CENTRAL PETROLEUM LIMITED

ABN 72 083 254 308

ASX:CTP

Central Petroleum

Activities Report and ASX Appendix 5B

REVIEW OF OPERATIONS FOR THE QUARTER ENDED 30 SEPTEMBER 2025

Highlights

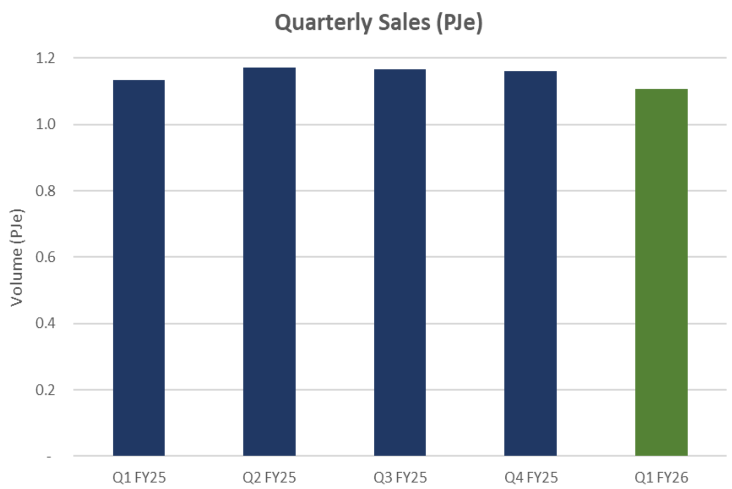
- **Sales volumes** of 1.1 PJe (Petajoule equivalent) were 4.5% lower than the June quarter, reflecting lower seasonal demand, temporary pipeline pressure restrictions and partial oil offtake constraints.
- **Unit sales prices:** the average realised delivered price across the portfolio was $10.15 / GJe (Gigajoule equivalent) for the September quarter, 28% higher than the same quarter last year, but slightly lower than the June quarter due a different mix of gas delivery points when the Northern Gas Pipeline was closed, and softer oil prices.
- **Sales revenue** of $11.2m for the September quarter was 6.6% lower than the record high June quarter, driven by the lower sales volumes and sales prices. Contracted take-or-pay provisions provide some protection for cash flows, with an additional $0.5m arising in respect of take-or-pay volumes not taken in the quarter.
- **Operating cash inflows** of $0.6m ($1.8m before net interest and exploration costs) were impacted by the lower sales revenues, a catch-up of $2.8m of overlift gas payments accrued since February, and Central's share of annual staff incentive payments (net of JV recoveries), including the cash-settlement of share rights.
- **Cash balance** at the end of the quarter was $26.7m, down from $27.5m at 30 June. Key cash flows included:
  - Net operating inflows of $1.8m (before net interest and exploration);
  - CAPEX of $1.0m;
  - Exploration related expenditures of $0.8m, including the finalisation of necessary rehabilitation and remediation works in the Southern Georgina Basin and preparation for seismic acquisition in EP115; and
  - Net interest payments of $0.5 million.
- **Net cash** was $3.3 million at 30 September, including $2.5 million of funds held as security for the loan facility.
- **Reserves upgrade:** the outperformance of the new Mereenie production wells resulted in a 9% increase (before production) in 2P oil and gas reserves at Mereenie at 30 June, effectively replacing 178% of Mereenie's FY2025 production. Dingo 1P gas reserves were upgraded by 6% before production, following new reservoir modelling. These reserve upgrades effectively replaced 98% of FY2025 production across Central's portfolio on a 1P basis, and 96% on a 2P basis.
- **Share buy-back:** opened an on-market share buy-back program, Central's first shareholder returns. To date, Central has not been able to purchase shares on-market due to ASX trading constraints.
- **New Gas Sales Agreement:** In October, Central secured a new Gas Sale Agreement (GSA) to supply 1.3 PJ (Central share) of gas over two years from 31 December 2025. The new GSA is for firm supply at a fixed price, with take-or-pay provisions, providing increased cash flow certainty.

Investor and Media Inquiries
Leon Devaney (MD and CEO)
+61 (07) 3181 3800

Production Activities

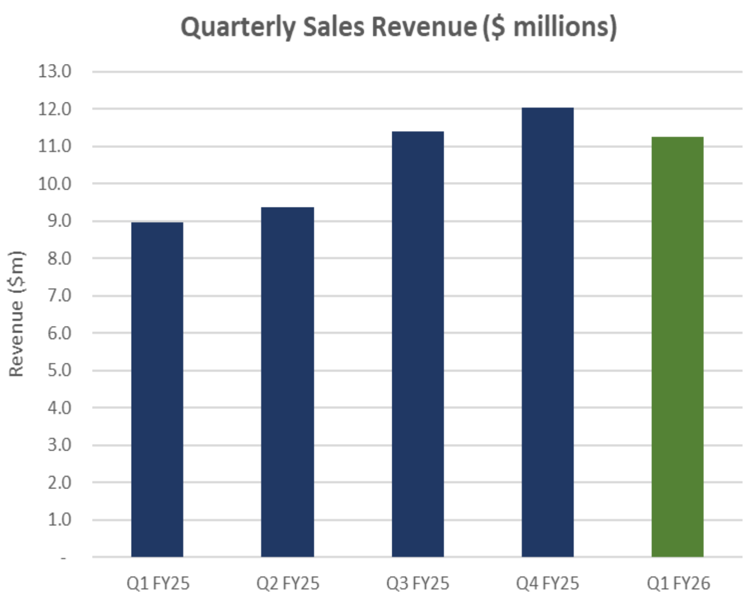
SALES VOLUMES

Central supplied 1.11 PJe (Central share) of gas from its gas fields in the Northern Territory (NT) in the September quarter, 4.5% lower than the June quarter due to a combination of lower seasonal demand, an extended closure of the Northern Gas Pipeline (NGP), temporary pipeline pressure restrictions and oil offtake constraints at Mereenie.



The NGP was closed for 65% of the quarter, preventing supply of gas to customers in eastern states at a time of weaker seasonal demand for gas in the Northern Territory. Central's alternative gas contracts within the Northern Territory provided significant mitigation against these NGP closures.

SALES REVENUE



Sales revenue for the September quarter was $11.2m, 6.6% lower than the record high June quarter, driven by the lower volumes and slightly lower sales prices. Contracted take-or-pay provisions provided some protection for cash flows. If the $0.5m receivable in respect of the September quarter take-or-pay volumes not taken was included as revenue, the September quarter revenue would only be 2.2% lower than the June quarter.

A further $0.5m of revenue was recognised in the quarter from the release of previously accrued take-or-pay balances as these volumes are unlikely to be delivered undertake-or-pay contracts.

The average delivered unit sales price for the portfolio was 2.2% lower than the June quarter at $10.15 / GJe due to a different mix of gas delivery points when the Northern Gas Pipeline was closed, and softer oil prices. The average price is 28% higher than the same quarter last year, benefitting from new gas contracts which commenced in January.

Sales Revenue (unaudited)		**Qtr v Qtr**		**YTD**	
Product	**Unit**	**Q4 FY25**	**Q1 FY26**	**FY25**	**FY26**
Gas	$'000	**11,218**	**10,435**	8,151	**10,435**
Crude and Condensate	$'000	**812**	**808**	810	**808**
Total Sales Revenue	**$'000**	**12,030**	**11,243**	8,961	**11,243**
Revenue per unit	$/GJe	**$10.38**	**$10.15**	$7.91	**$10.15**

MEREENIE OIL AND GAS FIELD (OL4 AND OL5) – NORTHERN TERRITORY

CTP - 25% interest (and Operator), Echelon Mereenie Pty Ltd - 42.5%, Horizon Australia Energy Pty Ltd - 25%, Cue Mereenie Pty Ltd - 7.5%

Average gross gas sales from the Mereenie field were 26.0 TJ/d (100% JV) for the September quarter, 7% lower than the previous quarter due to the closure of the Northern Gas Pipeline (NGP) and well turndowns associated with partial oil offtake constraints. The NGP was closed for two thirds of the quarter which led to temporary pipeline pressure restrictions and Central being unable to sell excess capacity into eastern markets at a time of seasonal low demand in the Northern Territory.

The gas sales capacity of the Mereenie field (excluding the impact associated with oil offtake constraints) was approximately 29 TJ/d (100% JV) at the end of the quarter.

Oil sales averaged 291 bbls/d (100% JV) during the quarter. Oil sales have been partially constrained by revised oil specifications under existing offtake arrangements. Central has been managing this partial constraint through sales to alternative customers, increased flaring and temporarily shutting lower gas-to-oil ratio wells as required to manage near-term offtake constraints. When these wells are offline, Mereenie's sales gas capacity is reduced to approximately 25 TJ/d (100% JV). Central considers the impact on gas sales from the oil constraints to be temporary and continues to seek a variety of oil specification mitigations and alternative commercial arrangements to return to maximum oil and gas production from Mereenie as quickly as possible.

Reserves upgrade: The outperformance of the new Mereenie production wells resulted in an increase in 1P and 2P reserves at Mereenie of 10% and 9% respectively as at 30 June (before production, net to Central). The 3 PJe of additional 2P reserves effectively replaces 178% of Central's share of FY2025 production from Mereenie.

PALM VALLEY (OL3) – NORTHERN TERRITORY

CTP - 50% interest (and Operator), Echelon Palm Valley Pty Ltd - 35%, Cue Palm Valley Pty Ltd - 15%

Production from the Palm Valley field averaged 6.2 TJ/d over the quarter (Central share: 3.1 TJ/d), 10% lower than the previous quarter due to lower seasonal demand (in conjunction with the extended NGP closure) and natural field decline.

Sales capacity was approximately 7.0 TJ/d (100% JV) at the end of the quarter.

DINGO GAS FIELD (L7) – NORTHERN TERRITORY

CTP - 50% interest (and Operator), Echelon Dingo Pty Ltd - 35%, Cue Dingo Pty Ltd - 15%

The Dingo gas field supplies gas directly to the Owen Springs Power Station in Alice Springs. Sales volumes quarter-on-quarter were steady, averaging 4.2 TJ/d (Central share: 2.1 TJ/d).

Reserves upgrade: 1P Dingo reserves increased by 6% (before production, net to Central) as at 30 June after the completion of new modelling of the field's performance. The 1.1 PJ increase replaces 142% of FY2025 production.

Exploration Activities

AMADEUS SUB-SALT EXPLORATION

Dukas (EP112), Jacko Bore (Mt Kitty) (EP125) and Mahler (EP82), operated by Santos.

CTP – 60% interest (EP82); 45% interest (EP112); 30% interest (EP125)

Applications for extension or renewal of exploration permits EP82, EP112 and EP125 have been lodged.

Central is in active discussions with new parties to fund sub-salt exploration programs targeting helium, naturally occurring hydrogen and hydrocarbons in the permits.

WESTERN AMADEUS BASIN

EP115

CTP – 100% interest

An application to extend EP115 was lodged during the quarter. Central is planning a 2D seismic acquisition program of 480km (or more) in EP115, to be conducted in 2026. The 2D seismic program is designed to acquire data over several conventional leads within the 11,000 km^2 permit. Planning is well advanced - an Environmental Management Plan has been lodged and other clearances are progressing. EP115 lies on trend with Palm Valley, Mereenie and the Surprise oil field on the oil-prone western flank of the Amadeus Basin.

Health, Safety and Environment

Central recorded no reportable safety or environmental incidents in the September quarter and the Company's TRIFR (Total Recordable Injury Frequency Rate) at the end of the quarter remained unchanged at 3.5.

Commercial

NEW GAS SUPPLY AGREEMENT

In October, Central announced a new Gas Supply Agreement (GSA) to supply 1.3 PJ (Central share) of gas to McArthur River Mining over two years from 31 December 2025. The new GSA is for firm supply at a fixed price, with take-or-pay provisions, providing increased cash flow certainty. Central's expected firm gas production from existing wells is now fully contracted until the end of 2027.

Corporate

CASH POSITION

Cash balances were $26.7m at the end of the quarter, slightly lower than the $27.5m at the end of June, reflecting lower net operating cash inflows for the quarter of $0.6 million after exploration costs and net interest costs. Key components of operating cash flow included:

- Cash receipts from customers of $13m, including $0.3m take-or-pay receipts, were 5.6% lower than the prior quarter, consistent with the lower revenues;
- Cash production, transportation and corporate costs of $11.1 million, were significantly higher than the previous quarter due to five months of overlift gas payments ($2.8m) (owing in respect of previous periods) and annual staff incentive payments, including the cash-settlement of share rights at the prevailing share price to reduce the dilutionary impact on existing shareholders;
- Exploration related expenditures of $0.8m, including the finalisation of necessary rehabilitation and remediation works in the Southern Georgina Basin and preparation for seismic acquisition in EP115; and
- Net interest payments of $0.5 million.

There was $1.0m of capital expenditure during the quarter.

No loan principal was repaid in the September quarter in line with the debt facility repayment schedule. No principal repayments are required until March 2027, but early repayments can be made at any time without penalty. Net cash at 30 September was $3.3m.

Fees, salaries and superannuation contributions paid to directors during the quarter, including annual incentives and cash-settled equity incentives paid to the Managing Director, amount to $0.68 million as disclosed at item 6.1 of the Appendix 5B.

The statement of cash flows for the quarter and financial year to date are attached to this report as Appendix 5B.

SHARE BUY-BACK

Central's inaugural on-market share buy-back program commenced on 15 September 2025. Central can buy-back up to 10% of its issued capital over a 12 month period. The ability to purchase shares on market is subject to factors such as prevailing share price, liquidity and other trading and regulatory constraints. At the date of this report, no shares had been bought-back under the buy-back program due to ASX trading constraints.

ISSUED CAPITAL

At the end of the quarter there were 752,749,622 ordinary shares on issue after the exercise of 7,491,308 rights in accordance with Central's Employee Rights Plan.

Leon Devaney
Managing Director and Chief Executive Officer
31 October 2025

This ASX announcement was approved and authorised for release by Leon Devaney, Managing Director and Chief Executive Officer

Annexure 1: Interests in Petroleum Permits and Licences

as at 30 September 2025

PETROLEUM PERMITS AND LICENCES GRANTED

Tenement	Location	Operator	CTP Consolidated Entity		Other JV Participants	
			Registered Legal Interest (%)	Beneficial Interest (%)	Participant Name	Beneficial Interest (%)
EP 82 (excl. EP 82 Sub-Blocks)[1(a)]	Amadeus Basin NT	Santos	29	60	Santos QNT Pty Ltd (“Santos”)	40
EP 82 Sub-Blocks	Amadeus Basin NT	Central	100	100		
EP 112 [1(b)]	Amadeus Basin NT	Santos	35	45	Santos	55
EP 115	Amadeus Basin NT	Central	100	100		
EP 125 [1(c)]	Amadeus Basin NT	Santos	24	30	Santos	70
OL 3 (Palm Valley)	Amadeus Basin NT	Central	50	50	Echelon Palm Valley Pty Ltd Cue Palm Valley Pty Ltd	35 15
OL 4 (Mereenie)	Amadeus Basin NT	Central	25	25	Echelon Mereenie Pty Ltd (“Echelon Mereenie”) Horizon Australia Energy Pty Ltd (“Horizon”) Cue Mereenie Pty Ltd (“Cue Mereenie”)	42.5 25 7.5
OL 5 (Mereenie)	Amadeus Basin NT	Central	25	25	Echelon Mereenie Horizon Cue Mereenie	42.5 25 7.5
L 6 (Surprise)	Amadeus Basin NT	Central	100	100		
L 7 (Dingo)	Amadeus Basin NT	Central	50	50	Echelon Dingo Pty Ltd (“Echelon Dingo”) Cue Dingo Pty Ltd (“Cue Dingo”)	35 15
RL 3 (Ooraminna)	Amadeus Basin NT	Central	100	100		
RL 4 (Ooraminna)	Amadeus Basin NT	Central	100	100		

PETROLEUM PERMITS AND LICENCES UNDER APPLICATION

Tenement	Location	Operator	CTP Consolidated Entity		Other JV Participants	
			Registered Interest (%)	Beneficial Interest (%)	Participant Name	Beneficial Interest (%)
EPA 92	Wiso Basin NT	Central	100	100		
EPA 111	Amadeus Basin NT	Santos	50	50	Santos	50
EPA 124 [2]	Amadeus Basin NT	Santos	50	50	Santos	50
EPA 129	Wiso Basin NT	Central	100	100		
EPA 130	Pedirka Basin NT	Central	100	100		
EPA 132	Georgina Basin NT	Central	100	100		
EPA 133	Amadeus Basin NT	Central	100	100		
EPA 137	Amadeus Basin NT	Central	100	100		
EPA 147	Amadeus Basin NT	Central	100	100		
EPA 149	Amadeus Basin NT	Central	100	100		
EPA 152	Amadeus Basin NT	Central	100	100		
EPA 160	Wiso Basin NT	Central	100	100		
EPA 296	Wiso Basin NT	Central	100	100		

PIPELINE LICENCES

Pipeline Licence	Location	Operator	CTP Consolidated Entity Registered Interest (%)	CTP Consolidated Entity Beneficial Interest (%)	Other JV Participants Participant Name	Other JV Participants Beneficial Interest (%)
PL 2	Amadeus Basin NT	Central	25	25	Echelon Mereenie Horizon Cue Mereenie	42.5 25 7.5
PL 30	Amadeus Basin NT	Central	50	50	Echelon Dingo Cue Dingo	35 15

Notes:

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

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

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

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

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

Abbreviations

1P	Proved reserves
2P	Proved and Probable reserves
GJe	Gigajoules equivalent*
NGP	Northern Gas Pipeline
NT	Northern Territory
PJ	Petajoules
PJe	Petajoules equivalent*
TJ/d	Terajoules per day
	*equivalent includes oil converted at 5.816 PJ per million barrels of oil

General Legal Disclaimer

*As new information comes to hand from data processing and new drilling and seismic information, preliminary results may be modified. Resources estimates, assessments of exploration results and other opinions expressed by Central Petroleum Limited (**Company**) in this announcement or report have not been reviewed by any relevant joint venture partners, therefore those resource estimates, assessments of exploration results and opinions represent the views of the Company only. Exploration programs which may be referred to in this announcement or report may not have been approved by relevant Joint Venture partners in whole or in part and accordingly constitute a proposal only unless and until approved.*

This document may contain forward-looking statements. Forward looking statements are only predictions and are subject to risks, uncertainties and assumptions which are outside the control of the Company. These risks, uncertainties and assumptions include (but are not limited to) commodity prices, currency fluctuations, economic and financial market conditions in various countries and regions, environmental risks and legislative, fiscal or regulatory developments, political risks, project delay or advancement, approvals and cost estimates. Actual values, results or events may be materially different to those expressed or implied in this document. Given these uncertainties, readers are cautioned not to place reliance on forward looking statements. Any forward looking statement in this document is valid only at the date of issue of this document. Subject to any continuing obligations under applicable law and the ASX Listing Rules, or any other Listing Rules or Financial Regulators' rules, the Company and its subsidiaries and each of their agents, directors, officers, employees, advisors and consultants do not undertake any obligation to update or revise any information or any of the forward looking statements in this document if events, conditions or circumstances change or that unexpected occurrences happen to affect such a statement. Sentences and phrases are forward looking statements when they include any tense from present to future or similar inflection words, such as (but not limited to) "forecast", "believe," "estimate," "anticipate," "plan," "predict," "may," "hope," "can," "will," "should," "expect," "intend," "is designed to," "with the intent," "potential," the negative of these words or such other variations thereon or comparable terminology, may indicate forward looking statements.

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Appendix 5B

Mining exploration entity or oil and gas exploration entity quarterly cash flow report

Name of entity

CENTRAL PETROLEUM LIMITED

ABN	Quarter ended ("current quarter")
72 083 254 308	30 SEPTEMBER 2025

Consolidated statement of cash flows		Current quarter $A'000	Year to date $A'000 *(3 Months)*
1.	**Cash flows from operating activities**		
1.1	Receipts from customers	12,976	12,976
1.2	Payments for		
	(a) exploration & evaluation	(748)	(748)
	(b) development	–	–
	(c) production and gas purchases	(9,401)	(9,401)
	(d) staff costs net of recoveries	(1,585)	(1,585)
	(e) administration and corporate costs (net of recoveries)	(168)	(168)
1.3	Dividends received (see note 3)	–	–
1.4	Interest received	239	239
1.5	Interest and other costs of finance paid	(759)	(759)
1.6	Income taxes paid	–	–
1.7	Government grants and tax incentives	–	–
1.8	Other (provide details if material)	–	–
1.9	**Net cash from / (used in) operating activities**	**554**	**554**

2.	**Cash flows from investing activities**		
2.1	Payments to acquire or for:		
	(a) entities	–	–
	(b) tenements	–	–
	(c) property, plant and equipment	(966)	(966)
	(d) exploration & evaluation	–	–
	(e) investments	–	–
	(f) other non-current assets	–	–

Consolidated statement of cash flows		**Current quarter $A'000**	**Year to date $A'000** *(3 Months)*
2.2	Proceeds from the disposal of:		
	(a) entities (net of transaction costs)	–	–
	(b) tenements	–	–
	(c) property, plant and equipment	–	–
	(d) investments	–	–
	(e) other non-current assets	–	–
2.3	Cash flows from loans to other entities	–	–
2.4	Dividends received (see note 3)	–	–
2.5	Other - Net (lodgement) or redemption of security deposits	(248)	(248)
2.6	**Net cash from / (used in) investing activities**	**(1,214)**	**(1,214**

3.	**Cash flows from financing activities**		
3.1	Proceeds from issues of equity securities (excluding convertible debt securities)	**–**	**–**
3.2	Proceeds from issue of convertible debt securities	–	–
3.3	Proceeds from exercise of options	–	–
3.4	Transaction costs related to issues of equity securities or convertible debt securities	–	–
3.5	Proceeds from borrowings	–	–
3.6	Repayment of borrowings	–	–
3.7	Transaction costs related to loans and borrowings	–	–
3.8	Dividends paid	–	–
3.9	Other (principal elements of lease payments)	(80)	(80)
3.10	**Net cash from / (used in) financing activities**	**(80)**	**(80)**

4.	**Net increase / (decrease) in cash and cash equivalents for the period**		
4.1	Cash and cash equivalents at beginning of period	27,471	27,471
4.2	Net cash from / (used in) operating activities (item 1.9 above)	554	554
4.3	Net cash from / (used in) investing activities (item 2.6 above)	(1,214)	(1,214)

Consolidated statement of cash flows		**Current quarter $A'000**	**Year to date $A'000 *(3 Months)***
4.4	Net cash from / (used in) financing activities (item 3.10 above)	(80)	(80)
4.5	Effect of movement in exchange rates on cash held	–	–
4.6	**Cash and cash equivalents at end of period**	**26,731**	**26,731**

5.	**Reconciliation of cash and cash equivalents** at the end of the quarter (as shown in the consolidated statement of cash flows) to the related items in the accounts	**Current quarter $A'000**	**Previous quarter $A'000**
5.1	Bank balances[1]	26,731	27,471
5.2	Call deposits	–	–
5.3	Bank overdrafts	–	–
5.4	Other (provide details)	–	–
5.5	**Cash and cash equivalents at end of quarter (should equal item 4.6 above)**	**26,731**	**27,471**

[1] *Includes the Group's share of Joint Venture bank accounts (Current Quarter $2,725,944, Previous Quarter $154,761)*

6.	**Payments to related parties of the entity and their associates**	**Current quarter $A'000**
6.1	Aggregate amount of payments to related parties and their associates included in item 1	679
6.2	Aggregate amount of payments to related parties and their associates included in item 2	–

Note: if any amounts are shown in items 6.1 or 6.2, your quarterly activity report must include a description of, and an explanation for, such payments.

Includes Directors Fees, Salaries, annual incentive and superannuation contributions.

7.	**Financing facilities** *Note: the term "facility' includes all forms of financing arrangements available to the entity.* *Add notes as necessary for an understanding of the sources of finance available to the entity.*	**Total facility amount at quarter end $A'000**	**Amount drawn at quarter end $A'000**
7.1	Loan facilities	28,000	23,384
7.2	Credit standby arrangements	–	–
7.3	Other (please specify)	–	–
7.4	**Total financing facilities**	28,000	23,384
7.5	**Unused financing facilities available at quarter end**		4,616
7.6	Include in the box below a description of each facility above, including the lender, interest rate, maturity date and whether it is secured or unsecured. If any additional financing facilities have been entered into or are proposed to be entered into after quarter end, include a note providing details of those facilities as well.		
	7.1 – Represents the Macquarie Bank loan facility which is a secured term loan facility maturing 31 December 2029 with interest accruing quarterly. Principal repayments commence March 2027 and continue quarterly thereafter until maturity. The interest rate at the end of the current quarter is 11.6264% (floating interest rate).		

8.	**Estimated cash available for future operating activities**	**$A'000**
8.1	Net cash from / (used in) operating activities (item 1.9)	554
8.2	(Payments for exploration & evaluation classified as investing activities) (item 2.1(d))	–
8.3	Total relevant outgoings (item 8.1 + item 8.2)	554
8.4	Cash and cash equivalents at quarter end (item 4.6)	26,731
8.5	Unused finance facilities available at quarter end (item 7.5)	4,616
8.6	Total available funding (item 8.4 + item 8.5)	31,347
8.7	**Estimated quarters of funding available (item 8.6 divided by item 8.3)**	**N/A**

Note: if the entity has reported positive relevant outgoings (ie a net cash inflow) in item 8.3, answer item 8.7 as "N/A". Otherwise, a figure for the estimated quarters of funding available must be included in item 8.7.

8.8 If item 8.7 is less than 2 quarters, please provide answers to the following questions:

8.8.1 Does the entity expect that it will continue to have the current level of net operating cash flows for the time being and, if not, why not?

Answer: N/A

8.8.2 Has the entity taken any steps, or does it propose to take any steps, to raise further cash to fund its operations and, if so, what are those steps and how likely does it believe that they will be successful?

Answer: N/A

8.8.3	Does the entity expect to be able to continue its operations and to meet its business objectives and, if so, on what basis?
	Answer: N/A
	Note: where item 8.7 is less than 2 quarters, all of questions 8.8.1, 8.8.2 and 8.8.3 above must be answered.

Compliance statement

1 This statement has been prepared in accordance with accounting standards and policies which comply with Listing Rule 19.11A.

2 This statement gives a true and fair view of the matters disclosed.

Date: 31 October 2025..

Authorised by: Leon Devaney, Managing Director and CEO.............
(Name of body or officer authorising release – see note 4)

Notes

1. This quarterly cash flow report and the accompanying activity report provide a basis for informing the market about the entity's activities for the past quarter, how they have been financed and the effect this has had on its cash position. An entity that wishes to disclose additional information over and above the minimum required under the Listing Rules is encouraged to do so.
2. If this quarterly cash flow report has been prepared in accordance with Australian Accounting Standards, the definitions in, and provisions of, *AASB 6: Exploration for and Evaluation of Mineral Resources* and *AASB 107: Statement of Cash Flows* apply to this report. If this quarterly cash flow report has been prepared in accordance with other accounting standards agreed by ASX pursuant to Listing Rule 19.11A, the corresponding equivalent standards apply to this report.
3. Dividends received may be classified either as cash flows from operating activities or cash flows from investing activities, depending on the accounting policy of the entity.
4. If this report has been authorised for release to the market by your board of directors, you can insert here: "By the board". If it has been authorised for release to the market by a committee of your board of directors, you can insert here: "By the [*name of board committee – eg Audit and Risk Committee*]". If it has been authorised for release to the market by a disclosure committee, you can insert here: "By the Disclosure Committee".
5. If this report has been authorised for release to the market by your board of directors and you wish to hold yourself out as complying with recommendation 4.2 of the ASX Corporate Governance Council's *Corporate Governance Principles and Recommendations*, the board should have received a declaration from its CEO and CFO that, in their opinion, the financial records of the entity have been properly maintained, that this report complies with the appropriate accounting standards and gives a true and fair view of the cash flows of the entity, and that their opinion has been formed on the basis of a sound system of risk management and internal control which is operating effectively.