ANNUAL REPORT

CENTRAL PETROLEUM LIMITED
ACN 083 254 308

2023

Central Petroleum

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CHAIR’S LETTER

Dear Shareholders,

It has been a popular topic in recent years to demonise natural gas as the harbinger for all manner of ills, from irreversible planet-destroying climate change to rapidly-rising energy costs. Against this backdrop, the Federal Government’s intervention in gas markets during the year appeared ill-conceived, but once the dust had settled, it seems unlikely to directly affect Central’s gas marketing and commercial prospects.

It is from within this confusing environment of fact and fantasy that voices of reason are now being respected, confirming the critical role that natural gas will play in the transition to a cleaner energy future.

It is becoming increasingly clear that it is not only the southern states that will face significant gas supply challenges in coming years. Northern Australia, the home of remote mining operations providing rare minerals, critical for the renewables transition, is facing reducing gas supplies as traditional offshore sources decline.

With over 55 PJs of uncontracted 2P reserves, Central’s gas fields are playing an increasingly important role in producing vital gas supplies for customers across the region.

This supply/demand dynamic has provided a strong gas market for Central, with robust demand and strong term gas prices vindicating our investments in additional production from our established fields.

Investment to increase production at Mereenie and Palm Valley this year has added over 11 TJ/day of gas into the market (100% JV) at a time when offshore production in the NT experienced significant production decline and alternate suppliers were struggling to meet demand.

Realised gas prices were significantly higher than the previous year and forward term gas contracts reflect continued gas supply constraints in the NT and Mt Isa regions.

Combined with our recent reserve upgrades, a strong term gas market should continue to support our operational cash flows and financial strength going forward.

In addition to the proven natural gas resources of the Amadeus Basin, there are strong indications that the basin could provide Australia with supplies of other gases – most notably helium, which already exists in low concentrations in our existing gas streams, and has previously been detected in commercial concentrations in previous exploration wells.

We are now advancing plans for a helium recovery unit at Mereenie to produce helium for the Australian market. The proposed Mereenie project would then be the sole source of domestically-produced helium, helping to satisfy Australia’s strategic need for helium which is used in many critical health and technology applications.

Production of helium at Mereenie would add a valuable new income stream for Central, and given the world-wide paucity of helium sources, elevate the attractiveness of Amadeus Basin’s sub-salt formations.

The failure of one of our joint-venturers to perform will delay the three sub-salt exploration wells that were planned to explore for helium, naturally-occurring hydrogen and natural gas. We are working to restructure and refinance the program so that these exciting prospects can be tested.

On the ground, we continue to work with the people and businesses in our local communities and the Traditional Owners of the land on which we operate. We appreciate their contributions to our success and hope that the opportunities and support we provide in these regions have long-lasting impact.

I thank my Board colleagues, Leon, our CEO and all of our staff at Central who have worked throughout the year to provide our customers with reliable and affordable energy.

Our strategic review continues to explore various opportunities to realise value for shareholders. I am sure you are aware of the issues which have confronted the industry since we started the review late last year. The gas price cap, a proposed mandatory code of conduct (which is now law) and the safeguard mechanism, have all been matters which caused material uncertainty in the sector. As was well reported in the media these material changes impacted the strategic decisions and plans at the international and national levels. These matters are now behind us, but nonetheless, have slowed our progress. We hope to be able to conclude this process in the near future and appreciate the patience of our shareholders and staff.

We remain confident in the future of our asset portfolio. The enduring value of our producing assets has been demonstrated with drilling success and reserve upgrades, helium is emerging as an additional income stream and our portfolio of exploration prospects continues to attract attention from potential investors.

We look forward to the year ahead and to sharing our progress with our shareholders.

Thank you,

Mick McCormack, Chair
19 September 2023

CHIEF EXECUTIVE OFFICER'S LETTER

Dear Fellow Shareholders,

I'm pleased to present Central Petroleum's FY2023 Annual Report.

It has been an eventful year for the Company, having maximised production during a winter energy crisis, re-prioritised an exploration drilling program, witnessed new government market intervention, seen our sub-salt exploration program delayed by a defaulting joint venture partner, booked reserve upgrades and embarked on the path towards commercial helium production.

The winter of 2022 will be remembered for the energy 'crisis' prompted by off-line coal fired generation and colder weather which resulted in historically high pricing for electricity, gas and oil. Central responded by supplying 77 TJ of gas to eastern markets over the winter months to help alleviate critical shortages and re-prioritised capital from its exploration program to near-term production opportunities.

This resulted in the Palm Valley 12 well, unsuccessful in its exploration and appraisal targets, ultimately flowing gas at over 11 TJ/day (100% JV), more than doubling capacity at the Palm Valley field whilst providing welcome new supply to customers in the Northern Territory and in eastern states. The performance of this well allowed Central to book 3 PJ of new gas reserves and supports the drilling of future wells at Palm Valley to target additional gas production and reserve additions.

We also brought on additional production capacity at Mereenie towards the end of the year, and would have recorded higher sales volumes if not for a number of temporary outages on the Northern Gas Pipeline during the year. Market demand for gas remains strong and higher gas prices offset the impact of the lower volumes and higher costs, resulting in our per unit gross profit increasing 12% from FY2022.

These increased margins are a clear indication of the strong performance and value of the production assets, with $39.3 million of revenue recognised, generating underlying EBITDAX of $15.8 million. Cash balances were $13.8 million, and debt reduced to $28.1 million at 30 June. A further $11 million is potentially available under the extended loan facility, providing additional financial flexibility for future development activity.

Having secured sufficient capital to proceed with the three well sub-salt exploration program, it was disappointing that our new joint venture partner has been unable to meet its funding commitments. This much-anticipated program, targeting substantial helium, hydrogen and natural gas resources, will now be delayed while we work to restructure the joint venture and associated exploration program.

We have seen increasing interest in our sub-salt exploration permits off the back of a proposed helium production facility at Mereenie. In August 2023 we announced a Memorandum of Understanding to work with experienced US-based helium developer and producer, Twin Bridges, towards a final investment decision for the construction of a Helium Recovery Unit (HRU) at Mereenie. The arrangement would see Twin Bridges design, build, fund and own the plant, providing Central with a share of future profits with minimal capital outlay and financial risk. Given strong helium market dynamics and brownfield economics associated with building and operating a HRU at Mereenie, the project appears very attractive.

Successful separation of helium from the existing gas stream on a commercial scale at Mereenie would demonstrate the potential of the Amadeus Basin as a world-class helium resource, and in particular, the large sub-salt prospects where relatively-high helium content has previously been measured.

Advancing the valuable helium potential of our Amadeus Basin interests will be a priority for Central in the next year, but will not detract from our focus on bringing more gas supply to Australian customers. New development wells are planned at Mereenie and are progressing through the joint venture approvals process. We are also pushing to advance exploration activity at the Mamlambo oil prospect and the Zevon sub-salt prospect through new farmout arrangements.

Whilst the Board continues to consider its options under a strategic review, Central remains focussed on creating opportunities and progressing value accretive projects that ensure shareholders receive the most value possible from their assets. I thank our staff for their dedication in safely and responsibly operating our remote gas fields during the year and in advancing our growth-orientated projects.

I expect the next year to be a period of key milestones and decisions for the Company, and remain confident that the value of our existing production and brownfield development opportunities will become increasingly visible as market price regulation and escalating costs create further barriers to new gas exploration and development.

I can assure our shareholders that everyone at Central is focussed on maximising shareholder return from our portfolio of assets, and we look forward to sharing that progress as the year unfolds.

Leon Devaney

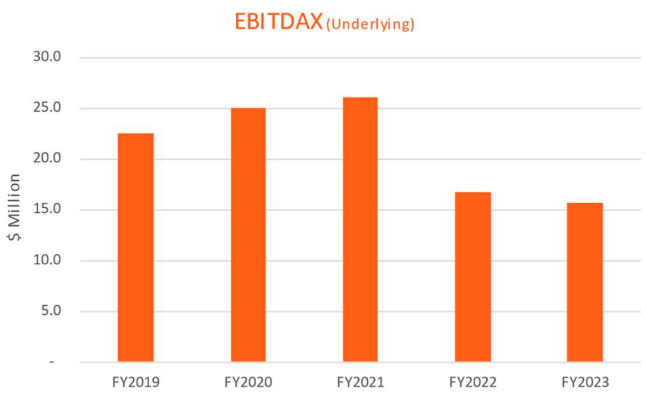
Leon Devaney, CEO

19 September 2023

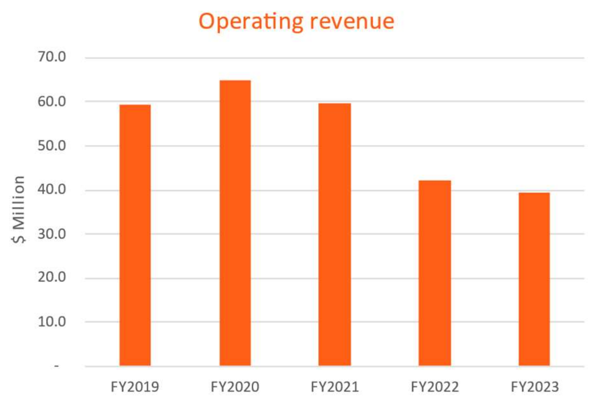
OPERATING AND FINANCIAL REVIEW

OPERATING HIGHLIGHTS

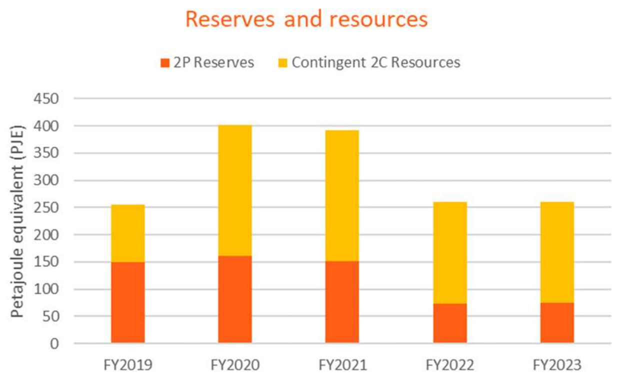
- The Group added an additional 5.9 PJ of Proved and Probable (2P) gas reserves at 30 June 2023, representing an increase of 8% (before production) to 75 PJe reflecting drilling and production results at Palm Valley and updated Dingo reservoir modelling.
- The Palm Valley 12 well was successfully tied into the Palm Valley processing facilities and flowed gas to market from late November 2022 at greater than 10 TJ per day.
- New gas sales agreements for the sale of gas were secured with:
  - Shell Energy for supply of 0.91 PJ of gas in CY2025; and
  - South 32 for supply of 0.55 PJ of gas over two years from 1 January 2023.
- Average sales prices were up 17% on FY2022 at $7.90 / GJe.
- Annual revenue from hydrocarbon sales of $38.2 million was up 12% from FY2022 on a like for like basis.
- In August 2023, agreement was reached to progress towards a final investment decision for construction of a helium recovery unit at Mereenie, demonstrating the potential of the Amadeus Basin as a world-class helium resource.



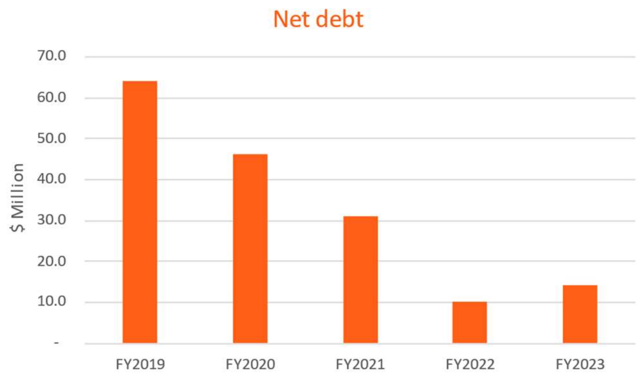
Underlying EBITDAX: Decreased 6% to $15.7m in FY2023*
(Earnings before interest, tax, depreciation, impairment, exploration costs, and profit on asset disposals)



Operating revenue: Decreased 7% to $39.3m in FY2023*



2P Reserves increased to 75.0 PJe after current year production. Refer Reserves and Resources Statement on page 20.



Net Debt: $14.3 million at 30 June 2023

* Note that Central disposed of 50% of its interests in its producing fields as at 1 October 2021, an effective 12.5% reduction in annual production capacity for FY2023 in comparison with FY2022

OPERATING AND FINANCIAL REVIEW

FINANCIAL REVIEW

The Consolidated Entity had a loss after income tax for the year ended 30 June 2023 of $8.0 million (2022: profit of $21.3 million).

The above result was after expensing exploration costs of $13.1 million (2022: $21.6 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 FY2022. Note that a direct comparison of annual results will be impacted by :

1. The FY2022 profit on sale of the Group's interests in its producing properties which completed on 1 October 2021 (which is excluded from underlying results to assist with comparability); and
2. The decrease in revenues, production costs, capital expenditure and exploration costs resulting from the 50% reduction in the Group's equity interest in its producing assets during FY2022 (from 1 October 2021).

The table below shows key metrics for the Group (refer Note 1(a) regarding restatement of expenses by function for FY2022):

Key Metrics	Total 2023	Total 2022[7]	Change	% Change
Decrease in FY23 production capacity due to asset sale				(12.5)%
Net Sales Volumes				
- Natural Gas (TJ)	**4,664**	**5,993**	(1,329)	(22.0)%
- Oil & Condensate (bbls)	**30,293**	**47,197**	(16,904)	(36.0)%
Sales Revenue ($'000)	**39,255**	**42,151**	(2,896)	(7.0)%
Gross Profit[7] ($'000)	**12,847**	**14,800**	(1,953)	(13.0)%
Underlying EBITDAX[1] ($'000)	**15,749**	**16,746**	(997)	(6.0)%
Underlying EBITDA[2] ($'000)	**2,656**	**(4,901)**	7,557	154.0%
Underlying EBIT[3] ($'000)	**(4,210)**	**(11,680)**	7,470	64.0%
Underlying loss after tax[4] ($'000)	**(8,170)**	**(15,239)**	7,069	46.0%
Statutory (loss)/profit after tax ($'000)	**(7,960)**	**21,320**	(29,280)	(137.0%)
Net cash (outflow)/inflow from Operations[5] ($'000)	**(2,056)**	**3,640**	(5,696)	(156.0)%
Capital expenditure[6] ($'000)	**12,815**	**10,053**	2,762	27.0%

1 Underlying EBITDAX is Earnings before Interest, Tax, Depreciation, Amortisation, Impairment and Exploration costs and profit on disposal of interests in producing properties (refer reconciliation below).
2 Underlying EBITDA is Earnings before Interest, Tax, Depreciation, Amortisation, Impairment and profit on disposal of interests in producing properties.
3 Underlying EBIT is Earnings before Interest, Tax and profit on disposal of interests in producing properties.
4 Underlying profit / loss after tax is statutory profit after tax, before profit on disposal of interests in producing properties.
5 Cashflow from Operations includes cash outflows associated with exploration activities.
6 Capital expenditure on tangible assets.
7 Refer Note 1(a) regarding restatement of FY2022 expenses by function.

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 $15.7 million, down 6% from $16.7 million in 2022 and consistent with the reduced earnings base which resulted from the disposal of 50% of the Group's interests in the Amadeus Basin producing properties on 1 October 2021 and reduced sales volumes. Further discussion on revenues and gross profit are included below.

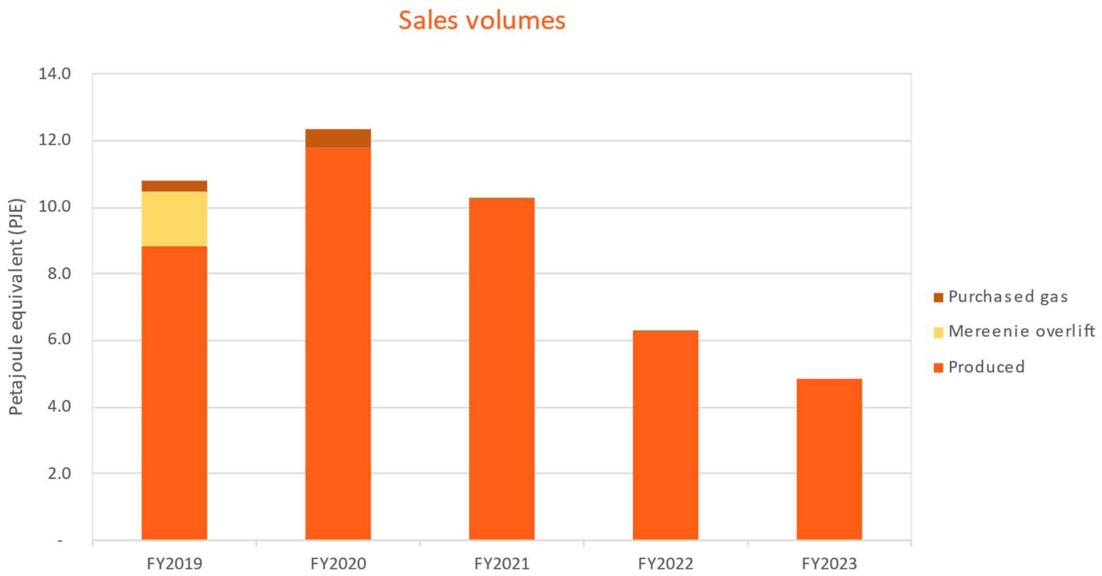
Underlying EBITDAX are earnings before interest, tax depreciation, amortisation, impairment, exploration and profit on disposal of interests in producing properties. Underlying EBITDAX is used by management as an indicative measure of underlying operating profit from operations as it excludes non-cash 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 $0.8 million this year (2022: $1.5 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	2023 $'000	2022 $'000
Statutory (loss)/profit before tax	(7,960)	21,320
Impact of farmout to Peak Helium net of impairment costs	(210)	—
Profit on disposal of 50% interest in Amadeus Basin producing properties	—	(36,559)
Underlying loss before tax	**(8,170)**	**(15,239)**
Net finance costs and restatement of financial assets	3,960	3,559
Underlying EBIT	**(4,210)**	**(11,680)**
Depreciation, amortisation and impairment	6,866	6,779
Underlying EBITDA	**2,656**	**(4,901)**
Exploration expenses	13,093	21,647
Underlying EBITDAX	**15,749**	**16,746**

Sales Volumes

Sales volumes were 23% lower than FY2022 at 4.8 PJe, with most of this difference due to the reduction in the Group's equity interests in the Amadeus Basin producing properties from 1 October 2021. On a like-for-like basis, volumes were 3% lower than FY2022 due to outages on the Northern Gas Pipeline affecting East Coast deliveries and natural field decline, offset by increased production from the new Palm Valley well, commissioned in late November 2022.



Note: Oil converted at 5.816 GJ/bbl.

Sales Revenue

Central recorded sales revenue of $39.3 million, down 7% on FY2022, reflecting the lower volumes, lower global oil prices and partially offset by higher realised gas prices. Average realised prices were up 17% on FY2022 at $7.90/GJe, reflecting increased domestic gas sales into the higher-priced east coast spot market. Sales revenue included $1.0 million released from deferred take-or-pay balances.

Gross Profit

Gross profit was $12.8 million, inclusive of non-cash depreciation and amortisation costs, a decrease of 13% on FY2022, in line with reduced equity interests following completion of the partial sale of interests in the producing assets from 1 October 2021. On a per unit basis this represents a gross profit of $2.65/GJe which is an increase of 12% from $2.36/GJe for FY2022, as the higher average sales price (up $1.17/GJe) more than offset the higher per-unit cost of sales. The unit cost of sales increased by 25%, reflecting fixed costs spread over lower volumes and includes additional transportation costs for spot sales to the East Coast market.

Net Assets/Liabilities

At 30 June 2023, the Group had a net asset position of $19.4 million compared to $26.5 million at 30 June 2022, reflecting the current year loss before share-based payments.

OPERATING AND FINANCIAL REVIEW

Included in liabilities on the Group's balance sheet are amounts recognised in respect of deferred revenue associated with pre-sales and make-up gas provisions amounting to $15.2 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, 0.71 PJ of previously over-lifted gas was repaid to a joint venture partner and 0.9 PJ of pre-sold gas was delivered.

Debt

The Group repaid $4.6 million of loan principal during the year and drew down $1 million under a new facility. The outstanding balance of the loan facility at 30 June 2023 was $28.1 million with $4.7 million due for repayment in FY2024.

Net debt increased $4.1 million to $14.3 million at 30 June 2023, reflecting reduced cash balances resulting largely from exploration activities.

The consolidated debt ratio at 30 June 2023 increased slightly to 0.29 (2022: 0.26). Debt ratio is defined as: Total Debt/Total Assets. Net gearing at 30 June 2023 was 27% (2022: 11% or 21% if re-based to 30 June 2023 market capitalisation). Net gearing is calculated as: Net Debt / (Market capitalisation + Net Debt). Debt service is supported by long term gas sales contracts and the Group's certified oil and gas reserves.

Net Cash Flow

Cash balances decreased by $7.8 million over the year. Net cash flow from production operations for 2023 was $13.8 million compared to $19.8 million for 2022, with the decrease reflecting the reduced interests in the Amadeus Basin producing properties from 1 October 2021 and lower sales volumes.

After net interest payments of $2.3 million, $4.1 million of corporate and staff expenses and $9.6 million for exploration activities, net cash outflow from operating activities was $2.1 million.

During the year, Central invested $2.9 million in capital projects, including ongoing work on installation of a compressor to recover flare gas at Mereenie and other sustaining capital expenditure at the three producing fields. A further $10.5 million of Central's share of Palm Valley and Dingo exploration costs and $9.9 million of development costs were paid ("carried") by joint venturers under the terms of the partial asset sale. Central repaid $4.6 million of debt during the year after drawing down an additional $1 million from the expanded facility.

Five Year Comparative Data

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

	2019 $ MILLION	2020 $ MILLION	2021 $ MILLION	2022 $ MILLION	**2023 $ MILLION**
Financial Data					
Operating revenue	59.36	65.05	59.83	42.15	**39.26**
Exploration expenditure	15.80	5.28	7.74	21.65	**13.09**
Profit/(loss) after income tax	(14.53)	5.41	0.25	21.32	**(7.96)**
EBITDAX	22.19	33.40	26.09	53.31	**15.96**
Underlying EBITDAX	22.19	25.01	26.09	16.75	**15.75**
Equity issued during year	—	—	—	—	**—**
Property, plant and equipment[1]	123.48	107.85	108.28	53.85	**60.19**
Cash[1]	17.81	25.92	37.17	21.65	**13.83**
Borrowings	(81.73)	(70.77)	(66.81)	(30.81)	**(27.53)**
Net Assets (Total Equity)	(5.62)	1.58	3.69	26.53	**19.39**
Net Working Capital (Net current assets/(liabilities))	(1.53)	6.75	8.25	22.31	**7.11**

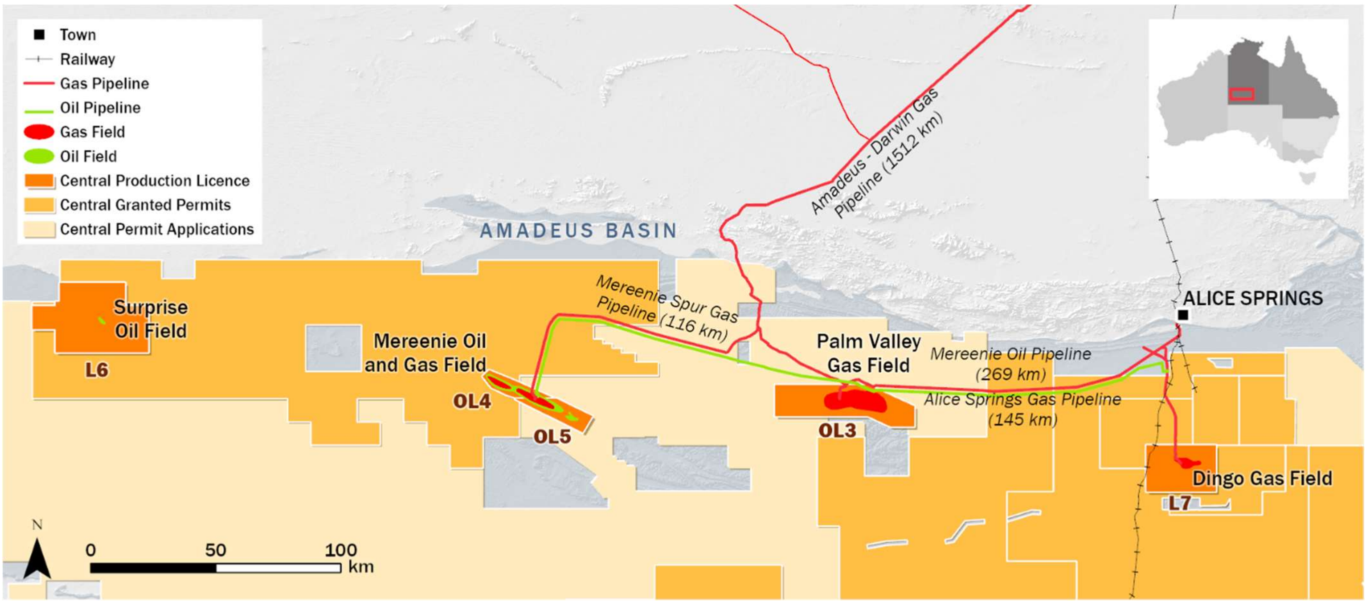
[1] Includes assets classified as held for sale.

	2019	2020	2021	2022	**2023**
Operating Data					
Gas Sales (TJ)	10,229	11,822	9,820	5,993	**4,664**
Oil Sales (barrels)	97,392	89,016	77,255	47,197	**30,293**
No. of employees at 30 June	99	92	85	88	**80**

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) and Queensland. Central is the operator of the largest onshore gas producing fields in the NT, supplying industrial customers, electricity generators and senior gas distributors from three producing fields near Alice Springs.

Producing Assets



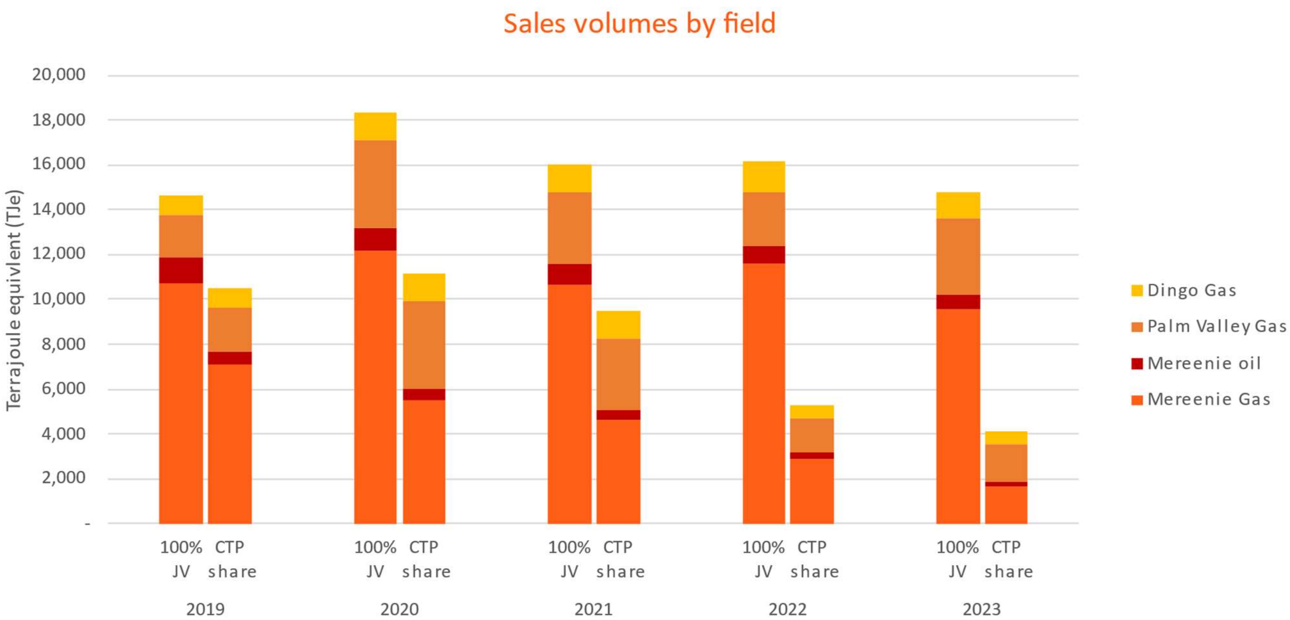
Location of Central's producing oil and gas fields

Sales Volumes (Central Petroleum's Share)

Product	Unit	FY 2023	FY 2022
Gas	PJ	4.7	6.0
Crude and Condensate	bbls	30,293	47,197
Total	**PJe**	**4.8**	**6.3**

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

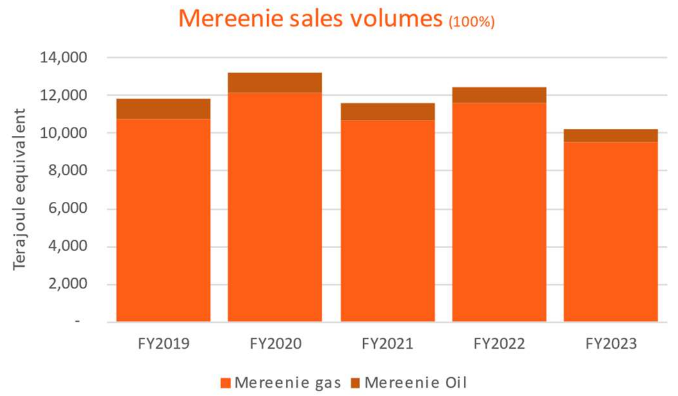
Central's sales volumes were 23% lower than FY2022 (note that Central had higher ownership interests in the producing fields for the first quarter of FY2022). On a like-for-like ownership basis, volumes were 3% lower than FY2022, with new production from Palm Valley offsetting the impact of temporary pipeline outages, natural field decline and lower demand for gas from the Dingo field.



OPERATING AND FINANCIAL REVIEW

Mereenie Oil and Gas Field (OL4 and OL5)

Northern Territory



Ownership interests	
Central Petroleum (operator)	**25.0%**
Macquarie Mereenie Pty Ltd	50.0%
NZOG Mereenie Pty Ltd	17.5%
Cue Mereenie Pty Ltd	7.5%

Reserves & Resources (Central share)[1]	Unit	1P	2P	2C
Gas	PJ	28.7	37.5	45.6
Oil	mmbbl	0.34	0.38	0.05
Total[2]	PJe	30.7	39.7	45.9

1 Reserves and resources are as at 30 June 2023. 2C gas resources include 27 PJ attributable to the Stairway Sandstone.

2 Oil converted at 5.816 PJ/mmbbl

Mereenie highlights

- Well recompletions boosted production capacity (May 2023)
- Agreement to progress planning for construction of a helium recovery unit (August 2023).

Operations

Full field gas production for the year was 9.5 PJ, averaging 26.2 TJ/d, down from the 11.6 PJ (31.7 TJ/d) produced in FY2022, impacted by several temporary shutdowns to the Northern Gas Pipeline during the year. Consequently, oil production was also lower at 348 bbl/d. Central's share of this Mereenie gas and oil production for FY2023 was 2.6 PJe, with a reduced ownership interest of 25% applying from 1 October 2021 when the partial asset sale completed (previously 50%).

A recompletion program was undertaken in the fourth quarter, with five existing wells which had previously produced from deeper zones being perforated to access gas in the shallower Pacoota 1 interval. The program increased field capacity by 1.4 TJ/d (0.35 TJ/d net to Central).

Future plans

Two new development wells are planned at Mereenie in the next 12 months to further increase production and offset natural field decline. Critical long lead items have been ordered and rig selection is progressing prior to final joint venture approval.

Helium Production Plans

Central and its Mereenie joint venturers are working with Twin Bridges LLC (Twin Bridges), a private US company specialising in helium appraisal and production, to progress a helium recovery unit (HRU) at Mereenie towards a final investment decision (FID).

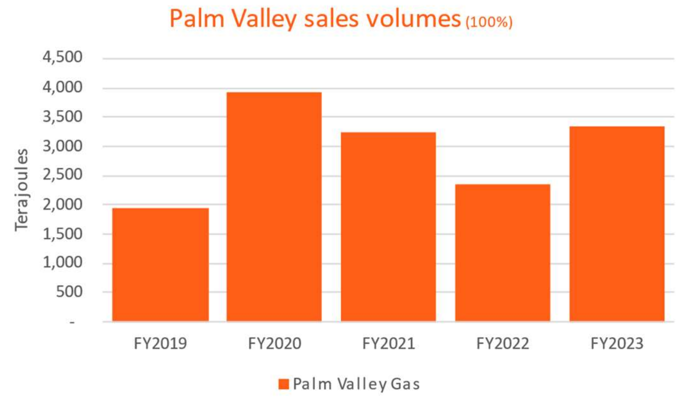
It is proposed that the HRU will be sized to process up to 30 TJ/d of Mereenie gas, which typically contains circa 0.2% helium, extracting up to 60,000 scfd of helium using proven membrane technology.

Preliminary technical and market reviews have been completed, with solid project economics leveraging on strong helium markets and the brownfield economics afforded by the existing gas stream and infrastructure at Mereenie.

Work is underway to achieve the necessary conceptual, design, engineering, commercial and financial milestones required to reach FID for the construction of the HRU at Mereenie. If the project proceeds, Twin Bridges will design, build, fund and own the HRU plant which will be integrated with the existing Mereenie gas processing facility operated by Central. Twin Bridges will market the produced helium with offtake arrangements already well advanced. Profits would be shared 50/50 between Twin Bridges and the Mereenie JV (Central 25% interest).

Palm Valley Gas Field (OL3)

Northern Territory



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

Reserves & Resources (Central share)[1]	Unit	1P	2P	2C
Gas	PJ	12.6	13.4	4.6

[1] Reserves and resources are as at 30 June 2023.

Palm Valley highlights

- PV12 well drilled and commissioned, more than doubling field production capacity (November 2022).
- 1P gas reserves increased by 27% (July 2023).

Operations

Production from the Palm Valley field was boosted by the commissioning of the successful PV12 production well in late November. The new well increased average field production from 5.2 TJ/d in October 2022 to a peak of 13.5 TJ/d in January 2023. The field averaged gas sales of 9.2 TJ/d through FY2023, recording an aggregate of 3.3 PJ, up 43% from 2.4 PJ in FY2022.

Central's share of Palm Valley gas sales for FY2023 was 1.7 PJ, with a reduced ownership interest of 50% applying from 1 October 2021 when the partial asset sale completed (previously 100%).

The successful P12 well, drilled laterally to a measured depth of 3,039m in the Pacoota-1 Sandstone, flowed gas at 11.8 mscfd when tested in October 2022 and was brought online as a production well in late November. This followed an unsuccessful PV12 exploration sidetrack, which was drilled into the deeper P2/P3 Sandstones after plans to drill to the deep Arumbera Sandstone were revised in July 2022 to reduce drilling risks.

Success at PV12 not only boosted production, but has also resulted in a reserves upgrade, adding 3 PJ of Proved (1P) gas reserves to Central's gas reserves at Palm Valley.

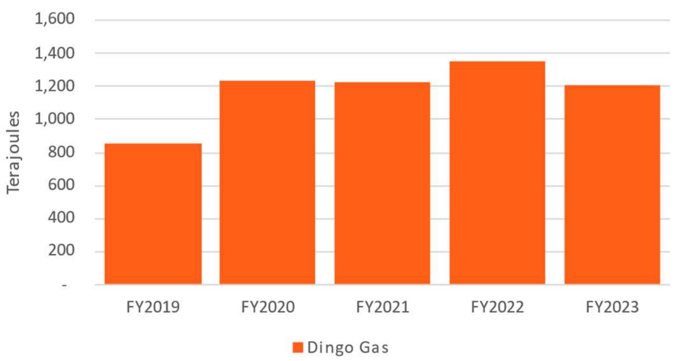
Future plans

The successful horizontal PV13 and PV12 wells, which were commissioned in May 2019 and November 2022 respectively, support the drilling of additional wells targeting gas reserves and production. Planning for additional wells is progressing.

The deeper Arumbera Sandstone has potential as a significant gas resource and remains an exploration target at Palm Valley. The Arumbera Sandstone is the production reservoir at the Dingo gas field, 100km to the east.

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

Northern Territory



Ownership interests	
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NZOG Dingo Pty Ltd	35.0%
Cue Dingo Pty Ltd	15.0%

Reserves & Resources (Central share)[1]	Unit	1P	2P	2C
Gas	PJ	19.4	21.9	—

1 Reserves and resources are as at 30 June 2023.

Dingo highlights

- 1P gas reserves increased by 23% (July 2023).

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 averaged 3.3 TJ/d across the year, an aggregate of 1.2 PJ, down 11% on FY2022 due to demand reverting to FY2020 and FY2021 levels. The daily contract volume of 4.4 TJ/d is subject to take-or-pay provisions under which Central will be paid in January 2024 for any gas nomination shortfall by the customer in CY2023.

Central's share of gas sales for FY2023 was 0.6 PJ, with a reduced ownership interest of 50% applying from 1 October 2021 when the partial asset sale completed (previously 100%).

Future plans

Additional development wells can be drilled in the future at Dingo to maintain contracted gas volumes when warranted by natural field decline and plans to add field compression are being investigated as a capital-effective interim alternative.

The deeper Pioneer Sandstone, which has flowed gas at the nearby Ooraminna prospect, and the Areyonga Formation lie below the existing production reservoir and could hold significant gas resources. A deep exploration well, previously scheduled for 2022, has been deferred to prioritise capital for production enhancement at Mereenie.

Appraisal Assets – Surat Basin

Range Gas Project (ATP 2031)

Surat Basin, Queensland

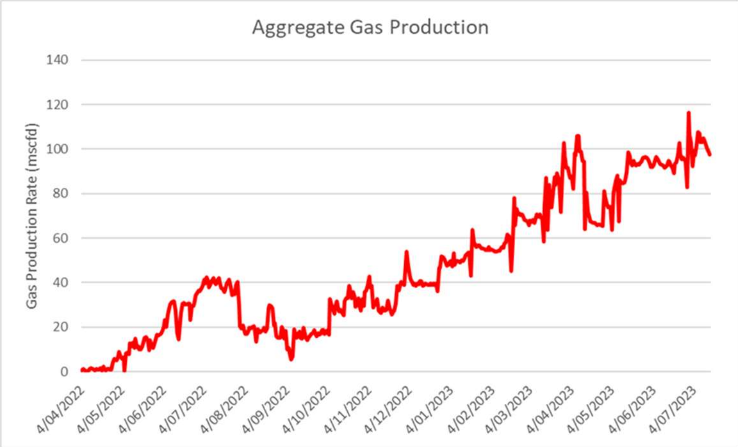
Central - 50% Interest, Incitec Pivot Queensland Gas Ltd (IPL) - 50%

Reserves & Resources (Central share)	Unit	1P	2P	2C
Gas	PJ	—	—	135

Central and joint venture partner, Incitec Pivot Limited are progressing appraisal for the 77km^2 Range coal seam gas (CSG) project which is strategically located in the heart of Queensland's CSG province which hosts thousands of wells producing from the same coal measures at similar depths.

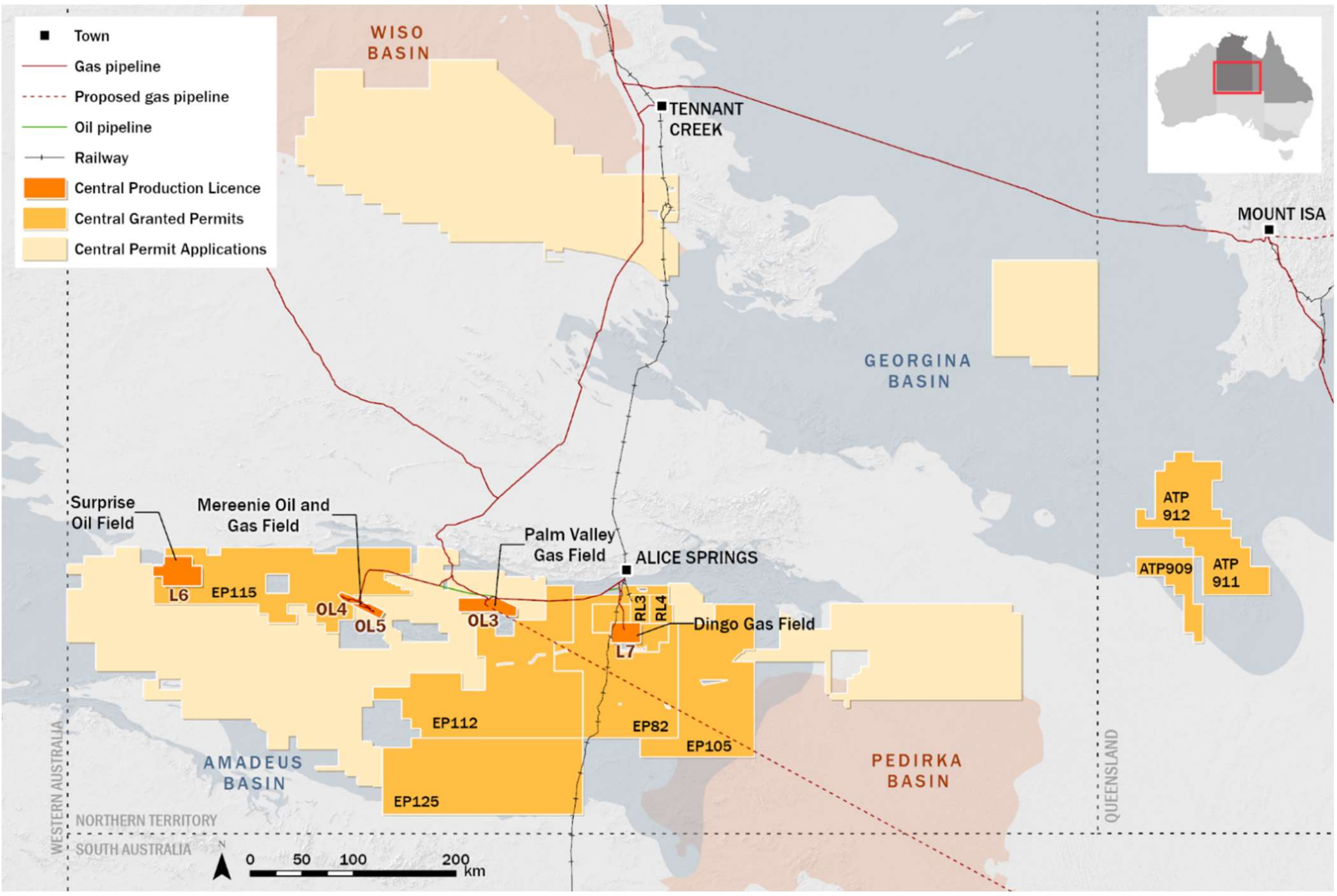
Range pilot operations

Production testing of three pilot wells continued throughout the year, with gas aggregate production rates increasing to approximately 100,000 scfd at the end of June from 40,000 scfd a year ago. Central and Incitec Pivot are considering plans to drill new pilot wells in the northeast of the permit.



Exploration Assets

Central Petroleum holds a significant portfolio of exploration opportunities across the Amadeus, Wiso, Georgina and Surat Basins in the Northern Territory and Queensland. The total area held by Central for exploration is 173,122 km^2 (64,153 km^2 granted and 108,969 km^2 under application).



Location of Central's Petroleum Permits, Licences and Applications in Central Australia

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.

Over 100 potential oil and gas targets have been identified within Central's Amadeus Basin footprint. Several high priority targets which can be drilled conventionally and without stimulation (hydraulic fracturing) have been identified, including:

- **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.
- **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. If successful, production wells could be tied into existing production facilities relatively quickly and efficiently; and
- **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.

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

Amadeus Basin, Northern Territory

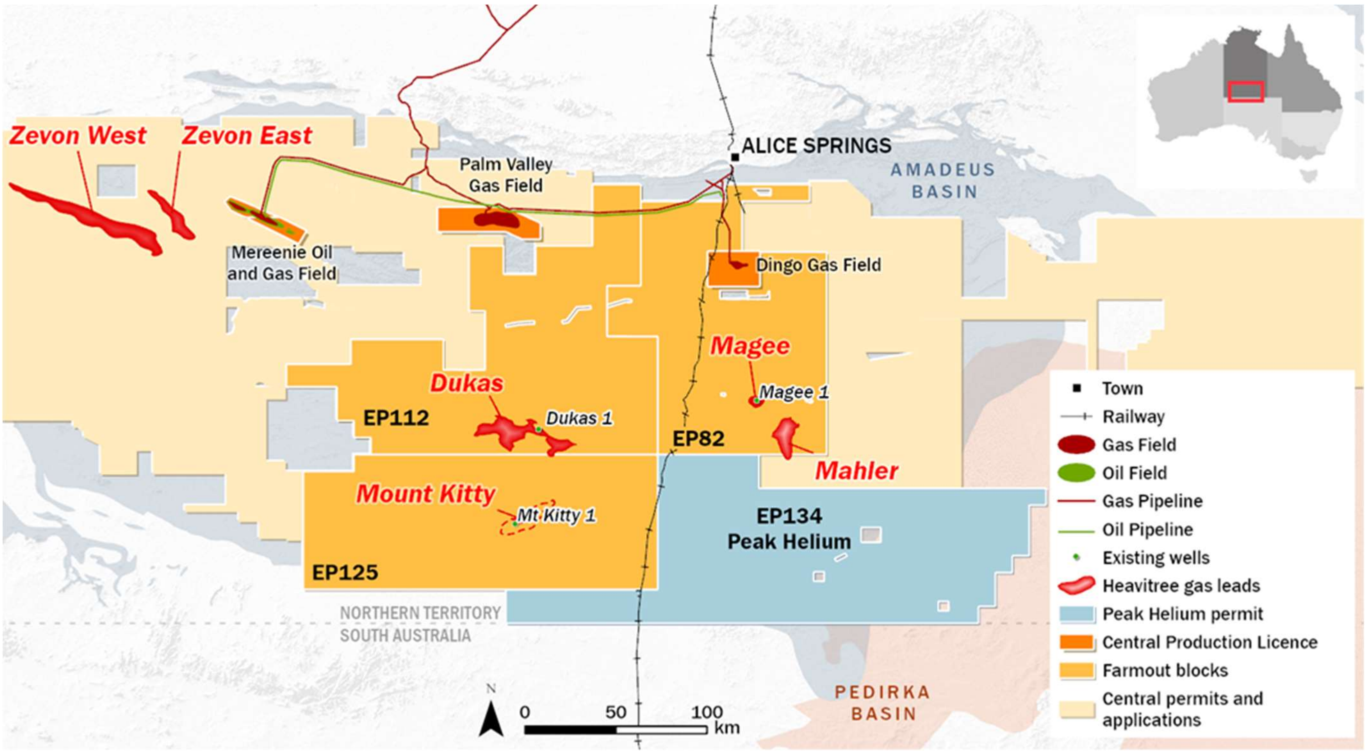
The Amadeus Basin hosts sub-salt targets within the Heavitree Formation and the fractured granitic basement sealed by extensive evaporitic units of the upper Gillen Formation. In addition to hydrocarbons, the presence of radiogenic basement rocks and an evaporitic sealing unit has created the ideal conditions 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 producing fields, Mereenie, Palm Valley and Dingo, and previous exploration wells at Mt Kitty and Magee have shown high concentrations of helium and hydrogen. These high-value non-hydrocarbon gases are generally associated with granitic basement and sub-salt prospects and Central is progressing a number of projects in the Amadeus Basin.

A major catalyst for a new phase of exploration is the planned construction of a helium recovery unit at the Mereenie gas field. 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.

While helium concentrations of >0.3% are considered helium-rich, helium concentrations of 6% were recorded at the Magee-1 well and gas flows at Mt Kitty contained 9% helium. Central is seeking to drill several sub-salt appraisal/exploration wells in the Southern Amadeus to further test these prospects along with the promising Dukas lead. Seismic data will also be acquired at the Zevon lead to the north-west of the Mereenie field later this year to identify the location for a possible exploration well.



Location of sub-salt targets

Progress on the Jacko Bore (Mt Kitty), Mahler (Magee) and Dukas explorations wells has been delayed while the joint ventures are restructured and funded following the apparent financial failure of one of the key joint venturers.

Jacko Bore 2 (EP125)

Central 24%; Peak Helium 56%; Santos 20%

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 at up to 530,000 scfd, including 11.5% hydrogen and 9% helium.

Mahler (EP82)

Central 29%; Peak Helium 51%; Santos 20%

The proposed Mahler exploration well will 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.

Dukas 2 (EP112)

Central 35%; Peak Helium 35%; Santos 30%

The proposed Dukas-2 well is planned to follow the Dukas-1 exploration well which was drilled in 2019 and suspended after encountering hydrocarbon-bearing gas from an overpressured zone close to the primary target at a depth of 3,704m. Traces of helium and hydrogen were detected in mud gases associated with the overpressured zone. The Dukas-2 well will target the same tight sandstone in the Heavitree formation below the salt seal with a higher-capacity rig.

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

Prospects	Jacko Bore (Mt Kitty)	Dukas	Mahler
Resource type	Contingent resource 2C (bcf)	Prospective resource (unrisked best estimate) (bcf)	Prospective resource (unrisked best estimate) (bcf)
Helium	4.3	39.9	0.6
Hydrogen	5.3	50.8	0.6
Natural gas	9.4	259.7	2.9

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.

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

The Zevon sub-salt lead in EP115 has been defined as a potentially very large closure (circa 1,600 km^2) from seismic and gravity studies. It is located in the north-western section of the Amadeus Basin between the Mereenie oil & gas field and the Surprise oil field.

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

A short 2D seismic survey planned to further define the Zevon lead and identify locations for an exploration well.

Amadeus Exploration – In-field opportunities

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

Central's producing fields at Mereenie, Palm Valley and Dingo are comprised of several vertical layers of producing and potential oil and gas reservoirs. There are opportunities to target other intervals which are not currently the principal production zones in each field. If successful, production wells could be tied into existing production facilities relatively quickly and efficiently.

The deeper targets remain to be explored at a later date, as capital for the planned 2022 deep exploration wells was redirected to a shallower target at Palm Valley and higher-priority production enhancement projects.

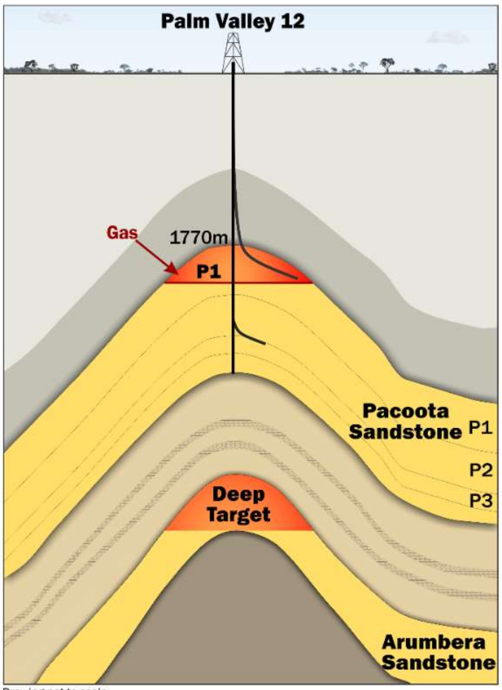
Palm Valley Deep (OL3)

Central - 50% interest (operator)

The Palm Valley Deep target has an estimated mean prospective resource of 123 PJ (61.5 PJ net to Central) in the deep Arumbera Sandstone (depth circa 3,500m) which is the productive interval at the Dingo field. A new gas resource of this size at Palm Valley would be a catalyst for a significant expansion of field production capacity and economic field life (current 2P gas reserves are 13 PJ net to Central).

The PV12 exploration well, drilled in 2022 was to target the deep Arumbera Sandstone, but after encountering difficult drilling conditions and reaching a depth of 2,335m, the joint venturers decided in July 2022 to replace the original PV Deep target with the lower P2/P3 target at a depth of approximately 2,060m. The lateral well drilled into the P2/P3 Sandstones did not detect gas flows and formation water was encountered.

A second lateral well was then drilled into the P1 Sandstones, the normal producing zone at Palm Valley and flowed gas at 11.8 mscfd when tested in October 2022 and was successfully brought online as a production well in late November 2022.



Drawing not to scale.

Dingo Deep (L7)

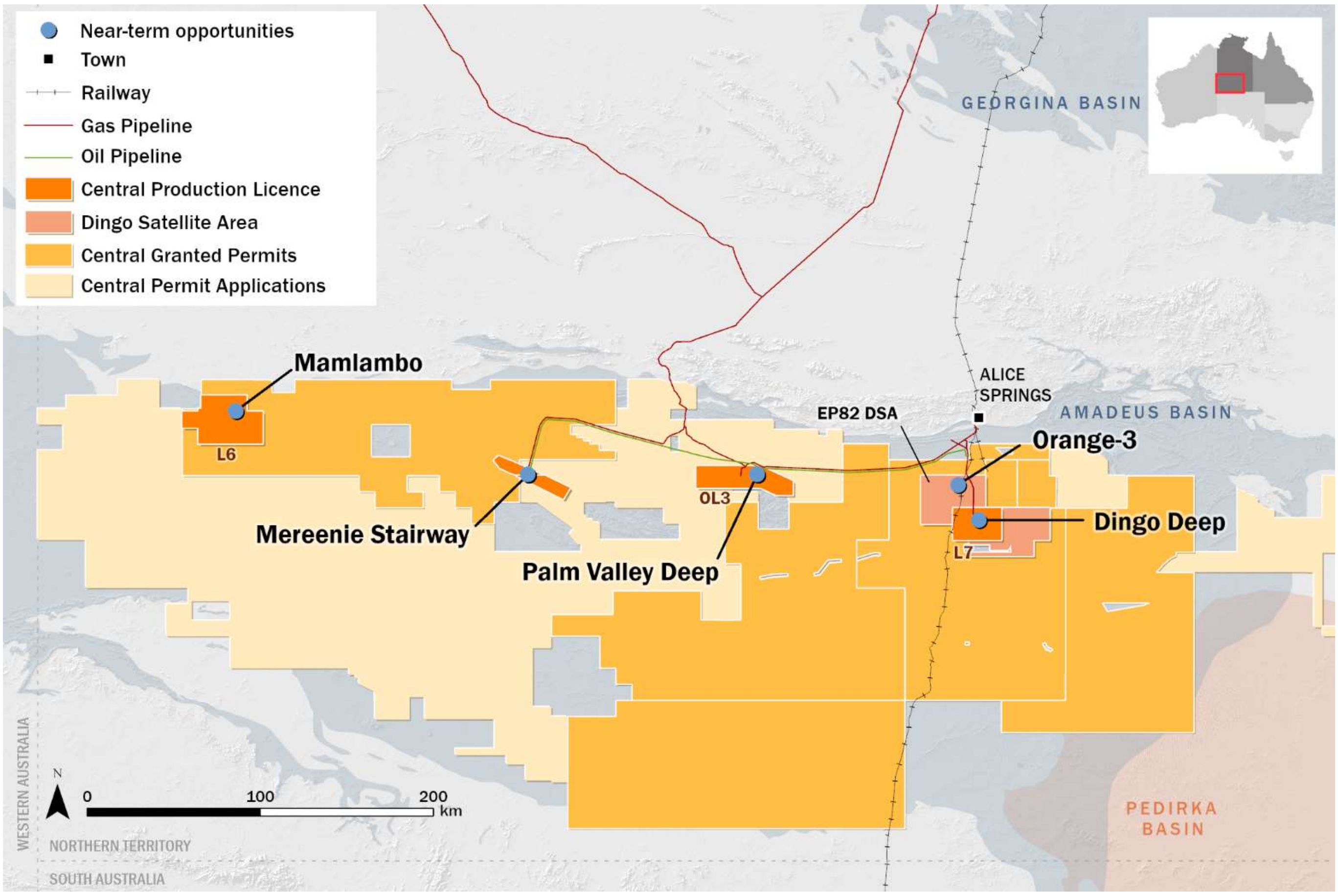
Central - 50% interest (operator)

The Dingo Deep target has an estimated mean prospective resource of 69 PJ (34.5 PJ net to Central) in the deeper Pioneer Sandstone and Areyonga Formation at a depth of up to 3,700m. Both formations have had gas shows with flows to surface achieved from the Pioneer Sandstones at the Ooraminna well. A successful exploration test would open up a new play fairway in the basin and could prompt the construction of new processing and pipeline infrastructure from the Dingo field which currently has 19 PJ of 2P gas reserves (net to Central).

Mereenie Stairway (OL4/OL5)

Central - 25% interest (operator)

The Stairway Sandstones which overlie the deeper producing Pacoota Sandstones at Mereenie are estimated to contain 108 PJ of 2C contingent gas resource (27 PJ net to Central). Gas has 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 which currently has 2P gas reserves of 39 PJ (net to Central).



Location map of immediate in-field and near-term exploration opportunities

Amadeus Exploration – Other opportunities

Amadeus Basin, Northern Territory

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:

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 exploration well could target the Lower Stairway Sandstone and the Pacoota Formation, both of which are proven reservoirs in the Surprise and Mereenie oil and gas fields. Total depth for a potential exploration well could be in the order of 1,300m.

Orange (EP82(DSA))

Central - 100% interest.

Previous exploration wells at Orange have encountered gas at the shallow Arumbera Sandstone, which is the producing zone at the Dingo field, some 23km to the south-east. A future exploration well at Orange would target a mean prospective gas resource of 401 PJ from the Arumbera Sandstone and the deeper Pioneer Sandstone and Areyonga Formation which are volumetrically significant and close to the existing Dingo pipeline.

Ooraminna (RL3 and RL4)

Central - 100% interest.

After analysing past exploration results at Ooraminna and taking into consideration the potential future costs and risks of exploration, appraisal and development, increasing regulatory hurdles and costs, and recent government intervention in gas markets, Central will relinquish its interests in the Ooraminna prospect.

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 106)

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.

Central's application for exploration permit EPA120 in the NT will not be approved due to overlapping sites of conservation significance.

ATP909, ATP911 and ATP912

Southern Georgina Basin, Queensland

Central - 100% interest.

Having reviewed the data acquired from previous activities in these areas and potential future costs and exploration risks, Central will complete the required rehabilitation work and relinquish its interests in these permits.

COMMERCIAL

Commercial activities during the year focussed on managing Central's asset portfolio to leverage existing ownership equity to fund development and exploration growth activities.

Central continued to negotiate new gas sale agreements (GSAs) to replace maturing contracts and gained direct access to the deeper, higher-priced east coast gas markets for the first time.

In August 2023, Central entered into a Memorandum of Understanding to progress towards a final investment decision for construction of a helium recovery unit at its Mereenie field, demonstrating the potential of the Amadeus Basin as a world-class helium resource.

Strategic Review

Central's Board has been working with RBC Capital Markets to conduct a strategic review of Central's asset portfolio, growth strategies and capital structure. This includes ongoing activities to assess various options to realise value for shareholders.

New Gas Sales Agreements

Despite government intervention in gas markets, there remains strong interest from gas users to secure reliable gas supply, and this has been reflected in stronger gas prices for new contracts. Two new gas sales agreements for the sale of gas were secured during the year with:

- Shell Energy for supply of 0.91 PJ of gas in CY2025; and
- South 32 for supply of 0.55PJ of gas over two years from 1 January 2023.

The successful new Palm Valley well and Mereenie recompletion program has provided additional developed gas volume for marketing to customers, and Central is currently negotiating several new supply agreements for future firm supply at attractive prices.

Central has also been able to provide non-contracted gas to customers on an as-available basis and to spot markets, utilising as-available transportation and market trading arrangements that allow for the sale of non-firm gas from the Mereenie gas field into the east coast trading hubs, including the Brisbane and Sydney Short Term Trading Markets. This has enabled Central to broaden its customer base and increase the average price for uncontracted gas, particularly during the winter/spring of 2022 when abnormally high gas prices were available.

Gas market outlook

Late in 2022, the Federal Government implemented a price cap of $12/GJ on the sale of gas produced in 2023 under the Gas Market Emergency Price Order which created a high level of uncertainty in gas markets during the March quarter of 2023. New regulations have been introduced to extend price controls, although Central is not expected to be directly impacted as its volumes fall below the threshold and Central only sells gas to Australian customers. Demand for gas in the near and medium term appears strong, with pricing higher than Central's historic averages.

Helium Recovery Unit

Subsequent to the end of the financial year, Central has entered into a Memorandum of Understanding (MOU) with its Mereenie co-venturers and Twin Bridges LLC (Twin Bridges), a private US company specialising in helium appraisal and production, to progress a helium recovery unit (HRU) at its Mereenie field in the Northern Territory towards a final investment decision (FID).

The proposed HRU project will target production of up to 60,000 scf of compressed helium gas per day, separating helium from the existing natural gas produced at Mereenie using proven membrane technology.

Preliminary technical and helium offtake negotiations have been completed indicating solid project economics, leveraging on the existing gas stream and infrastructure at Mereenie. The compressed helium gas is anticipated to be sold ex-field to a major helium aggregator and distributor in Australia. The Mereenie JV will share the operating profits from the HRU project on a 50/50 basis with Twin Bridges.

Under the terms of the non-binding MOU, Twin Bridges will design, build, fund and own the HRU, accelerating commencement of helium production and increasing project value through access to their proven helium processing and marketing expertise.

Additionally, successful production of helium at Mereenie will also demonstrate the potential of the Amadeus Basin as a world-class helium resource, where Central has a material position in several large sub-salt prospects where relatively-high helium content has previously been measured.

The only domestic production of helium in Australia is expected to cease when the Darwin LNG plant closes later this year. The proposed Mereenie HRU project would then be the sole source of domestically-produced helium, helping to satisfy Australia's strategic need for helium which is used in many critical health and technology applications.

ESG AND COMMUNITY

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

As embodied in our core values:

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

Environmental

We operate in some of Australia's most stunning and pristine environments, rich in indigenous culture with diverse flora and fauna.

As custodians of the land on which we operate, we aim to uphold the highest environmental standards and leave the smallest footprint, so that when we finish extracting unseen resources from far beneath the surface, the land will be just as we found it, for future generations to enjoy.

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.

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.

All personnel engaged by Central are responsible for taking reasonable and practicable steps to identify and mitigate adverse impacts to the environment while complying with applicable internal controls and environmental legislation.

We have had several visits and inspections during the year by multiple regulatory agencies to monitor environmental conditions associated with our operations and drilling programs. 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.

One environmental incident was reported to regulators after vegetation in a small area adjacent to the Palm Valley 12 drill site was impacted by an overspray of formation water, unexpectedly encountered during drilling, from the flare pit. The regulator has confirmed no breach of regulations or approval conditions occurred. In addition, recent onsite inspections and analysis have confirmed no long-term damage to the environment as a result of the incident.

Climate change and emissions

Central recognises that climate change is an increasingly 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 will add 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. This was particularly evident in the winter of 2022, when Central supplied 61 TJ of gas into eastern markets when electricity and gas supplies were critically short.

The residents and businesses of Alice Springs rely 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 and Queensland rely on our gas to supply rare minerals to worldwide markets.

Australians rely on natural gas from Central Petroleum

- 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 and Queensland rely on our gas to supply rare minerals to worldwide markets.
- Used for fertiliser manufacturing to sustain Australian agriculture.
- Supplied into the Northern Territory and Eastern States for residents, manufacturers and electricity generation.

We report our greenhouse emissions under the National Greenhouse and Energy Reporting Act 2007 (NGER). In the most recent completed reporting period, FY2022, our share of scope 1 and 2 emissions across our operations was 28,801 tons of CO_2e (51,198 tons in FY2021). While the aggregate drop primarily reflects the halving of Central's ownership interests from October 2021, on a per unit basis, our emissions intensity dropped from 4.99 $kgCO_2e$/GJe in FY2021 to 4.59 $KgCO_2e$/GJe in FY2022 due to a higher proportion of production from the lower-emissions Palm Valley field.

We have invested in several initiatives to reduce our emissions, including an $8 million flare gas recovery project at Mereenie. The new flare gas compressor is expected to be installed before the end of 2023, and is expected to reduce flare gas emissions at Mereenie by more than 25% 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.

Central is also investigating the possibility of using the depleted reservoirs in its long-producing Amadeus Basin fields for carbon capture and storage (CCS) in conjunction with potential CCS projects in the area.

Safety

At Central, the safety of our employees, contractors and the community are paramount.

During the year, over 324,926 hours were worked, with two recordable injuries, resulting in a Total Recordable Injury Frequency Rate (TRIFR) at 30 June 2023 of 6.1.

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.

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:

- 40% of our staff live locally.
- 25% of our staff are indigenous.
- Central paid over $2.6M of royalties and fees to the Northern Territory and Central Land Council in FY2023.
- Central and partners spent over $3.0M with local contractors and businesses in FY2023.

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 NT 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.

OPERATING AND FINANCIAL REVIEW

RESERVES AND RESOURCES STATEMENT

Net proved & probable (2P) oil and gas reserves were 75.0 PJe at 30 June 2023.

Aggregate Reserves and Resources

		As at 30/06/2022	01/07/2022 to 30/06/2023 Production	Other adjustments	As at 30/06/2023	Comprising[1] Developed	Undeveloped
Oil							
Proved reserves (1P)	mmbbl	0.37	(0.03)	—	**0.34**	0.32	0.02
Proved plus probable reserves (2P)	mmbbl	0.41	(0.03)	—	**0.38**	0.36	0.02
Contingent Resources (2C)	mmbbl	0.05	—	—	**0.05**	—	—
Gas							
Proved reserves (1P)	PJ	57.99	(4.01)	6.78	**60.76**	47.23	13.53
Proved plus probable reserves (2P)	PJ	70.96	(4.01)	5.88	**72.83**	56.80	16.03
Contingent Resources (2C)	PJ	187.49	—	(2.28)	**185.21**	—	—

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

Reserves and Resources by Field

		As at 30/06/2022	01/07/2022 to 30/06/2023 Production	Other Adjustments	As at 30/06/2023
Mereenie, oil					
Proved reserves (1P)	mmbbl	0.37	(0.03)	—	**0.34**
Proved plus probable reserves (2P)	mmbbl	0.41	(0.03)	—	**0.38**
Contingent Resources (2C)	mmbbl	0.05	—	—	**0.05**
Mereenie, gas					
Proved reserves (1P)	PJ	30.46	(1.73)	—	**28.73**
Proved plus probable reserves (2P)	PJ	39.21	(1.73)	—	**37.48**
Contingent Resources (2C)	PJ	45.60	—	—	**45.60**
Palm Valley					
Proved reserves (1P)	PJ	11.29	(1.68)	2.99	**12.61**
Proved plus probable reserves (2P)	PJ	12.73	(1.68)	2.36	**13.41**
Contingent Resources (2C)	PJ	6.84	—	(2.28)	**4.56**
Dingo					
Proved reserves (1P)	PJ	16.23	(0.60)	3.79	**19.42**
Proved plus probable reserves (2P)	PJ	19.02	(0.60)	3.52	**21.94**
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 reviewed by Mr Kevan Quammie who is a full-time employee of Central Petroleum holding the position of Exploration and Development Manager. Mr Quammie holds an M.Sc. Petroleum and Natural Gas Engineering from the Pennsylvania State University, 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.

The reserves and resources information in this document relating to:

- the Palm Valley and Dingo fields, as at 30 June 2023, were first reported to ASX on 27 July 2023, and are based on, and fairly represent information and supporting documentation reviewed by Mr John Hattner who is a full-time employee of Netherland, Sewell & Associates, Inc. ("NSAI"), holding the position of Senior Vice President;
- the Mereenie field were first reported to ASX on 27 July 2023, and are based on, and fairly represents information and supporting documentation reviewed by Mr Kevan Quammie who is a full-time employee of Central Petroleum Limited holding the position of Exploration and Development Manager and is a member in good standing of the Society of Petroleum Engineers; and
- the Range Gas Project resources were first reported to the market on 20 August 2019 and are based on, and fairly represent information and supporting documentation reviewed by Mr John Hattner who is a full-time employee of NSAI, holding the position of Senior Vice President and is a member in good standing of the Society of Petroleum Engineers.

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 a fast-changing 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 provides an integrated and coordinated approach to the management of climate change risks across the business.

Principal risks and uncertainties at 30 June 2023

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. 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.
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 portfolio of 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 also seeks value accretive opportunities to reduce carbon emissions and/or utilize or sequester carbon, with both Palm Valley and Mereenie potential candidates for carbon capture and storage (CCS). Central has opportunities to diversify its reliance on hydrocarbons by targeting valuable non-hydrocarbon gases such as helium and naturally occurring hydrogen which 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 operate with the required standards of safety management.
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.

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 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, increased tariffs, or restricted access to third party owned infrastructure.	We seek to work closely with customers and suppliers of infrastructure to mitigate the risk of delays or failure. We continue to explore alternative routes to market to diversify risk where possible.

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 9% of consolidated sales revenue in FY2023. 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 from December 2023 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. The Range coal seam gas project in the Surat Basin is increasing the geographical diversification of our business. We are also investigating other new ventures outside of the Amadeus Basin.

DIRECTORS' REPORT

FOR THE YEAR ENDED 30 JUNE 2023

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 2023.

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 Stuart Baker (resigned 30 August 2022)

Mr Stephen Gardiner

Mr Troy Harry (commenced 1 September 2022)

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 (2022: $Nil). No recommendation for payment of dividends has been made.

OPERATING AND FINANCIAL REVIEW

The operating and financial highlights for the financial year were:

- The Group added an additional 5.9 PJ of Proved and Probable (2P) gas reserves at 30 June 2023, representing an increase of 8% (before production) to 75 PJe, reflecting drilling and production results at Palm Valley and updated Dingo reservoir modelling.
- The Palm Valley 12 well was successfully tied into the Palm Valley processing facilities and flowed gas to market from late November 2022 at greater than 10 TJ per day.
- New gas sales agreements for the sale of gas were secured with:
    - Shell Energy for supply of 0.91 PJ of gas in CY2025; and
    - South 32 for supply of 0.55 PJ of gas over two years from 1 January 2023.
- Average sales prices were up 17% on FY2022 at $7.90 / GJe.
- Annual revenue from hydrocarbon sales of $38.2 million was up 12% from FY2022 on a like for like basis.
- In August 2023, agreement was reached to progress towards a final investment decision for construction of 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 2023, including principal risks is provided from pages 3 to 25 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 2023:

- A new production well was drilled and commissioned at Palm Valley, significantly increasing gas production from late November 2022.
- Drilling and production results at Palm Valley and updated Dingo reservoir modelling led to an additional 5.9 PJ of new 2P gas reserves being recorded.
- The debt facility was increased by two separate tranches of $6 million which are available to fund production growth opportunities across Central's Amadeus Basin gas projects.
- Doubts surrounding the ability of a joint venturer to fund its obligations under various farmin arrangements led to recognition of an impairment charge of $3 million. The relevant joint venturers are reconsidering the structure, timing, and funding of the sub-salt exploration program.

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

EVENTS SINCE THE END OF THE FINANCIAL YEAR

In August 2023, the Group reached agreement to progress towards a final investment decision for construction of a helium recovery unit at Mereenie, demonstrating the potential of the Amadeus Basin as a world-class helium resource.

No other significant matters or circumstances have arisen between 30 June 2023 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

Production enhancement
Two new development wells are being considered by the Mereenie joint venture and could be drilled by mid-2024 to boost production capacity at Mereenie for supply into strong gas markets.

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 are being reconsidered as committed farm-out funding is now unlikely to be forthcoming. Central is considering alternative arrangements for the permits and wells, including negotiation for deferral of permit commitments, new farm-outs, sourcing of additional funding or, alternatively, relinquishment of the permits.

Other proposed near-term exploration activity includes seismic acquisition at the large Zevon sub-salt lead to identify a possible site for an exploration well. Central is also planning to advance an oil exploration well at Mamlambo, subject to funding availability.

Helium Recovery Unit
Central and its partners at Mereenie will work with Twin Bridges, a private US company specialising in helium appraisal and production to achieve the necessary design, engineering, commercial and financial milestones required to reach FID for the construction of a helium recovery unit (HRU) at Mereenie. If the project proceeds, Twin Bridges will design, build, fund and own the HRU plant which will be integrated with the existing Mereenie gas processing facility operated by Central, targeting production of up to 60,000 scf of compressed helium gas per day.

Commercial
Demand for gas is expected to remain strong through FY2024, and Central expects to be able to commit to new gas supply contracts at higher pricing than in previous periods as existing contracts mature.

Further information on these activities is included from pages 1 to 25 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 38 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, gas processing, LNG and underground storage.

Mr McCormack is a former Managing Director and CEO of APA Group and former Director of Envestra (now Australian Gas Infrastructure Group), the Australian Pipeline Industry Association (now Australian Pipelines and Gas Association) and the Australian Brandenburg Orchestra. He is a non-executive director at Origin Energy and Austal Limited and a director of the Clontarf Foundation and the Australian Brandenburg Orchestra Foundation and a Fellow of the Australian Institute of Company Directors.

Directorships of other listed companies in the last three years: Director of Austal Limited from September 2020 and Director of Origin Energy Limited from December 2020.

Mr Leon Devaney BSc, MBA

Managing Director and Chief Executive Officer

Mr Devaney has over 20 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 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. 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)

Mr Troy Harry

Non-executive Director

Mr Harry has been a director of Central Petroleum Limited since 1 September 2022 and is a professional investor with interests in many ASX listed companies, as well as private businesses and property. He formerly had a career in stockbroking and funds management and was the founder of Trojan Investment Management Pty Ltd.

Mr Harry is currently a director of numerous private entities. He has not held any other ASX directorships in the last 3 years.

Through his associated entities, Mr Harry is a substantial shareholder in Central Petroleum Limited.

Ms Katherine Hirschfeld AM BE(Chem) 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 Spark Infrastructure RE Limited, its subsidiaries and related entities (which includes the Boards of SA Power Networks and Victoria Power Networks (Powercor and CityPower)) and Sims Limited.

Ms Hirschfeld has also been a board member and President of UN Women National Committee Australia and non-executive director of 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 member of Chief Executive Women and a Fellow of the Australian Institute of Company Directors and the Academy of Engineering and Technology. She is also an executive mentor/coach with Merryck & Co.

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) and President of the Chamber of Commerce and Industry WA.

Dr Kantsler is Managing Director of Transform Exploration Pty Ltd, a Non-Executive Director of ASX-listed Suvo Strategic Minerals Ltd, and a former Director of Oil Search Limited.

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

COMPANY SECRETARY

Mr Daniel White LLB, BCom, LLM

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

DIRECTORS' MEETINGS

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

	Full Meeting of Directors		Audit & Financial Risk Committee		Risk & Sustainability Committee		Remuneration & Nominations Committee		Strategic Review Committee	
Director	Eligible[1]	Attended	Eligible[1]	Attended[2]	Eligible[1]	Attended[2]	Eligible[1]	Attended[2]	Eligible[1]	Attended[2]
Stuart Baker[3]	3	3	0	0	—	0	1	1	0	0
Leon Devaney	12	12	—		—	4	—	5	—	30
Stephen Gardiner	12	12	4	4	4	4	4	5	30	26
Troy Harry[4]	9	9	4	4	—	4	4	4	30	29
Katherine Hirschfeld AM	12	12	4	4	4	4	—	5	30	26
Agu Kantsler	12	12	—	4	4	4	5	5	30	28
Michael McCormack	12	11	4	4	4	4	5	5	30	24

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 Stuart Baker resigned as Director on 30 August 2022.
4 Troy Harry was appointed as Director on 1 September 2022.

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	
	2023	2022
PwC Australian firm:	**$**	$
(i) Taxation services		
Income tax compliance	14,280	9,588
Other tax related services	47,512	10,579
Total remuneration from non-audit services	**61,792**	**20,167**

EXECUTIVE SUMMARY – REMUNERATION

Dear Shareholders,

The challenges of COVID seem a distant memory, however the resulting ripples from the social and economic disruption continue to impact our ability to maintain a skilled and productive workforce.

The return of overseas workers has alleviated some of the salary pressures, but this has been countered by demands to soften the impacts of the rising cost of living.

While our field-based staff can't participate in the work-from-home revolution, the undercurrent for increased flexibility remains throughout the labour markets. The battle remains to retain staff in a very competitive market.

It is in the context of these changing labour markets that we maintain a remuneration structure that seeks to balance expectations with performance and reward through a combination of competitive fixed remuneration and performance-based incentives.

Fixed remuneration

To counter rising cost of living pressures and to remain competitive, we increased remuneration across the Company by approximately 4.5% for FY2023, along with the 0.5% increase in compulsory superannuation contributions. Average salaries will rise by approximately 4% from July 2023 plus the 0.5% increase in superannuation contributions.

Short-term incentives

Staff, other than executives, participated in the Short Term Incentive Plan (STIP), which targets near-term performance through the achievement of personal and corporate objectives over the year, providing an opportunity to earn from 10% to 30% of base remuneration, depending on role and responsibility.

The FY2023 STIP award reflected a strong operating performance from the smaller asset base, with capital management performance exceeding its stretch target and operating cost control targets achieved. The STIP award would have been higher, but for a lack of progress on commercial initiatives and delays and cost overruns to our exploration and development programs, which also impacted sales volumes.

As a result, personnel were entitled to an average 51% of their maximum STIP incentive for the year, somewhat lower than in previous years.

With the uncertainty of the ongoing strategic review process, we extended a retention incentive to a handful of key operational personnel in an attempt to avoid the loss of key operational capability until the outcome of the review is known.

Executive incentives

Our executive team participated in an incentive program that integrates short and long-term components, with performance measured against the same corporate KPI targets as for the STIP. Of the maximum available in FY2023, 45% was awarded, with one-third to be paid this year and the balance converting into share rights vesting over the next three years.

LTIP

FY2023 marks the end of the final performance period for the discontinued Long Term Incentive Plan (LTIP). The LTIP's Absolute TSR performance for the three years from 1 July 2020 to 30 June 2023 failed to achieve the minimum growth hurdle of 10% pa. Whilst disappointing in absolute terms, Central's share price performance over this period was relatively strong when compared to our peers within the sector. The Relative TSR placed Central at the 59th percentile compared to its peers, resulting in 30% of rights vesting for this three year performance period. The Board has discretion to retest performance of these hurdles at 31 December 2023.

As in 2022, the independent Directors sacrificed a portion of their fees to acquire share rights to increase their alignment with shareholders.

To assist readers of this report to understand the actual remuneration which the senior executives have received this year, we have again included a Realised Remuneration table (refer Table 1 in section J of the Remuneration Report).

With the LTIP coming to an end this year and legacy executive options lapsing 'out-of-the-money', our remuneration structure is becoming less complex and more directly linked to performance. And while incentive awards this year were lower than in previous years, we believe that the appropriate structure is in place to drive higher performance across the organisation, and these results will ultimately be shared with our shareholders.

Michael (Mick) McCormack
Remuneration and Nominations Committee Chair

REMUNERATION REPORT
(AUDITED)

This Remuneration Report for the year ended 30 June 2023 (FY2023) 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 Share Option Plan (ESOP)
G	Executive Incentive Plan (EIP)
H	Short Term Incentive Plan (STIP)
I	Key operational employee retention incentive
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 Stuart Baker	Independent Non-executive Director (resigned 30 August 2022)
Mr Stephen Gardiner	Independent Non-executive Director
Mr Troy Harry	Non-executive Director (commenced 1 September 2022)
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
Dr Duncan Lockhart	General Manager Exploration (resigned 31 August 2022)
Mr Jonathan Snape	Chief Commercial Officer (resigned 20 January 2023)
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 2023 Summary of fixed and variable remuneration outcomes	
Salary increases in FY2023	An average 4.5% pay rise applied to eligible employees for FY2023 and compulsory superannuation contributions increased from 10% to 10.5%. As at 1 July 2023, salaries for eligible employees will rise, on average, by 4% for FY2024. In addition, employees will benefit from the statutory increase in compulsory superannuation contributions from 10.5% to 11%.
Short Term Incentive Plan (STIP)	Achievement of Group-wide corporate and individual KPIs resulted in payment of an average 51% of the maximum STIP to eligible employees. Refer Section H of this report.
Executive Incentive Plan (EIP)	Achievement of Group-wide corporate KPIs resulted in an award of 45% 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 G of this report.
Vesting of Share Rights previously granted under the Long Term Incentive Plan (LTIP)	The vesting rate for Share Rights issued under the Long Term Incentive Plan for the three year period ending 30 June 2023 was 29.935%. This may, at the Board's discretion, be eligible for retesting at 31 December 2023. Refer Section E of this report.

C. Remuneration Policy

The remuneration policy of the Group is to pay its directors and executives amounts in line with employment market conditions relevant to the oil and gas industry whilst reflecting Central's specific circumstances. The Group's remuneration practices and, in particular, its short term and long term incentive plans are focussed on creating strong linkages between shareholder value as measured by shareholder returns and executive remuneration. From FY2022, executives participate in an Executive Incentive Plan (EIP) that combines both short term annual KPIs and a longer-term, deferred equity-based component (refer Section G below).

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

For periods up to and ending on 30 June 2023, the remuneration of directors and executives consisted of the following key elements:

Non-executive directors:

1. Fees including statutory superannuation;
2. Up to 25% sacrifice of FY2023 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 FY2023.

The balance of fixed and maximum at risk remuneration for executives for FY2023 is summarised as follows:

C. Remuneration Policy (continued)

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:

		FY2019	FY2020	FY2021	FY2022	**FY2023**
Financial performance						
Operating revenue	$ million	59.36	65.05	59.83	42.15	**39.26**
Profit/(loss) after income tax	$ million	(14.53)	5.41	0.25	21.32	**(7.96)**
Underlying EBITDAX[1]	$ million	22.19	25.01	26.09	16.75	**15.75**
Shareholder wealth						
Share price at year end	$/share	$0.135	$0.081	$0.117	$0.110	**$0.053**
Absolute TSR (3 years)	% growth pa	15.5%	(16.1%)	(9.1%)	(4.6%)	**(13.1%)**
Relative TSR (3 years)	Percentile rank	88th	25th	57th	69th	**56th**
Incentive awarded						
STIP	% of maximum	82%	67%	67%	62.75%	**51.0%**
LTIP	% of maximum	75%	nil	31.5%	43%	**29.9%**
EIP	% of maximum	N/a	N/a	N/a	62.5%	**45.0%**

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

In the past five years, Central has recorded strong revenue and underlying EBITDAX results as expansion programs at the Group's Amadeus Basin oil and gas fields enabled increased production into new markets with the opening of the Northern Gas Pipeline in early 2019. In FY2022, the partial sale of the Company's producing oil and gas assets was completed, recognising a $36.6 million profit on the sale and providing funds to pay-down debt and fund new exploration and development activity. STIP awards from FY2019 to FY2022 have reflected this success, paid as a combination of cash, equity and deferred equity over those years. The FY2023 STIP/EIP award reflected a strong operating performance from the smaller asset base, with capital management performance exceeding its stretch target and operating cost control targets achieved. The STIP/EIP award in FY2023 however, would have been higher, but for a lack of progress on commercial initiatives and delays and cost overruns to the Company's exploration and development programs which also impacted sales volumes.

The LTIP awards over recent years have followed the Group's 3 year share price performance, resulting in a relatively high award in FY2019 as the share price reflected increasing production and announcement of the Range gas project. 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 have seen a decline in share price in absolute terms, but Central's shares have performed relatively well against those of its peers, resulting in a partial vesting of LTIPs for participants in those years.

D. Remuneration Consultants

The performance of the Group depends upon the quality of its directors and executives and the Company strives to attract, motivate and retain highly qualified and skilled management. Salaries and directors' fees are reviewed at least annually to ensure they remain competitive with the market.

For each annual remuneration review cycle, the Remuneration Committee considers whether to appoint a remuneration consultant and, if so, their scope of work.

No remuneration consultants were engaged for the July 2022 review of remuneration. Guerdon Associates were engaged to provide market information relating to a retention strategy in the context of the Strategic Review, as well as providing a determination on the relative total shareholder return performance hurdle relating to the LTIP's performance period ending 30 June 2023. Guerdon Associates also provided clarification on matters dealing with treatment of dividends and returns of capital as they relate to equity incentives.

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

The performance-linked LTIP was discontinued after FY2021 and the final year for measuring share price performance for these legacy plans was FY2023.

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

The LTIP has previously been a major component of the incentive framework for senior staff, and in developing the Employee Rights Plan, the Board focused on creating strong linkages between shareholder value as measured by shareholder returns and remuneration. Consequently, vesting conditions have been weighted equally between relative shareholder return and absolute shareholder return over a three-year period, aligning reward with share performance against peer companies and also with absolute share price growth.

The Group's Employee Rights Plan was last approved by shareholders in November 2022 to incentivise eligible employees (Non-Executive Directors are not eligible to participate in the LTIP).

The maximum number of performance rights vested in any year is determined by measuring Central's share price performance compared to a peer group of companies (relative measure) and its absolute share price movement over a three-year cycle, the last of which was the three-year period ending 30 June 2023.

FY2023 Performance

The following table details the percentage of Share Rights in respect of the three-year performance period ending 30 June 2023 which will vest (Vesting Percentage) as determined by the performance conditions, based on the 20-day VWAP prior to 30 June 2023 of $0.0578. The benchmark share price at the start of the performance period was $0.0882:

Hurdle	Definition	Hurdle Banding	Vesting Percentage	Result for Plan Year Vesting 30 June 2023
Absolute TSR[1] growth **(50% weighting)**	Company's absolute TSR calculated as at vesting date. This looks to align eligible employees' rewards to shareholder superior returns	**Company's Absolute TSR over 3 years**	**Share Rights Vesting**	
		25% pa plus	100%	
		20% to <25% pa	75%	
		15% to <20% pa	50%	
		10% to <15% pa	25%	
		Below 10% pa	0%	
Relative TSR – E&P[2] **(50% weighting)**	Company's TSR relative to a specific group of exploration and production companies[3] (determined by the Board within its discretion) calculated as at vesting date	**Company's Relative TSR**	**Share Rights Vesting**	
		76th percentile and above	100%	
		From 51st to 75th percentile	50% to 99%	(59.87%)
		Below 51st percentile	0%	

1 Total shareholder return (i.e. growth in share price plus dividends reinvested).
2 Exploration and Production.
3 The peer group of companies for the three-year performance period ended 30 June 2023 is: Armour Energy Limited, Blue Energy Limited, Buru Energy Limited, Carnarvon Energy Limited, Cooper Energy Limited, Comet Ridge Limited, Empire Energy Group Limited, FAR Limited, Galilee Energy Limited, Horizon Oil Limited, Icon Energy Limited, State Gas Limited, Strike Energy Limited, Triangle Energy Global Limited, Vintage Energy Limited and 3D Oil Limited.

Key terms and vesting conditions

For the purposes of determining the number of Share Rights to vest, the Company's absolute TSR and relative TSR are calculated as at the end of the performance period. The Vesting Percentage for each is determined by reference to the hurdle bandings set out in the above tables. The Share Rights for each applicable hurdle are then multiplied by the Vesting Percentage achieved for that hurdle to determine the total number of Share Rights which vest on the vesting date. Vested Share Rights may then be exercised in accordance with the Employee Rights Plan Rules. Each vested Share Right can be exercised at the rate of one Share Right for one Ordinary Share in the Company.

Employees must be employed by the Group at the end of the performance period in order for the Share Rights to vest. The maximum number of Share Rights that an employee was granted is a function of the employee's Total Fixed Remuneration (TFR) and the 20 trading days daily volume weighted average sale price of company shares sold on the ASX ending on the trading day prior to the start of the performance period.

If the Company is subject to a Change of Control Event, all unvested Share Rights will immediately vest at 100%, with any performance criteria being waived.

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

Participation

This share price-linked LTIP provided coverage for various levels of eligible employees from FY2021 which include:

a. One member of the Executive Management Team (EMT) received an LTIP percentage of 30% of their TFR until FY2019;
b. Eligible employees who are in roles which influence and drive the strategic direction of the Group's business or who are senior managers with responsibility for one or more defined functions, departments or outcomes were eligible to receive a maximum LTIP percentage of 20% or 30% of TFR; and
c. Eligible employees who are in roles which are focused on the key drivers of the operational parts of the Group's business received a maximum LTIP percentage of 10% of TFR.

All other eligible employees are integral to the success of the Group obtaining its goals and objectives and may participate in the Central Petroleum $1,000 Exempt Plan.

Conditions of the Central Petroleum $1,000 Exempt Plan include:

1. Share Rights can only be dealt with upon vesting at the end of the three-year service period; and
2. No performance conditions apply.

In 2021, Central conducted an external review of the effectiveness of the LTIP in providing a relevant incentive to all levels of personnel. The review took into account many factors, including the history of rewards under the scheme, taxation implications for employees, near and longer-term drivers of shareholder value and alternative incentive scheme structures used by peers and the broader market. As a result of the review:

i) No further LTIPs have been granted under the existing LTIP structure described above from 1 July 2021;
ii) The Managing Director (subject to shareholder approval) and EMT are eligible to participate in an Executive Incentive Plan (EIP) from FY2022 (refer Section G of this report); and
iii) Incentive for all other employees, including those in categories b and c above have been re-weighted to a single STIP opportunity (refer Section H of this report) with eligibility to participate in the Central Petroleum $1,000 Exempt Plan.

F. Long Term Incentive Plan – Executive Share Option Plan (ESOP)

Participation

The ESOP replaced the previous LTIP for participating executives and any Share Options granted under the ESOP replaced the LTIP Share Rights that would otherwise have been granted in FY2020, FY2021 and FY2022 under the LTIP.

Key terms and vesting conditions

Each Share Option was issued for no consideration and entitled the participant to subscribe for one Share upon exercise of the Share Option.

The amount payable upon exercise of each Share Option was $0.20 (Exercise Price). The Share Options were exercisable from 1 July 2022 until 30 June 2023.

Performance

No Share Options were exercised by 30 June 2023. All Share Options subsequently lapsed on 1 July 2023.

G. 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 and the following two years.

Key terms and vesting conditions

The EIP is an integrated incentive 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:

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.

G. Executive Incentive Plan (EIP) (continued)

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.

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.

FY2023 Performance

After assessment of the achievement of the Corporate KPIs (refer Section H of this report) and the Company's performance during the year, eligible executives were entitled to receive, on average, 45% of their maximum EIP bonus. Of this award, 33% was paid in September 2023, while the remaining 67% will be granted as Service Rights that vest over the next three years in equal tranches.

H. 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 in the next year 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 %

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

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.

From 1 July 2021, the CEO and executives who participate in the EIP are not eligible to participate in the STIP (refer Section G of this report).

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

FY2023 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, 51% of their maximum STIP bonus. The STIP bonuses are scheduled to be paid in September 2023.

The Financial Year 2023 STIP (FY2023 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		
	Maximum	Actual	Achievement
Corporate KPIs	60 %	27 %	45% satisfaction of corporate KPIs
Individual KPIs	40 %	24 % (avg)	60% satisfaction of individual KPIs
	100 %	51 % (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 FY2023 STIP, depending on their participation level.

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

Corporate KPIs for FY2023:

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%			●	
Recompletions/Development Assessed against budget, commercial viability, schedule and timing hurdles	17%	●			
Farmout Assessed against the number of binding agreements	17%	●			
Funding Assessed against the projected two year capital requirements for existing commitments in FY2023	17%				●
Traditional Owner cultural heritage Assessed against compliance with agreements	3%			●	
Safety Total Recordable Incident Frequency Rate (TRIFR)	3%		●		
Process Safety Unplanned or uncontrolled release of materials from a process (loss of primary containment – LOPC)	3%			●	
Environment Recordable environmental incidents	3%	●			
Alice Springs local and 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 FY2023 were assessed as achieving an average of 60% (or a weighted average of 24% out of a maximum possible 40%).

I. Key operational employee retention incentive

Participation

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

Key terms and vesting conditions

The retention incentive is a cash payment equal to 15% of the selected KMP's and employees' Total Fixed Remuneration (TFR). The retention incentive is conditional upon the employee remaining employed by the Group in the period up to when the payment is made after the earlier of completion of a transaction resulting from the Strategic Review and 30 June 2024.

J. Realised Remuneration

Table 1 identifies the Actual Remuneration received by Senior Executives in respect of the 2023 financial year. Realised Remuneration reflects the 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;
- Any Short Term Incentive awarded as share rights in lieu of cash for the financial year, and granted after the end of the financial year valued at the cash equivalent amount (but excluding any share rights which do not immediately vest); and
- The value of LTIP share rights vesting (if any) in respect of the three-year period ending 30 June, valued at the year-end share price (2023: 5.3 cents per share, 2022: 11.0 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	**2023**	**654,572**	**117,823**	**8,192**	**55,833**	**836,420**
	2022	625,750	156,438	7,470	—	789,658
Ross Evans	**2023**	**535,557**	**64,267**	**8,192**	**30,447**	**638,463**
	2022	511,860	85,310	7,470	—	604,640
Damian Galvin	**2023**	**353,926**	**42,471**	**8,192**	**20,108**	**424,697**
	2022	338,050	56,342	7,470	—	401,862
Duncan Lockhart[4]	**2023**	**113,160**	**—**	**2,007**	**4,043**	**119,210**
	2022	409,450	68,242	7,470	—	485,162
Jonathan Snape[5]	**2023**	**194,107**	**—**	**4,895**	**9,815**	**208,817**
	2022	330,001	55,000	6,984	—	391,985
Daniel White	**2023**	**475,523**	**57,063**	**8,192**	**50,994**	**591,772**
	2022	454,410	75,735	7,470	46,505	584,120
Total Executive KMP	**2023**	**2,326,845**	**281,624**	**39,670**	**171,240**	**2,819,379**
	2022	2,669,521	497,067	44,334	46,505	3,257,427

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 30 June 2023 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.

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 & Options[3] $	Total $	Percent of Remuneration %
Non-Executive Directors										
Stephen Gardiner	**2023**	**70,833**	—	—	**7,438**	—	—	**18,251**	**96,522**	—
	2022	62,500	—	—	6,250	—	—	18,603	87,353	—
Troy Harry[4]	**2023**	**66,402**	—	—	**6,972**	—	—	—	**73,374**	—
	2022	—	—	—	—	—	—	—	—	—
Katherine Hirschfeld	**2023**	**78,000**	—	—	**8,190**	—	—	**7,300**	**93,490**	—
	2022	78,000	—	—	7,800	—	—	7,441	93,241	—
Agu Kantsler	**2023**	**62,500**	—	—	**6,563**	—	—	**18,251**	**87,314**	—
	2022	62,500	—	—	6,250	—	—	18,603	87,353	—
Michael McCormack	**2023**	**117,500**	—	—	**12,338**	—	—	**33,895**	**163,733**	—
	2022	117,500	—	—	11,750	—	—	34,548	163,798	—
Former Non-Executive Directors										
Stuart Baker[5]	**2023**	**14,167**	—	—	**1,488**	—	—	—	**15,655**	—
	2022	67,500	—	—	6,750	—	—	18,603	92,853	—
Sub-total	**2023**	**409,402**	—	—	**42,989**	—	—	**77,697**	**530,088**	—
	2022	388,000	—	—	38,800	—	—	97,798	524,598	—
Executives										
Leon Devaney	**2023**	**640,142**	**117,823**	**8,192**	**25,292**	—	**22,307**	**177,683**	**991,439**	**30%**
	2022	613,881	156,438	7,470	23,568	—	13,639	277,153	1,092,149	40%
Ross Evans	**2023**	**508,712**	**81,370**	**8,192**	**25,292**	—	**9,717**	**117,477**	**750,760**	**26%**
	2022	501,018	85,310	7,470	23,568	—	7,119	241,598	866,083	38%
Damian Galvin	**2023**	**340,936**	**42,471**	**8,192**	**25,292**	—	**5,856**	**76,803**	**499,550**	**24%**
	2022	321,088	56,342	7,470	23,568	—	4,470	158,595	571,533	38%
Duncan Lockhart[6]	**2023**	**66,458**	—	**2,007**	**6,323**	—	**(15,824)**	**(43,061)**	**15,903**	—
	2022	400,660	68,242	7,470	23,568	—	5,506	192,505	697,951	37%
Jonathan Snape[7]	**2023**	**170,679**	—	**4,895**	**14,543**	—	**(2,706)**	**(21,944)**	**165,467**	—
	2022	315,318	55,000	6,984	23,568	—	2,706	39,722	443,298	21%
Daniel White	**2023**	**469,673**	**57,063**	**8,192**	**25,292**	—	**18,425**	**135,958**	**714,603**	**27%**
	2022	450,596	75,735	7,470	23,568	—	10,367	151,392	719,128	32%
Sub-total	**2023**	**2,196,600**	**298,727**	**39,670**	**122,034**	—	**37,775**	**442,916**	**3,137,722**	**24%**
	2022	2,602,561	497,067	44,334	141,408	—	43,807	1,060,965	4,390,142	35%
Total Remuneration	**2023**	**2,606,002**	**298,727**	**39,670**	**165,023**	—	**37,775**	**520,613**	**3,667,810**	**22%**
	2022	2,990,561	497,067	44,334	180,208	—	43,807	1,158,763	4,914,740	32%

1 Includes movements in annual leave provisions.
2 Short term incentives are unpaid at the end of the financial year.
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 evenly over the period from service commencement date to vesting date. 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 Troy Harry was appointed 1 September 2022.
5 Stuart Baker resigned 30 August 2022.
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	**2023**	**261,829**	**117,823**	**45.0%**	**55.0%**
	2022	250,300	156,438	62.5%	37.5%
Ross Evans[1]	**2023**	**142,815**	**64,267**	**45.0%**	**55.0%**
	2022	136,496	85,310	62.5%	37.5%
Damian Galvin	**2023**	**94,380**	**42,471**	**45.0%**	**55.0%**
	2022	90,147	56,342	62.5%	37.5%
Duncan Lockhart	**2023**	**N/A**	**N/A**	**N/A**	**N/A**
	2022	109,187	68,242	62.5%	37.5%
Jonathan Snape	**2023**	**N/A**	**N/A**	**N/A**	**N/A**
	2022	88,000	55,000	62.5%	37.5%
Daniel White	**2023**	**126,806**	**57,063**	**45.0%**	**55.0%**
	2022	121,176	75,735	62.5%	37.5%
Total	**2023**	**625,830**	**281,624**	**45.0%**	**55.0%**
	2022	795,306	497,067	62.5%	37.5%

1 In addition to this short term incentive, Ross Evans is also entitled to a retention incentive of 15% of total fixed remuneration implemented as part of the retention strategy made in connection with the Portfolio Strategic Review announced in August 2022. The incentive is 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 $17,103 relating to this retention incentive was accrued for the service period to 30 June 2023.

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]						
Stuart Baker[2]	**2023**	**—**	**—**	**—**	**—**	**—**
	2022	161,765	23 Nov 21	0.115	—	30 Jun 26
Stephen Gardiner	**2023**	**217,275**	**11 Nov 22**	**0.084**	**—**	**30 Jun 27**
	2022	161,765	23 Nov 21	0.115	—	30 Jun 26
Katherine Hirschfeld	**2023**	**86,910**	**11 Nov 22**	**0.084**	**—**	**30 Jun 27**
	2022	64,706	23 Nov 21	0.115	—	30 Jun 26
Agu Kantsler	**2023**	**217,275**	**11 Nov 22**	**0.084**	**—**	**30 Jun 27**
	2022	161,765	23 Nov 21	0.115	—	30 Jun 26
Michael McCormack	**2023**	**403,511**	**11 Nov 22**	**0.084**	**—**	**30 Jun 27**
	2022	300,420	23 Nov 21	0.115	—	30 Jun 26
Sub-total	**2023**	**924,971**				
	2022	850,421				
Executives[3]						
Leon Devaney	**2023**	**3,160,353**	**10 Nov 22**	**0.083**	**—**	**10 Nov 27**
	2022	—	—	—	—	—
Ross Evans	**2023**	**1,723,434**	**19 Sep 22**	**0.096**	**—**	**19 Sep 27**
	2022	—	—	—	—	—
Damian Galvin	**2023**	**1,138,215**	**19 Sep 22**	**0.096**	**—**	**19 Sep 27**
	2022	—	—	—	—	—
Duncan Lockhart[4]	**2023**	**76,283**	**19 Sep 22**	**0.096**	**—**	**19 Sep 27**
	2022	—	—	—	—	—
Jonathan Snape[5]	**2023**	**1,111,113**	**19 Sep 22**	**0.096**	**—**	**19 Sep 27**
	2022	—	—	—	—	—
Daniel White	**2023**	**1,530,000**	**19 Sep 22**	**0.096**	**—**	**19 Sep 27**
	2022	—	—	—	—	—
Sub-total	**2023**	**8,739,398**				
	2022	—				
Total	**2023**	**9,664,369**				
	2022	850,421				

K. Remuneration Details – Statutory tables (continued)

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

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 – 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 FY2022:

Grant Date	Expiry Date	Fair Value Per Right	Exercise Price	Price of Shares at Grant Date	Estimated Volatility	Risk Free Interest Rate	Dividend Yield
23 Nov 2021[1]	30 Jun 2026	$0.115	Nil	$0.115	N/A	N/A	—

[1] Share Rights granted to Non-Executive Directors. The fair value reflects the value of Director Fees sacrificed – Refer Section M of this report.

Table 5: Share Based Compensation – Share Rights Vested to Key Management Personnel during the Year

		Maximum Number of Rights Eligible for Vesting	EIP Year Commencing	LTIP Year Commencing[1]	Number of Rights Vested[1]	Proportion of Rights Vested[2]	Proportion of Rights Forfeited
Leon Devaney	**2023**	**1,053,451**	**01 Jul 21**	—	**1,053,451**	**100%**	**Nil**
	2022	—	—	—	—	—	—
Ross Evans	**2023**	**574,478**	**01 Jul 21**	—	**574,478**	**100%**	**Nil**
	2022	—	—	—	—	—	—
Damian Galvin	**2023**	**379,405**	**01 Jul 21**	—	**379,405**	**100%**	**Nil**
	2022	—	—	—	—	—	—
Duncan Lockhart[3]	**2023**	**76,283**	**01 Jul 21**	—	**76,283**	**100%**	**Nil**
	2022	—	—	—	—	—	—
Jonathan Snape[4]	**2023**	**185,186**	**01 Jul 21**	—	**185,186**	**100%**	**Nil**
	2022	—	—	—	—	—	—
Daniel White	**2023**	**510,000**	**01 Jul 21**	—	**510,000**	**100%**	**Nil**
	2023	**1,510,476**	—	**01 Jul 20**	**452,160**	**30%**	**70%**
	2022	983,204	—	01 Jul 19	422,777	43%	57%
Total	**2023**	**4,289,279**			**3,230,963**	**75%**	**25%**
	2022	983,204			422,777	43%	57%

[1] The number of Rights that vested in respect of plan years commencing 1 July 2019 and 1 July 2020 relates to Share Rights granted in prior financial years under the Long Term Incentive Plan. Prior to forfeiture and at the discretion of the Board, LTIP Rights for the plan year commencing 1 July 2020 may be subjected to retest against the performance hurdles at 31 December 2023.
[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.

In addition, 924,971 Share Rights vested on 30 June 2023 (2022: 850,421), 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 G 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 (refer Section F of this report).

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

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]	**2023**	**161,765**	**—**	**—**	**—**	**(161,765)**	**N/A**	**N/A**
	2022	—	161,765	—	—	N/A	161,765	—
Stephen Gardiner	**2023**	**161,765**	**217,275**	**—**	**—**	**N/A**	**379,040**	**—**
	2022	N/A	161,765	—	—	N/A	161,765	—
Katherine Hirschfeld	**2023**	**64,706**	**86,910**	**—**	**(64,706)**	**N/A**	**86,910**	**—**
	2022	—	64,706	—	—	N/A	64,706	—
Agu Kantsler	**2023**	**161,765**	**217,275**	**—**	**(161,765)**	**N/A**	**217,275**	**—**
	2022	—	161,765	—	—	N/A	161,765	—
Michael McCormack	**2023**	**300,420**	**403,511**	**—**	**(300,420)**	**N/A**	**403,511**	**—**
	2022	—	300,420	—	—	N/A	300,420	—
Sub-total	**2023**	**850,421**	**924,971**	**—**	**(526,891)**	**(161,765)**	**1,086,736**	**—**
	2022	—	850,421	—	—	N/A	850,421	—
Executives								
Leon Devaney	**2023**	**1,074,860**	**3,160,353**	**—**	**—**	**N/A**	**1,632,140**	**2,603,073**
	2022	2,333,280	—	(1,258,420)	—	N/A	578,689	496,171
Ross Evans	**2023**	**405,655**	**1,723,434**	**—**	**—**	**N/A**	**574,478**	**1,554,611**
	2022	1,184,509	—	(533,515)	(245,339)	N/A	—	405,655
Damian Galvin	**2023**	**243,198**	**1,138,215**	**—**	**—**	**N/A**	**379,405**	**1,002,008**
	2022	243,198	—	—	—	N/A	—	243,198
Duncan Lockhart[2]	**2023**	**304,213**	**76,283**	**(84,504)**	**—**	**(295,992)**	**N/A**	**N/A**
	2022	304,213	—	—	—	N/A	—	304,213
Jonathan Snape[3]	**2023**	**—**	**1,111,113**	**(740,742)**	**—**	**(370,371)**	**N/A**	**N/A**
	2022	N/A	—	—	—	N/A	—	—
Daniel White	**2023**	**2,820,949**	**1,530,000**	**(560,427)**	**(422,777)**	**N/A**	**510,000**	**2,857,745**
	2022	3,625,933	—	(551,415)	(253,569)	N/A	—	2,820,949
Sub-total	**2023**	**4,848,875**	**8,739,398**	**(1,385,673)**	**(422,777)**	**(666,363)**	**3,096,023**	**8,017,437**
	2022	7,691,133	—	(2,343,350)	(498,908)	—	578,689	4,270,186
Total	**2023**	**5,699,296**	**9,664,369**	**(1,385,673)**	**(949,668)**	**(828,128)**	**4,182,759**	**8,017,437**
	2022	7,691,133	850,421	(2,343,350)	(498,908)	N/A	1,429,110	4,270,186

[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 2023	Vesting Period End Date[2]	Maximum value yet to vest[3]
Key Management Personnel					
Leon Devaney	TBD[1]	Deferred Share Rights – FY2023 EIP[1]	—	—	150,552
	10 Nov 2022	Deferred Share Rights – FY2022 EIP	1,053,451	30 Jun 2025	43,718
	10 Nov 2022	Deferred Share Rights – FY2022 EIP	1,053,451	30 Jun 2024	29,146
	10 Nov 2022	Deferred Share rights – FY2022 EIP	1,053,451	30 Jun 2023	—
	11 Nov 2020	Deferred Share Rights – STIP[3]	496,171	01 Jul 2023	—
Ross Evans	TBD[1]	Deferred Share Rights – FY2023 EIP[1]	—	—	82,119
	19 Sep 2022	Deferred Share Rights – FY2022 EIP	574,478	30 Jun 2025	27,575
	19 Sep 2022	Deferred Share Rights – FY2022 EIP	574,478	30 Jun 2024	18,383
	19 Sep 2022	Deferred Share Rights – FY2022 EIP	574,478	30 Jun 2023	—
	11 Nov 2020	Deferred Share Rights – STIP[3]	405,655	01 Jul 2023	—
Damian Galvin	TBD[1]	Deferred Share Rights – FY2023 EIP[1]	—	—	54,268
	19 Sep 2022	Deferred Share Rights – FY2022 EIP	379,405	30 Jun 2025	18,211
	19 Sep 2022	Deferred Share Rights – FY2022 EIP	379,405	30 Jun 2024	12,141
	19 Sep 2022	Deferred Share Rights – FY2022 EIP	379,405	30 Jun 2023	—
	11 Nov 2020	Deferred Share Rights – STIP[3]	243,198	01 Jul 2023	—
Daniel White	TBD[1]	Deferred Share Rights – FY2022 EIP[1]	—	—	72,914
	19 Sep 2022	Deferred Share Rights – FY2022 EIP	510,000	30 Jun 2025	24,480
	19 Sep 2022	Deferred Share Rights – FY2022 EIP	510,000	30 Jun 2024	16,320
	19 Sep 2022	Deferred Share Rights – FY2022 EIP	510,000	30 Jun 2023	—
	11 Nov 2020	Deferred Share Rights – STIP[4]	327,269	01 Jul 2023	—
	24 Jul 2020	Deferred Share Rights – LTIP	1,510,476	30 Jun 2023	—
Total			**10,534,771**		**549,827**

1 Share rights as part of the FY2023 EIP are expected to be granted during FY2024. 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 2023 quarterly report, which is calculated as 5.86 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 FY2023 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.
4 The FY2020 STIP was awarded as rights to deferred shares instead of cash. These rights vested subsequent to the end of the financial year, on 1 July 2023.

Table 8: Options Holdings of Key Management Personnel

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:

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)[2]
Key Management Personnel									
Leon Devaney	**2023**	**5,105,000**	**—**	**$0.20**	**01 Jul 2023**	**—**	**—**	**N/A**	**5,105,000**
	2022	5,105,000	—	$0.20	01 Jul 2023	—	—	N/A	5,105,000
Ross Evans	**2023**	**4,170,025**	**—**	**$0.20**	**01 Jul 2023**	**—**	**—**	**N/A**	**4,170,025**
	2022	4,170,025	—	$0.20	01 Jul 2023	—	—	N/A	4,170,025
Damian Galvin	**2023**	**2,750,000**	**—**	**$0.20**	**01 Jul 2023**	**—**	**—**	**N/A**	**2,750,000**
	2022	2,750,000	—	$0.20	01 Jul 2023	—	—	N/A	2,750,000
Duncan Lockhart[1]	**2023**	**3,333,333**	**—**	**$0.20**	**01 Jul 2023**	**—**	**—**	**(3,333,333)**	**N/A**
	2022	3,333,333	—	$0.20	01 Jul 2023	—	—	N/A	3,333,333
Total	**2023**	**15,358,358**	**—**	**$0.20**	**01 Jul 2023**	**—**	**—**	**(3,333,333)**	**12,025,025**
	2022	15,358,358	—	$0.20	01 Jul 2023	—	—	N/A	15,358,358

1 Duncan Lockhart resigned 31 August 2022.
2 No options were exercised, and all options were subsequently cancelled on 1 July 2023.

K. Remuneration Details – Statutory tables (continued)

Table 9: Shareholdings of Key Management Personnel

Ordinary Shares		Held at Beginning of Year	Held at Date of Appointment	Other Purchases	Exercise of Rights	Held at Date of Departure	Held at End of Year
Non-Executive Directors							
Stuart Baker[1]	**2023**	**—**	**N/A**	**—**	**—**	**—**	**N/A**
	2022	—	N/A	—	—	N/A	—
Troy Harry[2]	**2023**	**N/A**	**53,340,268**	**—**	**—**	**N/A**	**53,340,268**
	2022	N/A	N/A	—	—	N/A	N/A
Stephen Gardiner	**2023**	**—**	**N/A**	**—**	**—**	**N/A**	**—**
	2022	N/A	—	—	—	N/A	—
Katherine Hirschfeld	**2023**	**760,850**	**N/A**	**—**	**64,706**	**N/A**	**825,556**
	2022	760,850	N/A	—	—	N/A	760,850
Agu Kantsler	**2023**	**—**	**N/A**	**—**	**161,765**	**N/A**	**161,765**
	2022	—	N/A	—	—	N/A	—
Michael McCormack	**2023**	**—**	**N/A**	**—**	**300,420**	**N/A**	**300,420**
	2022	—	N/A	—	—	N/A	—
Sub-total	**2023**	**760,850**	**53,340,268**	**—**	**526,891**	**N/A**	**54,628,009**
	2022	760,850	—	—	—	N/A	760,850
Other Key Management Personnel							
Leon Devaney	**2023**	**2,606,757**	**N/A**	**—**	**—**	**N/A**	**2,606,757**
	2022	2,606,757	N/A	—	—	N/A	2,606,757
Ross Evans	**2023**	**386,184**	**N/A**	**—**	**—**	**N/A**	**386,184**
	2022	140,845	N/A	—	245,339	N/A	386,184
Damian Galvin	**2023**	**141,000**	**N/A**	**—**	**—**	**N/A**	**141,000**
	2022	141,000	N/A	—	—	N/A	141,000
Duncan Lockhart[3]	**2023**	**—**	**N/A**	**—**	**—**	**—**	**N/A**
	2022	—	N/A	—	—	N/A	—
Jonathan Snape[4]	**2023**	**—**	**N/A**	**—**	**—**	**—**	**N/A**
	2022	N/A	—	—	—	N/A	—
Daniel White	**2023**	**2,562,643**	**N/A**	**—**	**422,777**	**N/A**	**2,985,420**
	2022	2,309,074	N/A	—	253,569	N/A	2,562,643
Sub-total	**2023**	**5,696,584**	**—**	**—**	**422,777**	**—**	**6,119,361**
	2022	5,197,676	—	—	498,908	—	5,696,584
Total KMP	**2023**	**6,457,434**	**53,340,268**	**—**	**949,668**	**—**	**60,747,370**
	2022	5,958,526	—	—	498,908	—	6,457,434

1 Stuart Baker resigned 30 August 2022.
2 Troy Harry was appointed 1 September 2022.
3 Duncan Lockhart resigned 31 August 2022.
4 Jonathan Snape resigned 20 January 2023.

L. Executive Service Agreements

The details of service agreements of the key management personnel of the Consolidated Entity as of 1 July 2023 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	$681,849	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 2023 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 provide rights relating to indemnity, insurance, and access to documents.

The table below summarises the Non-Executive Director fees for FY2023. 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 10 November 2022.

FY2023 Board Fees (per annum)	
Chair	$130,000
Non-Executive Director	$70,000

FY2023 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

19 September 2023

Auditor's Independence Declaration

As lead auditor for the audit of Central Petroleum Limited for the year ended 30 June 2023, 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
19 September 2023

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FINANCIAL REPORT

CONTENTS

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

The Financial Statements are presented in Australian currency.

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

Level 7, 369 Ann Street
Brisbane, Queensland 4000

A description of the nature of the Consolidated Entity's operations and its principal activities is included in the operating and financial review on pages 3 to 25. These pages are not part of these financial statements.

The financial statements were authorised for issue by the Directors on 19 September 2023. 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 2023

	NOTE	2023 $'000	2022* $'000
Revenue from contracts with customers – sale of hydrocarbons	2	39,255	42,151
Cost of sales	4(a)	(26,408)	(27,351)
Gross profit		**12,847**	**14,800**
Other income	3	1,880	37,300
Exploration expenditure	4(e)	(13,093)	(21,647)
General and administrative expenses net of recoveries	4(b)	(4,797)	(4,846)
Finance costs	4(c)	(4,797)	(4,287)
(Loss)/Profit before income tax		**(7,960)**	**21,320**
Income tax expense	5	—	—
(Loss)/Profit for the year		**(7,960)**	**21,320**
Other comprehensive profit/(loss) for the year, net of tax		—	—
Total comprehensive (loss)/profit for the year		**(7,960)**	**21,320**
Total comprehensive (loss)/profit attributable to members of the parent entity		**(7,960)**	**21,320**
Earnings per share for profit or loss attributable to the ordinary equity holders of the company:			
Basic (loss)/earnings per share (cents)	22(a)	**(1.09)**	**2.94**
Diluted (loss)/ earnings per share (cents)	22(b)	**(1.09)**	**2.88**

* Refer Note 1 regarding the restatement of FY2022 comparatives as a result of changing the presentation of certain expenses from by nature to by function.

The accompanying notes form part of these financial statements.

CONSOLIDATED BALANCE SHEET

AS AT 30 JUNE 2023

	NOTE	2023 $'000	2022 $'000
ASSETS			
Current assets			
Cash and cash equivalents	7	13,826	21,647
Trade and other receivables	8	6,675	26,872
Inventories	9	3,550	3,868
Total current assets		24,051	52,387
Non-current assets			
Property, plant and equipment	10	60,192	53,846
Right of use assets	11	551	922
Exploration assets	12	7,999	8,397
Other intangible assets	13	332	379
Other financial assets	14	3,053	4,410
Goodwill	15	1,953	1,953
Total non-current assets		74,080	69,907
Total assets		**98,131**	**122,294**
LIABILITIES			
Current liabilities			
Trade and other payables	16	3,009	13,526
Deferred revenue	2(b)	3,536	5,309
Borrowings	17(a)	4,376	4,500
Lease liabilities	11	426	413
Provisions	18	5,597	6,325
Total current liabilities		16,944	30,073
Non-current liabilities			
Deferred revenue	2(b)	11,632	13,614
Borrowings	17(b)	23,150	26,309
Lease liabilities	11	201	588
Provisions	18	26,816	25,180
Total non-current liabilities		61,799	65,691
Total liabilities		**78,743**	**95,764**
Net assets		**19,388**	**26,530**
EQUITY			
Contributed equity	19 (a)	197,776	197,776
Reserves	20	31,433	30,615
Accumulated losses	21	(209,821)	(201,861)
Total equity		**19,388**	**26,530**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

FOR THE YEAR ENDED 30 JUNE 2023

	Contributed Equity $'000	Reserves $'000	Accumulated Losses $'000	Total $'000
Balance at 1 July 2021	**197,776**	**29,094**	**(223,181)**	**3,689**
Total profit for the year	—	—	21,320	21,320
Other comprehensive loss	—	—	—	—
Total comprehensive profit for the year	—	—	21,320	21,320
Transactions with owners in their capacity as owners				
Share based payments	—	1,524	—	1,524
Share issue costs	—	(3)	—	(3)
	—	1,521	—	1,521
Balance at 30 June 2022	**197,776**	**30,615**	**(201,861)**	**26,530**
Total loss for the year	—	—	(7,960)	(7,960)
Other comprehensive loss	—	—	—	—
Total comprehensive loss 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**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED 30 JUNE 2023

	NOTE	2023 $'000	2022 $'000
Cash flows from operating activities			
Receipts from customers		38,050	44,333
Interest received		519	59
Other income		248	42
Government grants		—	11
Interest and borrowing costs		(2,853)	(2,472)
Payments for exploration expenditure		(9,629)	(10,121)
Payments to other suppliers and employees		(28,391)	(28,212)
Net cash (outflow)/inflow from operating activities	27	(2,056)	3,640
Cash flows from investing activities			
Payments for property, plant and equipment		(2,857)	(10,791)
Proceeds from sale of producing assets and property, plant and equipment	3(b)	3	28,305
Redemption/(lodgement) of security deposits and bonds		1,356	(108)
Net cash (outflow)inflow from investing activities		(1,498)	17,406
Cash flows from financing activities			
Payments for the issue of securities		(2)	(3)
Proceeds from borrowings	28(b)	1,000	—
Repayment of borrowings	28(b)	(4,625)	(36,000)
Transaction costs related to borrowings		(195)	—
Principal elements of lease payments	28(b)	(445)	(561)
Net cash outflow from financing activities		(4,267)	(36,564)
Net decrease in cash and cash equivalents		**(7,821)**	**(15,518)**
Cash and cash equivalents at the beginning of the financial year		**21,647**	**37,165**
Cash and cash equivalents at the end of the financial year	7	**13,826**	**21,647**

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.

Presentation Restatement

The presentation of the Consolidated Statement of Comprehensive Income has been restated in the current year to reclassify certain expenses by function rather than by nature to align with industry peers. Employee benefits and associated costs related to cost of sales or exploration activities had previously been allocated to these items. Share based payments and other employee benefits and associated costs, net of recoveries from joint venturers, have now been reclassified to general & administrative expenses. Depreciation and amortisation expenses have been re-allocated between cost of sales and general and administrative expenses (also reflected in Note 4 Expenses, Note 23 Segment Reporting, and Note 26 Deed of Cross Guarantee). To ensure comparability, amounts disclosed for the comparative period have been reclassified. The impacts of the reclassification for the Group for FY2022 are as follows:

		Reclassified 2022 expenses by function	
2022 Expenses as reported	**2022 As reported $'000**	**Allocated to Cost of Sales $'000**	**Allocated to General & Administrative $'000**
Cost of sales	(21,257)	(21,257)	—
General and administrative costs	(1,043)	—	(1,043)
Employee benefits and associated costs net of recoveries	(1,594)	—	(1,594)
Share based payments	(1,524)	—	(1,524)
Depreciation and amortisation	(6,779)	(6,094)	(685)
Total 2022 comparatives as reported in FY2023		**(27,351)**	**(4,846)**

(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 multiple cash flow forecast scenarios prepared by management for the next twelve months and believe the Group has sufficient cash flows under these scenarios to continue operations as planned.

The Group's ability to complete its planned three well sub-salt exploration program in its current form is dependent on farm-out arrangements under which the Group was to be carried for its share of the costs for two of the three planned wells (up to $10.6 million). The Directors have formed the view that Peak Helium will not be able to fund their obligations under the various farm-out arrangements and the relevant joint venturers are considering the future structure and timing of the exploration program. In the expectation that the farm-out funding is not forthcoming, the Group has alternative options available for the permits and wells. In assessing alternative arrangements, the Board has considered options such as deferral of permit commitments, new farm-outs or, alternatively, relinquishment of exploration permits. If permits are relinquished, the carrying value of relevant Exploration Assets could be impacted. The Board and management are confident alternative arrangements will be made and will not affect the Group's ability to continue as a going concern.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(a) Basis of Preparation (continued)

(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 2022 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.

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 K 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 FY2023 was assessed against estimated future cash flows from available 2P reserves over a 20-year period (refer Note 15).

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(a) Basis of Preparation (continued)

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.

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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED 30 JUNE 2023

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(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).

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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(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.

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 suffered impairment 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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(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.

(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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(n) Property, plant and Equipment – Development and Production Assets (continued)

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, 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.

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.

When an area of interest is abandoned or the Directors decide that it is not commercial, any accumulated costs in respect of that area are written off in the financial period the decision is made. Each area of interest is also reviewed at the end of each accounting period and accumulated costs written off to the extent that they will not be recoverable 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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(q) Goodwill (continued)

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.

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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(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 by Central Petroleum Limited.

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

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

(iv) Termination Benefits

Termination benefits are payable when employment is terminated by the Group before the normal retirement date, or when an employee accepts voluntary redundancy in exchange for these benefits.

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

(u) Contributed Equity

Ordinary shares are classified as equity. Incremental costs directly attributable to the issue of new shares or options are shown in equity as a deduction, net of tax, from the proceeds.

(v) Dividends

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

(w) Earnings Per Share

(i) Basic Earnings Per Share

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(w) Earnings Per Share (continued)

(ii) Diluted Earnings Per Share

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

(x) Goods and Services Tax (GST)

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

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

(y) Parent Entity Financial Information

The financial information for the Parent Entity, Central Petroleum Limited, disclosed in Note 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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(aa) Standards, Amendments and Interpretations

The Group has applied the following standards and amendments for the first time for their annual reporting period commencing 1 July 2022:

- AASB 2020-3 Amendments to Australian Accounting Standards – Annual Improvements 2018–2020 and Other Amendments [AASB 1, AASB 3, AASB 9, AASB 116, AASB 137 & AASB 141].

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

	2023 $'000	2022 $'000
Sale of hydrocarbon products - point in time		
Natural gas	34,731	36,255
Crude oil and condensate	3,488	5,896
Revenue released from Deferred Revenue in respect of 'take or pay' contracts[1]	1,036	—
Total revenue from contracts with customers	**39,255**	**42,151**

[1] Represents amounts paid for gas under take or pay 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.

(b) Contract Liabilities

	2023 Current $'000	**2023 Non-current $'000**	**2023 Total $'000**	2022 Current $'000	2022 Non-current $'000	2022 Total $'000
Deferred Revenue – take-or-pay contracts[1]	1,371	11,632	13,003	1,357	11,857	13,214
Deferred Revenue – other gas sales contracts[1]	2,165	—	2,165	3,952	1,757	5,709
Total contract liabilities	**3,536**	**11,632**	**15,168**	**5,309**	**13,614**	**18,923**

[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 2022	13,214	5,709	18,923
Revenue recognised from the delivery of gas	–	(4,114)	(4,114)
Revenue released from take or pay contracts	(1,036)	–	(1,036)
Gas paid for but not taken during the period	825	–	825
Finance charges	–	570	570
Carrying amount at 30 June 2023	**13,003**	**2,165**	**15,168**

3. OTHER INCOME

	2023 $'000	2022 $'000
Interest	533	63
Income from financial assets at amortised cost	304	665
Income from the farmout of exploration interests (a)	795	—
Profit on disposal of 50% of interests in Amadeus Basin producing properties (b)	—	36,559
Profit on disposal of inventory and other assets	248	13
Total other income	**1,880**	**37,300**

(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 has been recorded as Other Income in the current financial year relating to the farmout of exploration interests. This amount reflects reimbursement amounts relating to prior financial year exploration expenditure and reductions in rehabilitation obligations previously expensed.

(b) Disposal of 50% interest in Amadeus Basin producing properties

On 1 October 2021, the Group completed the sale of 50% of the Group's interests in its Amadeus Basin producing assets to New Zealand Oil and Gas Limited and Cue Energy Resources Limited. The Group recognised an accounting profit after tax of $36,559,000 in FY 2022 comprised as follows:

	2022 $'000
Cash consideration received, net of adjustments from effective date to completion date and net of cash included in disposal	29,561
Transaction costs	(1,256)
Net cash received	28,305
Fair Value of deferred consideration receivable post completion	29,849
Total consideration net of transaction costs	**58,154**
Carrying value of non-cash assets disposed	(62,512)
Carrying value of liabilities directly associated with assets disposed and included in the disposal	40,917
Profit on disposal (after tax)	**36,559**

4. EXPENSES

Refer Note 1(a) regarding the restatement of FY2022 comparatives as a result of changing presentation of expenses from by nature to by function.

(a) Cost of sales includes the following specific expenses

	NOTE	**2023 $'000**	2022 Restated $'000
Depreciation and amortisation	4(d)	6,295	6,094
Employee and contractor costs	4(f)	5,326	6,045
Gas purchases		4,416	4,041
Other production costs		5,073	4,969
Royalties		2,938	3,088
Transportation and storage		2,360	3,114
Total cost of sales		**26,408**	**27,351**

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

	NOTE	**2023 $'000**	2022 Restated $'000
Depreciation and amortisation	4(d)	571	685
Employee and contractor costs		1,650	1,232
Share based payments		820	1,524
Other costs		1,756	1,405
Total general and administrative expenses		**4,797**	**4,846**

(c) Finance costs include the following specific expenses

	NOTE	**2023 $'000**	2022 $'000
Interest and fees on debt facilities		2,998	2,394
Interest on lease liabilities	11(b)	49	78
Amortisation of deferred finance costs		342	—
Accretion charges		1,408	1,815
Total finance costs		**4,797**	**4,287**

4. EXPENSES (CONTINUED)

(d) Total Depreciation and amortisation

	NOTE	2023 $'000	2022 $'000
Depreciation			
Buildings	10	175	176
Producing assets	10	3,371	3,384
Plant and equipment	10	2,752	2,582
Leasehold improvements	10	10	16
Right of use assets	11(b)	442	521
Total depreciation		**6,750**	**6,679**
Amortisation			
Other intangible assets - software	13	116	100

(e) Exploration-related impairment expense

Impairment expenses of $3,486,000 (FY2022: Nil) are included in exploration expenditure and relate to the following:

Exploration Assets

The Group intends to relinquish its interest in RL3 and RL4 and, as a result, has recognised the impairment of exploration assets during the year amounting to $398,000 (Note 12).

Farmout Receivables

There is a risk that Peak Helium (Amadeus Basin) Pty Ltd ("Peak") may not be able to fund obligations under its various farmin arrangements. As a result, the Group has recorded an impairment expense of $3,088,000 in respect of amounts due by Peak for reimbursement of past costs.

(f) Government Grants

No subsidies were received in the current financial year. During the previous financial year $11,000 was received from the Northern Territory Government as training incentives for operational staff and recognised against net employee costs.

(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

	2023 $'000	2022 $'000
Current tax	—	—
Deferred tax	—	—
Income tax expense	**—**	**—**

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

	2023 $'000	2022 $'000
(Loss)/profit before income tax expense	(7,960)	21,320
Prima facie tax benefit/(expense) at 30% (2022: 30%)	2,388	(6,396)
Tax effect of amounts which are not deductible in calculating taxable income:		
Non-deductible expenses	(8)	(4)
Share based payments	(246)	(457)
Other items	—	(16)
Sub-total	2,134	(6,873)
Previously unrecognised deferred tax assets	—	6,873
Deferred tax assets not recognised	(2,134)	—
Income tax expense	**—**	**—**

(c) Amounts recognised directly in equity

	2023 $'000	2022 $'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

	2023 $'000	2022 $'000
Unutilised tax losses for which no deferred tax asset has been recognised	142,134	139,120
Potential tax benefit at 30%	**42,640**	**41,736**

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

	2023 $'000	2022 $'000
Deferred tax assets		
Provisions and accruals	9,788	9,507
Receivables	926	—
Deferred revenue	187	372
Other expenditure	253	125
Borrowing costs	140	68
Unutilised losses	51,936	51,222
Total deferred tax assets before set-offs	63,230	61,294
Set-off of deferred tax liabilities pursuant to set-off provisions	(9,296)	(9,487)
Net deferred tax assets not recognised	**53,934**	**51,807**
Movements in deferred tax assets		
Opening balance at 1 July	9,487	10,963
Charged to the income statement	(191)	(1,476)
Closing balance at 30 June	**9,296**	**9,487**
Deferred tax assets to be recovered after more than 12-months	6,241	7,248
Deferred tax assets to be recovered within 12-months	3,055	2,239
	9,296	**9,487**
Deferred tax liabilities		
Capitalised exploration	2,362	2,475
Property, plant and equipment	6,929	7,012
Other items	5	—
Total deferred tax liabilities before set-offs	9,296	9,487
Set-off of deferred tax assets pursuant to set-off provisions	(9,296)	(9,487)
Net deferred tax liabilities	—	—
Movements in deferred tax liabilities		
Opening balance at 1 July	9,487	10,963
Credited to the income statement	(191)	(1,476)
Closing balance at 30 June	**9,296**	**9,487**
Deferred tax liabilities to be recovered after more than 12-months	9,173	9,487
Deferred tax liabilities to be recovered within 12-months	123	—
	9,296	**9,487**

6. REMUNERATION OF AUDITORS

	2023 $	2022 $
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	227,684	210,745
(ii) Taxation services		
Income tax compliance	14,280	9,588
Other tax related services	47,512	10,579
Total taxation services	61,792	20,167
Total remuneration of PwC	**289,476**	**230,912**

7. CASH AND CASH EQUIVALENTS

	2023 $000	2022 $000
Cash and cash equivalents	**13,826**	**21,647**
Made up as follows:		
Corporate cash and bank balances (a)	13,296	20,577
Joint arrangements (b)	530	1,070
Total cash and cash equivalents	**13,826**	**21,647**

(a) $2,920,000 of this balance relates to cash held with Macquarie Bank Limited to be used for allowable purposes under the Facility Agreement (2022: $4,725,000), 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.

(i) Risk exposure

The Group's exposure to credit and interest rate risk is discussed in Note 32.

8. TRADE AND OTHER RECEIVABLES

	2023 $'000	2022 $'000
Current		
Trade debtors	55	639
Accrued income and recoveries (a)	3,963	3,533
Other receivables	545	578
Prepayments	1,361	1,302
Items measured at amortised cost:		
Deferred receivable from partial sale of producing assets (b)	751	20,820
	6,675	**26,872**

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 (refer Note 3(b)). This is classified as a Financial Asset measured at amortised cost. During the year, $20,373,000 was recouped through a free carry by the purchasers of Central's share of expenditure on certain exploration and development projects (2022: $9,695,000). An amount of $304,000 (2022: $665,000) was recognised as Other Income as a result of adjustments to amortised cost for the period.

9. INVENTORIES

	2023 $'000	2022 $'000
Crude oil and natural gas	108	45
Spare parts and consumables	1,412	1,228
Drilling materials and supplies at cost	2,030	2,595
	3,550	**3,868**

10. PROPERTY, PLANT AND EQUIPMENT

	Freehold Land and Buildings $'000	Producing Assets $'000	Plant and Equipment $'000	Total $'000
Year ended 30 June 2022				
Opening net book amount	930	33,873	19,185	53,988
Additions	—	6,145	3,908	10,053
Changes to rehabilitation estimates	—	(278)	3	(275)
Disposals and write offs	—	(2,984)	(778)	(3,762)
Depreciation charge	(176)	(3,384)	(2,598)	(6,158)
Closing net book amount	**754**	**33,372**	**19,720**	**53,846**
At 30 June 2022				
Cost	1,952	56,264	43,327	101,543
Accumulated depreciation	(1,198)	(22,892)	(23,607)	(47,697)
Net book amount at 30 June 2022	**754**	**33,372**	**19,720**	**53,846**
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**

At 30 June 2023, $2,891,000 of property plant and equipment balances relates to assets under construction and is not subject to depreciation until complete (2022: $2,011,000).

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:

	2023 $'000	2022 $'000
Right-of-use assets		
Land & Buildings	483	832
Plant & Equipment	68	90
	551	**922**
Lease Liabilities		
Current	426	413
Non-current	201	588
	627	**1,001**

Additions to the right-of-use assets during the 2023 financial year were $77,000 (2022: $24,000). Disposals and incentive adjustments amounted to $6,000 (2022: $36,000).

At 30 June 2023, the Group has entered into Leases which have not yet commenced. The total expected future cash outflows which the Group is committed to in respect of those leases amounts to $59,000 over a period of 36 months from the commencement date.

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

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

	2023 $'000	2022 $'000
Depreciation charge of right-of-use assets		
Land & Buildings	373	367
Plant & Equipment	69	154
Total depreciation of right-of-use assets	**442**	**521**
Interest expense	49	78
Expense related to short term leases included in cost of sales and general and administrative expenses	—	—

The total cash outflow for leases in 2023 was $493,000 (2022: $638,000).

(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. 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

	2023 $'000	2022 $'000
Acquisition costs of right to explore	**7,999**	**8,397**
Movement for the year:		
Balance at the beginning of the year	8,397	8,397
Impairment expense (Note 4(e))	(398)	—
Balance at the end of the year	**7,999**	**8,397**

13. OTHER INTANGIBLE ASSETS

	2023 $'000	2022 $'000
Software		
At the beginning of the year		
Cost	1,025	848
Accumulated amortisation	(646)	(546)
Net book value	**379**	**302**
Movements for the year		
Opening net book amount	379	302
Additions	69	177
Amortisation	(116)	(100)
Reclassified as held for sale	—	—
Closing net book amount	**332**	**379**
At the end of the year		
Cost	1,094	1,025
Accumulated amortisation	(762)	(646)
Net book value	**332**	**379**

14. OTHER FINANCIAL ASSETS

	2023 $'000	2022 $'000
Non-Current		
Security bonds on exploration permits and rental properties	**3,053**	**4,410**

Security bonds are provided to State or Territory governments in respect of certain performance obligations arising from awarded petroleum and mineral tenements. The bonds are typically provided as cash or as bank guarantees in favour of the State or Territory government 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

	2023 $'000	2022 $'000
Goodwill arising from business combinations	**1,953**	**1,953**

Impairment tests for goodwill and property, plant and equipment

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

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

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

2023	Producing Assets
Sales volumes	2P Reserves
Sales price (% annual growth rate)	2.5 – 4.1%
Operating costs (% annual growth rate)	2.5 – 4.1%
Post-tax discount rate (%)	11.00%

15. GOODWILL (CONTINUED)

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

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

16. TRADE AND OTHER PAYABLES

	2023 $'000	2022 $'000
Current		
Trade payables	878	7,817
Other payables	5	4
Accruals	2,126	5,705
	3,009	**13,526**

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

		2023 $'000	2022 $'000
(a)	Current[1]		
	Debt facilities	4,376	4,500
(b)	Non-current[1]		
	Debt facilities	23,150	26,309

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

18. PROVISIONS

	2023			2022		
	Current $'000	Non-Current $'000	Total $'000	Current $'000	Non-Current $'000	Total $'000
Employee entitlements (a)	4,365	763	5,128	4,043	878	4,921
Restoration and rehabilitation (b)	370	24,460	24,830	1,512	22,120	23,632
Joint Venture production over-lift (c)	862	1,593	2,455	770	2,182	2,952
	5,597	**26,816**	**32,413**	**6,325**	**25,180**	**31,505**

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

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

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

Movements in Provisions

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

2023	Employee Entitlements $'000	Restoration & Rehabilitation $'000	Joint Venture Production Over-Lift $'000	Total $'000
Carrying amount at start of year	4,921	23,632	2,952	31,505
Change in provision charged/(credited) to property, plant and equipment	—	(158)	—	(158)
Additional provisions charged to profit or loss	3,023	644	296	3,963
Unwinding of discount	—	837	—	837
Amounts used during the year	(2,816)	(125)	(793)	(3,734)
Carrying amount at end of year	**5,128**	**24,830**	**2,455**	**32,413**

19. CONTRIBUTED EQUITY

(a) Share capital

	2023 $'000	2022 $'000
729,405,268 fully paid ordinary shares (2022: 725,907,449)	**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

	2023 Number of Shares	2022 Number of Shares	**2023 $'000**	2022 $'000
Balance at start of year	725,907,449	724,093,661	197,776	197,776
Shares issued under Employee Incentive Plans	3,497,819	1,813,788	—	—
Balance at end of year	**729,405,268**	**725,907,449**	**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 subsequently 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 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	03 Oct 2022	1 Jul 2017	6,849	—	—	(6,849)	—
Employee LTIP rights	22 May 2024	1 Jul 2018	353,405	—	(11,893)	(268,635)	72,877
Employee LTIP rights	12 Nov 2024	1 Jul 2018	578,689	—	—	—	578,689
Employee LTIP rights	30 Jun 2024	1 Jul 2019	6,308,318	—	(3,455,606)	(2,533,679)	319,033
Employee Deferred Share rights[1]	30 Jun 2025	1 Jul 2019	3,692,054	—	(331,483)	—	3,360,571
Employee LTIP rights	30 Jun 2025	1 Jul 2020	9,074,800	—	(373,731)	—	8,701,069
Employee LTIP rights	30 Jun 2026	1 Jul 2021	426,192	61,476	(112,767)	—	374,901
Employee LTIP rights	30 Jun 2027	1 Jul 2022	—	540,992	(33,812)	—	507,180
Executive Incentive Plan							
EIP Share Rights	30 Jun 2027	1 Jul 2021	—	8,739,398	(925,927)	—	7,813,471
Non-Executive Director rights [2]							
Director Share Rights	30 Jun 2026	1 Jul 2021	850,421	—	—	(688,656)	161,765
Director Share Rights	30 Jun 2027	1 Jul 2022	—	924,971	—	—	924,971
Total			**21,290,728**	**10,266,837**	**(5,245,219)**	**(3,497,819)**	**22,814,527**

[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 have 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

	2023 $'000	2022 $'000
Share options reserve	**31,433**	**30,615**
Movements:		
Balance at start of year	30,615	29,094
Share based payment costs (a)	820	1,524
Transaction costs	(2)	(3)
Balance at end of year	**31,433**	**30,615**

(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.

21. ACCUMULATED LOSSES

	2023 $'000	2022 $'000
Movements in accumulated losses were as follows:		
Balance at the start of year	(201,861)	(223,181)
Net (loss)/profit for the year	(7,960)	21,320
Balance at end of year	**(209,821)**	**(201,861)**

22. EARNINGS/(LOSS) PER SHARE

		2023	2022
(a)	**Basic (loss)/earnings per share (cents)**	**(1.09)**	2.94
(b)	**Diluted (loss)/earnings per share (cents)**	**(1.09)**	2.88
(c)	**(Loss)/Profit used in earnings per share calculation**		
	(Loss)/Profit attributed to ordinary equity holders ($'000)	**(7,960)**	21,320
(d)	**Weighted average number of ordinary shares**		
	Weighted average number of shares used as the denominator in calculating basic loss/earnings per share	**728,113,749**	**725,363,955**
	Adjustments for the calculation of diluted loss/earnings per share:		
	Employee share rights	—	15,343,575
	Weighted average number of shares used as the denominator in calculating diluted loss/earnings per share	**728,113,749**	**740,707,530**

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)

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 and amortisation expense	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	**72,694**	**11,618**	**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.

23. SEGMENT REPORTING (CONTINUED)

(e) Performance monitoring and evaluation (continued)

2022[4]	Producing Assets 2022 $'000	Exploration Assets 2022 $'000	Unallocated Items 2022 $'000	Consolidation 2022 $'000
Revenue from contracts with customers				
Natural gas	36,255	—	—	36,255
Crude oil and condensate	5,896	—	—	5,896
Total revenue from contracts with customers	**42,151**	**—**	**—**	**42,151**
Cost of sales	(27,351)	—	—	(27,351)
Gross profit	**14,800**	**—**	**—**	**14,800**
Other income[1]	37,227	10	—	37,237
Exploration expenditure	(15,748)	(5,899)	—	(21,647)
Finance costs	(3,963)	(41)	(220)	(4,224)
General and administrative expenses[2]	—	—	(4,846)	(4,846)
Statutory profit / (loss) before income tax	**32,316**	**(5,930)**	**(5,066)**	**21,320**
Taxes	—	—	—	—
Statutory profit / (loss) for the year	**32,316**	**(5,930)**	**(5,066)**	**21,320**
Add Finance costs net of interest income	3,962	41	221	4,224
Add Depreciation and amortisation	6,095	—	684	6,779
Add Exploration expenditure	15,748	5,899	—	21,647
EBITDAX[3]	**58,121**	**10**	**(4,161)**	**53,970**
Segment assets	**91,954**	**13,038**	**17,302**	**122,294**
Segment liabilities	**(73,212)**	**(13,741)**	**(8,811)**	**(95,764)**
Capital expenditure				
Property, plant and equipment	9,695	—	358	10,053
Intangibles	122	—	55	177
Total capital expenditure	**9,817**	**—**	**413**	**10,230**

1 Other income in the Producing Assets segment includes $36,559,000 profit on disposal of 50% interest in Amadeus Basin producing properties (Refer Note 3(b)).
2 Includes share based payments of $1,524,000 which is a non-cash item.
3 EBITDAX is earnings before interest, taxation, depreciation, amortisation, impairment and exploration expense.
4 FY2022 restated to reflect expenses by function (refer Note 1(a)).

	2023 $'000	2022 $'000
Revenue from external customers by geographical location of production:		
Australia	**39,255**	**42,151**
Non-current assets by geographical location:		
Australia	**74,080**	**69,907**

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.

	2023 $'000	**% of Sales Revenue**	2022 $'000	% of Sales Revenue
Largest customer	15,068	38%	13,622	32%
Second largest customer	5,762	15%	7,850	19%
Third largest customer	4,183	11%	6,478	15%
Fourth largest customer	3,923	10%	4,478	11%
Fifth largest customer	—	—	4,414	10%

24. PARENT ENTITY INFORMATION

(a) Summary financial information

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

	2023 $'000	2022 $'000
Balance Sheet		
Current assets	15,098	23,128
Non-current assets	18,311	19,162
Total assets	33,409	42,290
Current liabilities	(6,609)	(18,129)
Non-current liabilities	(1,144)	(1,550)
Total liabilities	(7,753)	(19,679)
Net assets	**25,656**	**22,611**
Shareholders' equity		
Issued capital	197,776	197,776
Reserves	31,433	30,615
Accumulated losses	(203,553)	(205,780)
Total equity	**25,656**	**22,611**
Profit/(loss) for the year	**2,227**	**(223)**
Total comprehensive profit/(loss)	**2,227**	**(223)**

(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	**2023 %**	2022 %
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	Western Australia	Ordinary	100	100
Central Geothermal Pty Ltd	Western Australia	Ordinary	100	100
Central Petroleum Services Pty Ltd	Western Australia	Ordinary	100	100
Central Petroleum PVD Pty Ltd	Queensland	Ordinary	100	100
Central Petroleum (NT) Pty Ltd	Queensland	Ordinary	100	100
Jarl Pty Ltd	Queensland	Ordinary	100	100
Central Petroleum Mereenie Pty Ltd	Queensland	Ordinary	100	100
Central Petroleum Mereenie Unit Trust	N/A	Units	100	100
Central Petroleum WS (NO 1) Pty Ltd	Queensland	Ordinary	100	100
Central Petroleum WS (NO 2) Pty Ltd	Queensland	Ordinary	100	100

(c) Key management personnel compensation

	2023 $	2022 $
Short-term employee benefits	2,944,399	3,531,962
Post-employment benefits	165,023	180,208
Long-term benefits	37,775	43,807
Share based payments	520,613	1,158,763
	3,667,810	**4,914,740**

Detailed remuneration disclosures are provided in the remuneration report on pages 33 to 48.

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 Eastern 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 2023.

	2023 $'000	2022* $'000
Revenue from the sale of goods	20,783	13,645
Cost of sales	(15,952)	(8,641)
Gross profit	4,831	5,004
Other income	1,854	29,875
Exploration expenses	(13,011)	(21,647)
Finance costs	(1,626)	(1,740)
General and administrative expenses	(4,376)	(4,291)
(Loss)/profit before income tax	(12,328)	7,201
Income tax credit/(expense)	1,567	(10)
(Loss)/Profit for the year	(10,761)	7,191
Other comprehensive profit/(loss) for the year, net of tax	—	—
Total comprehensive (loss)/profit for the year	**(10,761)**	**7,191**
Accumulated losses at the beginning of the financial year	(210,853)	(218,044)
(Loss)/profit for the year	(10,761)	7,191
Accumulated losses at the end of the financial year	**(221,614)**	**(210,853)**

* FY2022 restated to reflect expenses by function (refer Note 1(a)).

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.

	2023 $'000	2022 $'000
ASSETS		
Current assets		
Cash and cash equivalents	13,718	21,410
Trade and other receivables	4,806	21,557
Inventories	2,613	3,075
Total current assets	21,137	46,042
Non-current assets		
Property, plant and equipment	30,323	24,997
Right of use assets	512	858
Exploration assets	7,999	8,397
Other intangible assets	265	314
Other financial assets	2,259	2,728
Deferred Tax Assets	5,178	5,064
Goodwill	1,953	1,953
Total non-current assets	48,489	44,311
Total assets	**69,626**	**90,353**
LIABILITIES		
Current liabilities		
Trade and other payables	14,113	22,958
Deferred revenue	1,006	992
Borrowings	2,639	2,821
Lease liabilities	396	386
Provisions	4,508	5,098
Total current liabilities	22,662	32,255
Non-current liabilities		
Deferred revenue	11,572	11,824
Borrowings	12,163	14,266
Lease liabilities	186	543
Provisions	15,448	13,927
Total non-current liabilities	39,369	40,560
Total liabilities	**62,031**	**72,815**
Net assets	**7,595**	**17,538**
EQUITY		
Contributed equity	197,776	197,776
Reserves	31,433	30,615
Accumulated losses	(221,614)	(210,853)
Total equity	**7,595**	**17,538**

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

	2023 $'000	2022 $'000
Profit after income tax	**(7,960)**	**21,320**
Adjustments for:		
Depreciation and amortisation	6,866	6,779
Impairment	3,486	—
Lease incentive	—	30
Profit on disposal of assets	—	(36,559)
Exploration costs funded by Joint Venture partners	7,421	7,572
Share-based payments	820	1,524
Financing costs and interest (non-cash)	1,641	1,150
Changes in assets and liabilities relating to operating activities:		
Decrease in trade and other receivables	129	358
Decrease/(increase) in inventories	317	(2,330)
(Decrease)/increase in trade and other payables	(10,681)	7,781
Decrease in deferred revenue	(4,324)	(4,155)
Increase in provisions	229	170
Net cash (outflow)/inflow from operations	**(2,056)**	**3,640**

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 $9,863,000 (2022: $2,040,000) of the Group's share of costs for the acquisition of property, plant and equipment. These amounts form part of the deferred consideration component of the sale proceeds (refer Note 3 (b)).

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 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 debt

	2023 $'000	2022 $'000
Cash and cash equivalents (including cash classified as held for sale)	13,826	21,647
Borrowings and leases – repayable within one year	(4,802)	(4,913)
Borrowings and leases – repayable after one year	(23,351)	(26,897)
Net debt	**(14,327)**	**(10,163)**
Cash	13,826	21,647
Gross Debt – fixed interest rates	(627)	(1,001)
Gross debt – variable interest rates	(27,526)	(30,809)
Net debt	**(14,327)**	**(10,163)**

28. CASH FLOW INFORMATION (CONTINUED)

(b) Net debt reconciliation (continued)

Movement in Net Debt

	Other Assets	Liabilities from Financing Activities		
	Cash $'000	Borrowings $'000	Leases $'000	Total $'000
Net debt 1 July 2021	**37,165**	**(66,809)**	**(1,659)**	**(31,303)**
Cash flows	(15,518)	36,000	561	21,043
Other non-cash movements	—	—	97	97
Net debt 30 June 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 debt 30 June 2023	**13,826**	**(27,526)**	**(627)**	**(14,327)**

29. CONTINGENCIES

(a) Contingent liabilities

(i) Exploration Permits

The Consolidated Entity had contingent liabilities at 30 June 2023 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 (2022: $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.

Under the resulting business combination transaction, a fair value of Nil was ascribed to this contingent liability. No change has been made to the fair value in subsequent years.

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. Based on current reserves and production profiles for the Palm Valley Gas Field, and current Northern Territory gas market conditions, it is not anticipated that a gas price bonus will be payable over the relevant term and have therefore ascribed a $nil value to this contingent liability. Should access to additional reserves and significantly higher priced markets eventuate, this contingent liability will be reviewed. Importantly, any future payment of the Gas Price Bonus would only occur where sales and revenues from the Palm Valley gas field materially exceed Central's acquisition assumptions.

30. COMMITMENTS

(a) Capital commitments

	2023 $'000	2022 $'000
The Consolidated Entity has the following capital expenditure commitments:		
The following amounts are due:		
Within one year	1,241	982
	1,241	**982**

(b) Exploration commitments

	2023 $'000	2022 $'000
The Consolidated Entity has the following minimum exploration expenditure commitments:		
The following amounts are due:		
Within one year	11,200	39,398
Later than one year but not later than three years	18,454	38,799
Later than three years but not later than five years	—	—
	29,654	**78,197**

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
2023								
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**	**—**			**—**	**$0.20**	**—**
2022								
20 Aug 2019	30 Jun 2023	13,046,116	—	$0.20	$0.120	(930,070)	12,116,046	—
07 Nov 2019	30 Jun 2023	5,105,000	—	$0.20	$0.087	—	5,105,000	—
Totals		**18,151,116**	**—**		**$0.111**	**(930,070)**	**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 weighted average remaining contractual life at 30 June 2023 was Nil years (2022: 1 year). The values of Executive Options were calculated at the date of grant using a Black Scholes valuation.

31. SHARE BASED PAYMENTS (CONTINUED)

(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.

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
2023							
11 Nov 2020	30 Jun 2020[1]	3,692,054	—	$0.130	—	(331,483)	3,360,571
2022							
11 Nov 2020	30 Jun 2020[1]	3,692,054	—	$0.130	—	—	3,692,054

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

The weighted average remaining contractual life of outstanding STIP share rights at the end of the year was 2.0 years (2022: 3.0 years).

(c) Rights to shares — Non-Executive Directors Offer

Under the Non-Executive Director offers for FY2023 and FY2022, 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	Exercised During the Year	Cancelled or Forfeited During the Year	Vested and exercisable at End of Year
2023							
23 Nov 2022	30 Jun 2023	850,421	924,971	$0.084	(688,656)	—	1,086,736
2022							
23 Nov 2021	30 Jun 2022	—	850,421	$0.115		—	850,421

The weighted average remaining contractual life of outstanding Non-Executive Director share rights at the end of the year was 3.9 years (2022: 4.0 years).

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

From FY2022, Key Management Personnel were eligible to participate in the EIP, an integrated incentive plan with both short term and long term components. The value of the EIP that is awarded is determined at the end of the first 12-month performance period upon measurement of performance against Board established KPI targets for that year. The incentive awarded is then split into two components:

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

The number of Service Rights awarded for any single Plan Year 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:

							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
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

31. SHARE BASED PAYMENTS (CONTINUED)

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

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

At 30 June 2023, no rights had been granted under the EIP for the plan year ended 30 June 2023. Share rights, as part of the FY2023 EIP are expected to be granted during FY2024. 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:

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**

The weighted average fair value of share rights granted under the Long Term Incentive Plan during the year was $0.09 (2022: $0.105). The weighted average remaining contractual life of outstanding share rights at the end of the year was 2.1 years (2022: 2.7 years).

The fair values of deferred share rights granted are valued using methodology that takes into account market and peer 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.

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 Forfeited During the Year	Balance at End of Year
2022							
17 Aug 2021	30 Jun 2022	—	450,780	$0.105	—	(24,588)	426,192
18 Sep 2020	30 Jun 2018	1,198	—	$0.130	—	—	1,198
24 Jul 2020	30 Jun 2021	9,417,632	—	$0.065	—	(796,972)	8,620,660
24 Jul 2020	30 Jun 2021	499,488	—	$0.089	—	(45,348)	454,140
24 Jul 2020	30 Jun 2020	30,545	—	$0.089	—	—	30,545
07 Nov 2019	30 Jun 2019	1,837,109	—	$0.119	—	(1,258,420)	578,689
23 Aug 2019	30 Jun 2020	311,019	—	$0.190	—	(36,900)	274,119
23 Aug 2019	30 Jun 2020	6,480,842	—	$0.155	—	(477,188)	6,003,654
09 May 2019	30 Jun 2019	756,584	—	$0.101	(31,848)	(696,724)	28,012
17 Apr 2019	30 Jun 2019	28,793	—	$0.111	(9,069)	(19,724)	—
17 Apr 2019	30 Jun 2019	2,566	—	$0.150	(2,566)	—	—
24 Sep 2019	30 Jun 2019	5,176,154	—	$0.087	(1,549,532)	(3,367,216)	259,406
24 Sep 2019	30 Jun 2019	292,883	—	$0.120	(220,773)	(6,123)	65,987
01 Sep 2017	30 Jun 2018	12,500	—	$0.115	—	(6,849)	5,651
Totals		**24,847,313**	**450,780**		**(1,813,788)**	**(6,736,052)**	**16,748,253**

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

(f) Expenses arising from share-based payment transactions

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

	2023 $	2022 $
Share Rights issued to employees	**820,165**	**1,524,197**

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 2023 is nil (2022: nil), no loss allowance provision has been recorded at 30 June 2023 (2022: nil).

The Group has impaired a receivable amounting to $3,088,000 (2022: nil) which arose during the financial year in relation to the farmout of interests in certain exploration assets. Further details are set out in Note 4(e).

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.

32. FINANCIAL RISK MANAGEMENT (CONTINUED)

(a) Credit Risk (continued)

The aging of the Consolidated Entity's trade receivables at reporting date was:

Trade receivables	Gross 2023 $'000	Gross 2022 $'000	Expected Credit Loss Provision 2023 $'000	Expected Credit Loss Provision 2022 $'000
Current: 0-30 days	**4,563**	4,750	—	—
	4,563	**4,750**	**—**	**—**

The trade receivables at 30 June 2023 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.

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

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)

(b) Liquidity Risk (continued)

2022 ($'000)	≤ 6 Months	6–12 Months	1–5 Years	≥ 5 Years	Contractual Cash Flow	Carrying Amount
Financial Assets						
Cash and cash equivalents	21,647	—	—	—	21,647	21,647
Trade and other receivables	25,252	621	—	—	25,873	25,570
Other financial assets	—	—	4,410	—	4,410	4,410
	46,899	**621**	**4,410**	**—**	**51,930**	**51,627**
Financial Liabilities						
Trade and other payables	(13,526)	—	—	—	(13,526)	(13,526)
Interest bearing liabilities	(3,706)	(3,644)	(30,495)	(68)	(37,913)	(31,810)
	(17,232)	**(3,644)**	**(30,495)**	**(68)**	**(51,439)**	**(45,336)**

(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	
	2023 %	2022 %	**2023 $'000**	2022 $'000	**2023 $'000**	2022 $'000	**2023 $'000**	2022 $'000	**2023 $'000**	2022 $'000
Financial Assets:										
Cash and cash equivalents	**4.2**	0.9	**13,826**	21,647	**—**	—	**—**	—	**13,826**	21,647
Trade and other receivables	**—**	—	**—**	—	**—**	—	**4,563**	4,750	**4,563**	4,750
Other financial assets	**0.7**	0.2	**—**	—	**528**	785	**2,525**	3,625	**3,053**	4,410
Total Financial Assets			**13,826**	**21,647**	**528**	**785**	**7,088**	**8,375**	**21,442**	**30,807**
Financial Liabilities:										
Trade and other payables	**—**	—	**—**	—	**—**	—	**(3,009)**	(13,526)	**(3,009)**	(13,526)
Interest bearing liabilities	**9.8**	7.3	**(27,526)**	(30,809)	**(627)**	(1,001)	**—**	—	**(28,153)**	(31,810)
Total Financial Liabilities			**(27,526)**	**(30,809)**	**(627)**	**(1,001)**	**(3,009)**	**(13,526)**	**(31,162)**	**(45,336)**
Net Financial Assets / (Liabilities)			**(13,700)**	**(9,162)**	**(99)**	**(216)**	**4,079**	**(5,151)**	**(9,720)**	**(14,529)**

32. FINANCIAL RISK MANAGEMENT (CONTINUED)

(c) Interest Rate Risk (continued)

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 and comparatives for 2022 have been restated on the same basis.

	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
2023 ($'000)				
Cash and cash equivalents	69	(69)	—	—
Interest bearing liabilities	(141)	141	—	—
2022 ($'000)				
Cash and cash equivalents	102	(102)	—	—
Interest bearing liabilities	(154)	154	—	—

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.

(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 by the sales of only Proved Developed Producing reserves, divided by the outstanding loan amount must be greater than 1.3:1.

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

(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:

32. FINANCIAL RISK MANAGEMENT (CONTINUED)

(f) Currency Risk (continued)

	2023 $'000	2022 $'000
Trade and other receivables (USD)	281	457
Trade and other payables:		
- USD	(46)	(1,082)
- 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.

	2023 $'000	2022 $'000
Australian dollar +10% movement in exchange rate	(13)	57
Australian dollar -10% movement in exchange rate	16	(69)

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	2023 %	2022 %
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	Oil & gas exploration	29.00	60.00
EP 105	Oil & gas exploration	60.00	60.00
EP 112	Oil & gas exploration	35.00	45.00
EP 125	Oil & gas exploration	24.00	30.00
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	Oil & gas exploration	50.00	50.00

The Joint Arrangements are accounted for 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 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:

	2023 $'000	2022 $'000
Current assets		
Cash and cash equivalents	530	1,070
Trade and other receivables	3,412	3,063
Inventory	3,161	3,300
Assets classified as held for sale	—	—
Total current assets	7,103	7,433
Non-current assets		
Property, plant and equipment	51,173	44,086
Right of use assets	88	113
Other financial assets	—	2,432
Total non-current assets	51,261	46,631
Current liabilities		
Trade and other payables	2,834	7,996
Lease liabilities	32	28
Deferred revenue	1,371	1,357
Provision for production over-lift	862	770
Restoration provision	300	1,445
Liabilities directly associated with assets classified as held for sale	—	—
Total current liabilities	5,399	11,596
Non-current liabilities		
Deferred revenue	11,632	11,857
Lease liabilities	68	96
Provision for production over-lift	1,594	2,182
Restoration provision	19,885	18,165
Total non-current liabilities	33,179	32,300
Net assets	**19,786**	**10,168**
Joint arrangement contribution to loss before tax		
Revenue	39,255	35,973
Other income	72	7
Expenses	(34,629)	(37,301)
Profit before income tax	**4,698**	**(1,321)**

34. EVENTS OCCURRING AFTER THE REPORTING PERIOD

In August 2023, the Group reached agreement to progress towards a final investment decision for construction of a helium recovery unit at Mereenie, demonstrating the potential of the Amadeus Basin as a world-class helium resource.

No matters or circumstances have arisen between 30 June 2023 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.

DIRECTORS' DECLARATION

1. In the Directors' opinion:

   a) the financial statements and notes set out on pages 51 to 97 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 2023 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; and

   c) 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 2023.

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

19 September 2023

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 2023 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 Group financial report comprises:

- the consolidated balance sheet as at 30 June 2023
- 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, which include significant accounting policies and other explanatory information
- 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.

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

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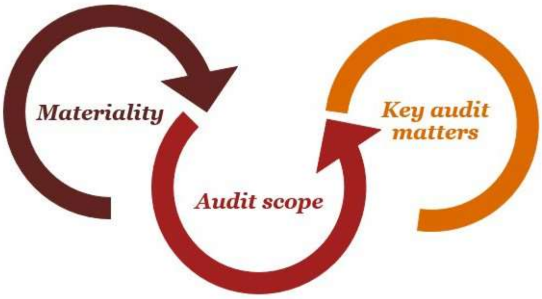
individually or in aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial report.

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.



Materiality	Audit scope
• For the purpose of our audit we used overall Group materiality of $0.98m, which represents approximately 1% of the Group's total assets. • We applied this threshold, together with qualitative considerations, to determine the scope of our audit and the nature, timing and extent of our audit procedures and to evaluate the effect of misstatements on the financial report as a whole. • We chose Group total assets because, in our view, it is the benchmark against which the performance of the Group is most commonly measured and is a generally accepted benchmark in the oil and gas industry for entities at a similar stage of development. • We utilised a 1% threshold based on our professional judgement, noting it is within the range of commonly acceptable thresholds.	• Our audit focused on where the Group made subjective judgements; for example, significant accounting estimates involving assumptions and inherently uncertain future events. • The Group produces oil and gas from its interests in fields in the Northern Territory and continues to conduct exploration and evaluation activities in respect of tenements located in the Northern Territory and Queensland.

Key audit matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial report for the current period. The key audit matters were addressed in the context of our audit of the financial report as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters. Further, any commentary on the outcomes of a particular audit procedure is made in that context. We communicated the key audit matters to the Audit and Financial Risk Committee.

Key audit matter	How our audit addressed the key audit matter
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 that the Group will continue to meet its commitments, realise its assets and settle its 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 funding 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).	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. • enquired of management and the board of directors as to their knowledge of events or conditions that may cast significant doubt on the Group's ability to continue as a going concern. • evaluated the Group's plans for future actions (including alternative options in relation to the current exploration permits), whether the outcome is likely to improve the situation and whether they 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 amount of the facility available for drawdown and projected debt compliance over the forecast period. • requested written representations from management regarding their plans for future action and the feasibility of these plans. • evaluated whether, in view of the requirements of Australian Accounting Standards, the financial report provides adequate disclosures about these events or conditions.

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 2023, 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 that gives a true and fair view in accordance with Australian Accounting Standards and the Corporations Act 2001 and for such internal control as the directors determine is necessary to enable the preparation of the financial report that gives a true and fair view and 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.

pwc

Report on the remuneration report

Our opinion on the remuneration report

We have audited the remuneration report included in pages 33 to 48 of the directors' report for the year ended 30 June 2023.

In our opinion, the remuneration report of Central Petroleum Limited for the year ended 30 June 2023 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	Brisbane
Partner	19 September 2023

ASX ADDITIONAL INFORMATION

DETAILS OF QUOTED SECURITIES AS AT 14 SEPTEMBER 2023

Top holders

The 20 largest registered holders of the quoted securities as at 14 September 2023 were:

	Name	No. of Shares	%
1	Norfolk Enchants Pty Ltd <Trojan Retirement Fund A/c>	37,500,000	5.14
2	UBS Nominees Pty Ltd	29,957,170	4.11
3	Moranbah Nominees Pty Ltd <Chris Wallin Super Fund A/C>	19,526,612	2.68
4	Brazil Farming Pty Ltd	17,785,209	2.44
5	Citicorp Nominees Pty Limited	16,371,468	2.24
6	Macquarie Bank Limited <Metals Mining and AG A/C>	14,166,667	1.94
7	Mr Philip Gasteen <Thrushton Investment A/C>	11,305,161	1.55
8	Chembank Pty Limited <Philandron A/C>	10,000,000	1.37
9	Kensington Capital Partners Pty Ltd	8,000,000	1.10
10	Mrs Faina Stolyar	7,929,577	1.09
11	JH Nominees Australia Pty Ltd <Harry Family Super Fund A/C>	7,840,268	1.07
12	J P Morgan Nominees Australia Pty Ltd	7,549,309	1.03
13	Justwright Investments Pty Ltd <Justwright Super Fund A/C>	7,000,000	0.96
14	PA and RE Gibson Pty Ltd <PA&RE Gibson Super Fund A/C>	7,000,000	0.96
15	Mr Peter Vrettos	6,412,406	0.88
16	Mr Donald Leonard Cottee	5,830,594	0.80
17	Chembank Pty Limited <CABAC Super Fund A/c>	5,512,544	0.76
18	Mr Stuart Francis Howes	5,000,701	0.69
19	Mr James Donald Bruce Cochrane + Mrs Joan Elizabeth Cochrane <Bruce & Joan Cochrane A/C>	5,000,001	0.69
20	Mr Chris Carr + Mrs Betsy Carr	5,000,000	0.69
20	Garmi Holdings Pty Ltd	5,000,000	0.69
20	Garmi Holdings Pty Ltd <Pemco Super Fund A/c>	5,000,000	0.69
20	Mr Peter Andrew Gibson + Mrs Robyn Elizabeth Gibson	5,000,000	0.69
	Total	**249,687,687**	**34.23**

DISTRIBUTION SCHEDULE

A distribution schedule of the number of holders in each class of equity securities as at 14 September 2023 was:

Size of holding	Listed fully paid shares	Unlisted share rights
1 – 1,000	724	1
1,001 – 5,000	1,664	1
5,001 – 10,000	906	12
10,001 – 100,000	2,237	43
100,001 – Over	877	27
Total	**6,408**	**84**

ASX ADDITIONAL INFORMATION

SUBSTANTIAL SHAREHOLDERS

Substantial shareholders as disclosed by notices received by the Company as at 13 September 2023 with holdings of 5% or more of the total votes attached to the voting shares or interests in the Entity:

Holder	Units
Troy Harry	55,000,000

UNMARKETABLE PARCELS

Holdings less than a marketable parcel of ordinary shares (being 9,434 shares as at 14 September 2023):

Holders	Units
3,036	9,477,401

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 2023 Corporate Governance Statement reflects the corporate governance practices in place throughout the 2023 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

Tenement	Location	Operator	CTP Consolidated Entity Registered Interest (%)	CTP Consolidated Entity Beneficial Interest (%)	Other JV Participants Participant Name	Other JV Participants Beneficial Interest (%)
EP82 (excl. EP82 Sub-Blocks) [1(a)]	Amadeus Basin NT	Santos	29	29	Santos QNT Pty Ltd ("Santos")	20
					Peak Helium (Amadeus Basin) Pty Ltd ("Peak")	51
EP82 Sub-Blocks	Amadeus Basin NT	Central	100	100		
EP105	Amadeus/Pedirka Basin NT	Santos	60	60	Santos	30
					Peak	10
EP112 [1(b)]	Amadeus Basin NT	Santos	35	35	Santos	30
					Peak	35
EP115	Amadeus Basin NT	Central	100	100		
EP125[1(c)]	Amadeus Basin NT	Santos	24	24	Santos	20
					Peak	56
OL3 (Palm Valley)	Amadeus Basin NT	Central	50	50	NZOG Palm Valley Pty Ltd	35
					Cue Palm Valley Pty Ltd	15
OL4 (Mereenie)	Amadeus Basin NT	Central	25	25	Macquarie Mereenie Pty Ltd	50
					NZOG Mereenie Pty Ltd	17.5
					Cue Mereenie Pty Ltd	7.5
OL5 (Mereenie)	Amadeus Basin NT	Central	25	25	Macquarie Mereenie Pty Ltd	50
					NZOG Mereenie Pty Ltd	17.5
					Cue Mereenie Pty Ltd	7.5
L6 (Surprise)	Amadeus Basin NT	Central	100	100		
L7 (Dingo)	Amadeus Basin NT	Central	50	50	NZOG Dingo Pty Ltd	35
					Cue Dingo Pty Ltd	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		
ATP2031 (Range Gas Project)	Surat Basin QLD	Central	50	50	Incitec Pivot Queensland Gas Pty Ltd	50

PERMITS AND LICENCES UNDER APPLICATION

Tenement	Location	Operator	CTP Consolidated Entity Registered Interest (%)	CTP Consolidated Entity Beneficial Interest (%)	Other JV Participants Participant Name	Other JV Participants Beneficial Interest (%)
EPA92	Wiso Basin NT	Central	100	100		
EPA111[3]	Amadeus Basin NT	Santos	100	50	Santos	30
					Peak	20
EPA124 [4]	Amadeus Basin NT	Santos	100	50	Santos	30
					Peak	20
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	Macquarie Mereenie Pty Ltd	50
					NZOG Mereenie Pty Ltd	17.5
					Cue Mereenie Pty Ltd	7.5
PL30	Amadeus Basin NT	Central	50	50	NZOG Dingo Pty Ltd	35
					Cue Dingo Pty Ltd	15

Notes:

[1] Completion of the farmout agreement with Peak Helium (Amadeus Basin) Pty Ltd (***Peak***) occurred on 31 March 2023. Upon completion, a partial transfer of Central's interest in three permits was made:

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

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

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

Peak's right to earn and retain interests in these permits remains subject to Peak satisfying its obligations under a farmout agreement announced to the ASX on 9 February 2022. Peak's interests as stated assume such obligations have been met, otherwise may be subject to change.

[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)
Bopd	barrel of oil per day
CSG	coal seam gas
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
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
Mr Troy Harry, Non-Executive Director
Ms Katherine Hirschfeld AM, BE(Chem), 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.