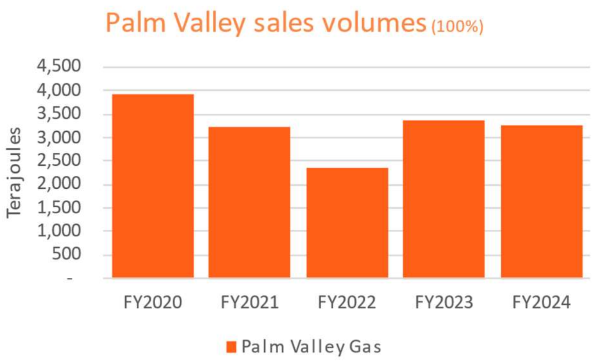
Stairway Sandstone

The Stairway Sandstones which overlie the deeper producing Pacoota Sandstones at Mereenie are estimated to contain 27 PJ of 2C contingent gas resource (net to Central). Gas has previously flowed from the Upper Stairway Sandstone while drilling deeper production wells, providing a good indication of the presence of open natural fractures in the crestal region of the Mereenie field. If successful, production from the Stairway would significantly increase production capacity and the economic life of the Mereenie field.

The Mereenie Joint Venture is progressing permitting and approvals for up to two Stairway appraisal wells in advance of a joint venture FID which will require further gas contracting and funding arrangements.

Palm Valley Gas Field (OL3)

Northern Territory



Ownership interests	
Central Petroleum (operator)	**50.0%**
Echelon Palm Valley Pty Ltd[1]	35.0%
Cue Palm Valley Pty Ltd	15.0%

Reserves & Resources (Central share)[1]	Unit	1P	2P	2C
Gas	PJ	10.9	11.7	6.5

1 Formerly NZOG Palm Valley Pty Ltd

2 Reserves and resources are as at 30 June 2024.

Palm Valley highlights

- 42% increase in 2C contingent gas resources
- Planning commenced for new wells to boost production

Operations

Production from the Palm Valley field averaged 8.9 TJ/d through FY2024, recording an aggregate of 3.3 PJ, consistent with FY2023 sales. Central's share of Palm Valley gas sales for FY2024 was 1.6 PJ.

Strong performance from the two most recently drilled wells has led to a 1.9 PJ increase in 2C contingent resources (Central share).

Future plans

Planning for new Palm Valley wells

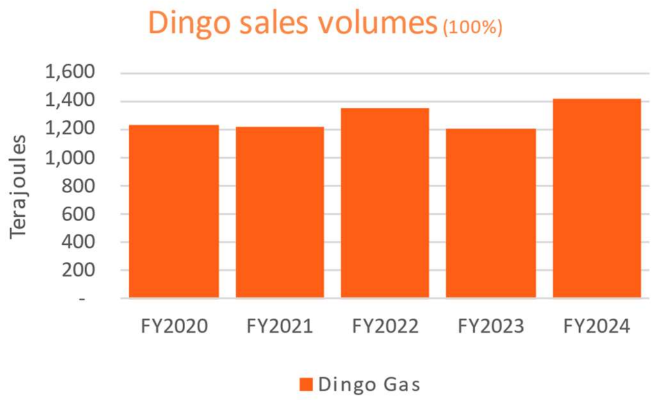
The new six year gas supply agreement with the Northern Territory Government provides a clear market signal to accelerate investment in field production increases, including drilling new wells at Palm Valley. The Palm Valley joint venture has been progressing permitting and approvals for two new Palm Valley appraisal wells in advance of a joint venture FID which will require further gas contracting and funding arrangements by Central.

Exploration potential

The deeper Arumbera Sandstone, which is the production reservoir at the Dingo gas field has potential as a significant gas resource and remains an option for future exploration drilling.

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

Northern Territory



Ownership interests	
Central Petroleum (operator)	**50.0%**
Echelon Dingo Pty Ltd[1]	35.0%
Cue Dingo Pty Ltd	15.0%

Reserves & Resources (Central share)[1]	Unit	1P	2P	2C
Gas	PJ	18.7	22.8	—

[1] Formerly NZOG Dingo Pty Ltd

[2] Reserves and resources are as at 30 June 2024.

Dingo highlights

- Record gas production, up 18% on FY2023
- 2P gas reserves increased by 7%

Operations

The Dingo gas field supplies gas through a dedicated 50 km gas pipeline to Brewer Estate in Alice Springs for use in the Owen Springs Power Station.

Sales volumes at Dingo were the highest on record, averaging 3.9 TJ/d across the year, an aggregate of 1.4 PJ (Central share 0.7 PJ), up 18% on FY2023. The daily contract volume of 4.4 TJ/d is subject to take-or-pay provisions under which Central will be paid in January 2025 for any gas nomination shortfall by the customer in CY2024.

After a review of field performance and updated modelling, proved and probable (2P) gas reserves were revised upwards by 1.6 PJ (net to Central, an increase of 7%.

Future plans

New production wells

Additional development wells can be drilled in the future at Dingo to maintain contracted gas volumes when warranted by natural field decline.

Exploration potential

The deeper Pioneer Sandstone has flowed gas at the nearby Ooraminna prospect and is an option for future exploration drilling, lying below the existing Dingo production reservoir and potentially holding significant gas resources.

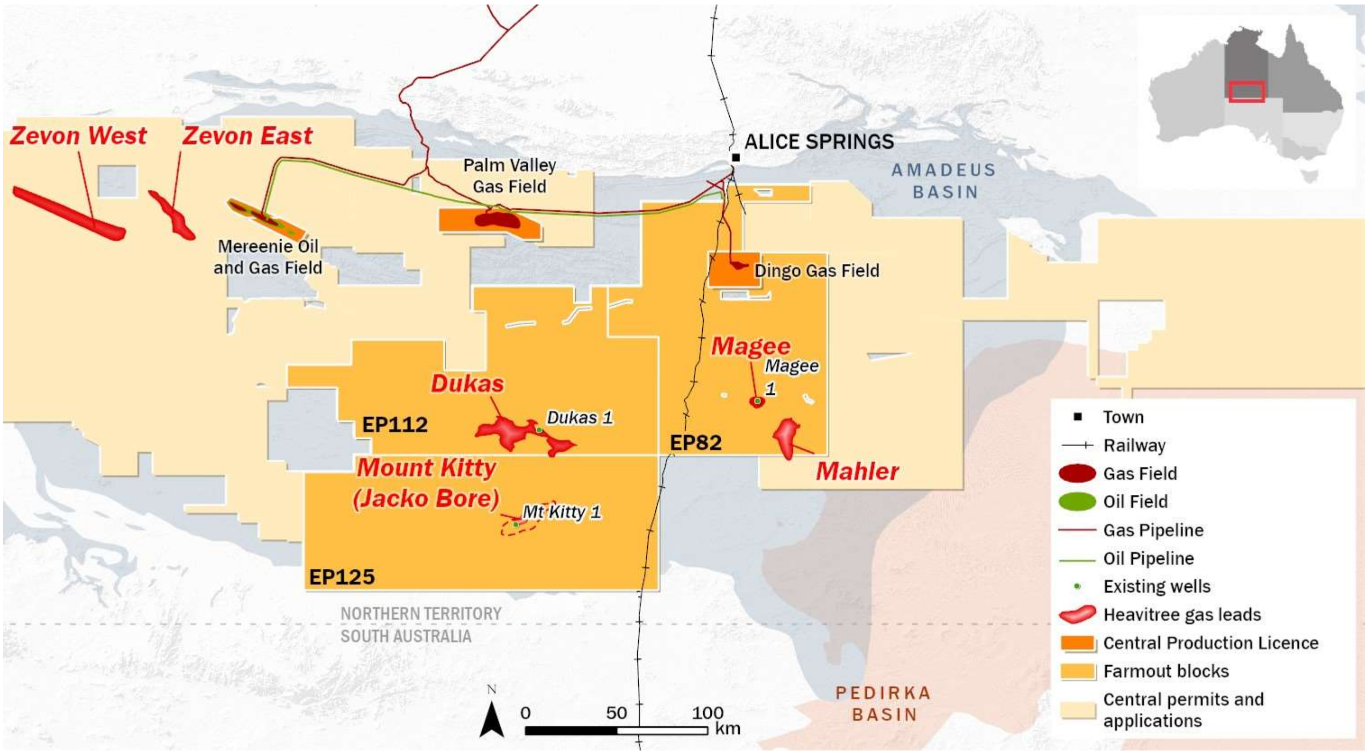
OPERATING AND FINANCIAL REVIEW

Exploration Assets

Central Petroleum holds a significant portfolio of exploration opportunities across the Amadeus, Wiso and Georgina Basins in the Northern Territory. The total area held by Central for exploration is 173,045 km^2 (64,076 km^2 granted and 108,969 km^2 under application).

Amadeus Basin

Central Petroleum has significant operations within the proven Amadeus Basin, which has some of Australia's largest prospective onshore resources of conventional gas. The Amadeus Basin has provided reliable, high-quality oil and gas since the 1980s, yet it is relatively under-explored and is believed to hold significant additional gas resources, including helium and naturally-occurring hydrogen, with good prospectivity for oil on the western flank of the basin.



Location of sub-salt targets

Amadeus Exploration – Sub-salt targets with helium and hydrogen potential

Amadeus Basin, Northern Territory

Large sub-salt targets with helium and hydrogen potential

The Amadeus Basin contains several large, potentially multi-Tcf sub-salt targets that are also prospective for helium and hydrogen.

The Amadeus Basin hosts sub-salt targets within the Heavitree Formation and the fractured granitic basement sealed by extensive evaporitic units of the upper Gillen Formation. 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

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. 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 (Jacko Bore 1) contained 9% helium.

Central is seeking to drill several sub-salt appraisal/exploration wells in the Southern Amadeus through farmouts to further test these prospects. Planning for a seismic acquisition program is also underway for EP115 (including the Zevon lead), following a successful 2D seismic test line acquired in late 2023 which confirmed a new efficient, low-impact acquisition methodology.

Central is working with a major global helium supplier to progress a helium recovery and liquefaction unit at Mereenie to extract helium from the existing Mereenie gas stream, which typically contains circa 0.2% helium. Successful production of helium at Mereenie would provide a new revenue stream for the Mereenie field and demonstrate the potential of the Amadeus Basin as a world-class helium resource, where Central has a material position in highly prospective acreage.

The return of Central's interests in several sub-salt permits from a defaulting party last year are in the final government approval stages which we expect to be completed shortly. Renewed sub-salt exploration at the Jacko Bore (Mt Kitty), Mahler (Magee) and Dukas prospects has been progressing, with farmout discussions at an advanced stage.

Jacko Bore 2 (EP125)

Central 30%; Santos 70% (Operator)

Farmout discussions are progressing to secure part funding for an appraisal well, to be drilled within 12 months. The proposed Jacko Bore 2 exploration well will target helium, naturally-occurring hydrogen and natural gas in the fractured basement by re-entering the existing Mt Kitty-1 (Jacko Bore-1) well and drilling a deviated/horizontal sidetrack to test up to 500m of the fractured basement reservoir at a depth of approximately 2,000m. The vertical Mt Kitty-1 exploration well flowed gas containing 11.5% hydrogen and 9% helium at up to 530,000 scfd.

Dukas 2 (EP112)

Central 45%; Santos 55% (Operator)

The Dukas-1 exploration well was drilled in 2019 and suspended after it encountered hydrocarbon-bearing gas from an overpressured zone close to the primary target, with traces of helium and hydrogen detected in mud gases. Central is progressing discussions to secure farmout funding for a new well at Dukas which will target the same sub-salt Heavitree formation with a higher-capacity rig.

Mahler (EP82)

Central 60%; Santos 40% (Operator)

Central is progressing farmout discussions and hopes to secure funding for the proposed Mahler exploration well to target helium, naturally-occurring hydrogen and natural gas in the fractured basement and Heavitree formation at depths up to 2,000m. The well is planned to be drilled up-dip and approximately 20km to the southeast of the Magee-1 exploration well which flowed gas, including 6.2% 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	Prospective resource (unrisked best estimate)	Prospective resource (unrisked best estimate)
	(bcf)	(bcf)	(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.

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.

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.

Zevon (EP 115)

Central – 100% interest

Regional geological play mapping has highlighted that EP 115 has the potential to be highly prospective for helium and hydrogen in association with hydrocarbon gasses.

A 2D seismic test line was acquired at Zevon in November 2023, confirming that the new acquisition methodology returned high quality data with reduced environmental impact and significantly reduced cost. This bodes well for future seismic campaigns throughout EP115 and the wider Amadeus Basin. Based on the results of this test line, Central is updating its plans to acquire additional seismic in the licence to further delineate a number of leads and prospects that have been identified in the block.

OPERATING AND FINANCIAL REVIEW

Amadeus Exploration – In-field opportunities

Palm Valley (OL3); Dingo (L7); Mereenie (OL4/OL5), Amadeus Basin, Northern Territory

In-field opportunities

There are opportunities to target other intervals at Mereenie, Palm Valley and Dingo which are not currently the principal production zones in each field.

Central's producing fields at Mereenie, Palm Valley and Dingo comprise several stacked layers of producing and potential 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.

Amadeus Exploration – Other opportunities

Amadeus Basin, Northern Territory

Other opportunities

Oil and gas opportunities are located close to existing producing fields from intervals which have been known to produce oil or gas from nearby wells.

Central has identified several other promising lower-risk, high reward exploration targets close to productive areas which can be pursued relatively quickly once capital is allocated. The targets include the Mamlambo oil prospect.

Mamlambo (L6)

Central - 100% interest.

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. Total depth for a potential well would be in the order of 1,300m.

In-field and other 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.

Exploration Application Areas, Northern Territory

Amadeus, Pedirka and Wiso Basins — Various Areas (see table on page 101)

Central continued to evaluate a number of these areas and has been working to gain Native Title/Aboriginal Land Rights Act clearance and secure the other necessary approvals in advance of the award of exploration permit status.

COMMERCIAL

Gas markets

Northern Territory gas markets experienced considerable volatility during the year, with the Northern Gas Pipeline (NGP), which allows the supply of gas from the Northern Territory to eastern states, being closed for much of the past 12 months due to supply-side interruptions. At these times there was insufficient surplus gas in the Northern Territory to meet the NGP's minimum volumes and Central was therefore unable to supply gas to its customers in the Mt Isa region or access east coast spot markets while the pipeline was off-line. The NGP is expected to remain closed until at least late 2024 when a new Blacktip field appraisal well is expected to be drilled offshore Darwin.

The interruptions impacted Central's sales volumes by approximately 10%, or $4 million in revenue for the financial year. A new short-term as-available gas sales agreement (GSA) with the Northern Territory's Power and Water Corporation (PWC) has allowed Central to largely mitigate the impact of the pipeline closure from April. For the second half of 2024, Central's gas fields at Mereenie, Palm Valley and Dingo are expected to supply around half of the Northern Territory's daily gas requirements, with the remainder coming from offshore gas fields such as Blacktip and Bayu Undan.

It was in the context of this transportation and supply-side market uncertainty that Central undertook a series of targeted marketing initiatives during the year, including an extensive gas sale expression of interest process, which successfully concluded with new GSAs with the NT Government that have strengthened and largely de-risked Central's forward revenues through to the end of the decade.

The pricing for Central's contracted gas portfolio from 2025 reflects strong market demand for firm gas supply on a term basis, with minimal transportation costs. Central's average portfolio contracted gas price from 2025 is expected to step-up from the $7.90 / GJe realised in the June 2024 quarter.

New Gas Sales Agreements

New agreements to provide higher, more reliable cash flows

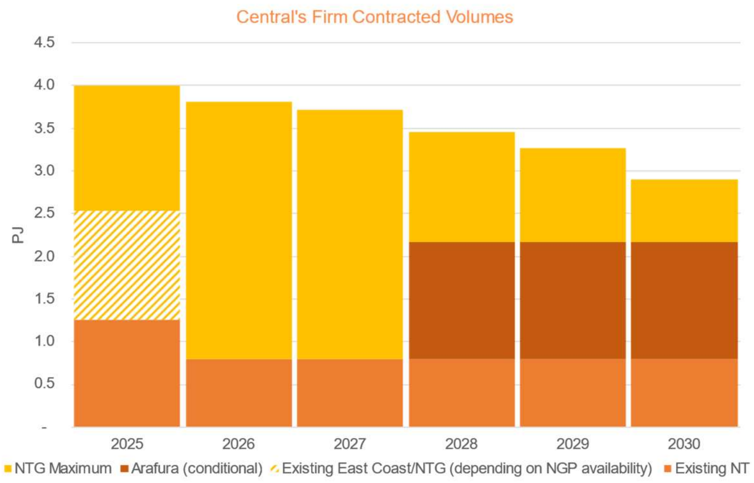
The new GSAs are expected to provide more reliable cash flows for Central from 1 January 2025, benefitting from higher average contracted gas prices and more consistent, firm sales that will not be affected by NGP interruptions. This increased cash flow certainty is expected to underwrite new investments to increase production, support debt extension initiatives and accelerate returns to shareholders.

As-available contract for 2024

In April, Central entered into an as-available supply agreement with PWC in the Northern Territory for the supply of up to 2.1 PJ of gas (Central's share) until the end of 2024. This agreement provides Central with a market for gas that it could not otherwise deliver to its customers in the Mt Isa region due to the suspension of the NGP.

South 32 in 2025

The existing two-year gas supply agreement with South32 Cannington Pty Ltd was extended by a further 12 months. An additional 1.46 PJ of gas will be supplied to South32 at Mount Isa in 2025 (Central share: 0.36 PJ).



Northern Territory Government (NTG) contracts from 2025

Central entered into new GSAs for the supply of up to 12.0 PJ of gas (Central share) to NTG for six years from 2025. The GSAs are structured as a base load gas supply providing a high degree of certainty in Central's forward gas revenues, regardless of the operating status of the NGP over the foreseeable future. The contracts include:

- the supply of up to 1.5 PJ of gas from Mereenie in 2025 if the NGP is closed and Central is unable to deliver gas to its existing east coast customers, further mitigating risks to cash flow from any ongoing NGP interruptions; and
- up to 3.3 PJ of gas from two new proposed Mereenie wells over six years from 2025.

Arafura contract from 2028

Central secured a new conditional GSA to supply up to 4.1 PJ of gas (Central share) to Arafura's Nolan's rare earths project in the Northern Territory over three years from 2028. The GSA is subject to Arafura's board approving a final investment decision to proceed with the project by 31 December 2024.

The new contracts will mean that Central's expected long-term firm production is now fully contracted (subject to Arafura approvals) at fixed prices (plus CPI) for the next six years, including up to 1.5 TJ/d (Central share) from two new wells to be drilled at Mereenie.

OPERATING AND FINANCIAL REVIEW

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 stakeholders.

Environmental

Central is committed to conducting its operations in an environmentally responsible and sustainable manner aligned with community, cultural and social expectations. We believe that achieving and maintaining positive environmental outcomes is critical to the success of our business. As custodians of the land on which we operate, we aim to uphold the highest environmental standards and leave the smallest footprint.

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 State legislation. 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 over 99% 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 an increasing realisation in the community that the transition to renewable energy will take longer and be more complex than initially indicated and is contributing to cost of living pressures.

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

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.

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 worldwide markets.

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.

We report our greenhouse emissions under the National Greenhouse and Energy Reporting Act 2007 (NGER). In the most recent completed reporting period, FY2023, our share of scope 1 and 2 emissions across our operations was consistent with the previous year, at 21,685 tons of CO_2e (21,612 tons in FY2022). On a per unit basis, our emissions intensity increased from 3.90 kgCO_2e/GJe in FY2022 to 4.48 KgCO_2e/GJe in FY2023 due to increased flaring at the Range CSG gas project and increased gas volumes at Palm Valley.

We have invested in several initiatives to reduce our emissions, including the $8 million flare gas compressor at Mereenie, which was commissioned this year and is expected to reduce flare gas emissions at Mereenie by more than 33% and overall emissions across our three production sites by approximately 10%, based on current emissions. As older legacy equipment is replaced, we are installing more efficient appliances which will further reduce Scope 1 emissions across our operations.

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 220,133 hours were worked, with no recordable injuries, resulting in a zero Total Recordable Injury Frequency Rate (TRIFR) at 30 June 2024.

Community

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

In the Northern Territory, for example:

- 35% of our staff live locally.
- 23% of our on-site staff are indigenous.
- Central and partners paid over $8.0 million in royalties to the Northern Territory and Central Land Council for FY2024.
- Central and partners spent over $1.8 million with local contractors and businesses and incurred over $1.9 million in fees and levies to the Northern Territory government, in FY2024.

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.

RESERVES AND RESOURCES STATEMENT

Net proved & probable (2P) oil and gas reserves were 73.3 PJe at 30 June 2024.

Aggregate Reserves and Resources

		As at 30/06/2023	01/07/2023 to 30/06/2024 Production	Disposal	Other adjustments	As at 30/06/2024	Comprising[1] Developed	Undeveloped
Oil								
Proved reserves (1P)	mmbbl	0.34	(0.03)	—	(0.01)	**0.30**	0.28	0.01
Proved plus probable reserves (2P)	mmbbl	0.38	(0.03)	—	0.01	**0.36**	0.34	0.02
Contingent Resources (2C)	mmbbl	0.05	—	—	—	**0.05**	—	—
Gas								
Proved reserves (1P)	PJ	60.76	(3.69)		0.56	**57.62**	45.21	12.41
Proved plus probable reserves (2P)	PJ	72.83	(3.69)		2.03	**71.17**	54.93	16.24
Contingent Resources (2C)	PJ	185.21	—	(135.05)	8.44	**58.60**	—	—

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

Reserves and Resources by Field

		As at 30/06/2023	01/07/2023 to 30/06/2024 Production	Disposal	Other Adjustments	As at 30/06/2024
Mereenie, oil						
Proved reserves (1P)	mmbbl	0.34	(0.03)	—	(0.01)	**0.30**
Proved plus probable reserves (2P)	mmbbl	0.38	(0.03)	—	0.01	**0.36**
Contingent Resources (2C)	mmbbl	0.05	—	—	—	**0.05**
Mereenie, gas						
Proved reserves (1P)	PJ	28.73	(1.35)	—	0.68	**28.06**
Proved plus probable reserves (2P)	PJ	37.48	(1.35)	—	0.50	**36.64**
Contingent Resources (2C)	PJ	45.60	—	—	—	**45.60**
Palm Valley						
Proved reserves (1P)	PJ	12.61	(1.64)	—	(0.07)	**10.90**
Proved plus probable reserves (2P)	PJ	13.41	(1.64)	—	(0.09)	**11.69**
Contingent Resources (2C)	PJ	4.56	—	—	1.94	**6.50**
Dingo						
Proved reserves (1P)	PJ	19.42	(0.71)	—	(0.05)	**18.66**
Proved plus probable reserves (2P)	PJ	21.94	(0.71)	—	1.62	**22.84**
Range (Surat Basin, Qld)						
Contingent Resources (2C)	PJ	135.05	—	(135.05)	—	**—**

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.

OPERATING AND FINANCIAL REVIEW

Principal risks and uncertainties at 30 June 2024

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 evolving expectations of social responsibility and ethical decision making, which 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, loss of license to operate 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 strengthen our regulatory compliance framework and supporting tools. We proactively maintain open dialogue with governments, regulators and stakeholders within jurisdictions in which we operate. Our fraud and corruption framework aims to prevent, detect, and respond to unethical behaviour. It incorporates policies, procedures, and training to ensure activities are conducted ethically.
Growth		
Our future growth depends on our ability to identify, acquire, explore, appraise and develop resources.	The inability to identify and commercialise growth opportunities, or realise their full value, may result in a loss of shareholder value. Unsuccessful exploration and renewal of upstream resources may impede delivery of our strategy.	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 provide reserve estimates.

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 remains uncertain 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.	We are focused on ensuring our business is robust in a potentially carbon constrained market and engage proactively with key industry and government stakeholders. Our future is predominantly focused on supplying natural gas as a transitional fuel which could see demand for gas increase in the medium term as part of the transition to a clean energy future compared to other energy sources. Central has locked-in sales for estimated firm forward production until 2030 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 potentially exist in some of its production and exploration permits.
It is believed that 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 and interrupt Central's operations.	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 is 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 is an area of focus for Central and our risk management framework includes auditing and verification processes for our critical controls. We also regularly review our operations and activities 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 are focussed on securing and developing the right people to support the operation and development of our portfolio of assets and opportunities. 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
Operating		
The production and delivery of hydrocarbon products safely and reliably are key elements of our operational and financial performance and directly impact 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 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 maximise 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.
Environment		
Our environmental performance underpins our licence to operate.	Our operations by their nature have the potential to impact air quality, biodiversity, land and water resources and related ecosystems. A failure to manage these could adversely impact not just the environment, but our people, the communities in which we operate, our reputation and our licence to operate.	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 carry third party environmental liability insurance in addition to well control insurance 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, can lead to scarcity of available capital and may impact the prioritisation of exploration, development or production opportunities. This can lead to delayed approvals or forfeited tenure, which may impact Central's 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.	Negative impacts to revenue as a result of infrastructure failure or closure, increased tariffs, or restricted access to third party owned infrastructure. Over the past year Central has been exposed to multiple 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 until 2030 at fixed pricing on a take-or-pay basis within the NT, mitigating exposure to interruptions to the NGP.

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 USD commodity price variability with respect to crude oil sales which are impacted by broader economic factors beyond our control. 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.	Oil revenue represented less than 10% of consolidated sales revenue in FY2024. The majority of Central's revenue is from natural gas sales denominated in AUD 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 mandated gas price caps as its level of production falls below eligibility thresholds and its gas supplies are only to domestic markets.
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.
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 and infrastructure failure.	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.

DIRECTORS' REPORT
FOR THE YEAR ENDED 30 JUNE 2024

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 2024.

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.

Mr Michael (Mick) McCormack (Chair)

Mr Leon Devaney (Managing Director)

Mr Stephen Gardiner

Mr Troy Harry (resigned 5 February 2024)

Ms Katherine Hirschfeld AM

Dr Agu Kantsler

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 (2023: $Nil). No recommendation for payment of dividends has been made.

OPERATING AND FINANCIAL REVIEW

The operating and financial highlights for the financial year were:

- Central sold its 50% interest in the Range CSG Project (ATP2031) for $12.5 million, releasing capital and realising a book profit of $13.8 million.
- Gas which was pre-sold in 2020 was fully delivered by December 2023, releasing additional gas volumes for sale on usual cash terms and boosting cash flows from January 2024 onwards.
- New gas sales agreements (GSAs) were secured including:
  - An as available GSA with Power & Water Corporation in the NT for the supply of up to 2.1 PJ (Central share) until the end of 2024;
  - New GSAs for the firm base supply of up to 12 PJ (Central share) of gas to the Northern Territory Government for six years from 2025 to 2030; and
  - A revised GSA for the supply of up to 4.1 PJ of gas to Arafura's Nolan's rare earth project over three years from 2028, subject to project FID by 31 December 2024.
- In August 2023, agreement was reached to progress a helium recovery unit at Mereenie, demonstrating the potential of the Amadeus Basin as a world-class helium resource.

A detailed review of the operating and financial performance for the year ended 30 June 2024, including principal risks is provided on pages 3 to 21 of this Annual Report.

SIGNIFICANT CHANGES IN THE STATE OF AFFAIRS

The financial position and performance of the Group was particularly affected by the following events and transactions during the year ended 30 June 2024:

- Central sold its 50% interest in the Range CSG Project (ATP2031), releasing capital and realising a book profit of $13.8 million.
- Interruptions to the Northern Gas Pipeline impacted sales during the year.
- New gas sale agreements were secured and are expected to provide more reliable cash flows for Central, largely mitigating exposure to the Northern Gas Pipeline.
- Agreement was reached to progress a helium recovery and liquefaction unit at Mereenie. Work continues with parties that include a major helium distributor.

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

EVENTS SINCE THE END OF THE FINANCIAL YEAR

In July 2024, new Gas Sale Agreements were executed and are expected to provide more reliable cash flows for Central from 1 January 2025, benefitting from higher average contracted gas prices and more consistent, firm sales that will not be affected by interruptions to the Northern Gas Pipeline.

No other significant matters or circumstances have arisen between 30 June 2024 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 FY2025, with new gas sale agreements expected to provide more reliable cash flows, benefiting from higher average contracted gas prices and more consistent firm sales that will not be affected by pipeline interruptions

Production enhancement
Two new development wells are expected to be drilled at Mereenie in the first half of 2025 to boost production capacity for supply into new gas sale agreements. Planning has also commenced for two new wells at Palm Valley.

Exploration
A significant, three well sub-salt exploration campaign in the southern Amadeus Basin is planned, targeting high-value helium, naturally occurring hydrogen and natural gas resources. The structure, timing and funding of the exploration program is dependent on finalising farmout arrangements.

Other proposed near-term exploration activity includes seismic acquisition in EP115, which hosts the large Zevon lead, to identify a possible site for an exploration well.

Helium Recovery Unit
Central and its partners at Mereenie are working with a major global helium supplier to progress towards a final investment decision for the construction of a helium recovery and liquefaction unit at Mereenie. Successful production of helium at Mereenie would demonstrate the potential of the Amadeus Basin as a world-class helium resource, where Central has a material position in several sub-salt prospects.

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

Mr Michael (Mick) McCormack BSurv, GradDipEng, MBA, FAICD

Independent Non-executive Chair

Mr McCormack was appointed as a director on 1 September 2020 and has over 40 years' experience in the energy infrastructure sector in Australia and his career has encompassed all aspects of the sector, including commercial development, design, construction, operation and management of most of Australia's natural gas pipelines and gas distribution systems. His experience extends to gas-fired and renewable power generation, electricity transmission, gas processing, LNG and underground storage.

Mr McCormack is a former Managing Director and CEO of APA Group (2004-2019), former Non-executive Director of Austal Limited (2020 – 2024) and former Director of Envestra (now Australian Gas Infrastructure Group) and the Australian Pipeline Industry Association (now Australian Pipelines and Gas Association). He is a Non-executive Director at Origin Energy Limited and Whitehaven Coal Limited, a Director of the Clontarf Foundation and is Chair of the Australian Brandenburg Orchestra Foundation and is the Patron of the Australian Ice Hockey League. He is also a Fellow of the Australian Institute of Company Directors.

Directorships of other listed companies in the last three years: Director of Origin Energy Limited, Director of Whitehaven Coal Limited from February 2024, and Austal Limited to March 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 recently sold 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.

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.

INFORMATION ON DIRECTORS (CONTINUED)

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.

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

Independent Non-executive Director

Dr Kantsler has been a director of Central Petroleum Limited since 15 June 2020 and is one of Australia's most respected and experienced petroleum exploration executives, having led Woodside Petroleum's world-wide exploration, business development and geotechnical activities as Executive Vice President Exploration and New Ventures from 1995 to 2009. He also led Woodside's Health, Safety and Security Department during 2009 and 2010.

Prior to joining Woodside, Dr Kantsler worked for Shell in various international locations. He has served as Director and Chairman of the Australian Petroleum Production & Exploration Association (APPEA), President of the Chamber of Commerce and Industry WA and Non-Executive Director of Oil Search Limited and Suvo Strategic Minerals Ltd.

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

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		Strategic Review Committee	
Director	Eligible[1]	Attended	Eligible[1]	Attended[2]	Eligible[1]	Attended[2]	Eligible[1]	Attended[2]	Eligible[1]	Attended[2]
Leon Devaney	9	9	—		—	5	—	8	—	13
Stephen Gardiner	9	9	4	4	5	5	8	8	15	14
Troy Harry[3]	5	5	2	2	—	2	4	4	15	15
Katherine Hirschfeld AM	9	8	4	4	5	5	—	7	15	13
Agu Kantsler	9	7	—	4	5	4	8	7	15	13
Michael McCormack	9	9	4	4	5	5	8	8	15	13

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 Troy Harry resigned as Director on 5 February 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 over 99% 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 49.

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	
	2024	2023
PwC Australian firm:	**$**	$
(i) Taxation services		
Income tax compliance	15,300	14,280
Other tax related services	21,581	47,512
Total remuneration from non-audit services	**36,881**	**61,792**

EXECUTIVE SUMMARY – REMUNERATION

Dear Shareholders,

The Board continued to focus on finding the right remuneration balance to retain and attract high-quality staff, while also providing appropriate performance incentives that are aligned with shareholder expectations. However we acknowledge that the 2023 Remuneration Report failed to get the support of 75% of eligible shareholders who voted at Central's 2023 Annual General Meeting.

We have responded by making significant changes to the remuneration structure of our executive team for FY2025 and beyond to further align the performance of management and staff with the interests of shareholders.

The CEO's remuneration package has been re-weighted with a reduced fixed remuneration and new at-risk incentives with much higher share price appreciation hurdles. The pay of other executives has been frozen at 2024 level, and we have consolidated our executive team to four, down from the six executives that Central has historically employed. The revised short and long-term incentives now include an equity-linked plan that only rewards significant increases above a minimum hurdle share price of 8 cents per share (a minimum 50% increase on the 5.3 cents share price at 30 June 2024).

I've no doubt the Company's struggling share price had a large part to play in the shareholder vote last year. However, the results and accomplishments over the past year have driven significant improvements in our forecasted free cash flows and future shareholder returns. The sale of the Range gas project at a significant profit has strengthened our balance sheet; our pre-sold gas has been fully returned, increasing our gas sales in a stronger market; and our new six-year, higher-priced firm gas contracts provide a new level of financial capacity.

Our staff did a commendable job in maintaining a reliable supply of gas to our customers in the face of variable demand, and did so with a clean safety record for the year. Management has negotiated the pipeline-driven challenges which threatened current and future revenues and cash flows, redirecting gas into an alternative contract in the Northern Territory for the remainder of this year. The recently announced six-year contracts for gas supply to the Northern Territory Government, stretching from next year until 2030, will mitigate market and transportation risks and provide energy security for the region.

To maintain our capability and incentivise exceptional future performance, Central's new FY2025 executive incentive plan offers a remuneration structure that addresses shareholder expectations for share price appreciation.

Fixed remuneration

To maintain competitiveness in the labour market and counteract the effects of rising costs of living for our staff, fixed remuneration rose by an average 4% across the board for FY2024, plus the required 0.5% increase in the superannuation guarantee. A similar increase has been applied for the 2025 financial year, except for the CEO, whose fixed remuneration has decreased by 13% and executives whose pay has been frozen at FY2024 levels, the second time in five years that executive pay has been frozen.

I also note there has been no increase in Directors' Fees for the last six years.

Short-term incentives

Depending on role and seniority, the maximum FY2024 opportunity ranges from 10% to 30% of fixed remuneration.

The short-term incentive awarded for FY2024 was impacted by the lower production volumes and delays to various commercial, development and farmout initiatives, resulting in an award to staff (other than executives) of 54% of the maximum available, including measurement against personal KPIs.

A small number of select key operational staff also received a retention incentive which was offered to maintain operational capability during the strategic review process which was completed this year.

Executive incentives

For FY2024, executives participated in the third and final year of the Executive Incentive Plan (EIP) with short and long-term components.

The EIP provided for the CEO the ability to receive up to a maximum of 120% of fixed remuneration and 80% for other eligible executives.

Of the maximum available, 51% was awarded, based on the same corporate KPIs as the short-term incentives for other staff, but without a personal KPI component. One third has been paid as cash and two thirds will be granted as equity which can vest over the next three years.

The Board has acknowledged feedback from shareholders and undertaken an independent benchmarking review of executive incentive plans, resulting in a revised incentive plan for executives for FY2025.

The annual short-term component provides the CEO with the ability to earn up to circa 63% of his now reduced fixed remuneration upon achieving stretch corporate performance targets each year. Other eligible executives can earn up to circa 42% of their fixed remuneration. Upon determination of the achieved reward at the end of FY2025, 80% will be paid as cash and 20% as share rights which vest a year later.

The long-term component is based entirely on the absolute appreciation of share price rather than including any relative peer group share price appreciation component. This is designed to directly align management and shareholders, comprising of share rights whose vesting requires the achievement of fixed share price appreciation targets over three years.

The new long-term plan only provides a reward where the share price increases to at least 8 cents per share in three years (an increase of about 50% from the 30 June share price of 5.3 cents per share). At that threshold level, the CEO would earn a long-term incentive of 50% of his reduced FY2025 fixed remuneration (15% for other executives), increasing to 218% of fixed remuneration if the share price reaches 16 cents, more than triple today's price (65% for other executives). In addition, the number of shares awarded under the long-term incentive plan is based on pricing at the time of vesting such that executives don't benefit from the current low share price.

We believe that the much more conservative remuneration and incentive arrangements for FY2025 provide the appropriate balance of incentive to retain and attract quality staff and drive longer term share price appreciation that will ultimately benefit all shareholders.

Michael (Mick) McCormack
Remuneration and Nominations Committee Chair

REMUNERATION REPORT
(AUDITED)

This Remuneration Report for the year ended 30 June 2024 (FY2024) 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	Key operational employee retention incentive
I	FY2025 Executive Incentive Plan (FY25 EIP)
J	Realised Remuneration
K	Remuneration Details – Statutory Tables
L	Executive Service Agreements
M	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

Mr Michael (Mick) McCormack	Independent Non-executive Chair
Mr Leon Devaney	Managing Director and Chief Executive Officer
Mr Stephen Gardiner	Independent Non-executive Director
Mr Troy Harry	Non-executive Director (resigned 5 February 2024)
Ms Katherine Hirschfeld AM	Independent Non-executive Director
Dr Agu Kantsler	Independent Non-executive Director

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 2024 Summary of fixed and variable remuneration outcomes	
Fixed remuneration	An average 4% pay rise applied to eligible employees for FY2024 and compulsory superannuation contributions increased from 10.5% to 11%.
Executive Incentive Plan (EIP)	Achievement of Group-wide corporate KPIs resulted in an award of 51% with 1/3 of the awarded value being payable as cash (or equity) and 2/3 being Share Rights to vest progressively over the next 3 years. Refer Section F of this report.
Short Term Incentive Plan (STIP)	Achievement of Group-wide corporate and individual KPIs resulted in payment of an average 54% of the maximum STIP to eligible employees. Refer Section H of this report.
Key operational employee retention incentive	A select group including an executive and key operational employees earned a retention incentive equal to 15% of their fixed remuneration in connection with the strategic review first announced in August 2022 and completed in FY2024.
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 2024 fully vested on 30 June 2024 for those employees meeting the relevant service requirements. Refer Section E of this report.

At the Company's 2023 Annual General Meeting, 47.31% of the votes cast were against the adoption of the FY2023 Remuneration Report. In response to this vote by eligible shareholders, the Board has conducted a review of remuneration of executives and taken the following action:

a. Amended the Managing Director / CEO's remuneration arrangements, resulting in a 13% decrease in total fixed remuneration;
b. Frozen total fixed remuneration at FY2024 levels for Directors and other Key Management Personnel for FY2025;
c. Implemented a revised incentive plan for FY2025, which includes share price performance hurdles for the Managing Director / CEO and other Key Management Personnel (refer Section I of this report);
d. Held the number of KMPs at four, down from six two years ago; and
e. Retained a smaller Board of four Non-executive Directors, down from five at the start of the year.

Fixed remuneration changes for FY2025

Following a market review of comparable companies, the Managing Director and CEO's fixed remuneration has been reduced from 1 July 2024, and other executives' fixed remuneration has been frozen at FY2024 levels.

As at 1 July 2024, salaries for other eligible employees will rise, on average, by 4% for FY2025, with an added benefit from the statutory increase in compulsory superannuation contributions from 11% to 11.5%.

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.

From FY2022, executives have participated in an Executive Incentive Plan (EIP) that combined both short term annual KPIs and a longer-term, deferred equity-based component (refer Section F of this report). For FY2025, it is proposed that executives participate in a revised EIP which includes 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 I 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 2024, the remuneration of directors and executives consisted of the following key elements:

C. Remuneration Policy (continued)

Non-executive directors:

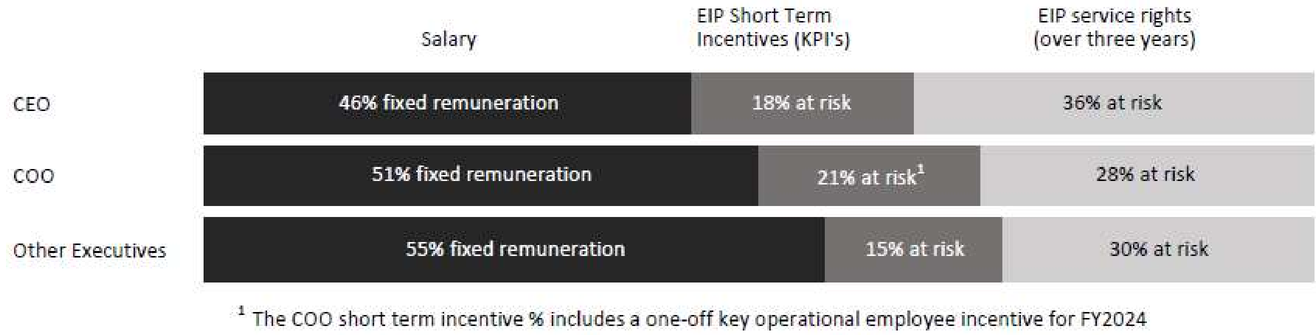
1. Fees including statutory superannuation;
2. Up to 25% sacrifice of FY2024 base fees (inclusive of superannuation but excluding committee fees) in order to receive an equivalent value in the form of Share Rights issued under the Group’s Employee Rights Plan; and
3. No participation in short or long 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 FY2024.

The balance of fixed and maximum at risk remuneration for executives for FY2024 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:

		FY2020	FY2021	FY2022	FY2023	**FY2024**
Financial performance[1]						
Operating revenue	$ million	65.0	59.8	42.2	39.3	**37.2**
Profit/(loss) after income tax	$ million	5.4	0.2	21.3	(8.0)	**12.4**
Underlying EBITDAX[2]	$ million	25.0	26.1	16.8	15.8	**13.8**
Net cash/(debt)	$ million	(46.1)	(31.3)	(10.2)	(14.3)	**0.8**
Shareholder wealth						
Share price at year end	$/share	$0.081	$0.117	$0.110	$0.053	**$0.053**
Absolute TSR (3 years)	% growth pa	(16.1%)	(9.1%)	(4.6%)	(13.1%)	**N/a**
Relative TSR (3 years)	Percentile rank	25th	57th	69th	56th	**N/a**
Incentive awarded						
STIP	% of maximum	67.0%	67.0%	62.75%	51.0%	**54.0%**
LTIP	% of maximum	nil	31.5%	43%	29.9%	**N/a**
EIP	% of maximum	N/a	N/a	62.5%	45.0%	**51.0%**

[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 FY2020 and FY2021 reflected these results and were paid as a combination of cash, equity and deferred equity over those years. 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.

C. Remuneration Policy (continued)

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.

Share price performance was not relevant for the LTIP vesting during FY2024 following changes to the LTIP (which is now limited to the $1,000 Exempt Plan with no share price performance hurdles), and the establishment of the EIP from FY2022. The LTIP awards over prior years followed the Group's 3 year share price performance. COVID-related market weakness impacted the FY2020 award, with only participants in the $1,000 Exempt Plan LTIP receiving any value. 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.

D. Remuneration Consultants

No remuneration consultants were engaged to provide remuneration recommendations in relation to the remuneration of any Key Management Personnel for FY2024.

Guerdon Associates were engaged to provide market information relating to a revised short and long term incentive strategy for FY2025, and provided market information from peer companies relating to fixed and variable remuneration for Key Management Personnel for FY2025.

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

The final three year performance period for performance-linked LTIP plans ended on 30 June 2023. These plans vested in August of 2023 at the vesting rate of 29.935% following final approval of the board.

All eligible employees may now participate in the Central Petroleum $1,000 Exempt Plan (other than key management personnel) 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)

Participation

In 2021, Central established an EIP for key executives to align executive performance with the achievement of key objectives for FY2022, FY2023 and FY2024. The Executive Incentive Plan has been revised for FY2025, with details outlined at Section I of this report.

Key terms and vesting conditions

The EIP is an integrated incentive with both short term and long-term components. The value of the EIP award is 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 is then split into two components:

a) 33% is paid 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 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 maximum opportunity for the executive team as a percentage of TFR is:

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

The Board has ultimate discretion to assess the achievement of the KPI targets, including application of an overriding good conduct 'gateway'. The Board can determine whether the award payment at the end of the first performance period is paid as cash or equivalent Company securities. 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 is 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.

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.

F. Executive Incentive Plan (continued)

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 J and K of this report.

FY2024 Performance

After assessment of the achievement of the Corporate KPIs (refer Section G of this report) and the Company's performance during the year, eligible executives were entitled to receive, on average, 51% of their maximum EIP bonus. Of this award, 33% was paid in August 2024, while the remaining 67% will be granted as Service Rights that vest over the next three years in equal tranches.

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.

FY2024 Performance

After assessment of the achievement of the KPIs below and the Group's performance during the year, eligible employees were entitled to receive, on average, 54% of their maximum STIP bonus. The STIP bonuses were paid in August 2024.

The Financial Year 2024 STIP (FY2024 STIP) was designed to recognise and reward individual effort by connecting individual KPIs and corporate KPIs and was assessed across three categories:

KPI Category	Percent Allocation of STIP		Achievement
	Maximum	Actual	
Corporate KPIs	60 %	31 %	51% satisfaction of corporate KPIs
Individual KPIs	40 %	23 % (avg)	57.5% satisfaction of individual KPIs
	100 %	54 % (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 FY2024 STIP, depending on their participation level.

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

Corporate KPIs for FY2024:

Objective	Weighting	Performance Outcome for FY2023			
		0%	Threshold 25%	Target 100%	Stretch 125%
Production (gas – sales volume) Assessed against budget	17%		●		
Total Cost[1] Total group operating and capital expenditure for agreed scope of works assessed against budget	17%			●	
Growth & Development Milestones Assessed against budget, commercial viability and schedule	15%	●			
Farmout Assessed against the number of binding agreements	15%		●		
Subsalt Restructure Joint Ventures and permits	15%		●		
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 is assessed as a separate KPI.

Individual KPIs

Individual KPIs provide significant relevance to each role in each department, and for FY2024 were assessed as achieving an average of 57.5% (or a weighted average of 23% out of a maximum possible 40%).

H. Key operational employee retention incentive

Participation

For the Chief Operating Officer and a small number of other selected operational employees, a retention incentive was implemented as part of the retention strategy made in connection with the Strategic Review announced in August 2022.

Key terms and vesting conditions

The retention incentive was a cash payment equal to 15% of the participants' Total Fixed Remuneration (TFR). The retention incentive was conditional upon the participant remaining employed by the Group in the period up to when the payment was due, being as soon as possible after the earlier of completion of a transaction resulting from the Strategic Review and 30 June 2024. The bonus was paid to eligible employees in August 2024.

I. FY2025 Executive Incentive Plan (FY25 EIP)

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

The FY25 EIP is made up of two components consisting of a:

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.

I. FY2025 Executive Incentive Plan (FY25 EIP) (continued)

FY25 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) The 20% balance of the awarded value is granted as Service Rights that vest at the end of the year following the initial one year performance period (Retention Period).

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.

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.

The FY25 Long Term Incentive

As a long term incentive, from FY2025 eligible executives will be 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 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.

For the FY2025 plan year, the Performance Rights will be 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 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 and 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.

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. Vested Performance Rights may be exercised in accordance with the Employee Rights Plan Rules. The Board may convert vested Share Rights into either Shares or cash or a combination thereof. The 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 the 20-trading days ending on 30 June 2027.

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.

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.

J. Realised Remuneration

Table 1 identifies the actual remuneration received by Senior Executives in respect of the 2024 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 Incentive awarded as cash for the financial year but paid after the end of the financial year; and
- The value of EIP and LTIP share rights vesting (if any) in respect of the three-year period ending 30 June, valued at the year-end share price (2024: 5.3 cents per share, 2023: 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

	Year	Total Fixed Remuneration[1] $	STIP / EIP $	Other Benefits[2] $	Shares[3] $	Total $
Executive KMP						
Leon Devaney	**2024**	**681,849**	**139,097**	**8,839**	**153,172**	**982,957**
	2023	654,572	117,823	8,192	55,833	836,420
Ross Evans[6]	**2024**	**558,079**	**156,233**	**8,839**	**90,697**	**813,848**
	2023	535,557	64,267	8,192	30,447	638,463
Damian Galvin	**2024**	**369,179**	**50,208**	**8,839**	**58,606**	**486,832**
	2023	353,926	42,471	8,192	20,108	424,697
Duncan Lockhart[4]	**2024**	**—**	**—**	**—**	**—**	**—**
	2023	113,160	—	2,007	4,043	119,210
Jonathan Snape[5]	**2024**	**—**	**—**	**—**	**—**	**—**
	2023	194,107	—	4,895	9,815	208,817
Daniel White	**2024**	**495,639**	**67,407**	**8,839**	**78,782**	**650,667**
	2023	475,523	57,063	8,192	50,994	591,772
Total Executive KMP	**2024**	**2,104,746**	**412,945**	**35,356**	**381,257**	**2,934,304**
	2023	2,326,845	281,624	39,670	171,240	2,819,379

1 Total Fixed Remuneration includes salaries, fees and superannuation contributions.
2 Includes car parking and other fringe benefits.
3 Shares comprise any shares to vest from the EIP or LTIP from prior years where the performance period ended on 30 June of the relevant year and are valued at that date. Vesting will occur upon the issue of a vesting notice.
4 Duncan Lockhart resigned 31 August 2022.
5 Jonathan Snape resigned 20 January 2023.
6 Ross Evans' STIP/EIP Includes a key operational employee retention incentive. Refer Section H above.

K. 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 $	Termination Benefits $	LSL (Accrued) $	Rights[3] $	Total $	Percent of Remuneration %
Non-Executive Directors										
Stephen Gardiner	**2024**	**72,500**	**—**	**—**	**7,975**	**—**	**—**	**19,309**	**99,784**	**—**
	2023	70,833	—	—	7,438	—	—	18,251	96,522	—
Katherine Hirschfeld	**2024**	**85,000**	**—**	**—**	**9,350**	**—**	**—**	**—**	**94,350**	**—**
	2023	78,000	—	—	8,190	—	—	7,300	93,490	—
Agu Kantsler	**2024**	**62,500**	**—**	**—**	**6,875**	**—**	**—**	**19,309**	**88,684**	**—**
	2023	62,500	—	—	6,563	—	—	18,251	87,314	—
Michael McCormack	**2024**	**117,500**	**—**	**—**	**12,925**	**—**	**—**	**35,860**	**166,285**	**—**
	2023	117,500	—	—	12,338	—	—	33,895	163,733	—
Former Non-Executive Directors										
Stuart Baker[4]	**2024**	—	—	—	—	—	—	—	—	—
	2023	14,167	—	—	1,488	—	—	—	15,655	—
Troy Harry[5]	**2024**	**47,816**	**—**	**—**	**5,260**	**—**	**—**	**—**	**53,076**	**—**
	2023	66,402	—	—	6,972	—	—	—	73,374	—
Sub-total	**2024**	**385,316**	**—**	**—**	**42,385**	**—**	**—**	**74,478**	**502,179**	**—**
	2023	409,402	—	—	42,989	—	—	77,697	530,088	—
Executives										
Leon Devaney	**2024**	**679,448**	**139,097**	**8,839**	**27,399**	**—**	**12,600**	**216,083**	**1,083,466**	**33%**
	2023	640,142	117,823	8,192	25,292	—	22,307	177,683	991,439	30%
Ross Evans	**2024**	**547,708**	**139,130**	**8,839**	**27,399**	**—**	**16,196**	**126,848**	**866,120**	**31%**
	2023	508,712	81,370	8,192	25,292	—	9,717	117,477	750,760	26%
Damian Galvin	**2024**	**331,213**	**50,208**	**8,839**	**27,399**	**—**	**5,509**	**83,857**	**507,025**	**26%**
	2023	340,936	42,471	8,192	25,292	—	5,856	76,803	499,550	24%
Duncan Lockhart[6]	**2024**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
	2023	66,458	—	2,007	6,323	—	(15,824)	(43,061)	15,903	—
Jonathan Snape[7]	**2024**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
	2023	170,679	—	4,895	14,543	—	(2,706)	(21,944)	165,467	—
Daniel White	**2024**	**471,549**	**67,407**	**8,839**	**27,399**	**—**	**9,253**	**112,638**	**697,085**	**26%**
	2023	469,673	57,063	8,192	25,292	—	18,425	135,958	714,603	27%
Sub-total	**2024**	**2,029,918**	**395,842**	**35,356**	**109,596**	**—**	**43,558**	**539,426**	**3,153,696**	**30%**
	2023	2,196,600	298,727	39,670	122,034	—	37,775	442,916	3,137,722	24%
Total Remuneration	**2024**	**2,415,234**	**395,842**	**35,356**	**151,981**	**—**	**43,558**	**613,904**	**3,655,875**	**28%**
	2023	2,606,002	298,727	39,670	165,023	—	37,775	520,613	3,667,810	22%

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. Refer Section H above.
3 The fair values of share rights granted under the LTIP are valued using methodology that takes into account market and peer performance hurdles. The values of rights 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. Rights granted under the EIP at valued at market value on the grant date. 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 Stuart Baker resigned 30 August 2022.
5 Troy Harry was appointed 1 September 2022 and resigned 5 February 2024.
6 Duncan Lockhart resigned 31 August 2022.
7 Jonathan Snape resigned 20 January 2023.

K. Remuneration Details – Statutory tables (continued)

Table 3: Short Term Incentives Awarded

		Maximum $	Awarded $	Awarded %	Forfeited %
Leon Devaney	**2024**	**272,740**	**139,097**	**51.0%**	**49.0%**
	2023	261,829	117,823	45.0%	55.0%
Ross Evans[1]	**2024**	**229,161**	**156,233**	**68.2%**	**31.8%**
	2023	142,815	64,267	45.0%	55.0%
Damian Galvin	**2024**	**98,448**	**50,208**	**51.0%**	**49.0%**
	2023	94,380	42,471	45.0%	55.0%
Daniel White	**2024**	**132,170**	**67,407**	**51.0%**	**49.0%**
	2023	126,806	57,063	45.0%	55.0%
Total	**2024**	**732,519**	**412,945**	**56.4%**	**43.6%**
	2023	625,830	281,624	45.0%	55.0%

1 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 is 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[1,5]						
Stephen Gardiner	**2024**	**386,182**	**14 Nov 23**	**0.050**	**—**	**30 Jun 28**
	2023	217,275	11 Nov 22	0.084	—	30 Jun 27
Katherine Hirschfeld	**2024**	**—**	**—**	**—**	**—**	**—**
	2023	86,910	11 Nov 22	0.084	—	30 Jun 27
Agu Kantsler	**2024**	**386,182**	**14 Nov 23**	**0.050**	**—**	**30 Jun 28**
	2023	217,275	11 Nov 22	0.084	—	30 Jun 27
Michael McCormack	**2024**	**717,196**	**14 Nov 23**	**0.050**	**—**	**30 Jun 28**
	2023	403,511	11 Nov 22	0.084	—	30 Jun 27
Sub-total	**2024**	**1,489,560**				
	2023	924,971				
Executives[2]						
Leon Devaney[5]	**2024**	**4,021,260**	**14 Nov 23**	**0.050**	**—**	**14 Nov 28**
	2023	3,160,353	10 Nov 22	0.083	—	10 Nov 27
Ross Evans	**2024**	**2,193,405**	**14 Sep 23**	**0.053**	**—**	**14 Sep 28**
	2023	1,723,434	19 Sep 22	0.096	—	19 Sep 27
Damian Galvin	**2024**	**1,449,525**	**14 Sep 23**	**0.053**	**—**	**14 Sep 28**
	2023	1,138,215	19 Sep 22	0.096	—	19 Sep 27
Duncan Lockhart[3]	**2024**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
	2023	76,283	19 Sep 22	0.096	—	19 Sep 27
Jonathan Snape[4]	**2024**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
	2023	1,111,113	19 Sep 22	0.096	—	19 Sep 27
Daniel White	**2024**	**1,947,534**	**14 Sep 23**	**0.053**	**—**	**14 Sep 28**
	2023	1,530,000	19 Sep 22	0.096	—	19 Sep 27
Sub-total	**2024**	**9,611,724**				
	2023	8,739,398				
Total	**2024**	**11,101,284**				
	2023	9,664,369				

1 Represents a portion of Directors Fees sacrificed. These Share Rights vested on 30 June – Refer Section M of this report.
2 Represent Rights awarded under the Executive Incentive Plan which vest over three years on 30 June of the current and two subsequent financial years.
3 Duncan Lockhart resigned 31 August 2022.
4 Jonathan Snape resigned 20 January 2023. 740,742 of these Share Rights were subsequently cancelled and a further 185,185 did not vest.
5 Share Rights were issued to Directors in accordance with approvals obtained under ASX Listing Rule 10.14.

K. 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 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 – Refer Section M of this report.

The following factors and assumptions were used in determining the fair value of rights granted to key management personnel during FY2023:

Grant Date	Expiry Date	Fair Value Per Right	Exercise Price	Price of Shares at Grant Date	Estimated Volatility	Risk Free Interest Rate	Dividend Yield
19 Sep 2022[1]	19 Sep 2027	$0.096	Nil	$0.096	N/A	N/A	—
10 Nov 2022[1]	10 Nov 2027	$0.083	Nil	$0.083	N/A	N/A	—
11 Nov 2022[2]	30 Jun 2027	$0.084	Nil	$0.084	N/A	N/A	—

[1] EIP Rights for the plan year commencing 1 July 2021.
[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 01 Jul 22	EIP Commencing 01 Jul 21	STIP Year Commencing 01 Jul 19[5]	LTIP Year Commencing 01 Jul 20[1]	Number of Rights Vested[1]	Proportion of Rights Vested[2]	Proportion of Rights Forfeited
Leon Devaney	**2024**	**1,340,420**	**1,053,451**	**496,171**	**—**	**2,890,042**	**100%**	**Nil**
	2023	—	1,053,451	—	—	1,053,451	100%	Nil
Ross Evans	**2024**	**731,135**	**574,478**	**405,655**	**—**	**1,711,268**	**100%**	**Nil**
	2023	—	574,478	—	—	574,478	100%	Nil
Damian Galvin	**2024**	**483,175**	**379,405**	**243,198**	**—**	**1,105,778**	**100%**	**Nil**
	2023	—	379,405	—	—	379,405	100%	Nil
Duncan Lockhart[3]	**2024**	N/A	**N/A**	**N/A**	**N/A**	N/A	N/A	N/A
	2023	—	76,283	—	—	76,283	100%	Nil
Jonathan Snape[4]	**2024**	N/A	**N/A**	**N/A**	**N/A**	N/A	N/A	N/A
	2023	—	185,186	—	—	185,186	100%	Nil
Daniel White	**2024**	**649,178**	**510,000**	**327,269**	**—**	**1,486,447**	**100%**	**Nil**
	2023	—	510,000	—	—	510,000	100%	Nil
	2023	—	—	—	1,510,476	452,160	30%	70%
Total	**2024**	**3,203,908**	**2,517,334**	**1,472,293**	**—**	**7,193,535**	**100%**	**Nil**
	2023	—	2,778,803	—	—	2,778,803	100%	Nil
	2023	—	—	—	1,510,476	452,160	30%	70%

[1] The number of Rights that vested in respect of plan year commencing 1 July 2020 relates to Share Rights granted in prior financial years under the Long Term Incentive Plan.
[2] The proportion of Rights vested represents the proportion of the maximum number of Rights that were eligible for vesting during the financial year.
[3] Duncan Lockhart resigned 31 August 2022.
[4] Jonathan Snape resigned 20 January 2023.
[5] The FY2020 STIP was awarded as deferred share rights instead of cash. These rights vested 1 July 2023.

In addition, 1,489,560 Share Rights vested on 30 June 2024 (2023: 924,971), representing 100% of Share Rights granted during the year to Non-Executive Directors in return for the sacrifice of Directors' fees – refer Table 4 above.

K. 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 (refer Section F of this report).

Key Management Personnel have, in previous years, participated in the Group's Long Term Incentive Plans under which they may have received:

a) Rights to shares of the Company under the LTIP Employee Rights Plan (refer Section E of this report); and
b) Options over shares of the Company under the Executive Share Option 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 Holdings Of 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								
Stuart Baker[1]	**2024**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
	2023	161,765	—	—	—	(161,765)	N/A	N/A
Stephen Gardiner	**2024**	**379,040**	**386,182**	**—**	**(379,040)**	**N/A**	**386,182**	**—**
	2023	161,765	217,275	—	—	N/A	379,040	—
Katherine Hirschfeld	**2024**	**86,910**	**—**	**—**	**(86,910)**	**N/A**	**—**	**—**
	2023	64,706	86,910	—	(64,706)	N/A	86,910	—
Agu Kantsler	**2024**	**217,275**	**386,182**	**—**	**(217,275)**	**N/A**	**386,182**	**—**
	2023	161,765	217,275	—	(161,765)	N/A	217,275	—
Michael McCormack	**2024**	**403,511**	**717,196**	**—**	**(403,511)**	**N/A**	**717,196**	**—**
	2023	300,420	403,511	—	(300,420)	N/A	403,511	—
Sub-total	**2024**	**1,086,736**	**1,489,560**	**—**	**(1,086,736)**	**N/A**	**1,489,560**	**—**
	2023	850,421	924,971	—	(526,891)	(161,765)	1,086,736	—
Executives								
Leon Devaney	**2024**	**4,235,213**	**4,021,260**	**—**	**(2,128,311)**	**N/A**	**2,393,871**	**3,734,291**
	2023	1,074,860	3,160,353	—	—	N/A	1,632,140	2,603,073
Ross Evans	**2024**	**2,129,089**	**2,193,405**	**—**	**(980,133)**	**N/A**	**1,305,613**	**2,036,748**
	2023	405,655	1,723,434	—	—	N/A	574,478	1,554,611
Damian Galvin	**2024**	**1,381,413**	**1,449,525**	**—**	**(622,603)**	**N/A**	**862,580**	**1,345,755**
	2023	243,198	1,138,215	—	—	N/A	379,405	1,002,008
Duncan Lockhart[2]	**2024**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
	2023	304,213	76,283	(84,504)	—	(295,992)	N/A	N/A
Jonathan Snape[3]	**2024**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
	2023	—	1,111,113	(740,742)	—	(370,371)	N/A	N/A
Daniel White	**2024**	**3,367,745**	**1,947,534**	**(1,058,316)**	**(1,289,429)**	**N/A**	**1,159,178**	**1,808,356**
	2023	2,820,949	1,530,000	(560,427)	(422,777)	N/A	510,000	2,857,745
Sub-total	**2024**	**11,113,460**	**9,611,724**	**(1,058,316)**	**(5,020,476)**	**N/A**	**5,721,242**	**8,925,150**
	2023	4,848,875	8,739,398	(1,385,673)	(422,777)	(666,363)	3,096,023	8,017,437
Total	**2024**	**12,200,196**	**11,101,284**	**(1,058,316)**	**(6,107,212)**	**N/A**	**7,210,802**	**8,925,150**
	2023	5,699,296	9,664,369	(1,385,673)	(949,668)	(828,128)	4,182,759	8,017,437

[1] Stuart Baker resigned 30 August 2022
[2] Duncan Lockhart resigned 31 August 2022
[3] Jonathan Snape resigned 20 January 2023. Of the 370,371 rights held on departure, 185,185 subsequently lapsed.

K. Remuneration Details – Statutory tables (continued)

Table 7: Vesting Profile Of Share Rights Holdings Of Key Management Personnel

	Grant Date	Type	Maximum Number of Unvested Rights at 30 June 2024	Vesting Period End Date[2]	Maximum value yet to vest[3]
Key Management Personnel					
Leon Devaney	TBD[1]	Deferred Share Rights – FY2024 EIP[1]	—	—	165,260
	14 Nov 2023	Deferred Share Rights – FY2023 EIP	1,340,420	30 Jun 2026	31,117
	14 Nov 2023	Deferred Share Rights – FY2023 EIP	1,340,420	30 Jun 2025	17,872
	14 Nov 2023	Deferred Share Rights – FY2023 EIP	1,340,420	30 Jun 2024	—
	10 Nov 2022	Deferred Share Rights – FY2022 EIP	1,053,451	30 Jun 2025	17,175
	10 Nov 2022	Deferred Share Rights – FY2022 EIP	1,053,451	30 Jun 2024	—
Ross Evans	TBD[1]	Deferred Share Rights – FY2024 EIP[1]	—	—	90,175
	14 Sep 2023	Deferred Share Rights – FY2023 EIP	731,135	30 Jun 2026	17,991
	14 Sep 2023	Deferred Share Rights – FY2023 EIP	731,135	30 Jun 2025	10,333
	14 Sep 2023	Deferred Share Rights – FY2023 EIP	731,135	30 Jun 2024	—
	19 Sep 2022	Deferred Share Rights – FY2022 EIP	574,478	30 Jun 2025	10,833
	19 Sep 2022	Deferred Share Rights – FY2022 EIP	574,478	30 Jun 2024	—
Damian Galvin	TBD[1]	Deferred Share Rights – FY2024 EIP[1]	—	—	59,652
	14 Sep 2023	Deferred Share Rights – FY2023 EIP	483,175	30 Jun 2026	11,890
	14 Sep 2023	Deferred Share Rights – FY2023 EIP	483,175	30 Jun 2025	6,829
	14 Sep 2023	Deferred Share Rights – FY2023 EIP	483,175	30 Jun 2024	—
	19 Sep 2022	Deferred Share Rights – FY2022 EIP	379,405	30 Jun 2025	7,154
	19 Sep 2022	Deferred Share Rights – FY2022 EIP	379,405	30 Jun 2024	—
Daniel White	TBD[1]	Deferred Share Rights – FY2024 EIP[1]	—	—	80,086
	14 Sep 2023	Deferred Share Rights – FY2023 EIP	649,178	30 Jun 2026	15,974
	14 Sep 2023	Deferred Share Rights – FY2023 EIP	649,178	30 Jun 2025	9,175
	14 Sep 2023	Deferred Share Rights – FY2023 EIP	649,178	30 Jun 2024	—
	19 Sep 2022	Deferred Share Rights – FY2022 EIP	510,000	30 Jun 2025	9,617
	19 Sep 2022	Deferred Share Rights – FY2022 EIP	510,000	30 Jun 2024	—
Total			**14,646,392**		**561,133**

1 Share rights as part of the FY2024 EIP are expected to be granted during FY2025. The number of rights to be granted is determined based on Central Petroleum's share price for the 20 days after release of the June 2024 quarterly report, which is calculated as 5.03 cents per right.

2 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.

3 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. For the FY2024 EIP, the maximum value yet to vest is based on the proportion (two-thirds) of the total incentive that will convert to share rights. The minimum value to vest is nil, as the rights will be forfeited if the vesting conditions are not met.

K. Remuneration Details – Statutory tables (continued)

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	Retained on Departure	Number of Options Held at End of Year (Unvested)
Key Management Personnel									
Leon Devaney	**2024**	**5,105,000**	**—**	**$0.20**	**01 Jul 2023**	**(5,105,000)**	**—**	**N/A**	**—**
	2023	5,105,000	—	$0.20	01 Jul 2023	—	—	N/A	5,105,000
Ross Evans	**2024**	**4,170,025**	**—**	**$0.20**	**01 Jul 2023**	**(4,170,025)**	**—**	**N/A**	**—**
	2023	4,170,025	—	$0.20	01 Jul 2023	—	—	N/A	4,170,025
Damian Galvin	**2024**	**2,750,000**	**—**	**$0.20**	**01 Jul 2023**	**(2,750,000)**	**—**	**N/A**	**—**
	2023	2,750,000	—	$0.20	01 Jul 2023	—	—	N/A	2,750,000
Duncan Lockhart[1]	**2024**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
	2023	3,333,333	—	$0.20	01 Jul 2023	—	—	(3,333,333)	N/A
Total	**2024**	**12,025,025**	**—**	**$0.20**	**01 Jul 2023**	**(12,025,025)**	**—**	**N/A**	**—**
	2023	15,358,358	—	$0.20	01 Jul 2023	—	—	(3,333,333)	12,025,025

[1] Duncan Lockhart resigned 31 August 2022.

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							
Troy Harry[1]	**2024**	**53,340,268**	**N/A**	**—**	**—**	**(53,340,268)**	**N/A**
	2023	N/A	53,340,268	—	—	N/A	53,340,268
Stephen Gardiner	**2024**	**—**	**N/A**	**—**	**379,040**	**N/A**	**379,040**
	2023	—	N/A	—	—	N/A	—
Katherine Hirschfeld	**2024**	**825,556**	**N/A**	**—**	**86,910**	**N/A**	**912,466**
	2023	760,850	N/A	—	64,706	N/A	825,556
Agu Kantsler	**2024**	**161,765**	**N/A**	**—**	**217,275**	**N/A**	**379,040**
	2023	—	N/A	—	161,765	N/A	161,765
Michael McCormack	**2024**	**300,420**	**N/A**	**—**	**403,511**	**N/A**	**703,931**
	2023	—	N/A	—	300,420	N/A	300,420
Sub-total	**2024**	**54,628,009**	**—**	**—**	**1,086,736**	**(53,340,268)**	**2,374,477**
	2023	760,850	53,340,268	—	526,891	N/A	54,628,009
Other Key Management Personnel							
Leon Devaney	**2024**	**2,606,757**	**N/A**	**—**	**2,128,311**	**N/A**	**4,735,068**
	2023	2,606,757	N/A	—	—	N/A	2,606,757
Ross Evans	**2024**	**386,184**	**N/A**	**—**	**980,133**	**N/A**	**1,366,317**
	2023	386,184	N/A	—	—	N/A	386,184
Damian Galvin	**2024**	**141,000**	**N/A**	**—**	**622,603**	**N/A**	**763,603**
	2023	141,000	N/A	—	—	N/A	141,000
Daniel White	**2024**	**2,985,420**	**N/A**	**—**	**1,289,429**	**N/A**	**4,274,849**
	2023	2,562,643	N/A	—	422,777	N/A	2,985,420
Sub-total	**2024**	**6,119,361**	**—**	**—**	**5,020,476**	**—**	**11,139,837**
	2023	5,696,584	—	—	422,777	—	6,119,361
Total KMP	**2024**	**60,747,370**	**—**	**—**	**6,107,212**	**(53,340,268)**	**13,514,314**
	2023	6,457,434	53,340,268	—	949,668	—	60,747,370

[1] Troy Harry was appointed on 1 September 2022 and resigned on 5 February 2024.

L. Executive Service Agreements

The details of service agreements of the key management personnel of the Consolidated Entity as of 1 July 2024 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	$595,000	6-months
Ross Evans	Chief Operations Officer	Full time permanent	$558,079	6-months
Damian Galvin	Chief Financial Officer	Full time permanent	$369,179	6-months
Daniel White	Group General Counsel & Company Secretary	Full time permanent	$495,639	3-months

[1] Total Annual Fixed Remuneration, effective 1 July 2024 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).

M. 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 FY2024. 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 14 November 2023.

FY2024 Board Fees (per annum)	
Chair	$130,000
Non-Executive Director	$70,000

FY2024 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

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:

Michael McCormack
Chair

18 September 2024

Auditor's Independence Declaration

As lead auditor for the audit of Central Petroleum Limited for the year ended 30 June 2024, 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
18 September 2024

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FINANCIAL REPORT

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

The Financial Statements are presented in Australian currency.

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

Level 7, 369 Ann Street
Brisbane, Queensland 4000

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

The financial statements were authorised for issue by the Directors on 18 September 2024. 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 2024

	NOTE	2024 $'000	2023 $'000
Revenue from contracts with customers – sale of hydrocarbons	2	37,154	39,255
Cost of sales	4(a)	(27,365)	(26,408)
Gross profit		**9,789**	**12,847**
Other income	3	14,754	1,880
Exploration expenditure	4(f)	(3,990)	(13,093)
General and administrative expenses net of recoveries	4(c)	(3,386)	(4,797)
Finance costs	4(d)	(4,293)	(4,797)
Other expenses	4(b)	(452)	—
Profit/(loss) before income tax		**12,422**	**(7,960)**
Income tax expense	5	—	—
Profit/(loss) for the year		**12,422**	**(7,960)**
Other comprehensive profit/(loss) for the year, net of tax		—	—
Total comprehensive profit/(loss) for the year		**12,422**	**(7,960)**
Total comprehensive profit/(loss) attributable to members of the parent entity		**12,422**	**(7,960)**
Earnings per share for profit or loss attributable to the ordinary equity holders of the company:			
Basic earnings/(loss) per share (cents)	22(a)	**1.68**	**(1.09)**
Diluted earnings/(loss) per share (cents)	22(b)	**1.64**	**(1.09)**

The accompanying notes form part of these financial statements.

CONSOLIDATED BALANCE SHEET
AS AT 30 JUNE 2024

	NOTE	2024 $'000	2023 $'000
ASSETS			
Current assets			
Cash and cash equivalents	7	24,985	13,826
Trade and other receivables	8	5,450	6,675
Inventories	9	3,765	3,550
Total current assets		34,200	24,051
Non-current assets			
Property, plant and equipment	10	55,578	60,192
Right of use assets	11(a)	1,018	551
Exploration assets	12	7,674	7,999
Other intangible assets	13	376	332
Other financial assets	14	2,840	3,053
Goodwill	15	1,953	1,953
Total non-current assets		69,439	74,080
Total assets		**103,639**	**98,131**
LIABILITIES			
Current liabilities			
Trade and other payables	16	3,260	3,009
Deferred revenue	2(b)	1,087	3,536
Borrowings	17(a)	4,440	4,376
Lease liabilities	11(a)	624	426
Provisions	18	8,794	5,597
Total current liabilities		18,205	16,944
Non-current liabilities			
Deferred revenue	2(b)	10,237	11,632
Borrowings	17(b)	18,723	23,150
Lease liabilities	11(a)	426	201
Provisions	18	23,493	26,816
Total non-current liabilities		52,879	61,799
Total liabilities		**71,084**	**78,743**
Net assets		**32,555**	**19,388**
EQUITY			
Contributed equity	19 (a)	197,776	197,776
Reserves	20	41,488	31,433
Accumulated losses	21	(206,709)	(209,821)
Total equity		**32,555**	**19,388**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

FOR THE YEAR ENDED 30 JUNE 2024

	Contributed Equity $'000	Share Options Reserve $'000	Accumulated Profits Reserve $'000	Accumulated Losses $'000	Total $'000
Balance at 1 July 2022	**197,776**	**30,615**	**—**	**(201,861)**	**26,530**
Total loss for the year	—	—	—	(7,960)	(7,960)
Other comprehensive loss	—	—	—	—	—
Total comprehensive profit for the year	—	—	—	(7,960)	(7,960)
Transactions with owners in their capacity as owners					
Share based payments	—	820	—	—	820
Share issue costs	—	(2)	—	—	(2)
	—	818	—	—	818
Balance at 30 June 2023	**197,776**	**31,433**	**—**	**(209,821)**	**19,388**
Total profit for the year	—	—	—	12,422	12,422
Other comprehensive loss	—	—	—	—	—
Total comprehensive loss 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**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED 30 JUNE 2024

	NOTE	2024 $'000	2023 $'000
Cash flows from operating activities			
Receipts from customers		36,882	38,050
Interest received		912	519
Other income		3	248
Government grants		11	—
Interest and borrowing costs		(2,893)	(2,853)
Payments for exploration expenditure		(2,614)	(9,629)
Payments to other suppliers and employees		(25,439)	(28,391)
Net cash inflow/(outflow) from operating activities	27	6,862	(2,056)
Cash flows from investing activities			
Payments for property, plant and equipment		(2,939)	(2,857)
Proceeds from sale of producing assets and property, plant and equipment		3	3
Proceeds from sale of subsidiary net of transaction costs and cash disposed	3(b)	12,184	—
Redemption of security deposits and bonds		201	1,356
Net cash inflow/(outflow) from investing activities		9,449	(1,498)
Cash flows from financing activities			
Payments for the issue of securities		(4)	(2)
Proceeds from borrowings	28(b)	—	1,000
Repayment of borrowings	28(b)	(4,667)	(4,625)
Transaction costs related to borrowings		—	(195)
Principal elements of lease payments	28(b)	(481)	(445)
Net cash outflow from financing activities		(5,152)	(4,267)
Net increase/(decrease) in cash and cash equivalents		**11,159**	**(7,821)**
Cash and cash equivalents at the beginning of the financial year		**13,826**	**21,647**
Cash and cash equivalents at the end of the financial year	7	**24,985**	**13,826**

The accompanying notes form part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

(a) Basis of Preparation

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

Rounding of Amounts

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

(i) Going Concern

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

The Board has considered cash flow forecast scenarios prepared by management for the next twelve months and believe the Group has sufficient cash flows and access to capital to continue operations as planned. During FY2024, the Group realised over $12 million cash from the sale of its interest in the Range CSG assets in November 2023 and at year end had a cash balance of $25.0 million.

Central and its joint venturer continue to consider the future structure and timing of the three-well sub-salt exploration program following the termination of previous farm-out funding arrangements. Central is progressing discussions with a credible party for potential farmins to assist with funding the wells.

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 2023 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 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 FY2024 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 33.

(c) Segment Reporting

Operating segments are reported in Note 23 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.

Amounts received under pre-sale agreements are initially recognised as Deferred Revenue when no cash settlement option exists for the customer. Revenue is recognised as the product is physically supplied.

(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, including research and development concessions, 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. Research and development grants are recognised as other income in the profit and loss where they relate to exploration expenditure which has been expensed in the profit and loss. 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 a tax funding and a tax sharing agreement.

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 32.

(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 23).

(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 24, 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 2023:

- AASB 2021-5 Amendments to Australian Accounting Standards – Deferred Tax related to Assets and Liabilities arising from a Single Transaction [AASB 112]
- AASB 2021-2 Amendments to Australian Accounting Standards – Disclosure of Accounting Policies Definition of Accounting Estimates [AASB 7, AASB 101, AASB 108, AASB 134 & AASB Practice Statement 2].

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.

2. REVENUE FROM CONTRACTS WITH CUSTOMERS

(a) Revenue from contracts with customers

	2024 $'000	2023 $'000
Sale of hydrocarbon products - point in time		
Natural gas	30,963	34,731
Crude oil and condensate	3,155	3,488
Revenue released from Deferred Revenue [1]	3,036	1,036
Total revenue from contracts with customers	**37,154**	**39,255**

[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 23(f) – Segment Reporting.

2. REVENUE FROM CONTRACTS WITH CUSTOMERS (CONTINUED)

(b) Contract Liabilities

	2024 Current $'000	2024 Non-current $'000	2024 Total $'000	2023 Current $'000	2023 Non-current $'000	2023 Total $'000
Deferred Revenue – take-or-pay contracts[1]	1,087	10,237	11,324	1,371	11,632	13,003
Deferred Revenue – other gas sales contracts[1]	—	—	—	2,165	—	2,165
Total contract liabilities	**1,087**	**10,237**	**11,324**	**3,536**	**11,632**	**15,168**

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

Movements in Contract Liabilities

	Deferred Revenue from take or pay contracts $'000	Deferred Revenue from other contracts $'000	Total $'000
Carrying amount at 1 July 2023	**13,003**	**2,165**	**15,168**
Revenue recognised from the delivery of gas	(331)	(2,105)	(2,436)
Revenue released (forfeited gas)	(2,901)	(135)	(3,036)
Gas paid for but not taken during the period	1,553	–	1,553
Finance charges	–	75	75
Carrying amount at 30 June 2024	**11,324**	**—**	**11,324**

3. OTHER INCOME

	2024 $'000	2023 $'000
Interest	947	533
Income from financial assets at amortised cost	—	304
Income from the farmout of exploration interests (a)	—	795
Profit on disposal of subsidiary (b)	13,795	—
Government subsidies	11	—
Profit on disposal of inventory and other assets	1	248
Total other income	**14,754**	**1,880**

(a) Income from the farmout of exploration interests

On 31 March 2023 the Group completed the farmout of interests in certain exploration permits to Peak Helium (Amadeus Basin) Pty Ltd. In accordance with the Farmout Agreement, the Group was entitled to receive reimbursement of expenditure previously incurred and expensed by the Group from the effective date of the farmout transaction (1 October 2021). A total of $795,000 was recorded as Other Income in the prior year relating to the farmout of exploration interests. This amount reflected reimbursement amounts relating to the previous financial year (FY 2022) exploration expenditure and reductions in rehabilitation obligations previously expensed.

(b) 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**

4. EXPENSES

(a) Cost of sales includes the following specific expenses

	NOTE	2024 $'000	2023 $'000
Depreciation and amortisation	4(e)	6,748	6,295
Employee and contractor costs		5,963	5,326
Gas purchases		4,894	4,416
Other production costs		4,672	5,073
Royalties		3,104	2,938
Transportation and storage		1,984	2,360
Total cost of sales		**27,365**	**26,408**

(b) Other expenses include the following specific expenses

	2024 $'000	2023 $'000
Write off, impairment, and disposal of property, plant and equipment	442	—
Other costs	10	—
Total other expenses	**452**	**—**

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

	NOTE	2024 $'000	2023 $'000
Depreciation and amortisation	4(e)	598	571
Employee and contractor costs		1,334	1,650
Share based payments		749	820
Other costs		705	1,756
Total general and administrative expenses		**3,386**	**4,797**

(d) Finance costs include the following specific expenses

	NOTE	2024 $'000	2023 $'000
Interest and fees on debt facilities		2,865	2,998
Interest on lease liabilities	11(b)	43	49
Amortisation of deferred finance costs		291	342
Accretion charges		1,094	1,408
Total finance costs		**4,293**	**4,797**

4. EXPENSES (CONTINUED)

(e) Total depreciation and amortisation

	NOTE	2024 $'000	2023 $'000
Depreciation			
Buildings	10	176	175
Producing assets	10	3,485	3,371
Plant and equipment	10	3,100	2,752
Leasehold improvements	10	10	10
Right of use assets	11(b)	437	442
Total depreciation		**7,208**	**6,750**
Amortisation			
Other intangible assets - software	13	138	116

(f) Exploration-related impairment expense

Impairment expenses of $325,000 were recognised during the year for costs carried forward in respect of the Palm Valley Deep prospect. In FY2023, impairment expenses of $3,486,000 relating to the impairment of the Group's interest in RL3 and RL4 ($398,000) and impairment of amounts owing by Peak Helium (Amadeus Basin) Pty Ltd under farmin arrangements ($3,088,000) were included in exploration expenditure.

(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.

(a) Income tax expense

	2024 $'000	2023 $'000
Current tax	—	—
Deferred tax	—	—
Income tax expense	**—**	**—**

(b) Numerical reconciliation of income tax expense and prima facie tax benefit

	2024 $'000	2023 $'000
Profit/(Loss) before income tax expense	12,422	(7,960)
Prima facie tax (expense)/benefit at 30% (2023: 30%)	(3,726)	2,388
Tax effect of amounts which are not deductible in calculating taxable income:		
Non-deductible expenses	(8)	(8)
Share based payments	(225)	(246)
Other items	—	—
Sub-total	(3,959)	2,134
Previously unrecognised deferred tax assets	3,959	—
Deferred tax assets not recognised	—	(2,134)
Income tax expense	**—**	**—**

(c) Amounts recognised directly in equity

	2024 $'000	2023 $'000
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

	2024 $'000	2023 $'000
Unutilised tax losses for which no deferred tax asset has been recognised	131,696	142,134
Potential tax benefit at 30%	**39,509**	**42,640**

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

	2024 $'000	2023 $'000
Deferred tax assets		
Provisions and accruals	10,072	9,788
Receivables	—	926
Deferred revenue	—	187
Other expenditure	294	253
Borrowing costs	78	140
Unutilised losses	48,643	51,936
Total deferred tax assets before set-offs	59,087	63,230
Set-off of deferred tax liabilities pursuant to set-off provisions	(9,134)	(9,296)
Net deferred tax assets not recognised	**49,953**	**53,934**
Movements in deferred tax assets		
Opening balance at 1 July	9,296	9,487
Charged to the income statement	(162)	(191)
Closing balance at 30 June	**9,134**	**9,296**
Deferred tax assets to be recovered after more than 12-months	6,051	6,241
Deferred tax assets to be recovered within 12-months	3,083	3,055
	9,134	**9,296**
Deferred tax liabilities		
Capitalised exploration	2,271	2,362
Property, plant and equipment	6,863	6,929
Other items	—	5
Total deferred tax liabilities before set-offs	9,134	9,296
Set-off of deferred tax assets pursuant to set-off provisions	(9,134)	(9,296)
Net deferred tax liabilities	—	—
Movements in deferred tax liabilities		
Opening balance at 1 July	9,296	9,487
Credited to the income statement	(162)	(191)
Closing balance at 30 June	**9,134**	**9,296**
Deferred tax liabilities to be recovered after more than 12-months	8,947	9,173
Deferred tax liabilities to be recovered within 12-months	187	123
	9,134	**9,296**

6. REMUNERATION OF AUDITORS

	2024 $	2023 $
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	241,450	243,958
(ii) Taxation services		
Income tax compliance	15,300	14,280
Other tax related services	21,581	47,512
Total taxation services	36,881	61,792
Total remuneration of PwC	**278,331**	**305,750**

7. CASH AND CASH EQUIVALENTS

	2024 $000	2023 $000
Cash and cash equivalents	**24,985**	**13,826**
Made up as follows:		
Corporate cash and bank balances (a)	14,567	13,296
Joint arrangements (b)	418	530
Cash on term deposit (c)	10,000	—
Total cash and cash equivalents	**24,985**	**13,826**

(a) $2,759,000 of this balance relates to cash held with Macquarie Bank Limited to be used for allowable purposes under the Facility Agreement (2023: $2,920,000), including, but not limited to operating costs for the Palm Valley, Dingo and Mereenie fields, taxes, 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 is 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 32.

8. TRADE AND OTHER RECEIVABLES

	2024 $'000	2023 $'000
Current		
Trade debtors	17	55
Accrued income and recoveries (a)	3,943	3,963
Other receivables	1	545
Prepayments	1,489	1,361
Items measured at amortised cost:		
Deferred receivable from partial sale of producing assets (b)	—	751
	5,450	**6,675**

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 32(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.

8. TRADE AND OTHER RECEIVABLES (CONTINUED)

(b) Represents deferred consideration receivable in respect of the disposal of 50% of interests in the Amadeus Basin producing assets. This was classified as a Financial Asset measured at amortised cost. During the year, $751,000 was recouped through a free carry by the purchasers of Central's share of expenditure on certain exploration and development projects (2023: $20,373,000). In FY 2023, $304,000 was recognised as Other Income as a result of adjustments to amortised cost for the period (Current Year:Nil).

9. INVENTORIES

	2024 $'000	2023 $'000
Crude oil and natural gas	132	108
Spare parts and consumables	1,744	1,412
Drilling materials and supplies at cost	1,889	2,030
	3,765	**3,550**

10. PROPERTY, PLANT AND EQUIPMENT

	Freehold Land and Buildings $'000	Producing Assets $'000	Plant and Equipment $'000	Total $'000
Year ended 30 June 2023				
Opening net book amount	754	33,372	19,720	53,846
Additions	—	8,346	4,469	12,815
Changes to rehabilitation estimates	—	(168)	10	(158)
Disposals and write offs	—	—	(3)	(3)
Depreciation charge	(175)	(3,371)	(2,762)	(6,308)
Closing net book amount	**579**	**38,179**	**21,434**	**60,192**
At 30 June 2023				
Cost	1,952	64,442	47,779	114,173
Accumulated depreciation	(1,373)	(26,263)	(26,345)	(53,981)
Net book amount at 30 June 2023	**579**	**38,179**	**21,434**	**60,192**
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**

At 30 June 2024, $839,000 of property plant and equipment balances relates to assets under construction and is not subject to depreciation until complete (2023: $2,891,000).

In assessing the appropriateness of the recoverability of property, plant and equipment balances, the net book amounts above have been tested for impairment against expected future cash flows from the producing assets cash generating unit 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:

	2024 $'000	2023 $'000
Right-of-use assets		
Land & Buildings	951	483
Plant & Equipment	67	68
	1,018	**551**
Lease Liabilities		
Current	624	426
Non-current	426	201
	1,050	**627**

Additions to the right-of-use assets during the 2024 financial year were $904,000 (2023: $77,000). Disposals and incentive adjustments amounted to $Nil (2023: $6,000).

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

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

	2024 $'000	2023 $'000
Depreciation charge of right-of-use assets		
Land & Buildings	368	373
Plant & Equipment	69	69
Total depreciation of right-of-use assets	**437**	442
Interest expense	43	49
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 2024 was $524,000 (2023: $493,000).

(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

	2024 $'000	2023 $'000
Acquisition costs of right to explore	**7,674**	**7,999**
Movement for the year:		
Balance at the beginning of the year	7,999	8,397
Impairment expense (Note 4(f))	(325)	(398)
Balance at the end of the year	**7,674**	**7,999**

13. OTHER INTANGIBLE ASSETS

	2024 $'000	2023 $'000
Software		
At the beginning of the year		
Cost	1,094	1,025
Accumulated amortisation	(762)	(646)
Net book value	**332**	**379**
Movements for the year		
Opening net book amount	332	379
Additions	182	69
Amortisation	(138)	(116)
Closing net book amount	**376**	**332**
At the end of the year		
Cost	1,050	1,094
Accumulated amortisation	(674)	(762)
Net book value	**376**	**332**

14. OTHER FINANCIAL ASSETS

	2024 $'000	2023 $'000
Non-Current		
Security bonds on exploration permits and rental properties	**2,840**	**3,053**

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.

15. GOODWILL

	2024 $'000	2023 $'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 (now renamed Echelon Resources Limited) and Horizon Oil Limited entered into agreements with Macquarie Mereenie Pty Ltd to acquire the latter's interests 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 concluded that the transaction 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 2024. This change in estimate from the future cash flows method applied previously, to the recent market transaction approach, is due to the transaction representing a more reliable estimate of the fair value of the Assets.

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 73.3 PJ 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 2024.

15. GOODWILL (CONTINUED)

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

	2024 $'000	2023 $'000
Current		
Trade payables	1,133	878
Other payables	—	5
Accruals	2,127	2,126
	3,260	**3,009**

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 32.

17. BORROWINGS

		2024 $'000	2023 $'000
(a)	Current[1]		
	Debt facilities	4,440	4,376
(b)	Non-current[1]		
	Debt facilities	18,723	23,150

[1] Details regarding interest bearing liabilities are contained in Note 32(e).

The financing facility held with Macquarie Bank matures on 30 September 2025. The Group is in active discussions to refinance the facility.

18. PROVISIONS

	2024			2023		
	Current $'000	Non-Current $'000	Total $'000	Current $'000	Non-Current $'000	Total $'000
Employee entitlements (a)	5,092	708	5,800	4,365	763	5,128
Restoration and rehabilitation (b)	2,831	22,047	24,878	370	24,460	24,830
Joint Venture production over-lift (c)	871	738	1,609	862	1,593	2,455
	8,794	**23,493**	**32,287**	**5,597**	**26,816**	**32,413**

(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.

18. PROVISIONS (CONTINUED)

Movements in Provisions

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

2024	Employee Entitlements $'000	Restoration & Rehabilitation $'000	Joint Venture Production Over-Lift $'000	Total $'000
Carrying amount at start of year	5,128	24,830	2,455	32,413
Change in provision charged/(credited) to property, plant and equipment	—	(113)	—	(113)
Additional provisions charged to profit or loss	3,009	889	26	3,924
Unwinding of discount	—	1,019	—	1,019
Disposal of subsidiary (Note 3 (b))	—	(1,569)	—	(1,569)
Amounts used during the year	(2,337)	(178)	(872)	(3,387)
Carrying amount at end of year	**5,800**	**24,878**	**1,609**	**32,287**

19. CONTRIBUTED EQUITY

(a) Share capital

	2024 $'000	2023 $'000
740,147,003 fully paid ordinary shares (2023: 729,405,268)	**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

	2024 Number of Shares	2023 Number of Shares	2024 $'000	2023 $'000
Balance at start of year	729,405,268	725,907,449	197,776	197,776
Shares issued under Employee Incentive Plans	10,741,735	3,497,819	—	—
Balance at end of year	**740,147,003**	**729,405,268**	**197,776**	**197,776**

(b) Share Options

The following table shows the movement in options over ordinary shares during the year:

Class	Expiry Date	Exercise Price	Balance at Start of Year	Issued During the Year	Cancelled During the Year	Exercised During the Year	Balance at the End of the Year
Executive Share Option Plan	30 Jun 2023[1]	$0.200	17,221,046	—	(17,221,046)	—	—
Total			**17,221,046**	**—**	**(17,221,046)**	**—**	**—**

[1] The options were available to be exercised up to and including 30 June 2023. All of the unexercised options were cancelled on 1 July 2023.

(c) Share rights

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

19. CONTRIBUTED EQUITY (CONTINUED)

(c) Share rights (continued)

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	22 May 2024	1 Jul 2018	72,877	—	(6,123)	(66,754)	—
Employee LTIP rights	12 Nov 2024	1 Jul 2018	578,689	—	—	(578,689)	—
Employee LTIP rights	30 Jun 2024	1 Jul 2019	319,033	—	(157,897)	(161,136)	—
Employee Deferred Share rights[1]	30 Jun 2025	1 Jul 2019	3,360,571	—	—	(3,360,571)	—
Employee LTIP rights	30 Jun 2025	1 Jul 2020	8,701,069	—	(5,880,323)	(2,709,046)	111,700
Employee LTIP rights	30 Jun 2026	1 Jul 2021	374,901	—	(42,685)	—	332,216
Employee LTIP rights	30 Jun 2027	1 Jul 2022	507,180	—	(59,171)	—	448,009
Employee LTIP rights	30 Jun 2028	1 Jul 2023	—	1,051,206	(86,656)	—	964,550
Executive Incentive Plan							
EIP Share Rights	30 Jun 2027	1 Jul 2021	7,813,471	—	—	(2,778,803)	5,034,668
EIP Share Rights	30 Jun 2028	1 Jul 2022	—	9,611,724	—	—	9,611,724
Non-Executive Director rights [2]							
Director Share Rights	30 Jun 2026	1 Jul 2021	161,765	—	—	(161,765)	—
Director Share Rights	30 Jun 2027	1 Jul 2022	924,971	—	—	(924,971)	—
Director Share Rights	30 Jun 2028	1 Jul 2023	—	1,489,560	—	—	1,489,560
Total			**22,814,527**	**12,152,490**	**(6,232,855)**	**(10,741,735)**	**17,992,427**

1 In respect of year ended 30 June 2020, certain employees were awarded deferred share rights rather than cash short term incentives. These deferred share rights had a vesting date of 1 July 2023.
2 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.

20. RESERVES

	2024 $'000	2023 $'000
Share options reserve	32,178	31,433
Accumulated profits reserve	9,310	—
Total Reserves	**41,488**	**31,433**

Movements	**Share options reserve**	**Accumulated profits reserve**
Balance at 1 July 2022	30,615	—
Share based payments relating to employee incentive plans (a)	820	—
Transaction costs	(2)	—
Balance at 30 June 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 at30 June 2024	**32,178**	**9,310**

(a) Share based payments are provided to employees under the Employee Rights Plan and Executive Share Option Plan. Refer to Note 31 and Sections E, F and G 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.

21. ACCUMULATED LOSSES

	2024 $'000	2023 $'000
Movements in accumulated losses were as follows:		
Balance at the start of year	(209,821)	(201,861)
Net profit/(loss) for the year	12,422	(7,960)
Transfer of profits to accumulated profits reserve	(9,310)	—
Balance at end of year	**(206,709)**	**(209,821)**

22. EARNINGS/(LOSS) PER SHARE

		2024	2023
(a)	**Basic earnings/(loss) per share (cents)**	**1.68**	**(1.09)**
(b)	**Diluted earnings/(loss) per share (cents)**	**1.64**	**(1.09)**
(c)	**Profit/(Loss) used in earnings per share calculation**		
	Profit/(loss) attributed to ordinary equity holders ($'000)	**12,422**	**(7,960)**
(d)	**Weighted average number of ordinary shares**		
	Weighted average number of shares used as the denominator in calculating basic loss/earnings per share	**737,684,614**	**728,113,749**
	Adjustments for the calculation of diluted loss/earnings per share:		
	Employee share rights	20,948,527	—
	Weighted average number of shares used as the denominator in calculating diluted loss/earnings per share	**758,633,141**	**728,113,749**

Options and Rights on issue are considered to be potential ordinary shares and have not been included in the calculation of basic loss/earnings per share. Additionally, for 2023, any exercise of options or rights would be antidilutive as their exercise to ordinary shares would decrease the loss per share. In accordance with AASB 133, they are also excluded from the diluted loss per share calculation.

23. 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 tables and reconciliations below.

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

23. 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(b)).
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.

23. SEGMENT REPORTING (CONTINUED)

(e) Performance monitoring and evaluation (continued)

2023	Producing Assets 2023 $'000	Exploration Assets 2023 $'000	Unallocated Items 2023 $'000	Consolidation 2023 $'000
Revenue from contracts with customers				
Natural gas	34,731	—	—	34,731
Crude oil and condensate	3,488	—	—	3,488
Forfeited take or pay amounts	1,036	—	—	1,036
Total revenue from contracts with customers	**39,255**	**—**	**—**	**39,255**
Cost of sales	(26,408)	—	—	(26,408)
Gross profit	**12,847**	**—**	**—**	**12,847**
Other income[1]	556	977	347	1,880
Exploration expenditure	(6,862)	(6,231)	—	(13,093)
Finance costs	(4,446)	(63)	(288)	(4,797)
General and administrative expenses[2]	—	—	(4,797)	(4,797)
Statutory profit / (loss) before income tax	**2,095**	**(5,317)**	**(4,738)**	**(7,960)**
Taxes	—	—	—	—
Statutory profit / (loss) for the year	**2,095**	**(5,317)**	**(4,738)**	**(7,960)**
Add Finance costs net of interest income	3,965	54	(59)	3,960
Add Depreciation, amortisation and impairment	6,295	—	571	6,866
Add Exploration expenditure	6,862	6,231	—	13,093
EBITDAX[3]	**19,217**	**968**	**(4,226)**	**15,959**
Segment assets	**74,344**	**9,968**	**13,819**	**98,131**
Segment liabilities	**(64,310)**	**(5,768)**	**(8,665)**	**(78,743)**
Capital expenditure				
Property, plant and equipment	12,690	—	125	12,815
Intangibles	56	—	13	69
Total capital expenditure	**12,746**	**—**	**138**	**12,884**

1 Other income attributable to the Exploration Assets segment includes $795,000 relating to the Peak Helium Farmout (Refer Note 3(a)).
2 Includes share based payments of $820,000 which is a non-cash item.
3 EBITDAX is earnings before interest, taxation, depreciation, amortisation, impairment and exploration expense.

	2024 $'000	2023 $'000
Revenue from external customers by geographical location of production:		
Australia	**37,154**	**39,255**
Non-current assets by geographical location:		
Australia	**69,439**	**74,080**

23. 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.

	2024 $'000	**% of Sales Revenue**	2023 $'000	% of Sales Revenue
Largest customer	22,774	61%	15,068	38%
Second largest customer	4,414	12%	5,762	15%
Third largest customer	—	—	4,183	11%
Fourth largest customer	—	—	3,923	10%

24. PARENT ENTITY INFORMATION

(a) Summary financial information

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

	2024 $'000	2023 $'000
Balance Sheet		
Current assets	27,182	15,098
Non-current assets	18,011	18,311
Total assets	45,193	33,409
Current liabilities	(8,488)	(6,609)
Non-current liabilities	(994)	(1,144)
Total liabilities	(9,482)	(7,753)
Net assets	**35,711**	**25,656**
Shareholders' equity		
Issued capital	197,776	197,776
Reserves	41,488	31,433
Accumulated losses	(203,553)	(203,553)
Total equity	**35,711**	**25,656**
Profit for the year	**9,310**	**2,227**
Total comprehensive profit	**9,310**	**2,227**

(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 Borrower typical for a borrowing of this nature. Monies received through the operation of the Palm Valley, Dingo and Mereenie fields are subject to a proceeds account and can be distributed to the Parent Entity as available when no default exists. Revenues resulting from operations outside of these assets (such as the Surprise field) are not subject to a cash sweep or other restrictions under the Facility where no defaults exist.

25. RELATED PARTY TRANSACTIONS

(a) Parent Entity

The Parent Entity is Central Petroleum Limited.

(b) Subsidiaries

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

			Equity Holding	
Name of Entity	Place of Incorporation	Class of Shares	2024 %	2023 %
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 Petroleum Eastern Pty Ltd[1]	Western Australia	Ordinary	—	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

[1] Central Petroleum Eastern Pty Ltd was disposed on 30 November 2023. Refer Note 3(b)

(c) Key management personnel compensation

	2024 $	2023 $
Short-term employee benefits	2,846,432	2,944,399
Post-employment benefits	151,981	165,023
Long-term benefits	43,558	37,775
Share based payments	613,904	520,613
	3,655,875	**3,667,810**

Detailed remuneration disclosures are provided in the Remuneration Report on pages 29 to 43.

26. 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 2024.

	2024 $'000	2023 $'000
Revenue from the sale of goods	19,670	20,783
Cost of sales	(13,502)	(15,952)
Gross profit	6,168	4,831
Other income	14,716	1,854
Other expenses	(458)	—
Exploration expenses	(3,505)	(13,011)
Finance costs	(2,346)	(1,626)
General and administrative expenses	(3,376)	(4,376)
Profit/(loss) before income tax	11,199	(12,328)
Income tax credit	271	1,567
Profit/(loss) for the year	11,470	(10,761)
Other comprehensive profit/(loss) for the year, net of tax	—	—
Total comprehensive (loss)/profit for the year	**11,470**	**(10,761)**
Accumulated losses at the beginning of the financial year	(221,614)	(210,853)
Profit/(loss) for the year	11,470	(10,761)
Transfer to Accumulated Profits Reserve	(9,310)	—
Accumulated losses at the end of the financial year	**(219,454)**	**(221,614)**

26. 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.

	2024 $'000	2023 $'000
ASSETS		
Current assets		
Cash and cash equivalents	24,752	13,718
Trade and other receivables	3,969	4,806
Inventories	2,630	2,613
Total current assets	31,351	21,137
Non-current assets		
Property, plant and equipment	26,111	30,323
Right of use assets	678	512
Exploration assets	7,674	7,999
Other intangible assets	284	265
Other financial assets	2,046	2,259
Deferred Tax Assets	5,387	5,178
Goodwill	1,953	1,953
Total non-current assets	44,133	48,489
Total assets	**75,484**	**69,626**
LIABILITIES		
Current liabilities		
Trade and other payables	11,159	14,113
Deferred revenue	992	1,006
Borrowings	1,479	2,639
Lease liabilities	617	396
Provisions	7,658	4,508
Total current liabilities	21,905	22,662
Non-current liabilities		
Deferred revenue	10,237	11,572
Borrowings	11,014	12,163
Lease liabilities	84	186
Provisions	12,434	15,448
Total non-current liabilities	33,769	39,369
Total liabilities	**55,674**	**62,031**
Net assets	**19,810**	**7,595**
EQUITY		
Contributed equity	197,776	197,776
Reserves	41,488	31,433
Accumulated losses	(219,454)	(221,614)
Total equity	**19,810**	**7,595**

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

	2024 $'000	2023 $'000
Profit/(loss) after income tax	**12,422**	**(7,960)**
Adjustments for:		
Depreciation and amortisation	7,346	6,866
Impairment	325	3,486
Profit on disposal of subsidiary	(13,795)	—
Loss on disposal and write off of non-current assets	445	—
Exploration costs funded by Joint Venture partners	89	7,421
Share-based payments	749	820
Financing costs and interest (non-cash)	1,398	1,641
Changes in assets and liabilities relating to operating activities:		
Decrease in trade and other receivables	474	129
(Increase)/decrease in inventories	(215)	317
Increase/(decrease) in trade and other payables	1,007	(10,681)
Decrease in deferred revenue	(3,919)	(4,324)
Increase in provisions	536	229
Net cash inflow/(outflow) from operations	**6,862**	**(2,056)**

28. CASH FLOW INFORMATION

(a) Non-cash investing and financing activities

During the year, the purchasers of 50% of the Group's interests in the Amadeus Basin producing properties funded $663,000 (2023: $9,863,000) of the Group's share of costs for the acquisition of property, plant and equipment. These amounts formed part of the deferred consideration component of the sale proceeds which have now been fully recovered.

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

- Acquisition of right of use assets – Note 11(a); and
- Options and rights issued to employees under short and long term incentive plans – Note 31.

(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/(debt)

	2024 $'000	2023 $'000
Cash and cash equivalents	24,985	13,826
Borrowings and leases – repayable within one year	(5,064)	(4,802)
Borrowings and leases – repayable after one year	(19,149)	(23,351)
Net cash / (debt)	**772**	**(14,327)**
Cash	24,985	13,826
Gross Debt – fixed interest rates	(1,050)	(627)
Gross debt – variable interest rates	(23,163)	(27,526)
Net cash / (debt)	**772**	**(14,327)**

28. CASH FLOW INFORMATION (CONTINUED)

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

Movement in net cash/(debt)

	Other Assets	Liabilities from Financing Activities		
	Cash $'000	Borrowings $'000	Leases $'000	Total $'000
Net debt 1 July 2022	**21,647**	**(30,809)**	**(1,001)**	**(10,163)**
Cash flows	(7,821)	3,625	445	(3,751)
Amortisation of deferred borrowing costs	—	(342)	—	(342)
Non-cash lease adjustments	—	—	(71)	(71)
Net cash/(debt) 30 June 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/(debt) 30 June 2024	**24,985**	**(23,163)**	**(1,050)**	**772**

29. CONTINGENCIES

(a) Contingent liabilities

(i) Exploration Permits

The Consolidated Entity had contingent liabilities at 30 June 2024 in respect of certain joint arrangement payments. As partial consideration under the terms of the purchase agreement for EP105, there is a requirement to pay the vendor the sum of $1,000,000 (2023: $1,000,000) within 12-months following the commencement of any future commercial production from the permits. No commercial production is currently forecast from this permit.

(ii) Palm Valley Gas Field Gas Price Bonus

Under the Share Sale and Purchase Deed entered into with Magellan Petroleum Australia Pty Limited (Magellan) in February 2014 for the purchase of Palm Valley and Dingo gas fields and related assets, Central Petroleum Limited is obligated to pay to Magellan a Gas Price Bonus where the weighted average price of gas sold from the Palm Valley gas field during a contract year exceeds certain price hurdles during a period of 15 years following completion of the Agreement.

The Gas Price Bonus Amount is calculated as 25% of the difference between the weighted average price of gas actually sold (excluding GST and other costs) in a contract year and the gas price bonus hurdle applicable to that contract year (after adjusting for CPI), multiplied by the actual volume of gas originating and sold from the Palm Valley gas field. The weighted average price of gas sold from the Palm Valley gas field is currently below the Gas Price Bonus hurdle price and therefore no gas price bonus is payable at this time. Therefore, no value has been ascribed to this contingent liability at 30 June 2024.

On 26 July 2024 a new Gas Sales Agreement was executed by the Palm Valley Joint Venture partners for the supply of gas from 1 January 2025. The contracted price may result in this contingent liability becoming payable in future periods in respect of gas supplied from the Palm Valley field.

30. COMMITMENTS

(a) Capital commitments

	2024 $'000	2023 $'000
The Consolidated Entity has the following capital expenditure commitments:		
The following amounts are due:		
Within one year	378	1,241
	378	**1,241**

(b) Joint Venture exploration commitments

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

	2024 $'000	2023 $'000
The following amounts are due:		
Within one year	20,850	7,200
Later than one year but not later than three years	9,000	8,223
Later than three years but not later than five years	—	—
	29,850	**15,423**

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.

31. SHARE BASED PAYMENTS

(a) Employee options

An Executive Share Option Plan operated in respect of the three year period from FY2020 to provide incentives for key executives. Participation in the plan is at the Board's discretion.
Details of options issued under the plan are shown below.

Grant Date	Expiry Date	Balance at Start of Year	Granted During the Year	Exercise Price	Average Fair Value Per Option	Cancelled or Expired During the Year	Balance at End of Year	Vested and Exercisable
2024								
20 Aug 2019	30 Jun 2023[1]	12,116,046	—	$0.20	$0.120	(12,116,046)	—	—
07 Nov 2019	30 Jun 2023[1]	5,105,000	—	$0.20	$0.087	(5,105,000)	—	—
Totals		**17,221,046**	**—**		**$0.111**	**(17,221,046)**	**—**	**—**
Weighted average exercise price		**$0.20**					**—**	
2023								
20 Aug 2019	30 Jun 2023	12,116,046	—	$0.20	$0.120	—	12,116,046	—
07 Nov 2019	30 Jun 2023	5,105,000	—	$0.20	$0.087	—	5,105,000	—
Totals		**17,221,046**	**—**		**$0.111**	**—**	**17,221,046**	**—**
Weighted average exercise price		**$0.20**					**$0.20**	

[1] The options were exercisable up to and including 30 June 2023. No options were exercised and they were subsequently cancelled on 1 July 2023.

The values of Executive Options were calculated at the date of grant using a Black Scholes valuation.

(b) 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.

31. SHARE BASED PAYMENTS (CONTINUED)

Grant Date	Plan Year End	Balance at Start of Year	Number of Rights Granted	Average Fair Value Per Right	Exercised During the Year	Cancelled or Forfeited	Balance at End of Year
2024							
11 Nov 2020	30 Jun 2020[1]	3,360,571	—	$0.130	(3,360,571)	—	—
2023							
11 Nov 2020	30 Jun 2020[1]	3,692,054	—	$0.130	—	(331,483)	3,360,571

[1] Share rights in respect of the performance period ended 30 June 2020 had a deferred vesting date of 1 July 2023.

(c) 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
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)	—	—
2023							
23 Nov 2022	30 Jun 2023	—	924,971	$0.084	—	—	924,971
23 Nov 2021	30 Jun 2022	850,421	—	$0.115	(688,656)	—	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 (2023: 3.9 years).

(d) Rights to shares — Executive Incentive Plan (EIP)

Key Management Personnel are 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 is 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 following EIP movements occurred during the year:

31. SHARE BASED PAYMENTS (CONTINUED)

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

							Balance at End of Year	
Grant Date	Plan Year End	Balance at Start of Year	Number of Rights Granted During the Year	Average Fair Value Per Right	Exercised During the Year	Cancelled or Forfeited During the Year	Vested and Exercisable	Total Yet to Vest
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
2023								
19 Sep 2022	30 Jun 2022	—	5,579,045	$0.096	—	(925,927)	1,725,352	2,927,766
10 Nov 2022	30 Jun 2022	—	3,160,353	$0.083	—	—	1,053,451	2,106,902
Totals		—	8,739,398	$0.091	—	(925,927)	2,778,803	5,034,668

The weighted average fair value of share rights issued to key management personnel under the EIP during the financial year was $0.052 (2023: $0.091). The weighted average remaining contractual life of outstanding Executive Incentive Plan share rights at the end of the year was 3.94 years (2023 4.0 years).

At 30 June 2024, no rights had been granted under the EIP for the plan year ended 30 June 2024. Share rights, as part of the FY2024 EIP are expected to be granted during FY2025. The grant date is yet to be determined.

(e) 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.

The number of rights to be granted to eligible employees is determined 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 for those employees on a percentage based, share-price linked plan are determined by a combination of 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.

Rights for participants in the fixed $1,000 Exempt Plan vest at the end of the three year service period.

Share based payment expense for the year includes amounts expensed in respect of the following number of rights either granted or expected to be granted:

31. SHARE BASED PAYMENTS (CONTINUED)

(e) Rights to shares — Long Term Incentive Plans (continued)

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							
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
22 Aug 2022	30 Jun 2023	507,180		$0.090	—	(59,171)	448,009
22 Aug 2022	30 Jun 2022	55,257		$0.090	—	(9,901)	45,356
17 Aug 2021	30 Jun 2022	319,644	—	$0.105	—	(32,784)	286,860
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
07 Nov 2019	30 Jun 2019	578,689	—	$0.119	(578,689)	—	—
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)	—
09 May 2019	30 Jun 2019	28,012	—	$0.101	(28,012)	—	—
24 Sep 2019	30 Jun 2019	8,127	—	$0.087	(8,127)	—	—
24 Sep 2019	30 Jun 2019	36,738	—	$0.120	(30,615)	(6,123)	—
Totals		**10,553,749**	**1,051,206**		**(3,515,625)**	**(6,232,855)**	**1,856,475**

The weighted average fair value of share rights granted under the Long Term Incentive Plan during the year was $0.051 (2023: $0.09). The weighted average remaining contractual life of outstanding share rights at the end of the year was 3.2 years (2023: 2.1 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 Forfeited During the Year	Balance at End of Year
2023							
22 Aug 2022	30 Jun 2023	—	540,992	$0.090	—	(33,812)	507,180
22 Aug 2022	30 Jun 2022	—	61,476	$0.090	—	(6,219)	55,257
17 Aug 2021	30 Jun 2022	426,192	—	$0.105	—	(106,548)	319,644
18 Sep 2020	30 Jun 2018	1,198	—	$0.130	(1,198)	—	—
24 Jul 2020	30 Jun 2021	8,620,660	—	$0.065	—	(260,361)	8,360,299
24 Jul 2020	30 Jun 2021	454,140	—	$0.089	—	(113,370)	340,770
24 Jul 2020	30 Jun 2020	30,545	—	$0.089	(26,553)	(3,992)	—
07 Nov 2019	30 Jun 2019	578,689	—	$0.119	—	—	578,689
23 Aug 2019	30 Jun 2020	274,119	—	$0.190	(220,611)	(29,520)	23,988
23 Aug 2019	30 Jun 2020	6,003,654	—	$0.155	(2,286,515)	(3,422,094)	295,045
09 May 2019	30 Jun 2019	28,012	—	$0.101	—	—	28,012
24 Sep 2019	30 Jun 2019	259,406	—	$0.087	(251,279)	—	8,127
24 Sep 2019	30 Jun 2019	65,987	—	$0.120	(17,356)	(11,893)	36,738
01 Sep 2017	30 Jun 2018	5,651	—	$0.115	(5,651)	—	—
Totals		**16,748,253**	**602,468**		**(2,809,163)**	**(3,987,809)**	**10,553,749**

No rights were granted to key management personnel under the Long Term Incentive Plan during the current or prior financial year.

31. SHARE BASED PAYMENTS (CONTINUED)

(f) Expenses arising from share-based payment transactions

Total expenses arising from share-based transactions recognised during the year were:

	2024 $	2023 $
Share Rights issued to employees	**749,453**	**820,165**

32. 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 2024 is nil (2023: nil), no loss allowance provision has been recorded at 30 June 2024 (2023: 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	**2024 $'000**	2023 $'000	**2024 $'000**	2023 $'000
Current: 0-30 days	**3,868**	4,563	—	—
	3,868	**4,563**	**—**	**—**

The trade receivables at 30 June 2024 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 24(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.

32. FINANCIAL RISK MANAGEMENT (CONTINUED)

(b) Liquidity Risk (continued)

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

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)**

2023 ($'000)	≤ 6 Months	6–12 Months	1–5 Years	≥ 5 Years	Contractual Cash Flow	Carrying Amount
Financial Assets						
Cash and cash equivalents	13,826	—	—	—	13,826	13,826
Trade and other receivables	5,314	—	—	—	5,314	5,314
Other financial assets	—	—	3,053	—	3,053	3,053
	19,140	**—**	**3,053**	**—**	**22,193**	**22,193**
Financial Liabilities						
Trade and other payables	(3,009)	—	—	—	(3,009)	(3,009)
Interest bearing liabilities	(3,997)	(3,811)	(26,171)	(65)	(34,044)	(28,153)
	(7,006)	**(3,811)**	**(26,171)**	**(65)**	**(37,053)**	**(31,162)**

32. 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	
	2024 %	2023 %	**2024 $'000**	2023 $'000	**2024 $'000**	2023 $'000	**2024 $'000**	2023 $'000	**2024 $'000**	2023 $'000
Financial Assets:										
Cash and cash equivalents	**4.6**	4.2	**14,985**	13,826	**10,000**	—	**—**	—	**24,985**	13,826
Trade and other receivables	**—**	—	**—**	—	**—**	—	**3,961**	4,563	**3,961**	4,563
Other financial assets	**0.9**	0.7	**—**	—	**528**	528	**2,312**	2,525	**2,840**	3,053
Total Financial Assets			**14,985**	13,826	**10,528**	528	**6,273**	7,088	**31,786**	21,442
Financial Liabilities:										
Trade and other payables	**—**	—	**—**	—	**—**	—	**(3,260)**	(3,009)	**(3,260)**	(3,009)
Interest bearing liabilities	**10.0**	9.8	**(23,163)**	(27,526)	**(1,050)**	(627)	**—**	—	**(24,213)**	(28,153)
Total Financial Liabilities			**(23,163)**	(27,526)	**(1,050)**	(627)	**(3,260)**	(3,009)	**(27,473)**	(31,162)
Net Financial Assets / (Liabilities)			**(8,178)**	(13,700)	**9,478**	(99)	**3,013**	4,079	**4,313**	(9,720)

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
2024 ($'000)				
Cash and cash equivalents	75	(75)	—	—
Interest bearing liabilities	(117)	117	—	—
2023 ($'000)				
Cash and cash equivalents	69	(69)	—	—
Interest bearing liabilities	(141)	141	—	—

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.

32. FINANCIAL RISK MANAGEMENT (CONTINUED)

(e) Financing Facilities

The Group has a loan facility agreement (Facility) with Macquarie Bank Limited (Macquarie).

Interest costs are based on fixed spreads over the periodic Bank Bill Swap (BBSW) average bid rate. The Facility is structured as a partially amortising term loan and has a maturity date of 30 September 2025. Repayments comprise fixed quarterly principal repayments along with accrued interest. 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:

	2024 $'000	2023 $'000
Trade and other receivables (USD)	437	281
Trade and other payables:		
- USD	(112)	(46)
- CAD	—	(90)

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.

	2024 $'000	2023 $'000
Australian dollar +10% movement in exchange rate	(30)	(13)
Australian dollar -10% movement in exchange rate	36	16

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.

33. INTERESTS IN JOINT ARRANGEMENTS

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

	Principal Activities	2024 %	2023 %
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	29.00
EP 105	Oil & gas exploration	60.00	60.00
EP 112[1]	Oil & gas exploration	45.00	35.00
EP 125[1]	Oil & gas exploration	30.00	24.00
EPA 111	Oil & gas exploration – application	50.00	50.00
EPA 124	Oil & gas exploration – application	50.00	50.00
ATP 2031 - Range Gas Project[2]	Oil & gas exploration	—	50.00

[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 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] 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. Refer Note 3(b).

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.

33. 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:

	2024 $'000	2023 $'000
Current assets		
Cash and cash equivalents	417	530
Trade and other receivables	3,212	3,412
Inventory	3,406	3,161
Total current assets	7,035	7,103
Non-current assets		
Property, plant and equipment	47,543	51,173
Right of use assets	387	88
Total non-current assets	47,930	51,261
Current liabilities		
Trade and other payables	3,038	2,834
Lease liabilities	10	32
Deferred revenue	1,087	1,371
Provision for production over-lift	871	862
Restoration provision	299	300
Total current liabilities	5,305	5,399
Non-current liabilities		
Deferred revenue	10,237	11,632
Lease liabilities	396	68
Provision for production over-lift	738	1,594
Restoration provision	19,018	19,885
Total non-current liabilities	30,389	33,179
Net assets	**19,271**	**19,786**
Joint arrangement contribution to profit before tax		
Revenue	37,154	39,255
Other income	77	72
Expenses	(25,266)	(34,629)
Profit before income tax	**11,965**	**4,698**

34. EVENTS OCCURRING AFTER THE REPORTING PERIOD

In July 2024, new Gas Sale Agreements were executed and are expected to provide more reliable cash flows for Central from 1 January 2025, benefitting from higher average contracted gas prices and more consistent, firm sales that will not be affected by interruptions to the Northern Gas Pipeline.

No matters or circumstances have arisen between 30 June 2024 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 2024

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 46 to 91 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 2024 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 92 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 2024.

3. As at the date of this declaration, there are reasonable grounds to believe that the members of the Closed Group identified in Note 26 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:

Michael McCormack
Director
Brisbane

18 September 2024

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 2024 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 2024
- 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 2024
- the directors' declaration.

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.

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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	*Key audit matters*
• Our audit focused on where the Group made subjective judgements; for example, significant accounting estimates involving assumptions and inherently uncertain future events.	• Amongst other relevant topics, we communicated the following key audit matters to the Audit and Financial Risk Committee: ○ Basis of Preparation of the financial report; and ○ Valuation of exploration and evaluation assets.

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.

Key audit matter	*How our audit addressed the key audit matter*
Basis of Preparation of the financial report *Refer to note 1 (a) (i) of the financial report* As described in Note 1 of the financial report, the financial statements have been prepared by the Group 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. Assessing the appropriateness of the Group's basis of preparation for the financial report was a key audit matter due to its importance to the financial report and the level of judgement involved in assessing future	In assessing the appropriateness of the Group's going concern basis of preparation for the financial report, we performed the following procedures, amongst others: • evaluated the appropriateness of the Group's assessment of their ability to continue as a going concern, including whether the level of analysis is appropriate given the nature of the Group, the period covered is at least 12 months from the date of our auditor's report, and relevant information of which we are aware as a result of the audit has been included. • evaluated the Group's plans for future actions (including alternative options in relation to the current exploration permits), and whether they

Key audit matter	*How our audit addressed the key audit matter*
options and status of the three well sub-salt exploration program, in particular with respect to the Group forecasting future cash flows for a period of at least 12 months from the audit report date (cash flow forecasts).	are feasible in the circumstances. • evaluated selected data and assumptions used in the Group's cash flow forecasts for at least 12 months from the date of signing the auditor's report. • developed an understanding of what forecast expenditure in the cash flow forecast is committed and what could be considered discretionary. • read the terms associated with the debt agreement and assessed the projected debt compliance over the forecast period. • evaluated whether, in view of the requirements of Australian Accounting Standards, the financial report provides adequate disclosures about these events or conditions.
Valuation of exploration and evaluation assets ($7,674,000) *Refer to note 12 of the financial report and Note 1 (p)* 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. The Group concluded that there was an impairment indicator, and recognised an associated impairment expense for the Palm Valley Deep prospect of $325k. 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 that 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 is 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 2024, 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://www.auasb.gov.au/admin/file/content102/c3/ar1_2020.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 2024.

In our opinion, the remuneration report of Central Petroleum Limited for the year ended 30 June 2024 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
18 September 2024

ASX ADDITIONAL INFORMATION

DETAILS OF QUOTED SECURITIES AS AT 13 SEPTEMBER 2024

Top holders

The 20 largest registered holders of the quoted securities as at 13 September 2024 were:

	NAME	NO. OF SHARES	%
1	Norfolk Enchants Pty Ltd <Trojan Retirement Fund A/c>	48,594,871	6.57
2	Moranbah Nominees Pty Ltd <Chris Wallin Super Fund A/C>	19,526,612	2.64
3	Brazil Farming Pty Ltd	17,785,209	2.40
4	Citicorp Nominees Pty Limited	16,020,177	2.16
5	Maitri Pty Ltd <Coci Super Fund A/C>	15,180,139	2.05
6	Mr Peter Vrettos	14,867,172	2.01
7	Mr Kenneth John Beer + Mr Alexander Charles Beer <Beer Super Fund A/C>	14,840,846	2.01
8	Macquarie Bank Limited <Metals Mining and AG A/C>	14,166,667	1.91
9	JH Nominees Australia Pty Ltd <Harry Family Super Fund A/C>	12,842,031	1.74
10	Mr Philip Gasteen <Thrushton Investment A/C>	12,373,780	1.67
11	Chembank Pty Limited <Philandron A/C>	10,000,000	1.35
12	Kensington Capital Partners Pty Ltd	8,000,000	1.08
13	ITA Vero Pty Ltd <The Richmond A/c)	7,470,849	1.01
14-16	Garmi Holdings Pty Ltd <Pemco Super Fund A/c>	7,000,000	0.95
14-16	Justwright Investments Pty Ltd <Justwright Super Fund A/C>	7,000,000	0.95
14-16	PA and RE Gibson Pty Ltd <PA&RE Gibson Super Fund A/C>	7,000,000	0.95
17	BNP Paribas Nominees Pty Ltd	6,514,229	0.88
18	Chembank Pty Limited <CABAC Super Fund A/c>	6,000,000	0.81
19	Mr Donald Leonard Cottee	5,830,594	0.79
20	Ms Dian Paramita	5,127,400	0.69
	Total	**256,140,576**	**34.61**

DISTRIBUTION SCHEDULE

A distribution schedule of the number of holders in each class of equity securities as at 13 September 2024 was:

SIZE OF HOLDING	LISTED FULLY PAID SHARES	UNLISTED SHARE RIGHTS
1 – 1,000	121	-
1,001 – 5,000	244	-
5,001 – 10,000	446	3
10,001 – 100,000	2,093	62
100,001 – Over	819	8
Total	**3,723**	**73**

UNLISTED SECURITIES

At 13 September 2024, there were 17,992,427 unlisted share rights on issue.

ASX ADDITIONAL INFORMATION

SUBSTANTIAL SHAREHOLDERS

Substantial shareholders as disclosed by notices received by the Company as at 13 September 2024 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

UNMARKETABLE PARCELS

Holdings less than a marketable parcel of ordinary shares (being 10,417 shares as at 13 September 2024):

HOLDERS	UNITS
828	4,939,389

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

There is no current on-market buy-back of the Company's securities.

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 2024 Corporate Governance Statement reflects the corporate governance practices in place throughout the 2024 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		
EP105	Amadeus/Pedirka Basin NT	Santos	60	60	Santos	40
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		
ATP909[2]	Georgina Basin QLD	Central	100	100		
ATP911[2]	Georgina Basin QLD	Central	100	100		
ATP912[2]	Georgina Basin QLD	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[3]	Amadeus Basin NT	Santos	50	50	Santos	50
EPA124 [4]	Amadeus Basin NT	Santos	50	50	Santos	50
EPA129	Wiso Basin NT	Central	100	100		
EPA130	Pedirka Basin NT	Central	100	100		
EPA132	Georgina Basin NT	Central	100	100		
EPA133	Amadeus Basin NT	Central	100	100		
EPA137	Amadeus Basin NT	Central	100	100		
EPA147	Amadeus Basin NT	Central	100	100		
EPA149	Amadeus Basin NT	Central	100	100		
EPA152 [4]	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] The farmout agreement with Peak Helium (Amadeus Basin) Pty Ltd (***Peak***) has been terminated and 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 changed from 29% to 60%)

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

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

[2] Central intends to surrender its interests in the Georgina Basin (Qld permits ATP 909, ATP 911 and ATP 912). On 10 January 2023, Central submitted a relinquishment notice for ATP911. On 13 March 2023, a work program amendment was approved for ATP909 & ATP912 which includes only the abandonment of existing wells ahead of relinquishment.

[3] On 16 December 2021 Central received notice from the NT Department of Industry Tourism and Trade (DITT) that EPA111 had been placed in moratorium for a period of 5 years from 9 December 2021 until 9 December 2026.

[4] On 22 March 2018 (in respect of EPA124) and on 23 March 2018 (in respect of EPA152) Central received notice from DITT that EPA124 and EPA152, as applicable, had been placed in moratorium on 6 December 2017 for a five year period which ended on 6 December 2022. On 12 April 2023, Central was provided with consent to negotiate the grant of EPA152.

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
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
mmbl	Million barrels
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

Mr Michael (Mick) McCormack BSurv, GradDipEng, MBA, FAICD, 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, HonFIEAust, FTSE, FIChemE, FAICD, Independent Non-Executive Director
Dr Agu Kantsler BSc (Hons), PhD, GAICD, FTSE, Independent Non-Executive Director

GROUP GENERAL COUNSEL AND COMPANY SECRETARY

Mr Daniel White LLB, BCom, LLM

REGISTERED OFFICE

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STOCK EXCHANGE LISTING

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