2022

ANNUAL REPORT

Central Petroleum

Central Petroleum Limited
ACN 083 254 308

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Cover photo: View from Palm Valley 12 drilling site by Phil Allen

Forward-looking statements:

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

CHAIR'S LETTER

Dear Shareholders,

When we recently began our growth-oriented exploration program, we knew that going down this path would not be without risk. This is why the program was designed with multiple wells targeting a variety of prospects.

So, while it is disappointing that we haven't had the success we had hoped for from our exploration program, there have also been a number of positive developments in the last year which bode well for the Company's future. In particular, gas markets have strengthened, providing opportunities for higher revenues and margins from our existing producing fields, and we have seen strong interest in the helium and hydrogen prospects of our Amadeus Basin permits, stimulating investment in these opportunities.

Not everyone was surprised by the turmoil that energy markets experienced this winter. The headlong rush towards renewable energy has exposed vulnerabilities in the market's ability to reliably meet demand for electricity. It was natural gas which filled the gaps and kept the lights on, demonstrating the critical role that gas will continue to play as the world transitions to a lower-carbon future.

Central is well-placed to contribute to Australia's energy security in coming years. From May, Central and its partners were able to supply gas into the critically short east coast markets through newly secured transportation arrangements. These market dynamics prompted us to re-assess our capital allocation priorities, replacing the Dingo exploration well with high-value projects which could increase near-term production capacity from our existing fields.

That Central had this flexibility is a reflection of our diverse portfolio and the steps taken to ensure availability of capital for new projects.

Our exploration portfolio continues to attract international interest and investment in its helium and hydrogen prospectivity, driving the Company forward on a potential new path for growth. The introduction of Peak Helium as a new partner in three permits will be the catalyst for a substantial new three well sub-salt exploration program, starting next year. Success at any of the three leads could prove to be company-changing, such is the prospective size of each target and the flow-on potential for additional leads throughout the Amadeus Basin.

Other opportunities for oil at Mamlambo and sub-salt exploration at the Zevon lead are attracting interest from potential partners and we hope to be able to add these to our exploration program in the near future.

It has been a year of much activity, and we could not have drilled the five wells without the support of our local stakeholders – we thank the landowners and Traditional Owners of the land on which we operate. We value these relationships and continue to provide employment and business opportunities locally while respecting and protecting the local environment.

I thank my colleagues on the Board, our CEO, Leon Devaney and all the staff at Central who have contributed to our resilience and continue to work hard to build a stronger company.

Stuart Baker stepped down from the Board in August and I thank him for his contribution since 2018. We also welcome Troy Harry to the Board as a Director, bringing with him significant experience in equity markets.

Our growth strategy remains in progress, and we have a number of potentially value-accretive activities underway that could deliver success in the near-term: production growth from the Palm Valley 12 well and recompletions and new wells at Mereenie; three sub-salt exploration wells in 2023/2024; testing of the Range CSG pilot; and a possible Mamlambo exploration well and seismic acquisition at Zevon.

We see our portfolio as being increasingly valuable in a tightening gas market and with rising interest in helium and hydrogen prospects. The Company's value in the equity market however doesn't appear to reflect this optimism, and the Board will engage an independent advisor to assist with a review of the Company's asset portfolio, capital structure and growth opportunities.

While we conduct this review, we will continue to advance the various programs that are in progress, and we look forward to sharing the outcome of the review with our shareholders in the coming year.

Thank you,

Mick McCormack, Chair

16 September 2022

CHIEF EXECUTIVE OFFICER'S LETTER

Dear Fellow Shareholders,

I'm pleased to present Central Petroleum's FY2022 Annual Report.

It has been a busy year which has seen Central make progress in several key growth strategies, balanced by a disappointing initial result from our exploration program.

A key catalyst for drilling activity this year was the completion of the sale of 50% of our Amadeus Basin producing assets, welcoming NZOG and Cue as new joint venture partners. The asset sale crystallised part of the value we have created in our operating assets, with a book profit of $36.6 million from assets acquired only six years earlier. The acquisition of those operating assets has been a great investment, with a return on equity after debt service of over 33% per annum.

The asset sale allowed us to pay down $29 million of debt and fund the Palm Valley 12 exploration / appraisal well, new and recompleted wells at Mereenie and further production enhancement at Mereenie next year.

The recompletions and new wells drilled at Mereenie in 2021 boosted aggregate Mereenie production to over 12 PJe for the year and allowed Central and its partners to lock in a new four-year gas sale agreement from 1 January 2022 at very attractive prices.

The additional production capacity at Mereenie, combined with new transport and spot trading arrangements from early May, enabled us to deliver uncontracted non-firm gas into eastern markets for the first time. This commercial milestone was well timed, as the last quarter saw a near perfect storm in energy markets with geopolitical issues, off-line coal fired generation and colder weather resulting in historically high pricing for electricity, gas and oil.

Over a three-month period to the end of July 2022 we supplied over 85 TJ (Central share) of gas into eastern spot markets at an average delivered price of $36/GJ, generating over $3 million in revenue from our uncontracted non-firm production. The strong spot market pricing has since eased, but this continuing access to east coast spot pricing will provide ongoing margin support.

The Palm Valley 12 exploration well spud in April and has proved to be one of the more difficult onshore drilling assignments faced by Central due to the existence of highly fractured sub-strata that required repeated and extensive plugging and cementing. Whilst our decision to swap the original deep target for a shallower target was appropriate given the cost and drilling circumstances, the P2/P3 appraisal was ultimately not successful. As had always been the strategy to create value, the PV12 well is now being sidetracked into the existing production reservoir in the P1 for completion as a production well. Nonetheless, the Palm Valley exploration result was disappointing as we had hoped to find a significant new volume of gas for sale into strong gas markets.

With the delays experienced at Palm Valley and the strong market dynamics supporting additional near-term production, we also made the tough decision to defer the planned Dingo well to direct investment to increasing near-term production. Deferral of deep exploration and pivoting to lower risk appraisal and development gives us the best opportunity to quickly and significantly increase near-term production.

With the deep in-field targets able to be explored at a later date, we turn our attention to the farmout arrangement with Peak Helium announced in February which is the catalyst for three major new sub-salt exploration wells in the Amadeus Basin, starting in 2023. These wells, including the much-anticipated Dukas well, are seeking to unlock potentially large volumes of natural gas, helium and naturally occurring hydrogen. This commitment to sub-salt exploration drilling in 2023 reflects the buoyant market for these gasses and demonstrates the enormous potential of our sub-salt prospects.

There is also the potential to work with new partners to fund additional exploration in our portfolio, including the Mamlambo oil prospect, which could open up a new oil play on the western flank of the Amadeus Basin, and the large Zevon sub-salt lead.

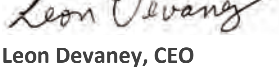
In Queensland, our Range CSG project continues to de-water, albeit at rates slower than initially anticipated. In order to increase our technical understanding of the permit, we drilled two new wells during the year and are currently conducting an extended three well production test. Gas flows are slowly building, and we will evaluate the results later this year in conjunction with a data swap covering neighbouring CSG permits.

Our producing assets continue to perform strongly. We booked $42.2 million of revenues, $16.7 million of underlying EBITDAX and a statutory profit of $21.3 million, inclusive of the $36.6 million profit on the partial asset sale which has also strengthened the balance sheet. Cash at year end was a healthy $21.6 million and net debt was reduced to $10.2 million. We also extended our debt facility for a further three years, with lower repayments, providing critical financial stability.

I thank our dedicated staff for their efforts in safely and efficiently operating our producing fields and for managing three separate drilling campaigns in challenging conditions. We farewell our GM Exploration, Dr Duncan Lockhart . I thank Duncan for his contribution to Central's exploration efforts over the past three years and wish him well in his future endeavours. I also thank our many stakeholders for their continued support throughout the year.

Although we didn't have initial success from our PV12 exploration well, it is important to keep this particular result in perspective. There remains much to look forward to, including a three well sub-salt campaign with enormous potential which will kick off within 12 months; the Range pilot continues to provide critical data; production enhancement programs are planned for Mereenie; and we are continuing to explore opportunities to progress new exploration at Mamlambo and Zevon.

Given the events over the past year, and subdued share price within a high energy market, the Board has initiated a review of our portfolio in order to ensure shareholders fully benefit from the value we create from our assets and we look forward to sharing this progress as it unfolds.



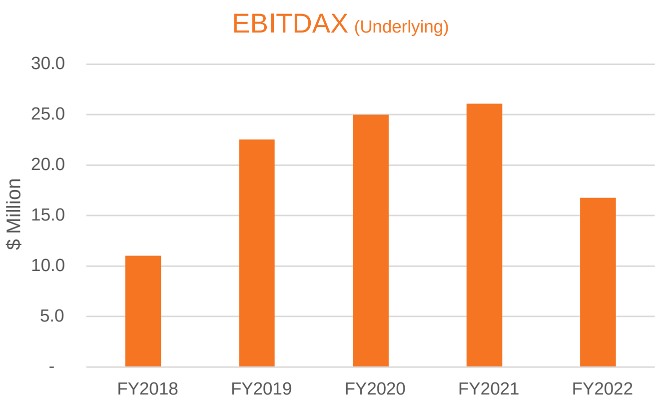
Leon Devaney, CEO

16 September 2022

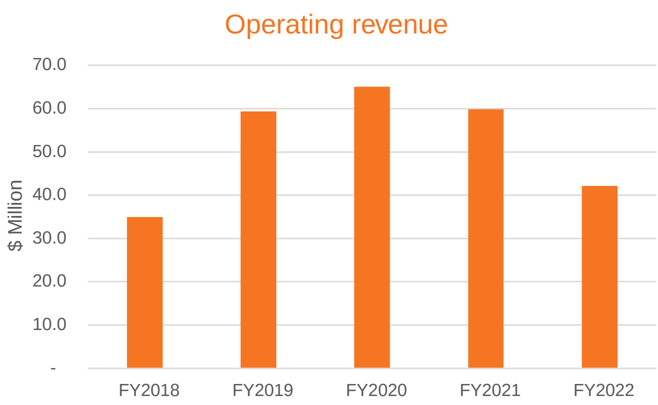
OPERATING AND FINANCIAL REVIEW

OPERATING HIGHLIGHTS

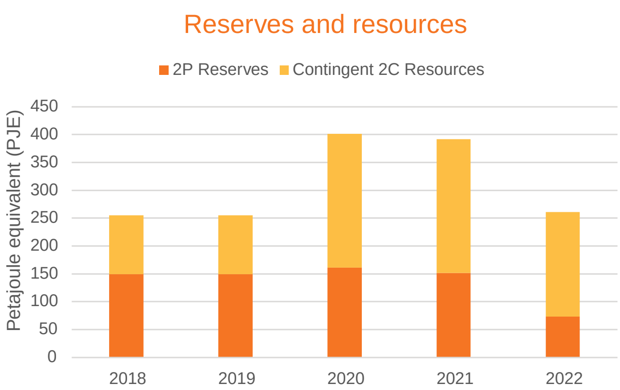
- On 1 October 2021, Central completed the sale of 50% of its interests in the Mereenie, Palm Valley and Dingo fields for consideration valued at circa $85 million, recording a book profit of $36.6 million and facilitating the retirement of $30 million of debt.
- Underlying EBITDAX of $16.7 million.
- Full year statutory profit after tax of $21.3 million.
- Reduced net debt by 67% to $10.2 million and extended the loan facility by three years to 30 September 2025.
- The Mereenie development program was completed, with new production brought online.
- Continued outperformance of the Palm Valley 13 well and Dingo gas field resulted in an increase of 3.5 PJe of 2P reserves as at 31 December 2021.
- Entered into a new gas sale agreement for the sale of 3.15 PJ of gas over four years from 1 January 2022.
- In early May 2022, Central entered into gas transport and spot trading arrangements allowing for the delivery of uncontracted gas into the Eastern Australian markets. Through May and June sales into these markets achieved an average delivered price of $34/GJ.
- Commenced drilling the Palm Valley 12 exploration well in April 2022. The sidetrack into the Lower P2/P3 Sandstones proved unsuccessful in August, and a second lateral appraisal well is currently being drilled into the P1 Sandstone which is the current production zone at Palm Valley.
- Entered into a farmout of interests in the Group's Amadeus Basin exploration tenements EP82, EP112 and EP125 with a three-well exploration program to commence in 2023. The Group will be free-carried for its share of costs (capped at $20 million gross cost per well) for two new sub-salt exploration wells targeting natural gas, helium and hydrogen.



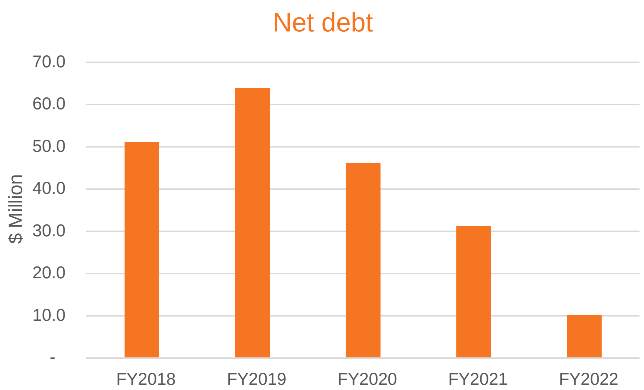
Underlying EBITDAX: Decreased 36% to $16.7m in FY2022*
(Earnings before interest, tax, depreciation, impairment, exploration costs, and profit on asset disposals)



Operating revenue: Decreased 30% to $42.1m in FY2022*



2P Reserves decreased due to disposals and production to 73.3 PJe



Net Debt: decreased by 67% to $10.2 million at 30 June 2022

* Note that Central disposed of 50% of its interests in its producing fields as at 1 October 2021, an effective 37.5% reduction in annual production capacity for FY2022

OPERATING AND FINANCIAL REVIEW

FINANCIAL REVIEW

The Consolidated Entity had a profit after income tax for the year ended 30 June 2022 of $21.3 million (2021: $0.3 million).

The above result was after expensing exploration costs of $21.6 million (2021: $7.7 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 FY2021. Note that a direct comparison of annual results will be impacted by:

1) The profit on sale of 50% of the Group's interests in its producing properties which completed on 1 October 2021 (which is excluded from the 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 from 1 October 2021.

The table below shows key metrics for the Group:

Key Metrics	Total 2022	Total 2021	Change	% Change
Decrease in FY22 production capacity due to asset sale				(37.5)%
Net Sales Volumes				
- Natural Gas (TJ)	**5,993**	**9,820**	(3,827)	(39.0)%
- Oil & Condensate (bbls)	**47,197**	**77,255**	(30,058)	(39.0)%
Sales Revenue ($'000)	**42,151**	**59,827**	(17,676)	(30.0)%
Gross Profit ($'000)	**20,894**	**30,975**	(10,081)	(33.0)%
Underlying EBITDAX[1] ($'000)	**16,746**	**26,088**	(9,342)	(36.0)%
Underlying EBITDA[2] ($'000)	**(4,901)**	**18,349**	(23,250)	(127.0)%
Underlying EBIT[3] ($'000)	**(11,680)**	**5,846**	(17,526)	(300.0)%
Underlying (loss)/profit after tax[4] ($'000)	**(15,239)**	**251**	(15,490)	N/a
Statutory profit after tax ($'000)	**21,320**	**251**	21,069	N/a
Net cash inflow from Operations[5] ($'000)	**3,640**	**24,136**	(20,496)	(85.0)%
Capital expenditure[6] ($'000)	**10,053**	**11,792**	(1,739)	(15.0)%

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. 2021 includes the proceeds from pre-sold gas.
6 Capital expenditure on tangible assets.

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

EBITDAX

Underlying EBITDAX for the year was $16.7 million, down 36% from $26.1 million in 2021 and consistent with the reduced earning base which resulted from the disposal of 50% of the Group's interests in the Amadeus Basin producing properties on 1 October 2021. Further discussion on revenues and gross profit are included below.

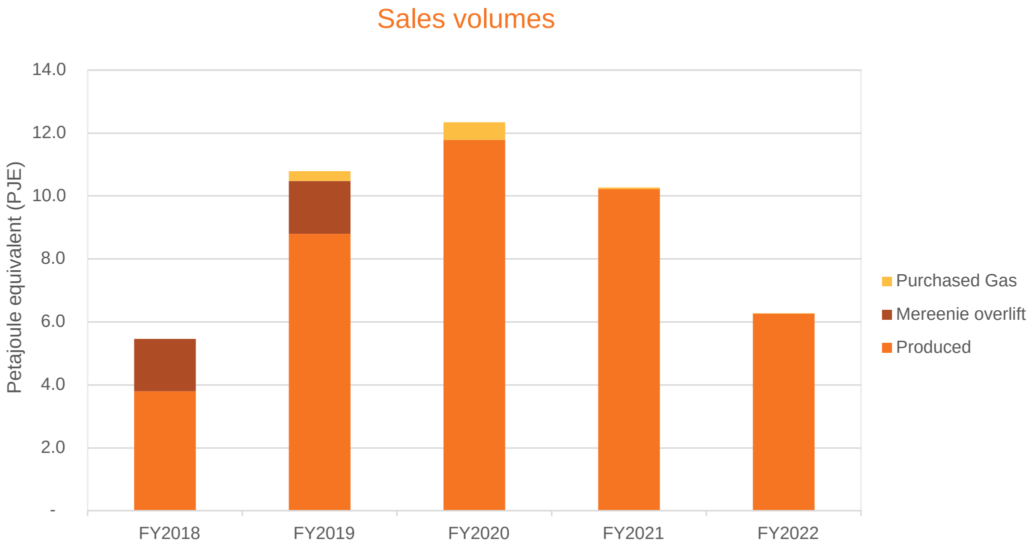
Underlying EBITDAX are earnings before interest, tax depreciation, amortisation, impairment, exploration and profit on disposal of interests in producing properties. Underlying EBITDAX is used by management as an indicative measure of underlying operating profit from operations as it excludes non-cash 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 $1.5 million this year (2021: $1.9 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	2022 $'000	2021 $'000
Statutory profit before tax	21,320	251
Profit on disposal of 50% interest in Amadeus Basin producing properties	(36,559)	—
Underlying (loss)/profit before tax	**(15,239)**	**251**
Net finance costs and restatement of financial assets	3,559	5,595
Underlying EBIT	**(11,680)**	**5,846**
Depreciation and amortisation	6,779	12,503
Underlying EBITDA	**(4,901)**	**18,349**
Exploration expenses	21,647	7,739
Underlying EBITDAX	**16,746**	**26,088**

Sales Volumes

Sales volumes were 39% lower than FY2021 at 6.3 PJe, reflecting the Group's reduced equity interests in the Amadeus Basin producing properties from 1 October 2021.



Note: Oil converted at 5.816 GJ/bbl.

Sales Revenue

Central recorded sales revenue of $42.2 million, down 30% on FY2021, reflecting the lower volumes, partially offset by stronger global oil prices and higher realised gas prices. Realised prices were up 15% on FY2021 at $6.73/GJe, reflecting higher global oil prices and domestic gas sales into the higher-priced east coast spot market in May and June.

Gross Profit

Gross profit was $20.9 million, increasing 10% from $3.02/GJe to $3.33/GJe on a per unit basis. The unit cost of sales increased by 21%, reflecting fixed costs spread over lower volumes and includes additional transportation costs for spot sales in May and June.

Other Income

A $36.6 million profit was recognised on disposal of 50% of the Group's interests in the Amadeus Basin producing properties which completed on 1 October 2021. Proceeds included $29.6 million of cash, deferred consideration in the form of a carry of the Group's share of future exploration and development costs with a fair value of $29.8 million and the assumption of liabilities associated with the disposed assets with a carrying value of $40.9 million at the time of completion.

Depreciation and Amortisation

Non-cash depreciation and amortisation costs decreased from $12.5 million to $6.8 million, reflecting the decrease in asset base following the 50% disposal transaction.

Net Assets/Liabilities

At 30 June 2022, the Group had a net asset position of $26.5 million, a significant improvement on FY2021 due to the net profit for the year before share based payments, including the $36.6 million gain from the partial sale of the Amadeus Basin producing properties.

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 $18.9 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, 0.75 PJ of previously over-lifted gas was repaid to a joint venture partner and 1.1 PJ of pre-sold gas was delivered.

Debt

The Group repaid $36.0 million of loan principal during the year including a $29 million repayment from the proceeds of the partial sale of the Amadeus Basin producing properties. The outstanding balance of the loan facility at 30 June 2022 was $30.8 million with $4.5 million due for repayment in FY2023.

During the year, the term of the loan facility was extended by three years to 30 September 2025.

Net debt reduced by 67% to $10.2 million at 30 June 2022 reflecting loan repayments from the proceeds of the partial asset sale.

The consolidated debt ratio at 30 June 2022 improved to 0.26 (2021: 0.39). Debt ratio is defined as: Total Debt/Total Assets. Net gearing at 30 June 2022 was 11% (2021: 27% or 28% if re-based to 30 June 2022 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 $15.5 million over the year. Net cash flow from production operations for 2022 was $19.8 million compared to $37.7 million for 2021, with the decrease reflecting the reduced interests in the Amadeus Basin producing properties from 1 October 2021 and the proceeds from the presale of gas in FY2021.

After payment of $2.5 million of interest costs, $3.7 million of corporate expenses and $10.1 million for exploration activities, net cash flow from operating activities was $3.6 million, down from $24.1 million in 2021. Exploration expenditure in FY2022 was $4.7 million higher than FY2021, reflecting additional activity this year on the Amadeus exploration program and Range pilot program.

During the year, Central invested $10.8 million in capital projects, including new production wells at Mereenie and other sustaining capital expenditure at the three producing fields.

A further $7.6 million of Central's share of exploration costs and $2.0 million of development costs were paid ("carried") by joint venturers under the terms of the partial asset sale.

Central repaid $36 million of debt during the year including a $29 million lump sum repayment from the proceeds of the partial asset sale.

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.

	2018 $ MILLION	2019 $ MILLION	2020 $ MILLION	2021 $ MILLION	**2022 $ MILLION**
Financial Data					
Operating revenue	34.94	59.36	65.05	59.83	**42.15**
Exploration expenditure	8.79	15.80	5.28	7.74	**21.65**
Profit/(loss) after income tax	(14.08)	(14.53)	5.41	0.25	**21.32**
EBITDAX	11.01	22.19	33.40	26.09	**53.31**
Underlying EBITDAX	11.01	22.19	25.01	26.09	**16.75**
Equity issued during year	25.47	—	—	—	**—**
Property, plant and equipment[1]	103.85	123.48	107.85	108.28	**53.85**
Cash[1]	27.22	17.81	25.92	37.17	**21.65**
Borrowings	(78.33)	(81.73)	(70.77)	(66.81)	**(30.81)**
Net Assets (Total Equity)	7.06	(5.62)	1.58	3.69	**26.53**
Net Working Capital (Net current assets/(liabilities))	17.19	(1.53)	6.75	8.25	**22.31**

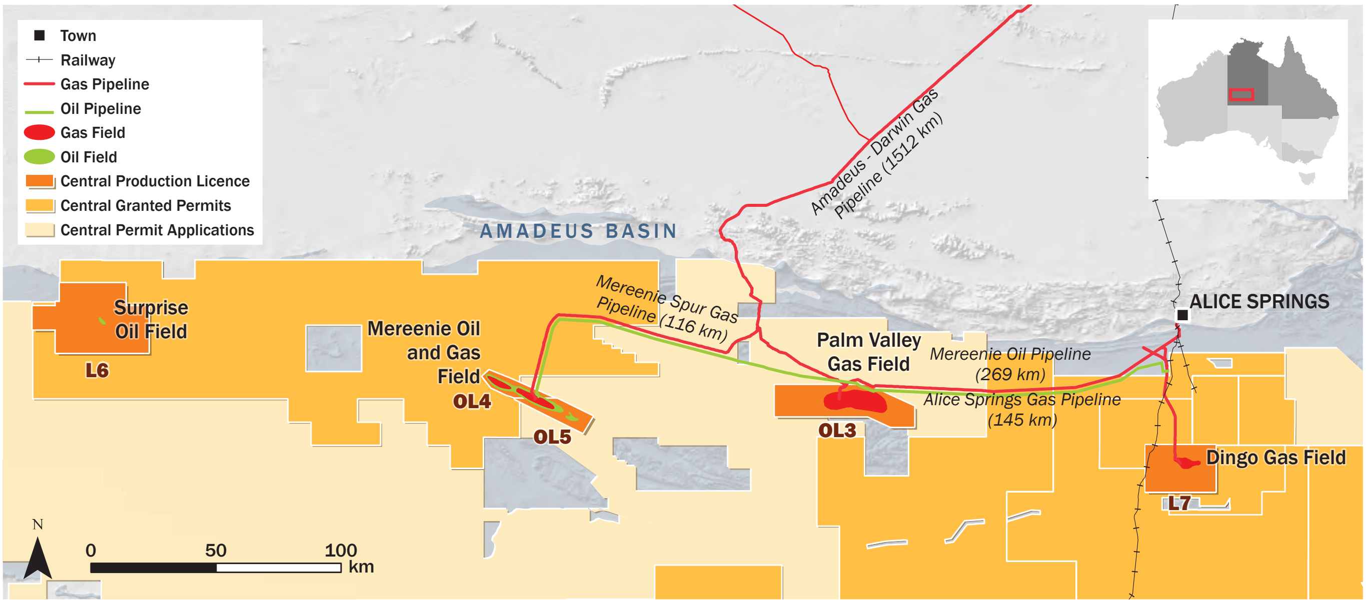
[1] Includes assets classified as held for sale

	2018	2019	2020	2021	**2022**
Operating Data					
Gas Sales (TJ)	4,842	10,229	11,822	9,820	**5,993**
Oil Sales (barrels)	105,619	97,392	89,016	77,255	**47,197**
No. of employees at 30 June	89	99	92	85	**88**

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



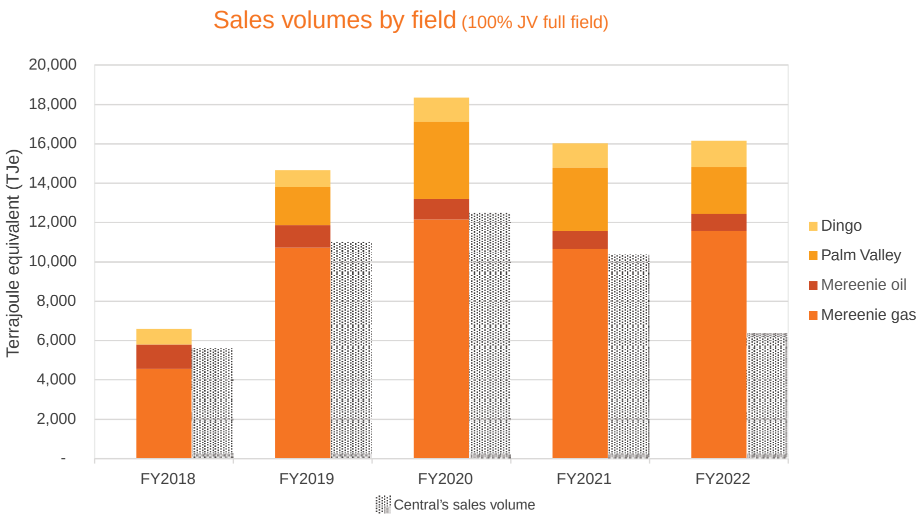
Location of Central's producing oil and gas fields

Sales Volumes (Central Petroleum's Share)

Product	Unit	FY 2022	FY 2021
Gas	PJ	6.0	9.8
Crude and Condensate	bbls	47,197	77,255
Total	**PJe**	**6.3**	**10.3**

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

Central's sales volumes were 39% lower than FY2021 at 6.3 PJe, reflecting reduced ownership interests following the sale of 50% of Central's interest in the Mereenie, Palm Valley and Dingo fields on 1 October 2021. On a full field basis, sales volumes increased slightly, up 1% as increased production from new wells at Mereenie and higher demand for Dingo gas offset natural decline at Palm Valley.



OPERATING AND FINANCIAL REVIEW

Mereenie Oil and Gas Field (OL4 and OL5)

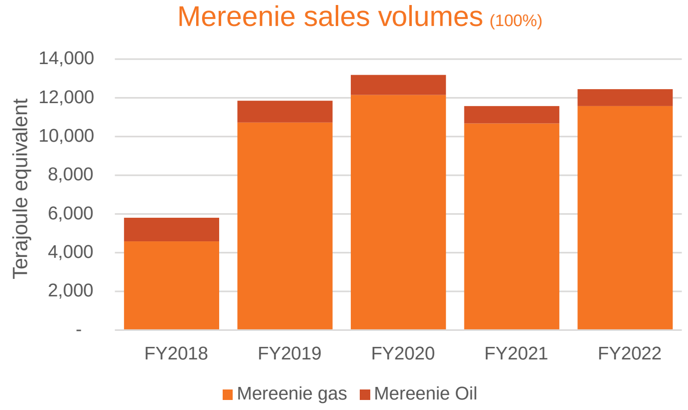
Northern Territory

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	30.5	39.2	45.6
Oil	mmbbl	0.37	0.41	0.05
Total[2]	PJe	32.6	41.6	45.9

1 Reserves and resources are as at 30 June 2022. 2C gas resources include 27 PJ attributable to the Stairway Sandstone.

2 Oil converted at 5.816 PJ/mmbbl



Operations

Full field gas production for the year was 11.6 PJ, averaging 31.7 TJ/d, up from the 10.7 PJ (29.5 TJ/d) produced in FY2021, benefitting from the commissioning of new production wells which were commissioned in the first quarter. Oil production averaged 410 bbl/d, down slightly from the 423 bbl/d produced in the previous year, as the new wells were crestally-located to target the gas cap, rather than the oil rim. Central's share of this Mereenie gas and oil production was 3.9 PJe, with a reduced ownership interest of 25% applying from 1 October 2021 when the partial asset sale completed (previously 50%).

Sustained gas flows were recorded from the Stairway Sandstone interval while drilling the WM28 production well, increasing the potential for additional reserves to be added with future appraisal.

In May 2022, Central entered into gas transport and spot trading arrangements allowing for the delivery of uncontracted gas into the eastern Australian markets for the first time. Through May and June 2022, in addition to supplying its contracted customers in the Northern Territory, Central supplied 61 TJ of gas from Mereenie into high-priced spot markets to support east coast gas users.

Mereenie oil and gas field central processing plant

Future plans

To further increase production and offset natural field decline in the next 12 months, it is planned to recomplete up to six existing wells to access producing zones which were previously behind pipe. Planning has also commenced on two new development wells at Mereenie.

The overlying Stairway Sandstone formation could contain up to 108 PJ of gas (27 PJ Central share), making it an ideal candidate for future appraisal.

Geology

The Mereenie hydrocarbon accumulation is contained in an elongated 4-way dip anticline that has a length of 40 km and width of more than 5 km. The reservoirs comprise a series of stacked sandstones of the Pacoota Formation, which have been the focus of development to date. This development has targeted both gas production and oil production from an oil rim. The overlying Stairway Sandstone has not been materially developed to date, but it represents significant upside potential as the Stairway Formation has produced gas in several wells.

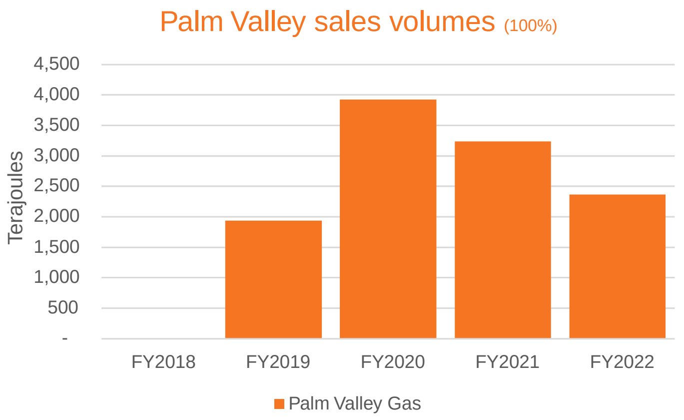
Palm Valley Gas Field (OL3)

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	11.3	12.7	6.8

[1] Reserves and resources are as at 30 June 2022.



Operations

Production from the Palm Valley field has continued to exceed expectations as a result of the ongoing outperformance of the PV13 production well. The field averaged gas sales of 6.5 TJ/d through FY2022, recording an aggregate of 2.4 PJ, down from 3.2 PJ in FY2021. The PV13 well is declining from its peak production plateau experienced in FY2020 but continues to outperform initial expectations. Central's share of Palm Valley gas sales was 1.5 PJ, with a reduced ownership interest of 50% applying from 1 October 2021 when the partial asset sale completed (previously 100%).

No new development wells were planned for FY2022 as additional production is expected from the PV12 exploration/appraisal well which, having been unsuccessful at its exploration target is being side-tracked as a lateral appraisal/production well in the producing P1 Pacoota Sandstone. Drilling progressed through the last quarter of the year after the well spud in April 2022. If successful in the Pacoota Sandstone, PV12 could be quickly tied-in to the existing Palm Valley processing infrastructure.

Future plans

Other potential locations have been identified for new lateral wells similar to the successful PV13 well in order to offset the field's natural decline, with timing of any future development to be determined by the outcome of the current PV12 appraisal well.

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.

Geology

Gas at Palm Valley is primarily reservoired in an extensive fracture system in the lower Stairway and Pacoota Sandstones. The anticlinal structure is approximately 29 km in length and 14 km in width. The deeper Arumbera Sandstone, which is the production interval at the Dingo field some 100 km to the east, has yet to be appraised and remains an exploration target.

Drilling at Palm Valley 12
by Phil Allen

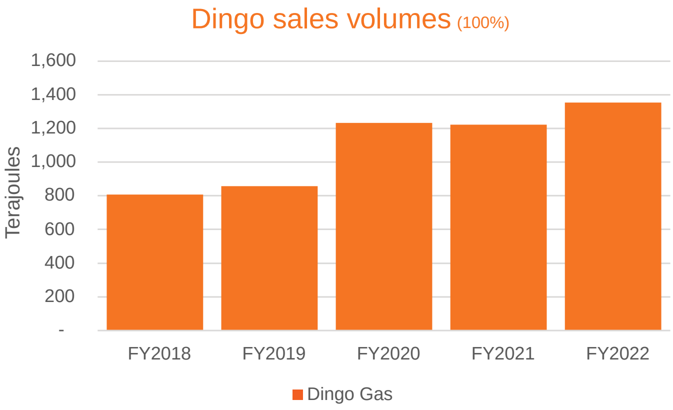
Dingo Gas Field (L7) and Dingo Pipeline (PL30)

Northern Territory

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

Reserves & Resources (Central share)[1]	Unit	1P	2P	2C
Gas	PJ	16.2	19.0	—

[1] Reserves and resources are as at 30 June 2022.



Instrumentation at Brewer Estate City Gate Station

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 3.7 TJ/d across the year, an aggregate of 1.4 PJ, up 10% on FY2021 due to increased demand from the power station. The daily contract volume of 4.4 TJ/d is subject to take-or-pay provisions under which Central will be paid in January 2023 for any gas nomination shortfall by the customer in CY2022. Central's share of gas sales was 0.9 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.

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.

Geology

Gas was discovered at the Dingo field in 1985 in the Neoproterozoic lower Arumbera Sandstone. The structure is 11 km by 5.6 km, and the productive reservoir is at a depth of approximately 3,000 metres subsurface.

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

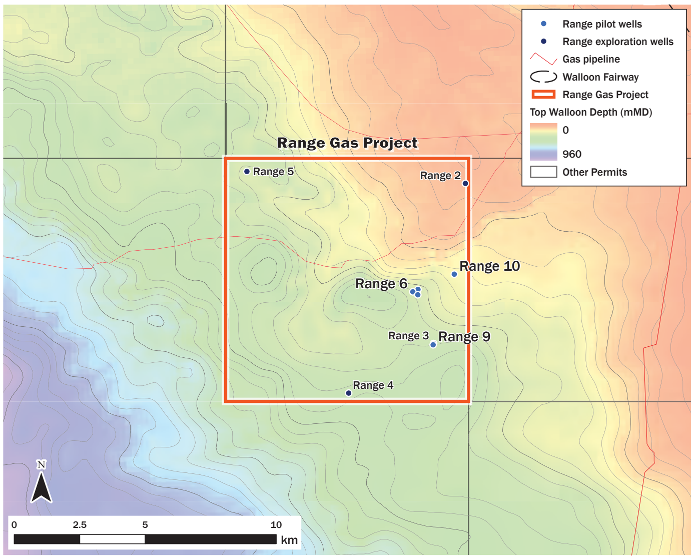
Central and joint venture partner, Incitec Pivot Limited are progressing appraisal for the 77km^2 Range coal seam gas (CSG) project which is strategically located in the heart of Queensland's CSG province which hosts thousands of wells producing from the same coal measures at similar depths.

Range pilot operations

Interference testing of the original Range pilot confirmed good communication between the three pilot wells. However, key water production targets were not met during the testing period.

Two new step-out wells (Range 9 and 10) were drilled in February 2022 to assess coal properties and water production rates at a distance of approximately 2km from the initial pilot location. The two new wells confirmed net coal of 29.8m and 28.6m respectively, compared to the average 25.5m of coal encountered at the site of the initial three well pilot. Despite being less than 2km from the original pilot, these results are more comparable to the average 32.9m of coal encountered in previous exploration wells. The new pilot step-out wells were tied into the existing water tank and an extended production test commenced in early April.

One of the original pilot wells, Range-6 was returned to production and testing of the three wells continues. Gas flows have been gradually increasing and the pilot wells are currently producing at an aggregate rate of 40,000 scfd.



Location of the Range Gas Project (ATP 2031) wells in relation to coal depth

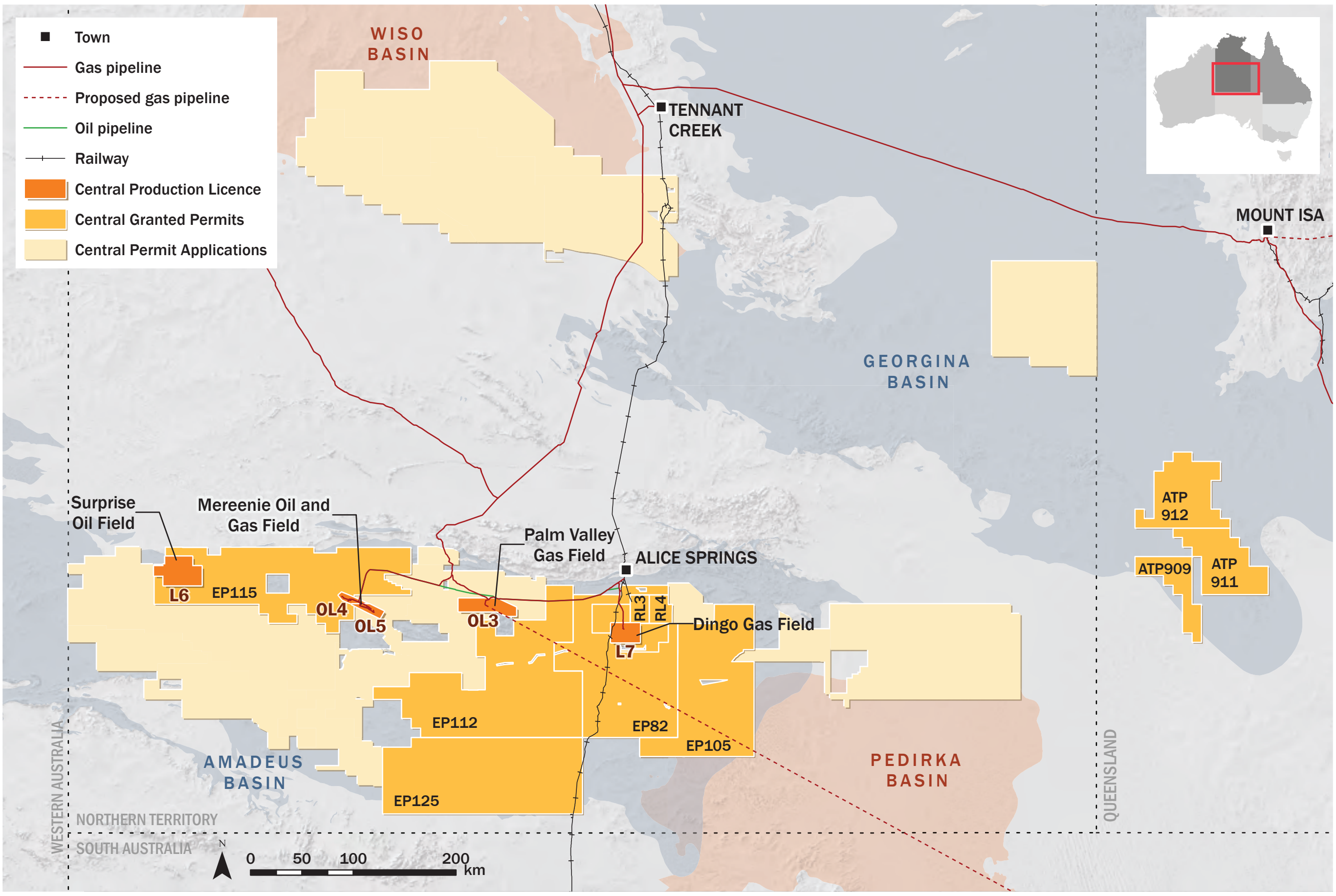
The new wells are intended to provide key information to support appraisal of the permit, including reservoir productivity (initially via water rates), gas desorption (when gas is first produced), zonal contribution (how much each coal seam is contributing) and the initial production profiles of gas and water ramp-up. This information will be reviewed in conjunction with data obtained from neighbouring permits.


Range-9 drilling site

OPERATING AND FINANCIAL REVIEW

Exploration Assets

Central Petroleum holds a significant portfolio of exploration opportunities across the Northern Territory and Queensland, including extensive positions in the long producing, yet underexplored Amadeus Basin in the NT, and frontier opportunities in the Wiso and Southern Georgina basins. The total area held by Central for exploration (both granted and under application) is 181,743 km^2 (72,197 km^2 granted and 109,545 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 it is believed to hold significant additional gas resources, with good prospectivity for oil on the western flank of the basin.

The Amadeus Basin is also prospective for helium and hydrogen. Previous exploration wells at Mt Kitty and Magee have shown high concentrations of helium and hydrogen and are attracting increasing international attention. A new joint venture partner, Peak Helium, will join Central and Santos to drill three exploration wells in 2023/2024, funding Central's share of costs for two of the three new wells (capped at $20 million total gross cost per well). These high-value non-hydrocarbon gases are generally associated with granitic basement and sub-salt prospects and the three well program will be a key driver for Central in progressing other sub-salt exploration in 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:

- **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;
- **Near term 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; and
- **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. Drilling is planned in 2023.

Amadeus exploration – 2022 drilling activity

Palm Valley

(OL3) Amadeus Basin, Northern Territory
(Central – 50% interest)

Drilling commenced on the PV12 exploration well on 17 April, with the primary target being the Arumbera Sandstone at an anticipated vertical depth of 3,560m (PV Deep).

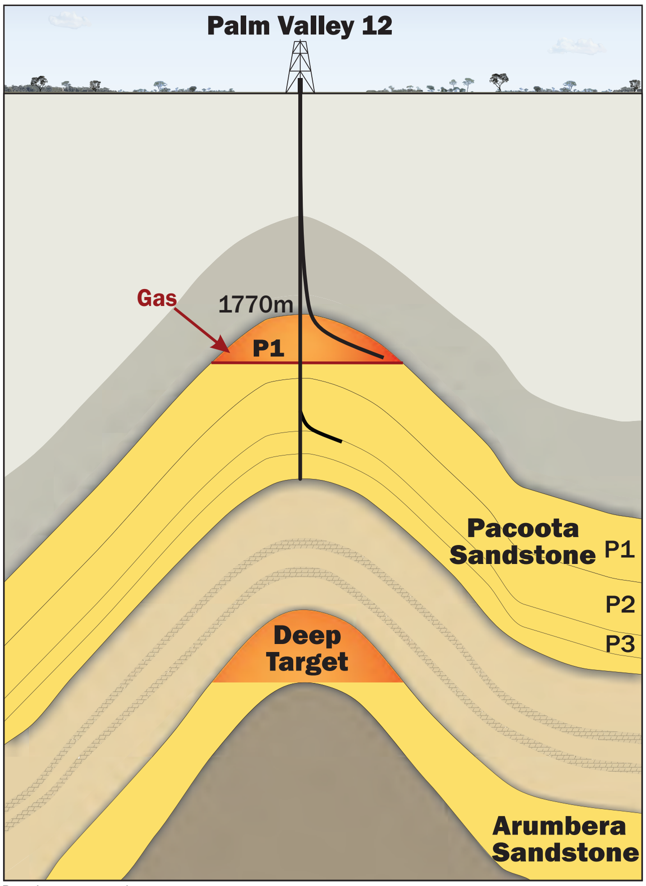
Gas shows were recorded whilst drilling through both the currently productive P1 Sandstone and the P2/P3 Sandstones located 90m below the P1.

Drilling progress was significantly slower that prognosed due to the vertical well encountering a number of heavily fractured intervals that absorbed significant volumes of drilling fluids and cement. Several cement plugs were set to enable the setting of casing to ensure well integrity. Having reached a depth of 2,335m, the joint venturers decided on 12 July to replace the original PV Deep target with the lower P2/P3 target at a depth of approximately 2,060m.

The vertical well was plugged back and the PV12 ST1 lateral well was drilled into the P2/P3 Sandstones. Although the vertical PV12 well intersected a major fracture zone within the lower P2 Sandstone and background gas was detected while drilling horizontally, gas flows were not detected from the lateral well and formation water was encountered.

The P2/P3 lateral well was plugged back and a second lateral well (PV12 ST2) side-tracked to test the shallower Pacoota (P1) Sandstone (approx. 1,770m depth), which is the current producing zone for the Palm Valley gas field. The PV12 ST2 lateral appraisal well is currently drilling into the Pacoota Sandstones. The lateral design is similar to the successful PV13 appraisal well drilled in 2019, which had a lateral extension of 300m and has already produced approximately 5.7 PJs in its first three years of production (gross JV).

Preparations are underway to connect the PV12 ST2 lateral well (if successful) into the Palm Valley production infrastructure.



Drawing not to scale.

Schematic of the Palm Valley 12 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 at Palm Valley and Dingo 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)

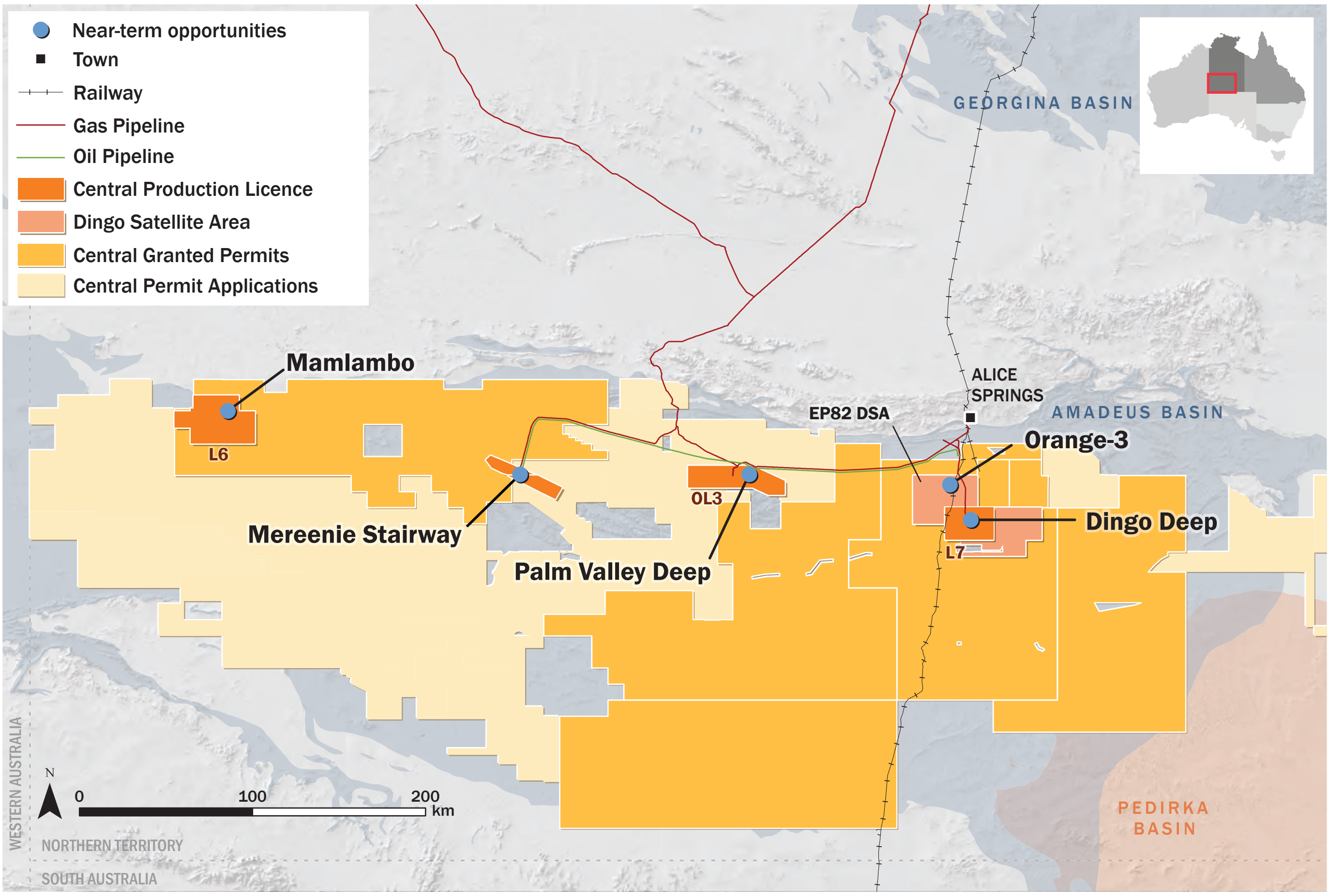
The Palm Valley Deep target has an estimated mean prospective resource of 123 PJ (61.5 PJ net to Central) in the deep Arumbera Sandstone (depth circa 3,500m) which is the productive interval at the Dingo field. A new gas resource of this size at Palm Valley would be a catalyst for a significant expansion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

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). While drilling the WM28 production well in 2021, gas flowed from the Upper Stairway Sandstone at 600,000 scfd, 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 – Near-term opportunities

Amadeus Basin, Northern Territory

Central has identified several other promising lower-risk, high reward exploration targets close to productive areas which it intends to pursue in the near term. 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.

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.

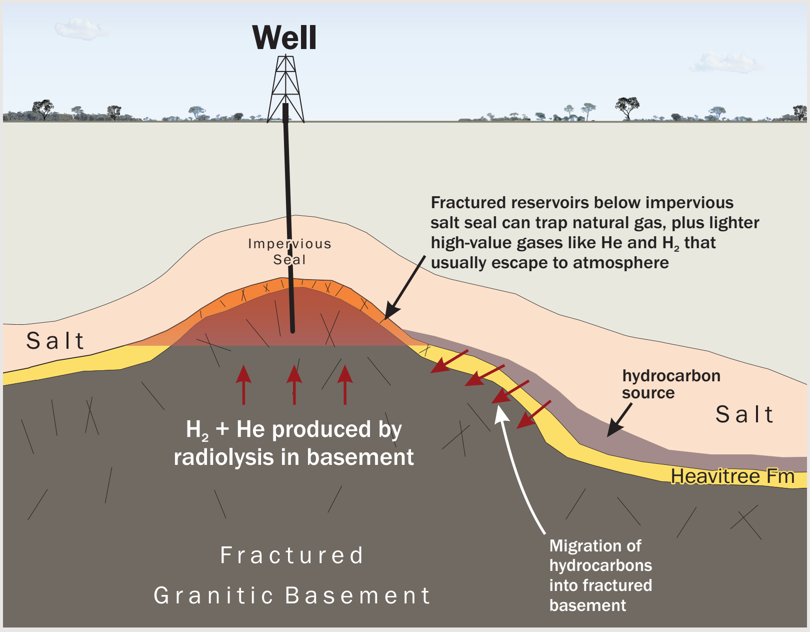
Amadeus exploration – Sub-salt targets with helium and hydrogen potential

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.

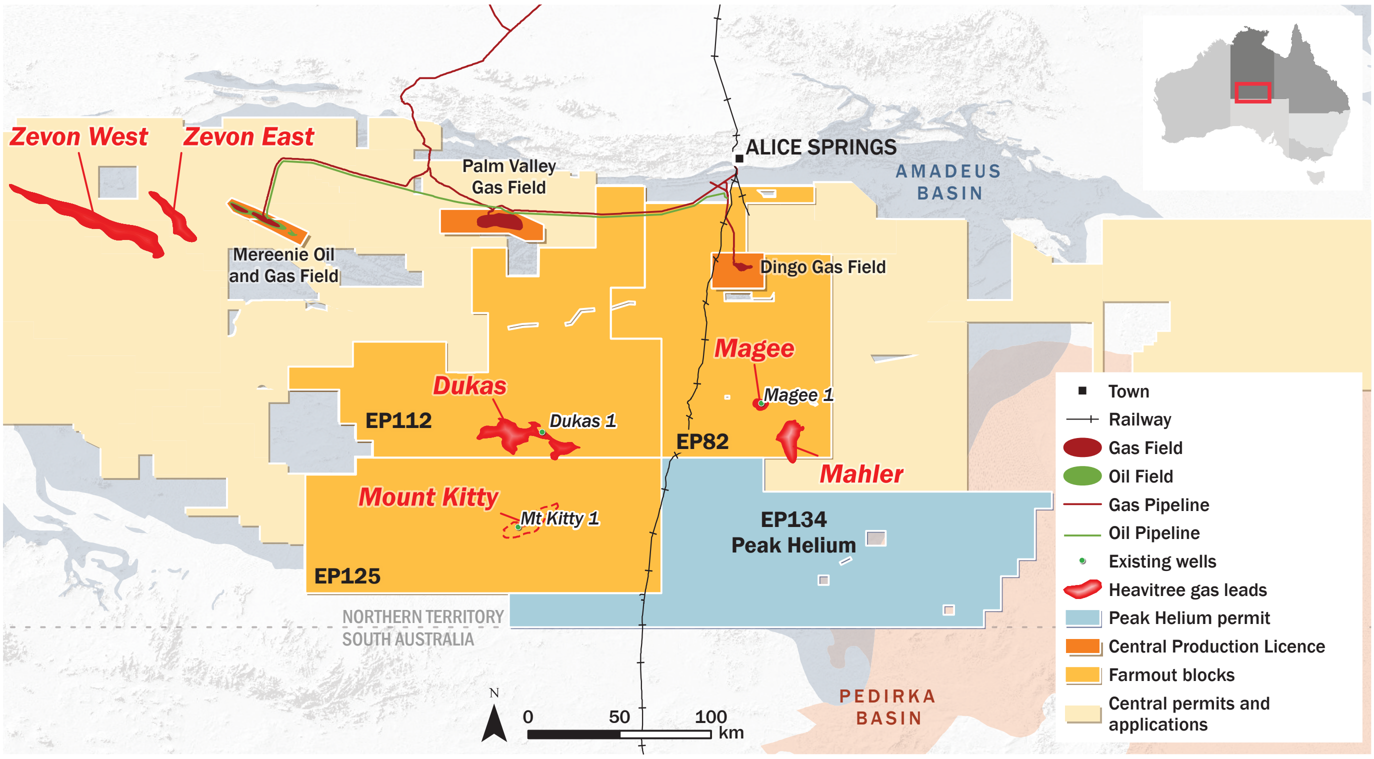
What is sub salt?

- The term "sub-salt" is commonly applied to the geology below deposits of salt (evaporites).
- Salt can form a very effective trap for not only hydrocarbons, but very light gasses like helium and hydrogen that typically escape to the atmosphere.
- Some of the largest oil and gas fields discovered are sub-salt, in numerous regions such as USA Gulf of Mexico, offshore Brazil and offshore West Africa.
- The Amadeus Basin has a unique combination of basin-wide salt formations extending over large areas with opportunities for hydrocarbons, plus helium and hydrogen produced by radiolysis at basement.



Farmout stimulates major sub-salt exploration program

In February, Central entered into a farmout of interests in three Amadeus Basin exploration tenements to Peak Helium (Amadeus Basin) Pty Ltd (Peak). Under the farmout, Central will be free carried (i.e. funded) by Peak for two new sub-salt exploration wells (capped at $20 million gross cost per well), one at Mt Kitty (EP 125) and the other at the Mahler prospect (EP 82).



Location of sub-salt targets

Combined with the planned Dukas exploration well, a total of three sub-salt exploration wells will now be prioritised for drilling in the Southern Amadeus Basin, starting in 2023, targeting hydrocarbons, helium and naturally occurring hydrogen. Relatively high helium concentrations of 9% and 6.3% have been recorded at the existing Mt Kitty and Magee wells respectively, with Mt Kitty also registering 11.5% hydrogen. Helium concentrations above 1% can be regarded globally as high, with a concentration of greater than 0.5% regarded as potentially economic.

Central retains an average 30% ownership interest in this major new exploration program that has enormous potential.

Dukas (EP 112)
Central – 35% interest (after farmout to Peak Helium)

Dukas is a geographically large (>400 km^2) gas prospect with multi-Tcf potential located in EP 112, approximately 175 km southwest of Alice Springs. The Dukas-1 exploration well was suspended at a depth of 3,704m in mid-2019 after encountering hydrocarbon-bearing gas from an over-pressured zone close to the primary target. Helium and hydrogen shows were evident in association with methane and nitrogen in mud gasses associated with the over-pressured zone. Although not from the reservoir section (which is yet to be encountered) this is an encouraging sign of the potential presence of these gases in the reservoir zone.

Santos (operator) is planning a new Dukas well, and is currently seeking tenders for a suitable drilling rig.

Mahler (EP 82)
Central 29% interest (after farm-out to Peak Helium)

The proposed Mahler exploration well is planned to be drilled in 2023, up-dip and approximately 20km south-east of the Magee 1 well which flowed hydrocarbon and helium (6.3%) gases in 1992. It is proposed that the well will evaluate the hydrocarbon, helium and hydrogen potential of the sub-salt fractured basement and Heavitree formation (if present), and as a secondary objective, the oil potential of the Bitter Springs Group carbonates.

Mt Kitty (EP 125)
Central - 24% interest (after farm-out to Peak Helium)

The Mt Kitty-1 well, drilled in 2014, flowed hydrocarbon, helium (9%) and hydrogen (11.5%) gases. It is planned that the Mt Kitty-1 well will be re-entered in 2023 and a lateral sidetrack drilled 500m into the fractured basement reservoir.

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 2D seismic survey is being planned to further define the Zevon lead.

Southern Amadeus Basin, Northern Territory

Various Exploration Permits (see table on page 104)

In addition to the sub-salt drilling program planned to commence in 2023 and the Zevon lead, secondary reservoir objectives are present within the post-salt units including the Areyonga Formation and Pioneer Sandstone, both of which are gas bearing at the Ooraminna discovery which requires additional appraisal.

Central continues to mature its geological interpretations in these permits, seeking to identify a variety of other exploration play types and targets which could be prospective for hydrocarbons and/or Helium.

Exploration Application Areas, Northern Territory

Amadeus, Pedirka and Wiso Basins — Various Areas (see table on page 104)

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.

Play types and leads are also being developed for the under-explored sedimentary section underlying the proven Ordovician Larapintine system. This deeper section is believed to be prospective for gas.

ATP909, ATP911 and ATP912

Southern Georgina Basin, Queensland
(CTP—100% interest)

Having reviewed the data acquired from previous activities, Central is currently reviewing its plans for the Southern Georgina Basin.

OPERATING AND FINANCIAL REVIEW

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. The completion of the partial sell-down of the Amadeus production assets in October 2021 was the catalyst for several infield development and exploration programs. Central also farmed-out partial interests in three exploration permits to enable drilling of three major sub-salt exploration wells, starting in 2023, targeting helium, naturally occurring hydrogen and hydrocarbons.

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.

Sell-down of Amadeus production assets

On 1 October 2021, Central completed the sale of 50% of its interests in the Mereenie, Palm Valley and Dingo fields to New Zealand Oil & Gas Limited (NZOG) and Cue Energy Resources Limited (Cue), recognising a book profit of $36.6 million. Cash proceeds were directed towards the repayment of $29 million of debt and a 'carry' component provided approximately $30 million to fund Central's share of development and exploration activity in those fields, including the Palm Valley 12 exploration / appraisal well. NZOG and Cue also assumed obligations to supply up to 4 PJ of gas (50% interest acquired at completion) under existing gas pre-sale and accumulated take-or-pay arrangements, valued at $20.2 million at the completion date.

Farmout to fund two new sub-salt exploration wells in the Amadeus Basin

In February 2022, Central announced it had entered into a farmout of partial interests in three Amadeus Basin exploration tenements to Peak Helium (Amadeus Basin) Pty Ltd (Peak). This arrangement will see accelerated drilling of three sub-salt exploration wells in the Southern Amadeus Basin, starting in 2023.

Under the farmout, Central will be free carried by Peak for its share of the cost of two new sub-salt exploration wells (capped at $20 million gross cost per well), one at Mt Kitty (EP125) and the other at the Mahler prospect (EP82). Peak will also join Central and Santos to drill a new Dukas exploration well in EP112.

In consideration for the two carried wells, Peak will earn partial interests in the following permits:

- 31% in EP82, excluding the Dingo Satellite Area (Central's interest will change from 60% to 29%)
- 10% in EP112 (Central's interests will change from 45% to 35%)
- 6% in EP125 (Central's interest will change from 30% to 24%).

New Gas Sales Agreement

Central executed a new GSA for the supply of 3.15 PJ of gas (Central's share) to the Northern Territory's Power and Water Corporation via a back-to-back GSA with Macquarie Mereenie Pty Limited.

The four-year supply term commenced on 1 January 2022, commercialising a portion of the increased production brought online from the 2021 Mereenie development campaign. The GSA is for firm supply, with take or pay provisions and a fixed price subject to annual CPI escalation.

Gas sales commence into the east coast trading markets

In May, Central and the other Mereenie Joint Venture participants secured 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 (STTMs) enabling it to broaden its customer base and increase the average price for uncontracted gas.

These arrangements enabled Central to supply 61 TJ (Central share) of gas into spot markets in May and June at an average delivered price of $34/GJ, generating over $2m (CTP share) in revenue from uncontracted production.

ESG AND COMMUNITY

In managing its business activities, 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.

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.

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. Audit of compliance with our environmental conditions outlined in the various EMPs over the course of the year identified over 99% compliance.

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

Palm Valley
by Phil Allen

OPERATING AND FINANCIAL REVIEW

Climate change and emissions

Central recognises that climate change is an increasingly significant environmental, social, and business issue. While there is growing pressure to accelerate the transition to renewable energy, the volatile energy markets experienced by east coast businesses and residents in the winter of 2022 have highlighted the critical role that natural gas will play providing cleaner, affordable, and reliable energy 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. The residents 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 rely on our gas to supply rare minerals to worldwide markets and Central supplied 61 TJ of gas into eastern markets in May and June 2022 when electricity and gas supplies were critically short.

The regulatory, scientific, and social response to climate change continues to evolve and, in this context, we continue to seek ways to minimise our carbon emissions while also providing affordable, reliable energy to our customers.

We report our greenhouse emissions under the National Greenhouse and Energy Reporting Act 2007 (NGER). In the most recent completed reporting period, FY2021, our share of scope 1 and 2 emissions across our operations was 51,198 tons of CO_2e (47,545 tons in FY2020).

We are working on several initiatives to reduce our emissions, including a flare gas recovery project at Mereenie, which will seek to reduce flare gas emissions by more than 25% and overall emissions at these sites by approximately 10%, based on current emissions. We expect to have these modifications operational in early 2023. 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 320,066 hours were worked, with two recordable injuries, resulting in a Total Recordable Injury Frequency Rate (TRIFR) at 30 June of 6.2.

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:

- 53% of our staff live locally
- 23% of our staff are indigenous
- Central paid over $4.5M of Royalties and fees to the Northern Territory and Central Land Council in FY2022
- Central and partners spent over $4.0M with local contractors and businesses in FY2022.

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.

RESERVES AND RESOURCES STATEMENT

Net proved & probable (2P) oil and gas reserves were 73.3 PJe at 30 June 2022.

Aggregate Reserves and Resources

		As at 30/06/2021	01/07/2021 to 30/06/2022 Production	Disposal adjustment	Other adjustments	As at 30/06/2022	Comprising[1] Developed	Undeveloped
Oil								
Proved reserves (1P)	mmbbl	0.69	(0.05)	(0.33)	0.06	**0.37**	0.35	0.02
Proved plus probable reserves (2P)	mmbbl	0.89	(0.05)	(0.43)	0.01	**0.41**	0.40	0.02
Contingent Resources (2C)	mmbbl	0.10	—	(0.05)	—	**0.05**	—	—
Gas								
Proved reserves (1P)	PJ	114.18	(5.26)	(57.63)	6.69	**57.99**	44.92	13.07
Proved plus probable reserves (2P)	PJ	146.50	(5.26)	(73.79)	3.50	**70.96**	54.66	16.29
Contingent Resources (2C)	PJ	239.88	—	(52.44)	—	**187.49**	—	—

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

Reserves and Resources by Field

		As at 30/06/2021	01/07/2021 to 30/06/2022 Production	Disposal Adjustment	Other Adjustments	As at 30/06/2022
Mereenie, oil						
Proved reserves (1P)	mmbbl	0.69	(0.05)	(0.33)	0.06	**0.37**
Proved plus probable reserves (2P)	mmbbl	0.89	(0.05)	(0.43)	0.01	**0.41**
Contingent Resources (2C)	mmbbl	0.10	—	(0.05)	—	**0.05**
Mereenie, gas						
Proved reserves (1P)	PJ	64.65	(2.88)	(33.38)	2.07	**30.46**
Proved plus probable reserves (2P)	PJ	87.22	(2.88)	(44.67)	(0.46)	**39.21**
Contingent Resources (2C)	PJ	91.20	—	(45.60)	—	**45.60**
Palm Valley						
Proved reserves (1P)	PJ	21.49	(1.52)	(10.40)	1.73	**11.29**
Proved plus probable reserves (2P)	PJ	24.42	(1.52)	(11.87)	1.70	**12.73**
Contingent Resources (2C)	PJ	13.68	—	(6.84)	—	**6.84**
Dingo						
Proved reserves (1P)	PJ	28.04	(0.85)	(13.84)	2.89	**16.23**
Proved plus probable reserves (2P)	PJ	34.86	(0.85)	(17.25)	2.26	**19.02**
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.

OPERATING AND FINANCIAL REVIEW

The reserves and resources information in this document relating to:

- the Mereenie, Palm Valley and Dingo fields are based on, and fairly represent 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 Netherland, Sewell & Associates, Inc., 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 2022

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 government policy. Failure to comply may impact our license to operate. Stakeholders have evolving expectations of social responsibility and ethical decision making. These are changing at a rate faster than governments can introduce or amend regulation.	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.

Context	Risk	Mitigation
Growth		
Our future growth depends on our ability to identify, acquire, explore, appraise, and develop resources.	The inability to identify and commercialise growth opportunities, or realise their full value, may result in a loss of shareholder value. Unsuccessful exploration and renewal of upstream resources may impede delivery of our strategy.	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 hydrocarbons 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.
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 have been measured in some of its exploration tenements.
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.

OPERATING AND FINANCIAL REVIEW

Context	Risk	Mitigation
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.
	Potential exposure of employees and contractors to COVID-19 could impact our operations and the communities in which we operate.	All operational activities including travel to and from sites are managed under Pandemic Management Plans. We continue to monitor and align our standards and approach with guidance from various government and health authorities.
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.	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.
	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.	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.
	In addition, our operations can be negatively impacted by employee and contractor availability due to the impacts associated with COVID-19 including shutting down for a period.	All operational employee and contractor activities are managed under Pandemic Management Plans aligned with the relevant regulatory requirements to minimise the risk to people and operations.
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
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; although this mechanism is focused on availability of supply and may not have a significant impact on price.	Oil revenue represented less than 15% of consolidated sales revenue in FY2022. 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.
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.
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.

OPERATING AND FINANCIAL REVIEW

Context	Risk	Mitigation
Geographic Concentration		
We face risks associated with the concentration of our production assets.	Central's revenue is derived from oil and gas production in the Amadeus Basin leaving Central exposed to downsides associated with weather conditions 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.
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.
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 can lead to scarcity of available capital and may impact the prioritisation of exploration, development or production opportunities. This can lead to delayed approvals which may impact Central's growth strategy.	We work closely with our joint venture partners to achieve mutually beneficial outcomes.

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 2022.

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 (2021: $Nil). No recommendation for payment of dividends has been made.

OPERATING AND FINANCIAL REVIEW

The operating and financial highlights for the financial year were:

- On 1 October 2021 Central completed the sale of 50% of its interests in the Mereenie, Palm Valley and Dingo fields for consideration valued at circa $85 million, recording a book profit of $36.6 million and reducing debt by $30 million around the completion date.
- EBITDAX of $53.3 million.
- Full year profit of $21.3 million.
- Reduced net debt by 67% to $10.2 million and extended loan facility by three years to 30 September 2025.
- Entered into a new gas sale agreement for the sale of 3.15 PJ of gas over four years from 1 January 2022.
- The Mereenie development program was completed, with new production brought online.
- Continued outperformance of the Palm Valley 13 well and Dingo gas field resulted in an increase of 3.5 PJe of 2P reserves (before production) as at 31 December 2021.
- Commenced drilling the Palm Valley 12 exploration well in April 2022. The sidetrack into the Lower P2/P3 Sandstones proved unsuccessful in August, and a second lateral appraisal well is currently being drilled into the P1 Sandstone which is the current production zone at Palm Valley.
- Entered into a farmout of interests in the Group's Amadeus Basin exploration tenements EP82, EP112 and EP125 with a three-well exploration program to commence in 2023. The Group will be free-carried for its share of costs (capped at $20 million gross cost per well) for two new sub-salt exploration wells targeting natural gas, helium and hydrogen.
- In early May 2022, Central entered into gas transport and spot trading arrangements allowing for the delivery of uncontracted gas into the Eastern Australian markets. Through May and June sales into these markets achieved an average delivered price of $34/GJ.

A detailed review of the operating and financial performance for the year ended 30 June 2022, including principal risks is provided from pages 3 to 26 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 2022:

- On 1 October 2021 Central completed the sale of 50% of its interests in the Mereenie, Palm Valley and Dingo fields for consideration valued at circa $85 million, recording a book profit of $36.6 million and reducing debt by $30 million around the completion date. The reduced interests in the production assets had a corresponding impact on revenue.
- Entered into a farmout of interests in the Group's Amadeus Basin exploration tenements EP82, EP112 and EP125. The Group will be free-carried for its share of the costs of two new sub-salt exploration wells targeting natural gas, helium and hydrogen. Drilling is expected to commence in 2023.

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

EVENTS SINCE THE END OF THE FINANCIAL YEAR

No significant matters or circumstances have arisen between 30 June 2022 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

The new Palm Valley 12 well is scheduled to be completed in the first half of FY2023 and tied-in to the Palm Valley processing plant to boost Palm Valley gas production.

Production-enhancing activities are planned for the Mereenie field, with the recompletion of up to six existing wells to produce from production zones which are currently behind pipe. Two new development wells are also being considered by the Mereenie joint venture and could be drilled by mid-2023 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 also expected to commence in 2023. Operated by Santos, and with Central's costs in two wells to be funded by new joint venture partner, Peak Helium, (capped at $20 million gross per well) these targets have potential for large hydrocarbon resources as well as high-value helium and naturally occurring hydrogen.

Other proposed near-term exploration activity includes an oil exploration well at Mamlambo and seismic acquisition at the large Zevon sub-salt lead, subject to funding availability.

Appraisal

Testing of three pilot wells will continue through the first half of FY2023 at Central's Range CSG project in Queensland and will provide data to assist with appraisal of the permit.

Commercial

Demand for gas is expected to remain strong through FY2023, 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 26 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 Eneregy 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, a role that he stepped down from in March 2021.

While at Oil Search, Stephen 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, Stephen held senior corporate finance roles at major multinational companies including CSR Limited and Pioneer International Limited. Stephen 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 was appointed as a director on 1 September 2022. He 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.

Troy is currently a director of numerous private entities and of The MND and Me Foundation Limited. He has not held any other ASX directorships in the last 3 years.

Through his associated entities, Troy 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)).

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.

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.

Prior to joining Woodside, Dr Kantsler worked for Shell in various international locations and has served as Director and Chairman of the Australian Petroleum Production & Exploration Association (APPEA).

Dr Kantsler is Managing Director of Transform Exploration Pty Ltd, a former Director or Oil Search Limited and a former President of the Chamber of Commerce and Industry WA.

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:

Director	Full Meeting of Directors		Audit & Financial Risk Committee		Risk & Sustainability Committee		Remuneration & Nominations Committee	
	Eligible[1]	Attended	Eligible[1]	Attended[2]	Eligible[1]	Attended[2]	Eligible[1]	Attended[2]
Stuart Baker	8	8	4	4	—	5	5	5
Leon Devaney	8	8	—	4	—	5	—	5
Stephen Gardiner[3]	8	8	4	4	5	5	—	5
Katherine Hirschfeld AM	8	8	4	4	5	5	—	5
Agu Kantsler	8	8	—	4	5	5	5	5
Michael McCormack	8	8	4	4	5	5	5	5

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 Stephen Gardiner was appointed 1 July 2021.

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) Unissued ordinary shares of Central Petroleum Limited or interests under option at the date of this report are as follows:

Class	Issue Price	Exercise Price	Expiry Date	Number on issue
Unlisted employee options	Nil	$0.20	30 Jun 2023	17,221,046

(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. Audit 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 their 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	
	2022	2021
PwC Australian firm:	**$**	$
(i) Taxation services		
Income tax compliance	9,588	9,129
Other tax related services	10,579	26,864
Total remuneration from non-audit services	**20,167**	**35,993**

EXECUTIVE SUMMARY – REMUNERATION

Dear Shareholders,

In contrast to the COVID-interrupted recent years, the year just gone has seen a raft of activity across our portfolio. We have completed drilling and commissioning two new production wells at Mereenie, drilled and commenced testing two pilot wells at our Range CSG project and are drilling at Palm Valley. The completion of the sale of 50% of our operating assets to New Zealand Oil & Gas and Cue Energy Resources realised a $36 million profit and released significant capital to retire debt and fund our growth activity.

Commercially, the introduction of a new joint venture partner in three exploration tenements has provided the catalyst for a three well sub-salt exploration program starting next year, targeting helium, hydrogen and hydrocarbons. We secured transportation arrangements which enabled us to supply gas into volatile east coast energy markets, boosting revenues from our smaller production base.

These have been achieved against the background of labour shortages, supply chain disruptions and rising costs. Last year I identified that attracting and retaining key personnel to progress these activities was a key priority, and it remains so. Competition for experienced personnel remains strong, with buoyant oil and gas markets driving increased activity across the industry at a time when access to skilled labour remains restricted.

To address these changing market dynamics and to re-weight incentives to reward short-term performance on our transformational growth programs, we tailored our FY2022 remuneration structure to provide targeted performance incentives across the Company. The key components are summarised below.

Fixed remuneration

Following the freeze in fixed remuneration for FY2021, remuneration from July 2021 increased by approximately 2% along with the 0.5% increase in compulsory superannuation contributions. With rising inflation pressures and to remain competitive, average salaries will rise by approximately 4.5% from July 2022 plus the 0.5% increase in superannuation contributions.

Short-term incentives

In FY2022, executives did not participate in the Short Term Incentive Plan (STIP). All other staff participated in the STIP which targeted near-term performance in lieu of participation in equity-based plans of previous years. Achievement of short term incentives depends on achieving 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 Company was successful in exceeding its revenue targets and controlling production and corporate costs, but slow progress on the Range gas project and slippages and cost overruns in the exploration drilling program detracted from overall performance. As a result, personnel were entitled to an average 62.75% of their maximum STIP incentive for the year.

Executive incentives

For FY2022 our executive team switched to a new incentive program that integrates short and long-term components. The CEO can earn up to 120% of his fixed remuneration, while other executives can be awarded up to 80%. Performance was measured against the same corporate KPI targets set for the STIP. Of the maximum available in FY2022, 62.5% was awarded, with one-third to be paid this year and the balance converting into share rights vesting over the next three years.

LTIP

The LTIP which has been in place for several years has been discontinued, replaced by the STIP and executive plan outlined above for FY2022.

In previous years, executives and senior employees participated in the Employee Rights Plan / Long Term Incentive Plan (LTIP) that was designed to align management's interests directly with those of shareholders through Total Shareholder Return (TSR) hurdles. The LTIP was measured over a three year performance period and targeted half of its reward outcomes to Central's shares outperforming those of its peer group (Relative TSR) and half to Absolute TSR. Absolute TSR must exceed 10% per annum for three years to achieve any part of this second element and 25% per annum for three years to receive the whole of this element.

As the legacy LTIP runs-off, performance against the relevant targets will be measured annually. The LTIP's Absolute TSR performance for the three years from 1 July 2019 to 30 June 2022 failed to achieve the minimum growth hurdle of 10% pa. Whilst disappointing, 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 86th percentile compared to its peers, resulting in 43% of rights vesting for this three year performance period. The Board has discretion to retest performance of these hurdles at 31 December 2022.

For the first time, Directors sacrificed a portion of their fees to acquire share rights to increase their alignment with our shareholders.

Consistent with previous years, we have included a Realised Remuneration table (refer Table 1 in section I of the Remuneration Report) to assist readers of this report to understand the actual remuneration which the senior executives have received this year – something which is not always clear with the statutory reporting requirements.

With the transition from legacy incentive plans to the new structure, the remuneration report appears complicated, but we are confident the remuneration structure introduced this year will meet the expectations of our shareholders and ensure that our team is focussed on extracting the best value from our portfolio of assets.

Michael (Mick) McCormack
Remuneration and Nominations Committee Chair

REMUNERATION REPORT
(AUDITED)

This Remuneration Report for the year ended 30 June 2022 (FY2022) 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	Realised Remuneration
J	Remuneration Details – Statutory Tables
K	Executive Service Agreements
L	Non-Executive Director Fee Arrangements

A. Directors and Key Management Personnel (KMP)

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

Directors

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
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. Company-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 2022 Summary of fixed and variable remuneration outcomes	
Salary increases in FY2022	A 2% pay rise applied to eligible employees for FY2022 and compulsory superannuation contributions increased from 9.5% to 10%. As at 1 July 2022, a 4.5% pay rise will apply to eligible employees for FY2023. In addition, employees will benefit from the statutory increase in compulsory superannuation contributions from 10% to 10.5%.
Short Term Incentive Plan (STIP)	Achievement of Company-wide corporate and individual KPIs resulted in payment of an average 62.75% of the maximum STIP to eligible employees. Refer Section H of this report.
Executive Incentive Plan (EIP)	Achievement of Company-wide corporate KPIs resulted in an award of 62.5% 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.
Executive Share Option Plan (ESOP)	Share Options granted to eligible executives in 2019 as long term incentives for FY2020, FY2021 and FY2022 vested on 1 July 2022. The options have an exercise price of $0.20 and expire on 30 June 2023. Refer Section F 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 2022 was 43%. This may, at the Board's discretion, be eligible for retesting at 31 December 2022. Refer Section E of this report.

C. Remuneration Policy

The remuneration policy of the Company 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 Company'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. Consequently, the major component of executive incentives has been the Employee Rights Plan/Long Term Incentive Plan (LTIP), Executive Share Option Plan (ESOP) and Executive Incentive Plan (EIP) rather than the Short Term Incentive Plan (STIP).

From FY2022, executives participate in a revised incentive plan that combines both short term annual KPIs and a longer-term, deferred equity-based component (refer Section G below).

For periods up to and ending on 30 June 2022, 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 FY2022 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 Company'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;
2. Participation in the Executive Incentive Plan (EIP), vesting over a 4 year period (from FY2022); and
3. Participation in a Long Term Incentive Plan (LTIPs or ESOPs), vesting over a 3 year period (no new grants after FY2021).

The balance of fixed and maximum at risk remuneration for executives for FY2022 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:

		FY2018	FY2019	FY2020	FY2021	**FY2022**
Financial performance						
Operating revenue	$ million	34.94	59.36	65.05	59.83	**42.15**
Profit/(loss) after income tax	$ million	(14.08)	(14.53)	5.41	0.25	**21.32**
Underlying EBITDAX	$ million	11.01	22.19	25.01	26.09	**16.75**
Shareholder wealth						
Share price at year end	$/share	$0.130	$0.135	$0.081	$0.117	**$0.110**
Absolute TSR (3 years)	% growth pa	5.7%	15.5%	(16.1%)	(9.1%)	**(4.6%)**
Relative TSR (3 years)	Percentile rank	75th	88th	25th	57th	**69th**
Incentive awarded						
STIP	% of maximum	33%	82%	67%	67%	**62.75%**
LTIP	% of maximum	49.5%	75%	nil	31.5%	**43%**
EIP	% of maximum	N/a	N/a	N/a	N/a	**62.5%**

In the past five years, Central has recorded strong revenue and underlying EBITDAX results as expansion programs at the Company'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 since FY2019 have reflected this success, paid as a combination of cash, equity and deferred equity over those years. The FY2022 STIP/EIP award reflected a strong operating performance from the smaller asset base, with revenue and cost control exceeding stretch targets. The STIP/EIP award in FY2022 however, would have been higher, but for delays and cost overruns to the Company's exploration and appraisal programs.

The LTIP awards over recent years have followed the Company'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 and FY2022 have seen relatively little share price growth 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 Company 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 2021 review of remuneration. Guerdon Associates were engaged to provide market information relating to Non-executive Director fee increases over the prior two years and upcoming 12-months (on account that fees for the Company's Directors have not increased since 2017).

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

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

Key terms and vesting conditions

The Company's LTIP was last approved by shareholders in November 2018 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.

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

FY2022 Performance

The following table details the percentage of Share Rights in respect of the three-year performance period ending 30 June 2022 which will vest (Vesting Percentage) as determined by the performance conditions, based on the 20-day VWAP prior to 30 June 2022 of $0.1183. The benchmark share price at the start of the performance period was $0.1361:

Hurdle	Definition	Hurdle Banding	Vesting Percentage	Result for Plan Year Vesting 30 June 2022
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%	● (86%)
		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 2022 is: Armour Energy Limited, Blue Energy Limited, Buru Energy Limited, Carnarvon Petroleum 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 and 3D Oil Limited.

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 Company 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.

Details of the LTIP Plan's key terms can be viewed on the Company's website at www.centralpetroleum.com.au/careers/why-work-for-central.

Participation

Up until FY2021, this LTIP has provided coverage for various levels of eligible employees which include:

a. The Managing Director who is principally responsible for achievement of Central's strategy:
   i) Up until FY2019 received a LTIP percentage of up to 50% of TFR, subject to shareholder approval; and
   ii) From FY2020 to FY2021 participated in the ESOP (refer Section F of this report);
b. The Executive Management Team (EMT) received a LTIP percentage up to 30% of their TFR until FY2019, after which they participated in only the ESOP in FY2020 and FY2021 (one EMT member did not participate in the ESOP and continued in the LTIP until FY2021);

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

c. Eligible employees who are in roles which influence and drive the strategic direction of the Company's business or who are senior managers with responsibility for one or more defined functions, departments or outcomes have been eligible to receive a maximum LTIP percentage of 20% or 30% of TFR until FY2021;

d. Eligible employees who are in roles which are focused on the key drivers of the operational parts of the Company's business have received a maximum LTIP percentage of 10% of TFR up until FY2021; and

e. All other eligible employees are integral to the success of the Company 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 employees in categories c, d and e above will be re-weighted to a single STIP opportunity (refer Section H of this report) and be eligible to participate in the Central Petroleum $1,000 Exempt Plan.

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

Participation

On 7 November 2019, shareholders approved the establishment of an ESOP for certain key executives. The ESOP replaced the previous LTIP for participating executives and any Share Options granted under the ESOP replaced the Share Rights that would otherwise have been granted in FY2020, FY2021 and FY2022 under the LTIP.

Key terms and vesting conditions

Each Share Option entitles the participant to subscribe for one Share upon exercise of the Share Option. Share Options have been issued for no consideration. Share Options do not give any rights to participate in dividends nor to participate in any pro rata issue of securities to Shareholders.

The amount payable upon exercise of each Share Option is $0.20 (Exercise Price). The Share Options are exercisable from 1 July 2022 until their Expiry Date, 30 June 2023. Once a Share Option is capable of exercise, it may be exercised at any time up until the Expiry Date. Share Options not exercised before the Expiry Date will automatically lapse. Shares issued on exercise of the Share Options rank equally with the then issued shares of the Company.

All Share Options become exercisable if the Company is subject to a change of control event and in the event that the Share Options have not been exercised before a scheme of arrangement record date or issue of compulsory acquisition notice in the case of a takeover, the Company will cancel the Share Options and pay a settlement fee to the participant of the greater of 5 cents per Share Option or an amount equal to the consideration offered under the scheme of arrangement or takeover bid minus the Exercise Price.

All of a participant's Share Options will lapse on the earliest to occur of:

i) the Expiry Date (30 June 2023); or

ii) unless otherwise stated in the offer, the date that the Board determines that any service or performance conditions stipulated in the offer as applying to the Share Options cannot be met.

A participant's Share Options will lapse if a Participant ceases to be an employee, except in certain circumstances at the Board's discretion. The number of Share Options which will lapse is a function of the number of days between 1 July 2019 and the participant's termination date as a proportion of the total days between 1 July 2019 and 1 July 2022.

Unless otherwise determined by the Board, a Share Option will immediately lapse if the participant purports to transfer, assign, mortgage, charge, encumber sell or otherwise dispose of the Share Option.

FY2022 Performance

At 30 June 2022, Central's ordinary shares were trading at $0.11 per share, well below the $0.20 exercise price of the Share Options.

G. Executive Incentive Plan (EIP)

Participation

Following a review of the Company's incentive plans 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. No further grants will be made to participating executives under the existing LTIP, ESOP and STIP as these plans have effectively been replaced by the EIP.

As the ESOP Share Options granted in 2019 were granted as incentives for three years, including FY2022, to avoid a double reward for that year, the maximum reward that can be obtained under the EIP will be proportionately reduced by the value of any ESOP Share Options that are subsequently exercised.

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.

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 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 performance 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.

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

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 Section J of this report.

FY2022 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, 62.5% of their maximum EIP bonus. Of this award, 33% is scheduled to be paid in September 2022, 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.

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

Participation in the STIP, or the provision of any Company security, does not form part of the participating employee's remuneration for the purposes of determining payments in lieu of notice of termination of employment, severance payments, leave entitlements, or any other compensation payable to a participating employee upon the termination of employment (unless the Board otherwise determines).

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 %

The maximum STIP % available in FY2022 increased from previous years for some eligible employees as they are no longer be eligible to receive grants under the LTIP (apart from the Central Petroleum $1,000 Plan).

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 Company’s business; and
d) Ability to influence the Company’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.

FY2022 Performance

After assessment of the achievement of the KPIs below and the Company’s performance during the year, eligible employees were entitled to receive, on average, 62.75% of their maximum STIP bonus. The STIP bonuses are scheduled to be paid in September 2022.

The Financial Year 2022 STIP (FY2022 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	Achieved
Corporate KPIs	50 %	31.25 %
Safety and Environment KPI’s	10 %	7.50 %
Individual KPIs	40 %	24.00 % (avg)
	100 %	62.75 % (avg)

The majority of employees could earn a maximum of 10% of TFR, whilst more senior employees could earn either a maximum of 20% or 30% of TFR from the FY2022 STIP, depending on their participation level.

Corporate KPIs for FY2022:

Objective	Weighting	Performance Outcome for FY2022			
		0%	25%	100%	125%
Revenue Assessed against budget	25%				●
Total Cost[1] Total company operating and capital expenditure for agreed scope of works assessed against budget	25%				●
Exploration (Dingo Deep & PV Deep) Assessed against budget, commercial viability, schedule and timing hurdles	25%	●			
Range Gas Project Assessed against budget, schedule and timing hurdles	25%	●			

[1] Not rewarded for works that were essential but not completed, e.g. capital project delay or deferral. Excludes exploration which is assessed as a separate KPI.

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

Safety and Environment KPIs for FY2022:

Objective	Weighting	Performance Outcome for FY2022			
		0%	50%	75%	100%
Traditional Owner cultural heritage	25%				●
Safety: Total Recordable Incident Frequency Rate (TRIFR)	25%		●		
Environment: Recordable environmental incidents	25%				●
Alice Springs local and indigenous employment	25%		●		

Individual KPIs

Individual KPIs provide significant relevance to each role in each department, and for FY2022 were assessed as achieving an average of 60% (or a weighted average of 24% out of a maximum possible 40%).

I. Realised Remuneration

Table 1 identifies the Actual Remuneration received by Senior Executives in respect of the 2022 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 (2022: 11.0 cents per share, 2021: 11.5 cents per share).

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

Table 1: Realised Remuneration

	Year	Total Fixed Remuneration[1] $	STIP / EIP $	Other Benefits[2] $	LTI Vested as Shares[3] $	Total $
Executive KMP						
Leon Devaney	**2022**	**625,750**	**156,438**	**7,470**	**—**	**789,658**
	2021	612,061	42,231	7,635	66,549	728,476
Ross Evans	**2022**	**511,860**	**85,310**	**7,470**	**—**	**604,640**
	2021	500,404	34,527	7,635	28,214	570,780
Damian Galvin	**2022**	**338,050**	**56,342**	**7,470**	**—**	**401,862**
	2021	330,001	21,449	7,635	—	359,085
Duncan Lockhart	**2022**	**409,450**	**68,242**	**7,470**	**—**	**485,162**
	2021	400,001	25,999	7,635	—	433,635
Robin Polson[4]	**2022**	**—**	**—**	**—**	**—**	**—**
	2021	335,132	21,783	7,635	21,861	386,411
Jonathan Snape[5]	**2022**	**330,001**	**55,000**	**6,984**	**—**	**391,985**
	2021	—	—	—	—	—
Daniel White	**2022**	**454,410**	**75,735**	**7,470**	**46,505**	**584,120**
	2021	444,080	28,864	7,635	29,160	509,739
Total Executive KMP	**2022**	**2,669,521**	**497,067**	**44,334**	**46,505**	**3,257,427**
	2021	2,621,679	174,853	45,810	145,784	2,988,126

1 Total Fixed Remuneration includes salaries, fees and superannuation contributions.
2 Includes car parking and other fringe benefits.
3 Long Term Incentive Vested as Shares comprises any LTI from prior years that was awarded or is expected to be awarded for the three-year period ending 30 June and valued at that date.
4 Robin Polson resigned 30 June 2021.
5 Jonathan Snape commenced 1 July 2021.

J. Remuneration Details – Statutory tables

Table 2: Remuneration of Directors and Key Management Personnel

		Short-Term			Post-Employment		Long-Term Benefits	Share-Based Payments		Variable Remuneration
		Salary/ Fees $	STI[1] $	Non-Monetary Benefits $	Superannuation Contributions $	Termination Benefits $	LSL (Accrued) $	Rights & Options[2] $	Total $	Percent of Remuneration %
Non-Executive Directors										
Stuart Baker	**2022**	**67,500**	**—**	**—**	**6,750**	**—**	**—**	**18,603**	**92,853**	**—**
	2021	85,000	—	—	8,075	—	—	—	93,075	—
Stephen Gardiner[3]	**2022**	**62,500**	**—**	**—**	**6,250**	**—**	**—**	**18,603**	**87,353**	**—**
	2021	—	—	—	—	—	—	—	—	—
Katherine Hirschfeld	**2022**	**78,000**	**—**	**—**	**7,800**	**—**	**—**	**7,441**	**93,241**	**—**
	2021	85,833	—	—	8,154	—	—	—	93,987	—
Agu Kantsler	**2022**	**62,500**	**—**	**—**	**6,250**	**—**	**—**	**18,603**	**87,353**	**—**
	2021	78,333	—	—	7,442	—	—	—	85,775	—
Michael McCormack[4]	**2022**	**117,500**	**—**	**—**	**11,750**	**—**	**—**	**34,548**	**163,798**	**—**
	2021	107,500	—	—	10,212	—	—	—	117,712	—
Former Non-Executive Directors										
Julian Fowles[5]	**2022**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
	2021	26,667	—	—	2,533	—	—	—	29,200	—
Wrixon Gasteen[6]	**2022**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
	2021	64,167	—	—	6,096	—	—	—	70,263	—
Sub-total	**2022**	**388,000**	**—**	**—**	**38,800**	**—**	**—**	**97,798**	**524,598**	**—**
	2021	447,500	—	—	42,512	—	—	—	490,012	—
Executives										
Leon Devaney	**2022**	**613,881**	**156,438**	**7,470**	**23,568**	**—**	**13,639**	**277,153**	**1,092,149**	**40%**
	2021	623,324	42,231	7,635	21,694	—	11,221	341,098	1,047,203	37%
Ross Evans	**2022**	**501,018**	**85,310**	**7,470**	**23,568**	**—**	**7,119**	**241,598**	**866,083**	**38%**
	2021	499,881	34,527	7,635	21,694	—	8,690	223,072	795,499	32%
Damian Galvin	**2022**	**321,088**	**56,342**	**7,470**	**23,568**	**—**	**4,470**	**158,595**	**571,533**	**38%**
	2021	318,460	21,449	7,635	21,694	—	4,218	130,751	504,207	30%
Duncan Lockhart	**2022**	**400,660**	**68,242**	**7,470**	**23,568**	**—**	**5,506**	**192,505**	**697,951**	**37%**
	2021	392,139	25,999	7,635	21,694	—	5,308	158,892	611,667	30%
Robin Polson[7]	**2022**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
	2021	318,593	21,783	7,635	21,694	—	5,870	134,477	510,052	31%
Jonathan Snape[8]	**2022**	**315,318**	**55,000**	**6,984**	**23,568**	**—**	**2,706**	**39,722**	**443,298**	**21%**
	2021	—	—	—	—	—	—	—	—	—
Daniel White	**2022**	**450,596**	**75,735**	**7,470**	**23,568**	**—**	**10,367**	**151,392**	**719,128**	**32%**
	2021	444,673	28,864	7,635	21,694	—	8,140	123,785	634,791	24%
Sub-total	**2022**	**2,602,561**	**497,067**	**44,334**	**141,408**	**—**	**43,807**	**1,060,965**	**4,390,142**	**35%**
	2021	2,597,070	174,853	45,810	130,164	—	43,447	1,112,075	4,103,419	31%
Total Remuneration	**2022**	**2,990,561**	**497,067**	**44,334**	**180,208**	**—**	**43,807**	**1,158,763**	**4,914,740**	**32%**
	2021	3,044,570	174,853	45,810	172,676	—	43,447	1,112,075	4,593,431	28%

1 Short term incentives are unpaid at the end of the financial year.

2 The fair values of share rights granted 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. The values are allocated to each reporting period evenly over the period from grant 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. In 2022 non-executive directors had the discretion to sacrifice up to 25% of their FY2022 Base Fees to earn share rights which automatically vested on 30 June 2022.

3 Stephen Gardiner was appointed 1 July 2021.

4 Mr McCormack commenced 1 September 2020.

5 Julian Fowles resigned 31 October 2020.

6 Wrix Gasteen resigned 28 November 2020.

7 Robin Polson resigned 30 June 2021.

8 Jonathan Snape commenced 1 July 2021.

J. Remuneration Details – Statutory tables (continued)

Table 3: Short Term Incentives Awarded

		Maximum $	Awarded $	Awarded %	Forfeited %
Leon Devaney	**2022**	**250,300**	**156,438**	**62.5%**	**37.5%**
	2021	61,206	42,231	69.0%	31.0%
Ross Evans	**2022**	**136,496**	**85,310**	**62.5%**	**37.5%**
	2021	50,040	34,527	69.0%	31.0%
Damian Galvin	**2022**	**90,147**	**56,342**	**62.5%**	**37.5%**
	2021	33,000	21,449	65.0%	35.0%
Duncan Lockhart	**2022**	**109,187**	**68,242**	**62.5%**	**37.5%**
	2021	40,000	25,999	65.0%	35.0%
Robin Polson	**2022**	**—**	**—**	**—**	**—**
	2021	33,513	21,783	65.0%	35.0%
Jonathan Snape	**2022**	**88,000**	**55,000**	**62.5%**	**37.5%**
	2021	—	—	—	—
Daniel White	**2022**	**121,176**	**75,735**	**62.5%**	**37.5%**
	2021	44,408	28,864	65.0%	35.0%
Total	**2022**	**795,306**	**497,067**	**62.5%**	**37.5%**
	2021	262,167	174,853	66.7%	33.3%

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						
Stuart Baker	**2022[1]**	**161,765**	**23 Nov 21**	**0.115**	**—**	**30 Jun 26**
	2021	—	—	—	—	—
Stephen Gardiner	**2022[1]**	**161,765**	**23 Nov 21**	**0.115**	**—**	**30 Jun 26**
	2021	—	—	—	—	—
Katherine Hirschfeld	**2022[1]**	**64,706**	**23 Nov 21**	**0.115**	**—**	**30 Jun 26**
	2021	—	—	—	—	—
Agu Kantsler	**2022[1]**	**161,765**	**23 Nov 21**	**0.115**	**—**	**30 Jun 26**
	2021	—	—	—	—	—
Michael McCormack	**2022[1]**	**300,420**	**23 Nov 21**	**0.115**	**—**	**30 Jun 26**
	2021	—	—	—	—	—
Sub-total	**2022**	**850,421**				
	2021	—				
Executives						
Leon Devaney	**2022**	**—**	**—**	**—**	**—**	**—**
	2021[2]	496,171	11 Nov 20	$0.130	—	30 Jun 25
Ross Evans	**2022**	**—**	**—**	**—**	**—**	**—**
	2021[2]	405,655	11 Nov 20	$0.130	—	30 Jun 25
Damian Galvin	**2022**	**—**	**—**	**—**	**—**	**—**
	2021[2]	243,198	11 Nov 20	$0.130	—	30 Jun 25
Duncan Lockhart	**2022**	**—**	**—**	**—**	**—**	**—**
	2021[2]	304,213	11 Nov 20	$0.130	—	30 Jun 25
Robin Polson	**2022**	**—**	**—**	**—**	**—**	**—**
	2021[2]	246,979	11 Nov 20	$0.130	—	30 Jun 25
Daniel White	**2022**	**—**	**—**	**—**	**—**	**—**
	2021[2]	327,269	11 Nov 20	$0.130	—	30 Jun 25
	2021	1,510,476	24 Jul 20	$0.065	—	30 Jun 25
Sub-total	**2022**	**—**				
	2021	3,533,961				
Total	**2022**	**850,421**				
	2021	3,533,961				

1 Represents a portion of Directors Fees sacrificed for FY2022. These Share Rights vested on 30 June 2022 – Refer Section L of this report.
2 Represents FY2020 STIP settled as Equity in the form of deferred share rights.

J. Remuneration Details – Statutory tables (continued)

The following factors and assumptions were used in determining the fair value of rights granted to key management personnel during 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 L of this report.

The following factors and assumptions were used in determining the fair value of rights granted to key management personnel during FY2021:

Grant Date	Expiry Date	Fair Value Per Right	Exercise Price	Price of Shares at Grant Date	Estimated Volatility	Risk Free Interest Rate	Dividend Yield
24 Jul 2020[1]	30 Jun 2025	$0.065	Nil	$0.089	72%	0.43%	—
11 Nov 2020[2]	30 Jun 2025	$0.130	Nil	$0.130	N/A	N/A	—

[1] LTIP Rights for the plan year commencing 1 July 2020.
[2] Deferred Share Rights awarded in lieu of cash under the STIP for the year ended 30 June 2020.

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

		Maximum Number of Rights Eligible for Vesting	LTIP Year Commencing	STIP Year Commencing	Number of Rights Vested[1]	Proportion of LTIP Rights Vested[2]	Proportion of LTIP Rights Forfeited[3]
Leon Devaney	**2022**	—	—	—	—	—	—
	2021	1,837,109	01 Jul 18	N/A	578,689	31.5%	68.5%
Ross Evans	**2022**	—	—	—	—	—	—
	2021	778,854	01 Jul 18	N/A	245,339	31.5%	68.5%
Robin Polson	**2022**	—	—	—	—	—	—
	2021	603,491	01 Jul 18	N/A	190,099	31.5%	68.5%
Daniel White	**2022**	**983,204**	**01 Jul 19**	**N/A**	**422,777**	**43.0%**	**57.0%**
	2021	804,984	01 Jul 18	N/A	253,569	31.5%	68.5%
Total	**2022**	**983,204**			**422,777**	**43.0%**	**57.0%**
	2021	4,024,438			1,267,696	31.5%	**68.5%**

[1] The number of Rights that vested during FY2021 relates to Rights granted in prior financial years under the Long Term Incentive Plan.
[2] The proportion of Rights vested represents the proportion of the maximum number of Rights that were eligible for vesting during the financial year under the Long Term Incentive Plan.
[3] Prior to forfeiture and at the discretion of the Board, Rights may be subjected to retest against the performance hurdles at 31 December 2022.

In addition, 850,421 Share Rights vested on 30 June 2022, 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.

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 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).

In FY2022, Non-Executive Directors were entitled to sacrifice up to 25% of their Base Fee to earn Share Rights which vested on 30 June 2022.

J. Remuneration Details – Statutory tables (continued)

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 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	**2022**	**—**	**161,765**	**—**	**—**	**N/A**	**161,765**	**—**
	2021	—	—	—	—	N/A	—	—
Stephen Gardiner	**2022**	**N/A**	**161,765**	**—**	**—**	**N/A**	**161,765**	**—**
	2021	N/A	—	—	—	N/A	N/A	N/A
Katherine Hirschfeld	**2022**	**—**	**64,706**	**—**	**—**	**N/A**	**64,706**	**—**
	2021	—	—	—	—	N/A	—	—
Agu Kantsler	**2022**	**—**	**161,765**	**—**	**—**	**N/A**	**161,765**	**—**
	2021	—	—	—	—	N/A	—	—
Michael McCormack	**2022**	**—**	**300,420**	**—**	**—**	**N/A**	**300,420**	**—**
	2021	N/A	—	—	—	N/A	—	—
Sub-total	**2022**	**—**	**850,421**	**—**	**—**	**N/A**	**850,421**	**—**
	2021	—	—	—	—	N/A	—	—
Executives								
Leon Devaney	**2022**	**2,333,280**	**—**	**(1,258,420)**	**—**	**N/A**	**—**	**1,074,860**
	2021	2,727,734	496,171	(890,625)	—	N/A	—	2,333,280
Ross Evans	**2022**	**1,184,509**	**—**	**(533,515)**	**(245,339)**	**N/A**	**—**	**405,655**
	2021	778,854	405,655	—	—	N/A	—	1,184,509
Damian Galvin	**2022**	**243,198**	**—**	**—**	**—**	**N/A**	**—**	**243,198**
	2021	—	243,198	—	—	N/A	—	243,198
Duncan Lockhart	**2021**	**304,213**	**—**	**—**	**—**	**N/A**	**—**	**304,213**
	2021	—	304,213	—	—	N/A	—	304,213
Robin Polson[1]	**2022**	**N/A**	**—**	**—**	**—**	**N/A**	**N/A**	**N/A**
	2021	603,491	246,979	—	—	850,470	N/A	N/A
Daniel White	**2022**	**3,625,933**	**—**	**(551,415)**	**(253,569)**	**N/A**	**—**	**2,820,949**
	2021	2,524,507	1,837,745	(736,319)	—	N/A	—	3,625,933
Sub-total	**2022**	**7,691,133**	**—**	**(2,343,350)**	**(498,908)**	**—**	**—**	**4,848,875**
	2021	6,634,586	3,533,961	(1,626,944)	—	850,470	—	7,691,133
Total	**2022**	**7,691,133**	**850,421**	**(2,343,350)**	**(498,908)**	**—**	**850,421**	**4,848,875**
	2021	6,634,586	3,533,961	(1,626,944)	—	850,470	—	7,691,133

[1] Robin Polson resigned 30 June 2021. Of the 850,470 Share Rights held at that date, 437,078 Share Rights were cancelled post departure.

J. Remuneration Details – Statutory tables (continued)

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

Table 7: Vesting profile of Share Rights Holdings of Key Management Personnel

	Grant Date	Type	Maximum Number of Unvested Rights at 30 June 2022	Vesting Date	Maximum value yet to vest[2]
Key Management Personnel					
Leon Devaney	TBD[1]	Deferred Share Rights – FY2022 EIP[1]	—	—	199,892
	11 Nov 2020	Deferred Share Rights – STIP[3]	496,171	01 Jul 2023	16,126
Ross Evans	TBD[1]	Deferred Share Rights – FY2022 EIP[1]	—	—	109,007
	11 Nov 2020	Deferred Share Rights - STIP[3]	405,655	01 Jul 2023	13,184
Damian Galvin	TBD[1]	Deferred Share Rights – FY2022 EIP[1]	—	—	71,992
	11 Nov 2020	Deferred Share Rights - STIP[3]	243,198	01 Jul 2023	7,904
Duncan Lockhart	TBD[1]	Deferred Share Rights – FY2022 EIP[1]	—	—	87,197
	11 Nov 2020	Deferred Share Rights - STIP[3]	304,213	01 Jul 2023	9,887
Jonathan Snape	TBD[1]	Deferred Share Rights – FY2022 EIP[1]	—	—	70,278
Daniel White	TBD[1]	Deferred Share Rights – FY2022 EIP[1]	—	—	96,773
	23 Aug 2019	Share Rights - LTIP	983,204	30 Jun 2022	—
	24 Jul 2020	Share Rights - LTIP	1,510,476	30 Jun 2023	32,727
	11 Nov 2020	Deferred Share Rights - STIP[3]	327,269	01 Jul 2023	10,636
Total			**4,270,186**		**725,603**

1 Share rights as part of the FY2022 EIP are expected to be granted during FY2023. 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 2022 quarterly report, which is calculated as 9.9 cents per right.
2 The maximum value of the share rights yet to vest has been determined as the amount of the grant date fair value of the rights that is yet to be expensed. For the FY2022 EIP, the maximum value yet to vest was estimated based on the share price at 30 June 2022. The minimum value to vest is nil, as the rights will be forfeited if the vesting conditions are not met.
3 The FY2020 STIP was awarded as rights to deferred shares instead of cash.

Table 8: Options Holdings of Key Management Personnel

Share Options		Number of Options Held at Start of Year	Options Granted as Compensation	Exercise Price	Expiry Date	Cancelled or Expired During the Year	Exercised and Converted to Shares	Retained on Departure	Number of Options Held at End of Year (Unvested)
Key Management Personnel									
Leon Devaney	**2022**	**5,105,000**	**—**	**—**	**—**	**—**	**—**	**N/A**	**5,105,000**
	2021	5,105,000	—	—	—	—	—	N/A	5,105,000
Ross Evans	**2022**	**4,170,025**	**—**	**—**	**—**	**—**	**—**	**N/A**	**4,170,025**
	2021	4,170,025	—	—	—	—	—	N/A	4,170,025
Damian Galvin	**2022**	**2,750,000**	**—**	**—**	**—**	**—**	**—**	**N/A**	**2,750,000**
	2021	2,750,000	—	—	—	—	—	N/A	2,750,000
Duncan Lockhart	**2022**	**3,333,333**	**—**	**—**	**—**	**—**	**—**	**N/A**	**3,333,333**
	2021	3,333,333	—	—	—	—	—	N/A	3,333,333
Robin Polson[1]	**2022**	**N/A**	**—**	**—**	**—**	**—**	**—**	**N/A**	**N/A**
	2021	2,792,758	—	—	—	—	—	(2,792,758)	N/A
Total	**2022**	**15,358,358**	**—**	**—**	**—**	**—**	**—**	**—**	**15,358,358**
	2021	18,151,116	—	—	—	—	—	(2,792,758)	15,358,358

1 Robin Polson resigned 30 June 2021. 930,070 options were cancelled post departure.

J. Remuneration Details – Statutory tables (continued)

Table 9: Shareholdings of Key Management Personnel

Ordinary Shares		Held at Beginning of Year	Held at Date of Appointment	SPP & On Market Purchase	Exercise of Rights	Net Change Other	Held at Date of Departure	Held at End of Year
Non-Executive Directors								
Stuart Baker	**2022**	**—**	**N/A**	**—**	**—**	**—**	**N/A**	**—**
	2021	—	N/A	—	—	—	N/A	—
Julian Fowles[1]	**2022**	**N/A**	**N/A**	**—**	**—**	**—**	**N/A**	**N/A**
	2021	100,000	N/A	—	—	—	(100,000)	N/A
Stephen Gardiner[2]	**2022**	**N/A**	**—**	**—**	**—**	**—**	**N/A**	**—**
	2021	N/A	N/A	—	—	—	N/A	N/A
Wrixon Gasteen[3]	**2022**	**N/A**	**N/A**	**—**	**—**	**—**	**N/A**	**N/A**
	2021	793,337	N/A	—	—	—	(793,337)	N/A
Katherine Hirschfeld	**2022**	**760,850**	**N/A**	**—**	**—**	**—**	**N/A**	**760,850**
	2021	760,850	N/A	—	—	—	N/A	760,850
Agu Kantsler	**2022**	**—**	**—**	**—**	**—**	**—**	**N/A**	**—**
	2021	—	—	—	—	—	N/A	—
Michael McCormack[4]	**2022**	**—**	**—**	**—**	**—**	**—**	**N/A**	**—**
	2021	N/A	—	—	—	—	N/A	—
Sub-total	**2022**	**760,850**	**—**	**—**	**—**	**—**	**N/A**	**760,850**
	2021	1,654,187	—	—	—	—	(893,337)	760,850
Other Key Management Personnel								
Leon Devaney	**2022**	**2,606,757**	**N/A**	**—**	**—**	**—**	**N/A**	**2,606,757**
	2021	2,606,757	N/A	—	—	—	N/A	2,606,757
Ross Evans	**2022**	**140,845**	**N/A**	**—**	**245,339**	**—**	**N/A**	**386,184**
	2021	140,845	N/A	—	—	—	N/A	140,845
Damian Galvin	**2022**	**141,000**	**N/A**	**—**	**—**	**—**	**N/A**	**141,000**
	2021	141,000	N/A	—	—	—	N/A	141,000
Duncan Lockhart	**2022**	**—**	**N/A**	**—**	**—**	**—**	**N/A**	**—**
	2021	—	N/A	—	—	—	N/A	—
Robin Polson[5]	**2022**	**N/A**	**N/A**	**—**	**—**	**—**	**N/A**	**N/A**
	2021	94,598	N/A	—	—	—	(94,598)	N/A
Jonathan Snape[6]	**2022**	**N/A**	**—**	**—**	**—**	**—**	**N/A**	**—**
	2021	N/A	N/A	—	—	—	N/A	N/A
Daniel White	**2022**	**2,309,074**	**N/A**	**—**	**253,569**	**—**	**N/A**	**2,562,643**
	2021	2,309,074	N/A	—	—	—	N/A	2,309,074
Sub-total	**2022**	**5,197,676**	**—**	**—**	**498,908**	**—**	**—**	**5,696,584**
	2021	5,292,274	—	—	—	—	(94,598)	5,197,676
Total KMP	**2022**	**5,958,526**	**—**	**—**	**498,908**	**—**	**—**	**6,457,434**
	2021	6,946,461	—	—	—	—	(987,935)	5,958,526

1 Julian Fowles resigned 31 October 2020.
2 Stephen Gardiner was appointed 1 July 2021.
3 Wrixon Gasteen resigned 28 November 2020.
4 Michael McCormack was appointed Director on 1 September 2020.
5 Robin Polson resigned 30 June 2021.
6 Jonathan Snape commenced 1 July 2021.

K. Executive Service Agreements

The details of service agreements of the key management personnel of the Consolidated Entity as of 1 July 2022 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	$654,572	6-months
Ross Evans	Chief Operations Officer	01 Dec 2022	$535,557	6-months
Damian Galvin	Chief Financial Officer	Full time permanent	$353,926	6-months
Duncan Lockhart	General Manager Exploration[3]	08 Jul 2022	$409,450	6-months
Jonathan Snape	Chief Commercial Officer	Full time permanent	$345,514	3-months
Daniel White	Group General Counsel & Company Secretary	Full time permanent	$475,523	3-months

[1] Total Annual Fixed Remuneration, effective 1 July 2022 includes compulsory superannuation contributions.
[2] In certain exceptional circumstances (such as breach or gross misconduct) a shorter notice period applies.
[3] Duncan Lockhart resigned effective 31 August 2022.

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

L. Non-Executive Director Fee Arrangements

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

The table below summarises the Non-Executive Director fees for FY2022. Directors had the discretion to sacrifice up to 25% of their FY22 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 2021.

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

FY2022 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.

Signed in accordance with a resolution of the directors:

Michael McCormack
Chair

16 September 2022

pwc

Auditor's Independence Declaration

As lead auditor for the audit of Central Petroleum Limited for the year ended 30 June 2022, 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
16 September 2022

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FINANCIAL REPORT

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

The Financial Statements are presented in Australian currency.

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

Level 7, 369 Ann Street
Brisbane, Queensland 4000

A description of the nature of the Consolidated Entity's operations and its principal activities is included in the operating and financial review on pages 3 to 26. These pages are not part of these financial statements.

The financial statements were authorised for issue by the Directors on 16 September 2022. 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 2022

	NOTE	2022 $'000	2021 $'000
Revenue from contracts with customers – sale of hydrocarbons	2	42,151	59,827
Cost of sales		(21,257)	(28,852)
Gross profit		**20,894**	**30,975**
Other income	3	37,300	155
Exploration expenditure		(21,647)	(7,739)
Employee benefits and associated costs net of recoveries	4(b)	(1,594)	(2,180)
Share based employment benefits	32(f)	(1,524)	(1,862)
General and administrative expenses net of recoveries		(1,043)	(924)
Depreciation and amortisation	4(a)	(6,779)	(12,503)
Finance costs	4(a)	(4,287)	(5,671)
Profit before income tax		**21,320**	**251**
Income tax expense	5	—	—
Profit for the year		**21,320**	**251**
Other comprehensive profit/(loss) for the year, net of tax		—	—
Total comprehensive profit for the year		**21,320**	**251**
Total comprehensive profit attributable to members of the parent entity		**21,320**	**251**
Earnings per share for profit or loss attributable to the ordinary equity holders of the company:			
Basic earnings per share (cents)	23	**2.94**	**0.03**
Diluted earnings per share (cents)	23	**2.88**	**0.03**

The accompanying notes form part of these financial statements.

CONSOLIDATED BALANCE SHEET
AS AT 30 JUNE 2022

	NOTE	2022 $'000	2021 $'000
ASSETS			
Current assets			
Cash and cash equivalents	7	21,647	37,159
Trade and other receivables	8	26,872	7,111
Inventories	9	3,868	1,621
Assets classified as held for sale	10	—	57,968
Total current assets		52,387	103,859
Non-current assets			
Property, plant and equipment	11	53,846	53,988
Right of use assets	12	922	1,455
Exploration assets	13	8,397	8,397
Intangible assets	14	379	302
Other financial assets	15	4,410	4,218
Goodwill	16	1,953	1,953
Total non-current assets		69,907	70,313
Total assets		**122,294**	**174,172**
LIABILITIES			
Current liabilities			
Trade and other payables	17	13,526	10,491
Deferred revenue	2(b)	5,309	5,244
Borrowings	18(a)	4,500	36,000
Lease liabilities	12	413	517
Provisions	19	6,325	3,918
Liabilities directly associated with assets classified as held for sale	10	—	39,436
Total current liabilities		30,073	95,606
Non-current liabilities			
Deferred revenue	2(b)	13,614	15,697
Borrowings	18(b)	26,309	30,809
Lease liabilities	12	588	992
Provisions	19	25,180	27,379
Total non-current liabilities		65,691	74,877
Total liabilities		**95,764**	**170,483**
Net assets		**26,530**	**3,689**
EQUITY			
Contributed equity	20 (a)	197,776	197,776
Reserves	21	30,615	29,094
Accumulated losses	22	(201,861)	(223,181)
Total equity		**26,530**	**3,689**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

FOR THE YEAR ENDED 30 JUNE 2022

	Contributed Equity $'000	Reserves $'000	Accumulated Losses $'000	Total $'000
Balance at 1 July 2020	**197,776**	**27,238**	**(223,432)**	**1,582**
Total profit for the year	—	—	251	251
Other comprehensive loss	—	—	—	—
Total comprehensive loss for the year	—	—	251	251
Transactions with owners in their capacity as owners				
Share based payments	—	1,862	—	1,862
Share issue costs	—	(6)	—	(6)
	—	1,856	—	1,856
Balance at 30 June 2021	**197,776**	**29,094**	**(223,181)**	**3,689**
Total profit for the year	—	—	21,320	21,320
Other comprehensive loss	—	—	—	—
Total comprehensive loss 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**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED 30 JUNE 2022

	NOTE	2022 $'000	2021 $'000
Cash flows from operating activities			
Receipts from customers		44,333	65,539
Interest received		59	82
Other income		42	73
Government grants		11	1,367
Interest and borrowing costs		(2,472)	(3,924)
Payments for exploration expenditure		(10,121)	(5,461)
Payments to other suppliers and employees		(28,212)	(33,540)
Net cash inflow from operating activities	28	3,640	24,136
Cash flows from investing activities			
Payments for property, plant and equipment		(10,791)	(6,489)
Proceeds from sale of producing assets, and property, plant and equipment	3(a)	28,305	9
Proceeds and deposits for the disposal of exploration permits		—	—
Lodgement of security deposits and bonds		(108)	(1,562)
Net cash inflow/(outflow) from investing activities		17,406	(8,042)
Cash flows from financing activities			
Payments for the issue of securities		(3)	(5)
Repayment of borrowings	29(b)	(36,000)	(4,000)
Transaction costs related to borrowings		—	(220)
Principal elements of lease payments	29(b)	(561)	(622)
Net cash outflow from financing activities		(36,564)	(4,847)
Net (decrease)/increase in cash and cash equivalents		**(15,518)**	**11,247**
Cash and cash equivalents at the beginning of the financial year		**37,165**	**25,918**
Cash and cash equivalents at the end of the financial year	7	**21,647**	**37,165**

The accompanying notes form part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

(a) Basis of Preparation

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

Rounding of Amounts

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

(i) Going Concern

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

(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 2021 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 evaluation activity. The Group makes provision for future restoration expenditure relating to work previously undertaken based on management's estimation of the work required and by obtaining cost estimates from relevant experts. Further information on the nature and carrying amount of restoration and rehabilitation obligations can be found in Note 19.

Share-based Payments

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(a) Basis of Preparation (continued)

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 cost of production, regulatory changes and commodity price movements. 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 13.

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 11, 12, 14 and 16. Testing for impairment of goodwill and other non-financial assets in FY2022 was assessed against a recent market transaction (refer Note 3(a)).

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 Profit or Loss and Other 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 statement of comprehensive income, statement of changes in equity and balance sheet respectively.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(b) Principles of Consolidation (continued)

(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 35.

(c) Segment Reporting

Operating segments are reported in Note 24 in a manner consistent with the internal reporting provided to the chief operating decision makers. The chief operating decision makers, who are responsible for allocating resources and assessing performance of the operating segments, have been identified as the Executive Management Team.

(d) Foreign Currency Translation

(i) Functional and Presentation Currency

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

(ii) Transactions and Balances

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

(e) Revenue Recognition

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

(i) Revenue from the sale of hydrocarbons

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

(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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(e) Revenue Recognition (continued)

(iii) Contract Liabilities

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

(iv) Interest Income

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

(f) Government Grants

Cash grants from the government, including research and development concessions, are recognised at their fair value where there is a reasonable assurance that the grant or refund will be received, and the Group has or will comply with any conditions attaching to the grant or refund. Research and development grants are recognised as other income in the profit and loss where they relate to exploration expenditure which has been expensed in the profit and loss. Grants in the form of wages subsidies are credited against employee costs. Non-monetary grants are recognised at a nominal amount.

(g) Income Tax

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

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

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

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

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 12(c).

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(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.

(k) Trade Receivables

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

The Group considers an allowance for expected credit losses (ECLs) for all receivables. The Group applies a simplified approach in calculating ECLs which is based on an assessment on its historical credit loss experience, adjusted for factors specific to the debtors and the economic environment. This includes, but is not limited to, financial difficulties of the debtor, probability that the debtor will enter bankruptcy or financial reorganisation and delinquency in payments. Information about the impairment of trade receivables and the Group’s exposure to credit risk, foreign currency risk and interest rate risk can be found in Note 33.

(l) Inventories

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

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

(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 15).

(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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

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

(i) Assets in Development

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

(ii) Producing Assets

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

Depreciation of producing assets is calculated for an asset or group of assets from the date of commencement of production. Depletion charges are calculated using the units of production method which will amortise the cost of carried forward exploration, evaluation, 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	40 years
Leasehold Improvements	2 – 6 years
Plant and Equipment	2 – 30 years
Motor Vehicles	5 – 10 years

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(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.

Goodwill is allocated to cash generating units for the purpose of impairment testing. The allocation is made to those cash-generating units or groups of cash-generating units that are expected to benefit from the business combination in which the goodwill arose. The units or groups of units are identified at the lowest level at which goodwill is monitored for internal management purposes, being the producing assets segments (Note 24).

(r) Trade and Other Payables

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

(s) Provisions

(i) Restoration and Rehabilitation

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

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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(s) Provisions

(iii) Other

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

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

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

(t) Employee Benefits

(i) Short-term Obligations

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

(ii) Long-term Employee Benefit Obligations

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

(iii) Share-based Payments

Share-based compensation benefits are provided to employees 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 terminations 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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(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.

(ii) Diluted Earnings Per Share

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

(x) Goods and Services Tax (GST)

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

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

(y) Parent Entity Financial Information

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

(z) Business Combinations

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

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

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

The excess of the:

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

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(z) Business Combinations (continued)

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

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

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

(aa) Standards, Amendments and Interpretations

The Group has applied the following standards and amendments for the first time for their annual reporting period commencing 1 July 2021:

- AASB 2020-4 Amendments to Australian Accounting Standards – Covid-19-Related Rent Concessions [AASB 16], and
- AASB 2020-8 Amendments to Australian Accounting Standards – Interest Rate Benchmark Reform – Phase 2 [AASB 4, AASB 7, AASB 9, AASB 16 and AASB 139]

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

	2022 $'000	2021 $'000
Sale of hydrocarbon products - point in time		
Natural gas	36,255	54,355
Crude oil and condensate	5,896	5,472
Total revenue from contracts with customers	**42,151**	**59,827**

Revenue relating to contracts with major customers is disclosed in Note 24(f) – Segment Reporting.

(b) Contract Liabilities

	2022			2021		
	Current $'000	**Non-current $'000**	**Total $'000**	Current $'000	Non-current $'000	Total $'000
Deferred Revenue – take-or-pay contracts[1]	1,357	11,857	13,214	1,357	11,017	12,374
Deferred Revenue – other gas sales contracts[2]	3,952	1,757	5,709	3,887	4,680	8,567
Total contract liabilities	**5,309**	**13,614**	**18,923**	**5,244**	**15,697**	**20,941**

1 Take-or-pay proceeds received are taken to revenue at the earlier of physical delivery of the gas to the customer, or upon forfeiture of the right to gas under the contract. No revenue has been recognised during the year for gas forfeited under take-or-pay contracts.

2 Deferred Revenue from other contracts represents gas pre-sold to customers which is yet to be delivered. Amounts are recognised as Deferred Revenue when no cash settlement option exists for the customer. Where a cash settlement option previously existed, the amount transferred to Deferred Revenue is the equivalent fair value of that cash settlement option at the time that option ceased to be available.

Movements in contract liabilities during the year included a reduction of $5,186,000 (2021: $7,908,000) recognised as revenue from amounts included in contract liabilities at the beginning of the year, partly offset by increases arising from finance charges, new take or pay amounts received or accrued and adjustments to reflect the disposal of 50% of the Group's interests in the Amadeus Basin producing properties on 1 October 2021.

3. OTHER INCOME

	2022 $'000	2021 $'000
Interest	63	76
Income from financial assets at amortised cost	665	—
Profit on disposal of 50% of interests in Amadeus Basin producing properties (a)	36,559	—
Profit on disposal of inventory and other assets	13	79
Total other income	**37,300**	**155**

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

On 25 May 2021, the Group announced it had entered into a binding agreement with New Zealand Oil and Gas Limited and Cue Energy Resources Limited to sell 50% of the Group's interests in its Amadeus Basin Producing Assets with an effective date of 1 July 2020. The transaction completed on 1 October 2021 with the Group recording an accounting profit after tax of $36,559,000 comprised as follows:

	$'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

(a) Profit before income tax includes the following specific expenses

	NOTE	2022 $'000	2021 $'000
Depreciation			
Buildings	11	176	332
Producing assets	11	3,384	6,942
Plant and equipment	11	2,582	4,577
Leasehold improvements	11	16	40
Right of use assets	12(b)	521	514
Total depreciation		**6,679**	**12,405**
Amortisation			
Software	14	100	98
Rental expense relating to operating leases not recognised on the Balance Sheet – Minimum lease payments	12(b)	—	9
Finance costs			
Interest and fees on debt facilities		2,394	4,074
Interest on lease liabilities	12(b)	78	70
Amortisation of deferred finance costs		—	36
Accretion charges		1,815	1,491
Total finance costs		**4,287**	**5,671**

4. EXPENSES (CONTINUED)

(b) Government Grants

During the year $11,000 (2021: $218,000) was received from the Northern Territory Government as training incentives for operational staff and recognised against net employee costs.

During the previous financial year, the Company recognised subsidies totalling $891,000 from the Australian Government against net employee costs. These subsidies were in response to the impacts of COVID-19 and received under the JobKeeper support package available to eligible affected businesses. No subsidies were received in the current financial year.

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.

	2022 $'000	2021 $'000
(a) Income tax expense		
Current tax	—	—
Deferred tax	—	—
Income tax expense	**—**	**—**

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

	2022 $'000	2021 $'000
Profit before income tax expense	21,320	251
Prima facie tax expense at 30% (2021: 30%)	6,396	75
Tax effect of amounts which are not deductible in calculating taxable income:		
Non-deductible expenses	4	18
Share based payments	457	559
Other items	16	10
Sub-total	6,873	662
Recognition of previously unrecognised deferred tax assets	(6,873)	(662)
Income tax expense	**—**	**—**

(c) Amounts recognised directly in equity

	2022 $'000	2021 $'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	2
Deferred tax assets not recognised	(1)	(2)
Net amounts recognised directly in equity	**—**	**—**

(d) Tax Losses

	2022 $'000	2021 $'000
Unutilised tax losses for which no deferred tax asset has been recognised	139.120	139,107
Potential tax benefit at 30%	**41,736**	**41,732**

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

	2022 $'000	2021 $'000
Deferred tax assets		
Provisions and accruals	9,507	14,469
Deferred revenue	372	999
Other expenditure	125	279
Borrowing costs	68	95
Unutilised losses	51,222	52,695
Total deferred tax assets before set-offs	61,294	68,537
Set-off of deferred tax liabilities pursuant to set-off provisions	(9,487)	(10,963)
Net deferred tax assets not recognised	**51,807**	**57,574**
Movements in deferred tax assets		
Opening balance at 1 July	10,963	14,276
Charged to the income statement	(1,476)	(3,313)
Closing balance at 30 June	**9,487**	**10,963**
Deferred tax assets to be recovered after more than 12-months	7,248	8,905
Deferred tax assets to be recovered within 12-months	2,239	2,058
	9,487	**10,963**
Deferred tax liabilities		
Capitalised exploration	2,475	2,516
Property, plant and equipment	7,012	8,447
Total deferred tax liabilities before set-offs	9,487	10,963
Set-off of deferred tax assets pursuant to set-off provisions	(9,487)	(10,963)
Net deferred tax liabilities	**—**	**—**
Movements in deferred tax liabilities		
Opening balance at 1 July	10,963	14,276
Credited to the income statement	(1,476)	(3,313)
Closing balance at 30 June[1]	**9,487**	**10,963**
Deferred tax liabilities to be recovered after more than 12-months	9,487	10,963
Deferred tax liabilities to be recovered within 12-months	—	—
	9,487	**10,963**

[1] At 30 June 2021 $4,781,000 of Deferred Tax Liabilities related to assets and liabilities classified as held for sale.

6. REMUNERATION OF AUDITORS

	2022 $	2021 $
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	208,963	202,956
(ii) Taxation services		
Income Tax compliance	9,588	9,129
Other tax related services	10,579	26,864
Total taxation services	20,167	35,993
Total remuneration of PwC	**229,130**	**238,949**

7. CASH AND CASH EQUIVALENTS

	2022 $000	2021 $000
Cash and cash equivalents	**21,647**	**37,165**
Made up as follows:		
Corporate cash and bank balances (a)	20,577	36,281
Joint arrangements (b)	1,070	878
Cash and cash equivalents per Balance Sheet	**21,647**	**37,159**
Bank balances included in assets classified as held for sale (Note 10)	—	6
Total cash and cash equivalents	**21,647**	**37,165**

(a) $4,725,000 of this balance relates to cash held with Macquarie Bank Limited to be used for allowable purposes under the Facility Agreement (2021: $11,112,000), 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 33.

8. TRADE AND OTHER RECEIVABLES

	2022 $'000	2021 $'000
Current		
Trade debtors	639	—
Accrued income and recoveries (a)	3,533	5,628
Other receivables	578	456
Prepayments	1,302	1,027
Items measured at fair value through profit and loss:		
Deferred receivable from partial sale of producing assets (b)	20,820	—
	26,872	**7,111**

(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.

Due to the nature of the Group's receivables, their carrying values are considered to approximate their fair values. The Group applies the simplified approach to providing for expected credit losses (refer Note 33(a)).

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(a)). This is classified as a Financial Asset measured at amortised cost. During the year, $9,695,000 was recouped through a free carry by the purchasers of Central's share of expenditure on certain exploration and development projects. An amount of $665,000 (2021: Nil) was recognised as Other Income as a result of adjustments to amortised cost for the period.

9. INVENTORIES

	2022 $'000	2021 $'000
Crude oil and natural gas	45	28
Spare parts and consumables	1,228	1,035
Drilling materials and supplies at cost	2,595	558
	3,868	**1,621**

10. ASSETS AND LIABILITIES CLASSIFIED AS HELD FOR SALE

At 30 June 2021, assets of $57,968,000 were classified as held for sale and liabilities of $39,436,000 were associated with the sale of 50% of the Group's interest in its producing assets in the Northern Territory. The transaction subsequently completed on 1 October 2021.

There were no assets classified as held for sale or associated liabilities at 30 June 2022.

At 30 June 2021, the major classes of assets comprising the sale interests classified as held for sale and associated liabilities were as follows:

	2021 $'000
Assets classified as held for sale	
Cash	6
Receivables	175
Inventories	1,053
Property plant and equipment	54,294
Right of use assets	145
Intangibles	17
Exploration assets	325
Goodwill	1,953
Total assets classified as held for sale	**57,968**

	2021 $'000
Liabilities directly associated with assets classified as held for sale	
Trade and other payables	1,596
Current deferred revenue	5,244
Current lease liabilities	26
Non-current deferred revenue	15,697
Non-current lease liabilities	124
Non-current provisions	16,749
Total liabilities directly associated with assets classified as held for sale	**39,436**

11. PROPERTY, PLANT AND EQUIPMENT

	Freehold Land and Buildings $'000	Producing Assets $'000	Plant and Equipment $'000	Total $'000
Year ended 30 June 2021				
Opening net book amount	2,179	68,596	37,070	107,845
Additions	—	5,937	5,855	11,792
Changes to rehabilitation estimates	—	536	4	540
Disposals and write offs	—	—	(4)	(4)
Depreciation charge	(332)	(6,942)	(4,617)	(11,891)
Reclassified as held for sale	(917)	(34,254)	(19,123)	(54,294)
Closing net book amount	**930**	**33,873**	**19,185**	**53,988**
At 30 June 2021				
Cost	1,952	53,381	40,211	95,544
Accumulated depreciation	(1,022)	(19,508)	(21,026)	(41,556)
Net book amount at 30 June 2021	**930**	**33,873**	**19,185**	**53,988**
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**

At 30 June 2022, $2,011,000 of property plant and equipment balances relates to assets under construction and is not subject to depreciation until complete (2021: $3,015,000).

12. LEASES

(a) Amounts recognised in the balance sheet

The balance sheet shows the following amounts relating to leases:

	2022 $'000	2021 $'000
Right-of-use assets		
Land & Buildings	832	1,211
Plant & Equipment	90	244
	922	**1,455**
Lease Liabilities		
Current	413	517
Non-current	588	992
	1,001	**1,509**

Additions to the right-of-use assets during the 2022 financial year were $24,000 (2021: $1,055,000). Disposals and incentive adjustments amounted to $36,000 (2021: Nil).

12. LEASES (CONTINUED)

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

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

	2022 $'000	2021 $'000
Depreciation charge of right-of-use assets		
Land & Buildings	367	359
Plant & Equipment	154	155
Total depreciation of right-of-use assets	**521**	**514**
Interest expense	78	70
Expense related to short term leases included in cost of sales and general and administrative expenses	—	9

The total cash outflow for leases in 2022 was $638,000 (2021: $691,000).

(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 8 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.

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.

12. LEASES (CONTINUED)

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

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.

13. EXPLORATION ASSETS

	2022 $'000	2021 $'000
Acquisition costs of right to explore	**8,397**	**8,397**
Movement for the year:		
Balance at the beginning of the year	8,397	8,722
Reclassified as held for sale (Note 10)	—	(325)
Balance at the end of the year	**8,397**	**8,397**

14. INTANGIBLE ASSETS

	2022 $'000	2021 $'000
Software		
At the beginning of the year		
Cost	848	788
Accumulated amortisation	(546)	(476)
Net book value	**302**	**312**
Movements for the year		
Opening net book amount	302	312
Additions	177	105
Amortisation	(100)	(98)
Reclassified as held for sale	—	(17)
Closing net book amount	**379**	**302**
At the end of the year		
Cost	1,025	848
Accumulated amortisation	(646)	(546)
Net book value	**379**	**302**

15. OTHER FINANCIAL ASSETS

	2022 $'000	2021 $'000
Non-Current		
Security bonds on exploration permits and rental properties	**4,410**	**4,218**

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.

16. GOODWILL

	2022 $'000	2021 $'000
Goodwill arising from business combinations	**1,953**	**1,953**

Movement

As at 30 June 2021, an additional $1,953,000 of goodwill was included in assets held for sale reflecting the 50% disposal interests (refer Note 10). The sale subsequently completed on 1 October 2021 (refer Note 3(a)).

Impairment tests for goodwill

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.

On 25 May 2021 the Group entered into a binding agreement with New Zealand Oil & Gas Limited (NZOG) and Cue Energy Resources Limited (Cue) to sell 50% of the Group's equity interests in its Amadeus Basin producing assets. The transaction completed on 1 October 2021 with the Group recording a book profit on sale of $36.6 million (refer Note 3(a)). The assets disposed represented 50% of the total cash generating unit upon which Central assesses recoverable amount each year.

Management and the Board have concluded that this transaction provides evidence of the fair value of the underlying assets, net of liabilities, being disposed and will therefore adopt the fair value less costs of disposal measurement methodology as at 30 June 2022.

Fair Value Measurement is governed by AASB 13 which defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. It assumes the asset or liability is exchanged in an orderly transaction between market participants at the measurement date under current market conditions.

Management and the Board believe the sale process meets the requirements of an orderly transaction where all parties were acting in their own economic best interests and therefore can be relied upon as evidence of the fair value of the assets being disposed net of the liabilities being transferred. In addition, since the sale completed, the Group announced an increase in 2P reserves at 31 December 2021 and commenced selling gas into the East Coast gas spot market at higher realised prices.

The value of the transaction consideration (grossed up for the value of liabilities assumed by the purchaser) substantially exceeds the net carrying value of the remaining 50% interests in the Amadeus Basin producing assets and associated goodwill. On this basis Management and the Board have concluded there is no impairment of the carrying value of Goodwill or other producing assets at 30 June 2022.

17. TRADE AND OTHER PAYABLES

	2022 $'000	2021 $'000
Current		
Trade payables	7,817	5,312
Other payables	4	31
Accruals	5,705	5,148
	13,526	**10,491**

Trade payables are usually non-interest bearing, provided payment is made within the terms of credit. The Consolidated Entity's exposure to liquidity and currency risks related to trade and other payables is disclosed in Note 33.

18. BORROWINGS

		2022 $'000	2021 $'000
(a)	Current[1]		
	Debt facilities	4,500	36,000
(b)	Non-current[1]		
	Debt facilities	26,309	30,809

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

19. PROVISIONS

	2022			2021		
	Current $'000	Non-Current $'000	Total $'000	Current $'000	Non-Current $'000	Total $'000
Employee entitlements (a)	4,043	878	4,921	3,184	1,084	4,268
Restoration and rehabilitation (b)	1,512	22,120	23,632	—	23,466	23,466
Joint Venture production over-lift (c)	770	2,182	2,952	734	2,829	3,563
	6,325	**25,180**	**31,505**	**3,918**	**27,379**	**31,297**

(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. The amounts are presented as current, since the Consolidated Entity does not have an unconditional right to defer settlement for these obligations. However, based on past experience, the Group does not expect all employees to take the full amount of accrued leave or require payment in the next 12-months. Current leave obligations that are not expected to be taken or paid within the next 12-months amount to $732,000 (2021: $635,000).

(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 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:

2022	Employee Entitlements $'000	Restoration & Rehabilitation $'000	Joint Venture Production Over-Lift $'000	Total $'000
Carrying amount at start of year	4,268	23,466	3,563	31,297
Change in provision charged/(credited) to property, plant and equipment	—	(275)	—	(275)
Additional provisions charged to profit or loss	2,652	65	118	2,835
Unwinding of discount	—	376	—	376
Amounts used during the year	(1,999)	—	(729)	(2,728)
Carrying amount at end of year	**4,921**	**23,632**	**2,952**	**31,505**

20. CONTRIBUTED EQUITY

(a) Share capital

	2022 $'000	2021 $'000
725,907,449 fully paid ordinary shares (2021: 724,093,661)	**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

	2022 Number of Shares	2021 Number of Shares	2022 $'000	2021 $'000
Balance at start of year	724,093,661	723,288,869	197,776	197,776
Shares issued under Employee Incentive Plans	1,813,788	804,792	—	—
Balance at end of year	**725,907,449**	**724,093,661**	**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	$0.200	18,151,116	—	(930,070)	—	17,221,046
Total			**18,151,116**	**—**	**(930,070)**	**—**	**17,221,046**

(c) Share rights

Under the Group's Employee Rights Plan, eligible employees may receive rights to shares in Central Petroleum Limited. The rights are granted in respect of a plan year which commences 1 July each year. The share rights remain unvested until the end of the performance period, which is three years commencing from the start of each plan year. Except in a limited number of 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 eligible employee, being either a fixed dollar amount (which are not subject to performance hurdles) or a percentage of the employee's base salary, divided by the volume weighted average share price at the start of the plan year.

For those determined by performance hurdles, final vesting percentages reference a combination of absolute total shareholder return and relative total shareholder return compared to a specific group of exploration and production companies.

Rights issued to non-executive directors during FY2022 were issued under a fee sacrifice arrangement. The number of rights issued was based on the value of fees sacrificed at a volume weighted average price for the 20 days immediately following the date on which the Company's 2021 full year results were released.

20. 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	13,698	—	(6,849)	—	6,849
Employee LTIP rights	22 May 2024	1 Jul 2018	6,256,980	—	(4,089,787)	(1,813,788)	353,405
Employee LTIP rights	12 Nov 2024	1 Jul 2018	1,837,109	—	(1,258,420)	—	578,689
Employee LTIP rights	30 Jun 2024	1 Jul 2019	6,822,406	—	(514,088)	—	6,308,318
Employee Deferred Share rights[1]	30 Jun 2025	1 Jul 2019	3,692,054	—	—	—	3,692,054
Employee LTIP rights	30 Jun 2025	1 Jul 2020	9,917,120	—	(842,320)	—	9,074,800
Employee LTIP rights	30 Jun 2026	1 Jul 2021	—	450,780	(24,588)	—	426,192
Non-Executive Director rights [2]							
Director Share Rights	30 Jun 2026	1 Jul 2021	—	850,421	—	—	850,421
Total			**28,539,367**	**1,301,201**	**(6,736,052)**	**(1,813,788)**	**21,290,728**

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 30 June 2023.

2 Directors had the discretion to sacrifice up to 25% of their FY 2022 Base Directors Fees to earn share rights. These rights vested on 30 June 2022 and may be exercised any time prior to the expiry date.

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

21. RESERVES

	2022 $'000	2021 $'000
Share options reserve	**29,094**	**27,238**
Movements:		
Balance at start of year	29,094	27,238
Share based payment costs (a)	1,524	1,862
Transaction costs	(3)	(6)
Balance at end of year	**30,615**	**29,094**

(a) Share based payments are provided to employees under the Employee Rights Plan and Executive Share Option Plan. Refer to Note 32 for further details of share-based payments.

22. ACCUMULATED LOSSES

	2022 $'000	2021 $'000
Movements in accumulated losses were as follows:		
Balance at the start of year	(223,181)	(223,432)
Net profit for the year	21,320	251
Balance at end of year	**(201,861)**	**(223,181)**

23. EARNINGS/(LOSS) PER SHARE

		2022	2021
(a)	**Basic earnings per share (cents)**	**2.94**	0.03
(b)	**Diluted earnings per share (cents)**	**2.88**	0.03
(c)	**Profit used in earnings per share calculation**		
	Profit attributed to ordinary equity holders ($'000)	**21,320**	251
(d)	**Weighted average number of ordinary shares**		
	Weighted average number of shares used as the denominator in calculating basic earnings per share	**725,363,955**	**723,619,673**
	Adjustments for the calculation of diluted earnings per share:		
	Employee share rights	15,343,575	17,469,319
	Weighted average number of shares used as the denominator in calculating diluted earnings per share	**740,707,530**	**741,088,992**

Options and Rights on issue are considered to be potential ordinary shares and have not been included in the calculation of basic earnings per share.

24. SEGMENT REPORTING

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

(a) Producing assets

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

(b) Development assets

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

(c) Exploration assets

Exploration and evaluation of permit areas.

(d) Unallocated items

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

(e) Performance monitoring and evaluation

Management monitors the operating results of the operating segments separately for the purpose of making decisions about resource allocation and performance assessment.

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

24. SEGMENT REPORTING (CONTINUED)

(e) Performance monitoring and evaluation (continued)

2022	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	(21,257)	—	—	(21,257)
Gross profit	**20,894**	**—**	**—**	**20,894**
Other income[1]	37,227	10	—	37,237
Share based employee benefits[2]	—	—	(1,524)	(1,524)
General and administrative expenses	—	—	(1,043)	(1,043)
Employee benefits and associated costs	—	—	(1,594)	(1,594)
EBITDAX[3]	**58,121**	**10**	**(4,161)**	**53,970**
Depreciation and amortisation[2]	(6,095)	—	(684)	(6,779)
Exploration expenditure	(15,748)	(5,899)	—	(21,647)
Interest revenue	17	—	46	63
Finance costs	(3,979)	(41)	(267)	(4,287)
Profit / (loss) before income tax	**32,316**	**(5,930)**	**(5,066)**	**21,320**
Taxes	—	—	—	—
Profit / (loss) for the year	**32,316**	**(5,930)**	**(5,066)**	**21,320**
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 Includes $36,559,000 profit on disposal of 50% interest in Amadeus Basin producing properties (Refer Note 3(a)).
2 Non-cash item.
3 EBITDAX is earnings before interest, taxation, depreciation, amortisation, and exploration expense.

24. SEGMENT REPORTING (CONTINUED)

(e) Performance monitoring and evaluation (continued)

2021	Producing Assets 2021 $'000	Exploration Assets 2021 $'000	Unallocated Items 2021 $'000	Consolidation 2021 $'000
Revenue from contracts with customers				
Natural gas	54,355	—	—	54,355
Crude oil and condensate	5,472	—	—	5,472
Total revenue from contracts with customers	**59,827**	**—**	**—**	**59,827**
Cost of sales	(28,852)	—	—	(28,852)
Gross profit	**30,975**	**—**	**—**	**30,975**
Other income	7	70	2	79
Share based employee benefits[1]	—	—	(1,862)	(1,862)
General and administrative expenses	—	—	(924)	(924)
Employee benefits and associated costs	—	—	(2,180)	(2,180)
EBITDAX[2]	**30,982**	**70**	**(4,964)**	**26,088**
Depreciation and amortisation[1]	(11,783)	—	(720)	(12,503)
Exploration expenditure	(1,012)	(6,727)	—	(7,739)
Interest revenue	21	—	55	76
Finance costs	(5,286)	(12)	(373)	(5,671)
Profit / (loss) before income tax	**12,922**	**(6,669)**	**(6,002)**	**251**
Taxes	—	—	—	—
Profit / (loss) for the year	**12,922**	**(6,669)**	**(6,002)**	**251**
Segment assets	**133,492**	**10,264**	**30,416**	**174,172**
Segment liabilities	**(150,774)**	**(5,462)**	**(14,247)**	**(170,483)**
Capital expenditure				
Property, plant and equipment	11,703	—	89	11,792
Intangibles	5	—	99	104
Total capital expenditure	**11,708**	**—**	**188**	**11,896**

	2022 $'000	2021 $'000
Revenue from external customers by geographical location of production:		
Australia	**42,151**	**59,827**
Non-current assets by geographical location:		
Australia	**69,907**	**70,313**

[1] Non-cash item.
[2] EBITDAX is earnings before interest, taxation, depreciation, amortisation, and exploration expense.

24. SEGMENT REPORTING (CONTINUED)

(f) Major Customers

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

	2022 $'000	**% of Sales Revenue**	2021 $'000	% of Sales Revenue
Largest customer	13,622	32%	20,028	33%
Second largest customer	7,850	19%	14,597	24%
Third largest customer	6,478	15%	10,468	17%
Fourth largest customer	4,478	11%	7,803	13%
Fifth largest customer	4,414	10%	—	—

25. PARENT ENTITY INFORMATION

(a) Summary financial information

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

	2022 $'000	2021 $'000
Balance Sheet		
Current assets	23,128	29,855
Non-current assets	19,162	20,938
Total assets	42,290	50,793
Current liabilities	(18,129)	(28,003)
Non-current liabilities	(1,550)	(1,922)
Total liabilities	(19,679)	(29,925)
Net assets	**22,611**	**20,868**
Shareholders' equity		
Issued capital	197,776	197,776
Reserves	30,615	29,094
Accumulated losses	(205,780)	(206,002)
Total equity	**22,611**	**20,868**
Loss for the year	**(223)**	**(3,647)**
Total comprehensive loss	**(223)**	**(3,647)**

(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.

26. RELATED PARTY TRANSACTIONS

(a) Parent Entity

The Parent Entity is Central Petroleum Limited.

(b) Subsidiaries

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

			Equity Holding	
Name of Entity	Place of Incorporation	Class of Shares	**2022 %**	2021 %
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

	2022 $	2021 $
Short-term employee benefits	3,531,962	3,265,233
Post-employment benefits	180,208	172,676
Long-term benefits	43,807	43,447
Share based payments	1,158,763	1,112,075
	4,914,740	**4,593,431**

Detailed remuneration disclosures are provided in the remuneration report on pages 34 to 48.

27. DEED OF CROSS GUARANTEE

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

The parties to the deed of cross guarantee are:

- Central Petroleum Limited
- Central Petroleum Projects Pty Ltd
- Ordiv Petroleum Pty Ltd
- Central Petroleum 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 profit or loss, 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 2022.

	2022 $'000	2021 $'000
Revenue from the sale of goods	13,645	24,984
Cost of sales	(5,981)	(10,342)
Gross profit	7,664	14,642
Other income	29,875	144
Share based employment benefits	(1,524)	(1,862)
General and administrative expenses	(1,025)	(912)
Depreciation and amortisation	(3,345)	(6,534)
Employee benefits and associated costs	(1,057)	(1,470)
Exploration expenditure	(21,647)	(7,736)
Finance costs	(1,740)	(2,871)
Loss before income tax	7,201	(6,599)
Income tax (expense)/ credit	(10)	2,547
Profit/(Loss) for the year	7,191	(4,052)
Other comprehensive profit/(loss) for the year, net of tax	—	—
Total comprehensive profit/(loss) for the year	**7,191**	**(4,052)**
Accumulated losses at the beginning of the financial year	(218,044)	(213,992)
Profit/(loss) for the year	7,191	(4,052)
Accumulated losses at the end of the financial year	**(210,853)**	**(218,044)**

27. DEED OF CROSS GUARANTEE (CONTINUED)

(b) Consolidated balance sheet

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

	2022 $'000	2021 $'000
ASSETS		
Current assets		
Cash and cash equivalents	21,410	37,153
Trade and other receivables	21,557	3,495
Inventories	3,075	899
Assets classified as held for sale	—	28,519
Total current assets	46,042	70,066
Non-current assets		
Property, plant and equipment	24,997	25,733
Right of use assets	858	1,366
Exploration assets	8,397	8,397
Intangible assets	314	295
Other financial assets	2,728	2,645
Deferred Tax Assets	5,064	6,291
Goodwill	1,953	1,953
Total non-current assets	44,311	46,680
Total assets	**90,353**	**116,746**
LIABILITIES		
Current liabilities		
Trade and other payables	22,958	22,115
Deferred revenue	992	992
Borrowings	2,821	16,034
Lease liabilities	386	492
Provisions	5,098	3,184
Liabilities directly associated with assets classified as held for sale	—	18,399
Total current liabilities	32,255	61,216
Non-current liabilities		
Deferred revenue	11,824	10,797
Borrowings	14,266	21,019
Lease liabilities	543	922
Provisions	13,927	13,966
Total non-current liabilities	40,560	46,704
Total liabilities	**72,815**	**107,920**
Net assets	**17,538**	**8,826**
EQUITY		
Contributed equity	197,776	197,776
Reserves	30,615	29,094
Accumulated losses	(210,853)	(218,044)
Total equity	**17,538**	**8,826**

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

	2022 $'000	2021 $'000
Profit after income tax	**21,320**	**251**
Adjustments for:		
Depreciation and amortisation	6,779	12,503
Lease incentive	30	—
Profit on disposal of assets	(36,559)	(6)
Exploration costs funded by Joint Venture partners as part of deferred consideration from sale of Amadeus Basin producing properties	7,572	—
Share-based payments	1,524	1,862
Restatement of financial assets at amortised cost	665	—
Financing costs and interest (non-cash)	485	1,747
Changes in assets and liabilities relating to operating activities:		
Decrease/(Increase) in trade and other receivables	358	(515)
Increase in inventories	(2,330)	(93)
Increase in trade and other payables	7,781	1,395
(Decrease)/Increase in deferred revenue	(4,155)	6,850
Increase in provisions	170	142
Net cash inflow from operations	**3,640**	**24,136**

29. CASH FLOW INFORMATION

(a) Non-cash investing and financing activities

Following completion of the disposal of 50% of the Group's interests in the Amadeus Basin producing properties on 1 October 2021, the purchasers have funded $2,040,000 (2021: Nil) of the Group's share of costs for the acquisition of property, plant and equipment in FY2022. These amounts form part of the deferred consideration component of the sale proceeds (refer Note 3 (a)).

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

- Acquisition of right of use assets – Note 12(a); and
- Options and rights issued to employees under short and long term incentive plans – Note 32.

(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

	2022 $'000	2021 $'000
Cash and cash equivalents (including cash classified as held for sale)	21,647	37,165
Borrowings and leases – repayable within one year[1]	(4,913)	(36,543)
Borrowings and leases – repayable after one year[1]	(26,897)	(31,925)
Net debt	**(10,163)**	**(31,303)**
Cash	21,647	37,165
Gross Debt – fixed interest rates	(1,001)	(1,659)
Gross debt – variable interest rates	(30,809)	(66,809)
Net debt	**(10,163)**	**(31,303)**

[1] Including leases associated with assets classified as held for sale at 30 June 2021.

29. 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 2020	**25,918**	**(70,773)**	**(1,226)**	**(46,081)**
Cash flows	11,247	4,000	622	15,869
Non-cash lease adjustments	—	—	(1,055)	(1,055)
Other non-cash movements	—	(36)	—	(36)
Net debt 30 June 2021	**37,165**	**(66,809)**	**(1,659)**	**(31,303)**
Cash flows	(15,518)	36,000	561	21,043
Non-cash lease adjustments	—	—	97	97
Net debt 30 June 2022	**21,647**	**(30,809)**	**(1,001)**	**(10,163)**

30. CONTINGENCIES

(a) Contingent liabilities

(i) Exploration Permits

The Consolidated Entity had contingent liabilities at 30 June 2022 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 (2021: $1,000,000) within 12-months following the commencement of any future commercial production from the permits. No commercial production is currently forecast from these permits.

(ii) Palm Valley Gas Field Gas Price Bonus

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

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

31. COMMITMENTS

	2022 $'000	2021 $'000
(a) Capital commitments		
The Consolidated Entity has the following capital expenditure commitments:		
The following amounts are due:		
Within one year	982	3,159
	982	**3,159**

(b) Exploration commitments

The Consolidated Entity has the following minimum exploration expenditure commitments:

	2022 $'000	2021 $'000
The following amounts are due:		
Within one year	39,398	11,742
Later than one year but not later than three years	38,799	56,400
Later than three years but not later than five years	—	—
	78,197	**68,142**

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.

As announced on 9 February 2022, the Group has entered into a farmout agreement with Peak Helium (Amadeus Basin) Pty Ltd in respect of certain exploration permits. Once completed, the Group's total exploration commitments as shown above will reduce from $78,197,000 to $59,359,000.

32. SHARE BASED PAYMENTS

(a) Employee options

An Executive Share Option Plan operates 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
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**	**—**
2021								
20 Aug 2019	30 Jun 2023	13,046,116	—	$0.20	$0.120	—	13,046,116	—
07 Nov 2019	30 Jun 2023	5,105,000	—	$0.20	$0.087	—	5,105,000	—
Totals		**18,151,116**	**—**		**$0.111**	**—**	**18,151,116**	**—**
Weighted average exercise price		**$0.20**	**—**			**—**	**$0.20**	**—**

The weighted average remaining contractual life at 30 June 2022 was 1 year (2021: 2 years). The values of Executive Options are calculated at the date of grant using a Black Scholes valuation.

32. 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 2022 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
2022							
11 Nov 2020	30 Jun 2020[1]	3,692,054	—	$0.130	—	—	3,692,054
2021							
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 30 June 2023.

The weighted average fair value of share rights issued under the Short Term Incentive Plan during the year was nil (2021: $0.13).

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

Under the FY2022 Non-Executive Director offer, Directors could agree to receive a maximum of 25% of their FY2022 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 2022. The following Non-Executive Director Share rights were granted during the 2022 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	Vested and exercisable at End of Year
2022							
23 Nov 2021	30 Jun 2022	—	850,421	$0.115	—	—	850,421

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

As at 30 June 2022, no share rights had been granted under the EIP. Share rights, as part of the FY2022 EIP are expected to be granted during FY2023. The number of rights to be granted is determined based on Central Petroleum Limited's share price for the 20-days after release or the June 2022 quarterly report (9.9 cents per right). 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 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.

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

32. SHARE BASED PAYMENTS (CONTINUED)

(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
11 Nov 2020	30 Jun 2020	3,692,054	—	$0.130	—	—	3,692,054
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		**28,539,367**	**450,780**		**(1,813,788)**	**(6,736,052)**	**20,440,307**

The weighted average fair value of share rights granted under the Long Term Incentive Plan during the year was $0.105 (2021: $0.084). The weighted average remaining contractual life of outstanding share rights at the end of the year was 2.7 years (2021: 3.5 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.

32. 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
2021							
11 Nov 2020	30 Jun 2020	—	3,692,054	$0.130	—	—	3,692,054
18 Sep 2020	30 Jun 2018	—	20,271	$0.130	(19,073)	—	1,198
24 Jul 2020	30 Jun 2021	—	9,417,632	$0.065	—	—	9,417,632
24 Jul 2020	30 Jun 2021	—	499,488	$0.089	—	—	499,488
24 Jul 2020	30 Jun 2020	—	30,545	$0.089	—	—	30,545
07 Nov 2019	30 Jun 2019	1,837,109	—	$0.119	—	—	1,837,109
13 Sep 2019	30 Jun 2017	50,700	—	$0.150	(50,700)	—	—
23 Aug 2019	30 Jun 2020	348,708	—	$0.190	—	(37,689)	311,019
23 Aug 2019	30 Jun 2020	7,004,467	—	$0.155	—	(523,625)	6,480,842
09 May 2019	30 Jun 2019	768,542	—	$0.101	—	(11,958)	756,584
17 Apr 2019	30 Jun 2019	49,321	—	$0.111	—	(20,528)	28,793
17 Apr 2019	30 Jun 2019	2,566	—	$0.150	—	—	2,566
24 Sep 2019	30 Jun 2019	5,302,029	—	$0.087	—	(125,875)	5,176,154
24 Sep 2019	30 Jun 2019	321,940	—	$0.120	—	(29,057)	292,883
02 Oct 2018	30 Jun 2016	639	—	$0.067	(639)	—	—
27 Jun 2018	30 Jun 2018	135,920	—	$0.102	—	(135,920)	—
16 May 2018	30 Jun 2018	6,562	—	$0.126	—	(6,562)	—
16 May 2018	30 Jun 2018	10,306	—	$0.175	(10,306)	—	—
01 Sep 2017	30 Jun 2018	4,400,423	—	$0.081	—	(4,400,423)	—
01 Sep 2017	30 Jun 2018	201,222	—	$0.115	(188,722)	—	12,500
20 Oct 2016	30 Jun 2017	517,575	—	$0.106	(517,575)	—	—
20 Oct 2016	30 Jun 2017	11,111	—	$0.135	(11,111)	—	—
09 Nov 2015	30 Jun 2016	6,666	—	$0.184	(6,666)	—	—
Totals		**20,975,806**	**13,659,990**		**(804,792)**	**(5,291,637)**	**28,539,367**

No rights were granted to key management personnel during FY2022. The following factors and assumptions were used in determining the fair value of share rights granted to key management personnel during FY2021:

Grant Date	Expiry Date	Fair Value Per Right	Exercise Price	Price of Shares at Grant Date	Estimated Volatility	Risk Free Interest Rate	Dividend Yield
24 Jul 2020[1]	30 Jun 2025	$0.065	Nil	$0.089	72%	0.43%	—
11 Nov 2020[2]	30 Jun 2025	$0.130	Nil	$0.130	N/A	N/A	—

[1] LTIP Rights for the plan year commencing 1 July 2020.
[2] Deferred share rights issued in lieu of cash under the short term incentive plan for the year commencing 1 July 2019.

(f) Expenses arising from share-based payment transactions

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

	2022 $	2021 $
Share Rights issued to employees	**1,524,197**	**1,862,072**

33. FINANCIAL RISK MANAGEMENT

The Consolidated Entity's principal financial instruments are cash and short-term deposits. The Consolidated Entity also has other financial assets and liabilities such as trade receivables, trade payables and borrowings, which arise directly from its operations. The Consolidated Entity's risk management objective with regard to financial instruments and other financial assets include gaining interest income and the policy is to do so with a minimum of risk.

The Group manages its exposure to key financial risks primarily through supervision by the Audit and Financial Risk Committee. One of the primary functions of this Committee is to assist the Board to fulfil its responsibility to exercise due care, diligence and skill with respect to the oversight and integrity of the management of financial risks and internal controls.

(a) Credit Risk

The credit risk on financial assets of the Consolidated Entity which have been recognised in the balance sheet is generally the carrying amount, net of any provision for expected credit losses. The Group applies the simplified approach to providing for expected credit losses prescribed by AASB 9, which permits the use of the lifetime expected loss provision for all trade receivables. Under this method, determination of the loss allowance provision and expected loss rate incorporates past experience and forward-looking information, including the outlook for market demand, the current economic environment, and forward-looking interest rates. As the expected loss rate at 30 June 2022 is nil (2021: nil), no loss allowance provision has been recorded at 30 June 2022 (2021: nil).

The Consolidated Entity trades only with recognised banks and large customers where the credit risk is considered minimal.

Customer credit risk is managed in accordance with the Group's established policy, procedures and controls. Outstanding customer receivables are regularly monitored and relate to the Groups' customers for which there is no history of credit risk or overdue payments. An impairment analysis is performed at each reporting date on an individual basis for the major customers.

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

	Gross		Expected Credit Loss Provision	
Trade and other receivables	**2022 $'000**	2021 $'000	**2022 $'000**	2021 $'000
Current: 0-30 days	**4,750**	6,084	—	—
	4,750	**6,084**	**—**	**—**

The trade receivables at 30 June 2022 relate predominantly to oil and gas sales which have all been received subsequent to year end.

A deferred receivable arising from the partial sale of interests in Producing Assets is recorded at fair value (refer Note 8(b)) which takes into account credit risk.

Credit risk also arises in relation to financial guarantees given by the Parent Entity and other non-borrowing Group entities to certain parties in respect of borrowings by other Group entities (refer Note 25(b)). Such guarantees are only provided in exceptional circumstances and are subject to specific Board approval.

33. FINANCIAL RISK MANAGEMENT (CONTINUED)

(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:

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)**

2021 ($'000)	≤ 6 Months	6–12 Months	1–5 Years	≥ 5 Years	Contractual Cash Flow	Carrying Amount
Financial Assets						
Cash and cash equivalents	37,159	—	—	—	37,159	37,159
Trade and other receivables	6,084	—	—	—	6,084	6,084
Other financial assets	—	—	4,218	—	4,218	4,218
	43,243	**—**	**4,218**	**—**	**47,461**	**47,461**
Financial Liabilities						
Trade and other payables	(10,491)	—	—	—	(10,491)	(10,491)
Interest bearing liabilities	(33,245)	(5,221)	(32,271)	(123)	(70,860)	(68,318)
	(43,736)	**(5,221)**	**(32,271)**	**(123)**	**(81,351)**	**(78,809)**

33. FINANCIAL RISK MANAGEMENT (CONTINUED)

(c) Interest Rate Risk

The Consolidated Entity's exposure to interest rate risk, which is the risk that a financial instrument's value will fluctuate as a result of changes in market interest rates and the effective weighted average interest rates on classes of financial assets and financial liabilities, is as follows:

	Weighted Average Effective Interest Rate		Floating Interest Rate		Fixed Interest		Non-Interest-Bearing		Total	
	2022 %	2021 %	**2022 $'000**	2021 $'000	**2022 $'000**	2021 $'000	**2022 $'000**	2021 $'000	**2022 $'000**	2021 $'000
Financial Assets:										
Cash and cash equivalents	0.9	0.3	21,647	37,159	—	—	—	—	21,647	37,159
Trade and other receivables	—	—	—	—	—	—	4,750	6,084	4,750	6,084
Other financial assets	0.2	0.0	—	—	785	908	3,625	3,310	4,410	4,218
Total Financial Assets			**21,647**	**37,159**	**785**	**908**	**8,375**	**9,394**	**30,807**	**47,461**
Financial Liabilities:										
Trade and other payables	—	—	—	—	—	—	(13,526)	(10,491)	(13,526)	(10,491)
Interest bearing liabilities	7.3	5.6	(30,809)	(66,809)	(1,001)	(1,509)	—	—	(31,810)	(68,318)
Total Financial Liabilities			**(30,809)**	**(66,809)**	**(1,001)**	**(1,509)**	**(13,526)**	**(10,491)**	**(45,336)**	**(78,809)**
Net Financial Assets / (Liabilities)			**(9,162)**	**(29,650)**	**(216)**	**(601)**	**(5,151)**	**(1,097)**	**(14,529)**	**(31,348)**

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 2021 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
2022 ($'000)				
Cash and cash equivalents	102	(102)	—	—
Interest bearing liabilities	(154)	154	—	—
2021 ($'000)				
Cash and cash equivalents	186	(127)	—	—
Interest bearing liabilities	(334)	334	—	—

These movements would not have any impact on equity other than retained earnings.

(d) Commodity Risk

The majority of gas sales are made under long term contracts and as such do not contain any commodity risk for the duration of the contract. The Consolidated Entity is exposed to commodity price fluctuations in respect of recorded crude oil sales and gas sales which are not subject to long term fixed price contracts. The effect of potential fluctuations is not considered material to balances recorded in these financial statements. The Board's current policy is not to hedge crude oil sales. The Board will continue to monitor commodity price risk and take action to mitigate that risk if it is considered necessary in light of the Group's overall product sales mix and forecast cash flows.

33. FINANCIAL RISK MANAGEMENT (CONTINUED)

(e) Financing Facilities

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

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 (2021: 30 September 2022). Repayments comprise fixed quarterly principal repayments of $1,125,000 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 Macquarie debt facility and certain liabilities associated with gas sales agreements with Macquarie Bank.
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:

	2022 $'000	2021 $'000
Trade and other receivables (USD)	457	1,609
Trade and other payables:		
- USD	(1,082)	(416)
- GBP	—	(3)
- EUR	—	(3)

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.

	2022 $'000	2021 $'000
Australian dollar +10% movement in exchange rate	57	(108)
Australian dollar -10% movement in exchange rate	(69)	132

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.

34. INTERESTS IN JOINT ARRANGEMENTS

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

	Principal Activities	2022 %	2021 %
OL4, OL5 and PL2 - Mereenie	Oil & gas production	25.00	50.00
OL3 - Palm Valley	Gas production	50.00	N/a
L7 and PL30 - Dingo	Gas production	50.00	N/a
EP 82[1]	Oil & gas exploration	60.00	60.00
EP 105	Oil & gas exploration	60.00	60.00
EP 112[2]	Oil & gas exploration	45.00	30.00
EP 125[3]	Oil & gas exploration	30.00	30.00
EPA 111	Oil & gas exploration – application	50.00	50.00
EPA 124	Oil & gas exploration – application	50.00	50.00
ATP 2031 - Range Gas Project	Oil & gas exploration	50.00	50.00

[1] Central's interest in EP82 will reduce to 29% upon satisfaction of conditions precedent to a farm-out agreement
[2] Central's interest in EP112 will reduce to 35% upon satisfaction of conditions precedent to a farm-out agreement
[3] Central's interest in EP125 will reduce to 24% upon satisfaction of conditions precedent to a farm-out agreement

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.

34. INTERESTS IN JOINT ARRANGEMENTS (CONTINUED)

The share in the assets and liabilities of the joint arrangements where less than 100% interest is held by the Company are included in the Consolidated Entity's balance sheet in accordance with the accounting policy described in Note 1(b)(ii) under the following classifications:

	2022 $'000	2021 $'000
Current assets		
Cash and cash equivalents	1,070	878
Trade and other receivables	3,063	4,424
Inventory	3,300	722
Assets classified as held for sale	—	29,227
Total current assets	7,433	35,251
Non-current assets		
Property, plant and equipment	44,086	28,264
Right of use assets	113	87
Other financial assets	2,432	1,328
Total non-current assets	46,631	29,679
Current liabilities		
Trade and other payables	7,996	3,382
Lease liabilities	28	25
Deferred revenue	1,357	365
Provision for production over-lift	770	734
Restoration provision	1,445	—
Liabilities directly associated with assets classified as held for sale	—	13,370
Total current liabilities	11,596	17,876
Non-current liabilities		
Deferred revenue	11,857	219
Lease liabilities	96	70
Provision for production over-lift	2,182	2,830
Restoration provision	18,165	12,800
Total non-current liabilities	32,300	15,919
Net assets	**10,168**	**31,135**
Joint arrangement contribution to loss before tax		
Revenue	35,973	35,248
Other income	7	12
Expenses	(37,301)	(30,172)
Profit before income tax	**(1,321)**	**5,088**

35. EVENTS OCCURRING AFTER THE REPORTING PERIOD

No matters or circumstances have arisen between 30 June 2022 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 95 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 2022 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 2022.

3. As at the date of this declaration, there are reasonable grounds to believe that the members of the Closed Group identified in Note 27 will be able to meet any obligations or liabilities to which they are or may become subject by virtue of the Deed of Cross Guarantee between the Company and those members of the Closed Group pursuant to ASIC Corporations (Wholly owned Companies) Instrument 2016/785.

This declaration is made in accordance with a resolution of the Directors of Central Petroleum Limited:

Michael McCormack
Director
Brisbane

16 September 2022

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 2022 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 2022
- 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.

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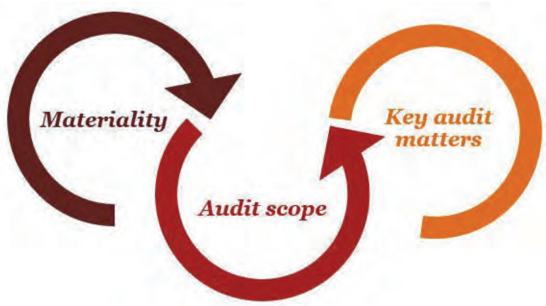
Our audit approach

An audit is designed to provide reasonable assurance about whether the financial report is free from material misstatement. Misstatements may arise due to fraud or error. They are considered material if individually or in aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial report.

We tailored the scope of our audit to ensure that we performed enough work to be able to give an opinion on the financial report as a whole, taking into account the geographic and management structure of the Group, its accounting processes and controls and the industry in which it operates.



Materiality	Audit scope
• For the purpose of our audit we used overall Group materiality of $1.2 million, 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
Profit on disposal of 50% interest in Amadeus Basin producing properties (Refer to note 3) On 1 October 2021, the Group completed the sale of 50% of its working interest in the Amadeus Basin producing assets to entities controlled by New Zealand Oil and Gas Limited ("NZOG") and Cue Energy Resources Limited ("Cue"). An accounting profit of $36.6m was recorded as a result of this transaction. The disposal was a key audit matter because of the transaction being non-routine and its financial significance to the financial statements.	To evaluate the Group's profit on disposal, we performed a number of procedures including the following: ● Read the terms of the Sale Agreement. ● Performed an evaluation over the date at which control was lost. ● Agreed net cash received from NZOG and Cue on completion to underlying bank statements. ● Evaluated management's key fair value assumptions related to valuation of deferred consideration. ● Recalculated the gain on sale by comparing the carrying value of the disposed assets and liabilities to consideration received, less transaction costs. ● Evaluated the reasonableness of the disclosures made in note 3, in light of the requirements of the Australian Accounting Standards.

Other information

The directors are responsible for the other information. The other information comprises the information included in the annual report for the year ended 30 June 2022, 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.

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.

Report on the remuneration report

Our opinion on the remuneration report

We have audited the remuneration report included in pages 34 to 48 of the directors' report for the year ended 30 June 2022.

In our opinion, the remuneration report of Central Petroleum Limited for the year ended 30 June 2022 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.

Pricewaterhouse Coopers

PricewaterhouseCoopers

Marcus Goddard
Partner

Brisbane
16 September 2022

ASX ADDITIONAL INFORMATION

DETAILS OF QUOTED SECURITIES AS AT 13 SEPTEMBER 2022

Top holders

The 20 largest registered holders of the quoted securities as at 13 September 2022 were:

	Name	No. of Shares	%
1	Norfolk Enchants Pty Ltd <Trojan Retirement Fund A/c>	37,500,000	5.17
2	UBS Nominees Pty Ltd	29,957,170	4.13
3	Mrs Faina Stolyar	20,000,000	2.76
4	Moranbah Nominees Pty Ltd <Chris Wallin Super Fund A/C>	19,526,612	2.69
5	Brazil Farming Pty Ltd	17,785,209	2.45
6	Citicorp Nominees Pty Limited	16,784,101	2.31
7	Macquarie Bank Limited <Metals Mining and AG A/C>	14,166,667	1.95
8	Mr Philip Gasteen <Thrushton Investment A/C>	11,945,080	1.65
9	Chembank Pty Limited <Philandron A/C>	10,000,000	1.38
10	Kensington Capital Partners Pty Ltd	8,000,000	1.10
11	JH Nominees Australia Pty Ltd <Harry Family Super Fund A/C>	7,840,268	1.08
12-13	Justwright Investments Pty Ltd <Justwright Super Fund A/C>	7,000,000	0.96
12-13	PA and RE Gibson Pty Ltd <PA&RE Gibson Super Fund A/C>	7,000,000	0.96
14	Mr Donald Leonard Cottee	5,830,594	0.80
15	Mr James Donald Bruce Cochrane + Mrs Joan Elizabeth Cochrane <Bruce & Joan Cochrane A/C>	5,000,001	0.69
16-19	Mr Chris Carr + Mrs Betsy Carr	5,000,000	0.69
16-19	Garmi Holdings Pty Ltd	5,000,000	0.69
16-19	Garmi Holdings Pty Ltd <Pemco Super Fund A/c>	5,000,000	0.69
16-19	Mr Peter Andrew Gibson + Mrs Robyn Elizabeth Gibson	5,000,000	0.69
20	Mrs Karen Driscoll + Mr Raymond Driscoll <Edwin Holdings Super A/c>	4,915,250	0.68
	Total	**243,250,952**	**33.51**

DISTRIBUTION SCHEDULE

A distribution schedule of the number of holders in each class of equity securities as at 13 September 2022 was:

	Number of Holders		
Size of Holding	Listed Fully Paid Shares	Unlisted Share Rights	Unlisted Options
1 – 1,000	742	1	—
1,001 – 5,000	1,736	3	—
5,001 – 10,000	953	12	—
10,001 – 100,000	2,407	48	—
100,001 – Over	899	25	5
Total	**6,737**	**89**	**5**

ASX ADDITIONAL INFORMATION

SUBSTANTIAL SHAREHOLDERS

Substantial shareholders as disclosed by notices received by the Company as at 13 September 2022 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 5,883 shares as at 13 September 2022):

Holders	Units
2,596	5,813,238

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 2022 Corporate Governance Statement reflects the corporate governance practices in place throughout the 2022 financial year. The Company's Corporate Governance Statement undergoes periodic review by the Board. A description of the Group's current corporate governance practices is set out in the Group's Corporate Governance Statement which can be viewed at www.centralpetroleum.com.au/about/corporate-governance/.

INTERESTS IN PETROLEUM PERMITS AND PIPELINE LICENCES

AT THE DATE OF THIS REPORT

PERMITS AND LICENCES GRANTED

			CTP Consolidated Entity		Other JV Participants	
Tenement	Location	Operator	Registered Interest (%)	Beneficial Interest (%)	Participant Name	Beneficial Interest (%)
EP82 (excl. EP82 Sub-Blocks) [1(a)]	Amadeus Basin NT	Santos	60	60	Santos QNT Pty Ltd (Santos)	40
EP82 Sub-Blocks	Amadeus Basin NT	Central	100	100		
EP105	Amadeus/Pedirka Basin NT	Santos	60	60	Santos	40
EP112 [1(b) & 2]	Amadeus Basin NT	Santos	30	45	Santos	55
EP115 (excl. EP115 North Mereenie Block)	Amadeus Basin NT	Central	100	100		
EP115 North Mereenie Block	Amadeus Basin NT	Central	100	100		
EP125[1(c)]	Amadeus Basin NT	Santos	30	30	Santos	70
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	Georgina Basin QLD	Central	100	100		
ATP911	Georgina Basin QLD	Central	100	100		
ATP912	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

			CTP Consolidated Entity		Other JV Participants	
Tenement	Location	Operator	Registered Interest (%)	Beneficial Interest (%)	Participant Name	Beneficial Interest (%)
EPA92	Wiso Basin NT	Central	100	100		
EPA111[3]	Amadeus Basin NT	Santos	100	50	Santos	50
EPA120	Amadeus Basin NT	Central	100	100		
EPA124 [4]	Amadeus Basin NT	Santos	100	50	Santos	50
EPA129	Wiso Basin NT	Central	100	100		
EPA130	Pedirka Basin NT	Central	100	100		
EPA131 [5]	Pedirka Basin NT	Central	100	0		
EPA132	Georgina Basin NT	Central	100	100		
EPA133 [6]	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] As announced on 9 February 2022, Central entered into a farmout of various interest in certain Amadeus Basin exploration tenements to Peak Helium (Amadeus Basin) Pty Ltd subject to the usual conditions precedent for a transaction of this nature being met by 12 October 2022. Upon completion, Peak Helium (Amadeus Basin) Pty Ltd will earn partial transfer of Central's interest in three permits as follows:

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

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

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

[2] As announced on 2 August 2021, Santos did not elect that Central be carried for the first $3 million of Dukas-1 well costs and therefore its interest in EP112 (including Dukas-1 well) will decrease from 70% to 55% (Central's interest in EP112 will increase from 30% to 45%)

[3] On 16 December 2021 Central received notice from the NT Department of Industry Tourism and Trade 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 EPA124) and on 23 March 2018 (in respect of EPA152) Central received notice from the NT Department of Primary Industry and Resources that EPA124 and EPA152, as applicable, had been placed in moratorium for a period of 5-years from 6 December 2017 until 6 December 2022.

[5] This exploration permit application has been disposed. Transfer of the registered interest is awaiting the grant of an exploration permit.

[6] This exploration permit application was placed into moratorium on 22 October 2015 for a five (5) year period ending on 22 October 2020. On 25 February 2021, Central was provided with consent to negotiate the grant of this exploration permit.

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 and amortisation
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.

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