# Interim Financial Report

Half-year ended 31 December

# 2017

Central Petroleum Limited
ABN 72 083 254 308

# CONTENTS

31 December 2017



***Forward-looking statements***

This report contains forward-looking statements. Please refer to the section below under the heading "**Forward-looking statements"**, which contains a notice in respect of these statements.

# DIRECTORS' REPORT

31 December 2017

The Directors present their report on the consolidated entity consisting of Central Petroleum Limited and the entities it controlled at the end of, or during, the half-year ended 31 December 2017.

## Directors

The names of the Directors of the parent company in office during the half-year and until the date of this report are:

Robert Hubbard
Richard I Cottee
Wrixon F Gasteen
Peter S Moore
Martin D Kriewaldt (appointed 23 October 2017)
Sarah Ryan (appointed 23 October 2017)
Timothy R Woodall (appointed 20 December 2017)

Directors have held office for the period and until the date of this report unless otherwise stated.

## Principal Activity

The principal continuing activity of the consolidated entity ("the Group") during the period was the exploration, development and production of hydrocarbons.

### Highlights for the half-year reporting period and up to the date of this report Commentary and Outlook

- Operating revenue increased by 39.8% over the previous corresponding period from $12.6 million to $17.7 million.
- Gas sales volumes increased 50.6% over the previous corresponding period, reflecting gas sold under the EDL NGD (NT) Pty Ltd ("EDL") Gas Supply Agreement ("GSA") which commenced in June 2017.
- Earnings before Interest, Taxes, Depreciation, Amortisation and Exploration Expenses ("EBITDAX") for the Producing Assets segment increased by 81.7% over the previous corresponding period from $4.8 million to $8.7 million.
- The Company successfully completed a fully underwritten institutional and sophisticated investor placement of shares and a fully underwritten traditional non-renounceable entitlement offer, at an issue price of A$0.10 per share, raising $25.5 million (net of costs).
- The consolidated entity held cash balances totalling $28.6 million at 31 December 2017.
- Testing of the Stairway Sandstone at Mereenie from the previously drilled West Mereenie 15 continued free flowing gas at sustainable rates with a low nitrogen content of 2.6%. Additional recompletion opportunities have been identified.
- Dr Sarah Ryan, Mr Martin Kriewaldt and Mr Tim Woodall joined the Central Board as independent Non-executive Directors as part of the Company's commitment to augment and strengthen the current Board.

This half-year reflects a full 6 months of gas delivered under the EDL GSA, with a pleasing continuation of prudent cost control leading to improved operating cash flow and profit performance.

The Company successfully completed an Equity Raising to support it Gas Acceleration Programme with the objective of substantially increasing its gas reserves in time to have delivery coincide with the Northern Gas Pipeline ("NGP") becoming operational in late 2018.

## Principal Activity (*continued*)

### Commentary and Outlook (*continued*)

The various pipeline regulation reviews and reforms continue to take shape with several key reforms being implemented over the next year, including Day Ahead Auction, binding arbitration for non-scheme pipelines, and a review into the National Gas Laws for covered pipelines. Central remains optimistic that these reforms will put downward pressure on transportation costs and thereby facilitating our ability to sell new gas supply into the east coast market following commencement of the Northern Gas Pipeline later this year.

The Mereenie Joint Marketing Agreement (“JMA”) between the Mereenie Joint Venture participants was announced on 25 September 2017 and remains subject to approval from the ACCC. We anticipate a decision from the ACCC could be made later this month.

Since the end of the current reporting period the Company announced it has signed a contract with Ensign Australia Pty Ltd for the forthcoming drilling programme of up to four wells, structured commercially as two required wells and an option for up to two further wells. Joint Venture approval of Mereenie wells is subject to ACCC interim clearance of joint marketing.

## Review of Operations and other Joint Venture Activities

### Mereenie Oil and Gas Field (OL4 and OL5) – Northern Territory

***(CTP – 50% interest [Operator], Macquarie Mereenie Pty Ltd – 50% interest))***

During the half-year:

- All gas nominations were met for the reporting period. With the increase in sales due to the EDL contract, the average gas production has been ~14.5-15.0 Tj/d.
    - Following the signing of a GSA with EDL on 24 April 2017, to supply 9.85PJ of gas over five years to the Northern Territory Pine Creek Power Station operated by EDL, the delivery of gas from Mereenie to Pine Creek under the GSA commenced on 1 June 2017 and continued successfully for the half-year with the field maintaining 100% production of all gas volumes nominated by our customer.
    - Oil production has been in line with budget expectations and has averaged 90-100 kl/d (560-628 Bopd).
- The maintenance team successfully conducted an annual shut down completing statutory inspections on 25 pressure safety valves (“PSV’s”), 15 internal vessel inspections and 45 external vessel inspections. The project team successfully managed this project in three days down from two weeks under previous operatorship.
- Central continued to work on development planning for Mereenie to provide additional supply into the Northern Territory or the NGP in 2018.
- Wellhead Safety Device fitted to EM20 in line with regulator’s requirements.
- Production Flowline from EM20 well has been re-routed and de-bottlenecked.
- Control improvements implemented on both refrigeration plants, resulting in more reliable operations.
- Wellpad control improvements at EM22, WM05 and well integrity campaign completed.
- New instrument air compressors purchased and delivered for the Central Treatment Plant (“CTP”).
- New inlet separators procured for Mereenie’s CTP from surplus available equipment.
- Received a visit from the NT Scientific Inquiry into Hydraulic Fracturing, i.e. Pepper Inquiry.
- Planning and permitting continued on the new wells West Mereenie 25 and 26.

## Review of Operations and other Joint Venture Activities *(continued)*

- An upgrade of the safety system was completed at Mereenie’s CTP facility, providing emergency de-pressuring functionality.

- A new control panel was installed on one of the compressors at Mereenie's CTP facility, replacing an obsolete unit.
- Central continued to work with local environmental experts to effect improvements in water runoff, erosion control, and weed management plans.
- Central continues to work closely with local rangers and emergency services through active participation in emergency response exercises and real life search and rescue operations.

## Health, Safety and the Environment

- The Health and Safety of staff remains the company's highest priority. Central recorded its first and only, 'Lost Time Injury' ("LTI"), a broken ankle, in September 2017. However rehabilitation and the company's Return to Work ("RTW") process have been efficiently managed and the staff member has now been cleared to resume full duties with no ongoing medical conditions.
- Training continues as a priority, particularly skills based training and accreditation for field based staff. To facilitate this, a trainer has been appointed to assist our Operator - Maintainer positions and qualifications. Central has entered into an arrangement with Charles Darwin University ("CDU") as our Registered Training Organisation ("RTO") to support this process.
- In a pre-emptive safety move, the Joint Venture has replaced crew change vehicles for the Mereenie site. The replaced vehicle's had high odometer readings for their age and the road environment is particularly harsh on the vehicles structure.  These vehicles represent an improvement to the safety of team members travelling to and from the field. New tracking systems and communication systems have been incorporated into each vehicle to streamline safety and daily management by Logistics teams.
- The final Field Environmental Management Plan (FEMP) was submitted to the Northern Territory Department of Primary Industries and Resources ("DPIR") first week in December 2017. It was submitted under new environmental regulations, also taking into account feedback received from the DPIR on earlier drafts. This document will serve as a template for the production of similar plans for all other sites.
- Central has actively sought local contractors to provide weed management and site environmental services. Recently contracts have been let with a local contractor who employs local Indigenous persons. Central was impressed by this business model and to date the results have been encouraging.

## Dingo Gas Field (L7) and Dingo Pipeline (PL30) – Northern Territory

***(CTP – 100% Interest)***

During the half-year:

- The field continued to supply Owen Springs Power Station ("OSPS") and gas demands have been met for the reporting period.
- Construction of TEG dehydration unit nearing completion in early February 2018.
- Construction of Water Bath Heater due to arrive to site in early February 2018.

## Review of Operations and other Joint Venture Activities *(continued)*

***Figure 1:*** *Water bath heater.*

### Health, Safety and the Environment

- Central is maintaining a comprehensive training program to up-skill current capabilities and competencies.
- An internal site safety audit was completed with no major non-conformances noted. Various minor issues were recognised and rectified.
- Ongoing staff training to ensure HSE obligations are met.
- Management of staff with Return To Work ("RTW") restrictions (non-work related injuries) continues to be managed and monitored.

## Review of Operations and other Joint Venture Activities *(continued)*

### Palm Valley Gas Field (OL3) – Northern Territory

***(CTP - 100% Interest)***

During the half-year:

- No production during the reporting period with the plant remaining on standby.
- General scheduled maintenance and repairs performed.
- Fracture modelling on Palm Valley main field using available surface fracture data as well as downhole log data completed. Target area has been identified.
- Planning and permitting continued for the new well location – Palm Valley 13.

The main producing reservoirs at Palm Valley are the Lower Stairway and Pacoota formations. To date, ~160 Bcf of gas has been produced from the naturally fractured reservoir. Original Gas in Place ("OGIP") estimates vary greatly over the field, but all are in excess of 1 Tcf. With the current wells, the Estimated Ultimate Recovery ("EUR") is predicted to be around ~200 Bcf. This is a very low recovery factor for a naturally fractured reservoir and implies a large quantity of gas still remaining in the ground. Production performance and interference testing have shown that the existing wells may not be connected to the total estimated gas in place volume, which implies that there are other compartments of the field that have not been drained and contain gas in possibly producible quantities. To determine the possible location and size of these areas that could be segregated from the producing wells, a natural fracture model has been created with data from seismic, outcrop, image logs, production and core data. The model predicts hydrocarbon resources which are the target for a deviated infill appraisal well which will prove the hypothesis, potentially leading to an increase in 2P reserves. A subsurface target and well trajectory has been identified, the subsequent well surface location has been selected and optimised to utilise an existing well pad and production facilities. The drilling program is being developed and licenses and approvals are currently being acquired.

### Surprise Production Licence (L6) – Northern Territory

***(CTP - 100% Interest)***

During the half-year:

- Surprise West remained shut-in during the half year. The well is currently being evaluated for a short term flow test.

## Exploration Review

### ATP 909, ATP 911 and ATP 912, Southern Georgina Basin – Queensland

***(CTP - 100% interest)***

During the half-year:

Central received the transfer of the previously TOTAL held 10% of the three permit areas. Central has drafted and submitted a first draft application for Project Status for the three permits. The draft was submitted seeking the Queensland Department of Natural Resources and Mines' ("DNRM") advice on the approach and detail required in the application to achieve the best possible outcome. DNRM has reviewed the initial 'Project Satus' submission with preliminary feedback. Central will consult with DNRM in Q1, 2018 with regard to the best approach to secure Project Status for the Southern Georgina permits.

Central also finalised lease arrangements for the Boulia warehouse and the consolidation of leases on which this facility sits.

## Review of Operations and other Joint Venture Activities *(continued)*

### Santos Stage 2 Farm out – Southern Amadeus Basin, Northern

At present a total of 932 km of seismic line data have been acquired—72% of the total 1,300 line km 2D required to meet Phase 2 Farm-in requirement.

There are good indications from improved seismic imaging as a result of the new acquisition parameters with improved definition of the Dukas Lead and the additional potential for a supra-salt lead. A five month extension to both phase 2 and phase 3 has been agreed. In addition, ~366 line km of new 2D seismic is currently being selected, acquisition is expected to restart in January 2018.

Due to the complexity of seismic processing, interpretation and depth conversion of the initial 932 km of data, Santos has requested a further 4 month extension of the Stage 2 end date to 3 July, 2018. Santos has also requested an additional 2 month extension on the Stage 3 end date to 3 June, 2019. Central is currently considering these requests.

***Figure 3: Line crew deploying equipment on AMSAN13-25 (10 meter group intervals)***

| Southern Amadeus Area | Total Santos Participating Interest after completion of Stage 1 | Total Santos Participating Interest after completion of Stage 2 |
|---|---|---|
| EP82 (excl. EP82 Sub-Blocks) | 25% | 40% (i.e. additional 15% earned) |
| EP105 | 25% | 40% (i.e. additional 15% earned) |
| EP106 * | 25% | 40% (i.e. additional 15% earned) |
| EP112 | 25% | 40% (i.e. additional 15% earned) |

* *Santos (as Operator) has continued the process of an application with the NT Department of Primary Industry and Resources for consent to surrender Exploration Permit 106.*

## Review of Operations and other Joint Venture Activities *(continued)*

The survey comprises two rounds. The first round of 2D seismic to mature the natural gas and helium prospective Dukas lead and to gather data for the Rossini lead has been completed. The second part of the seismic acquisition program will consist of additional 2D seismic lines over the Dukas Lead to bring the total program to 1,300 line km. Second round line locations are being confirmed for resumption of data acquisition in July 2018. Adverse weather conditions in the area have caused the focus to be concentrated on the Dukas Lead.

Central is actively reviewing data in these permits, seeking to upgrade a variety of exploration play types and targets, which could be prospective for hydrocarbons and/or helium.

The joint venture's exploration endeavours on these four permits focus on maturing large sub-salt leads. The primary reservoir objective is the Heavitree Quartzite. Secondary reservoir objectives in the Neoproterozoic units include the Areyonga Fm and Pioneer Ss which are gas bearing in the Ooraminna field.

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Central is actively reviewing data in these permits, seeking to upgrade a variety of exploration play types and targets, which could be prospective for hydrocarbons and/or helium.

### Amadeus Basin (includes EP115 North Mereenie Block), Northern Territory

Central's evaluation of inventory of leads and prospects is now completed. Play types and leads have been developed for the under-explored section underlying the proven Larapintine system, which is believed to be prospective for gas.

### Other Exploration and Application Areas

### Ooraminna Field

***(CTP—100% interest)***

Two wells have been drilled at Ooraminna with both wells having proved gas flow from the Pioneer formation. Although the flow rates were sub-economic, it is encouraging to note that the wells were drilled in an area with apparent low natural fracture density within the Pioneer formation. Structural mapping has been updated following the reprocessing of the seismic data. This has been augmented by outcrop mapping to assist in structural definition between seismic lines. This updated mapping has been incorporated into a natural fracture model which has defined areas with the greatest fracture density. The subsurface target and well trajectory have now been defined and the surface location of the Ooraminna 3 has also been identified. The appropriate licensing and approvals are currently being acquired and the drilling program for the well has been developed and sent to the DPIR for approval. The Ooraminna field has an inferred closure area of ~175 km2 and preliminary estimates of OGIP for the Pioneer formation range from ~125 Bcf to ~425 Bcf. Currently, there are no resources certified at Ooraminna, however, demonstrating increased productivity through drilling in areas of predicted increased natural fracture density will lead to resource/reserves certification.

No material developments occurred in Central's other exploration and application areas during the quarter. However, Central continues to work with stakeholders and progress discussions pertaining to the grant of application areas and rationalisation of low prospectivity areas.

## Operating and Financial Review

### Risks

Central was admitted to the ASX in 2006 and since that time has been exploring for and more recently producing oil and gas from onshore central Australia.

*General Risks*

As with most businesses, Central is exposed to a number of general risks that could materially affect its financial position, assets and liabilities, reputation, profits, prospects and share price. These could include:

- fluctuations in economic conditions in Australia and internationally, including fluctuations in economic growth, interest rates, exchange rates, inflation, and employment;
- fluctuations in stock markets, domestically and internationally;
- changes in government policies including fiscal policy, monetary policy, foreign policy;
- changes in political conditions;
- natural disasters and catastrophic events.

*Cash flow and liquidity risk*

Central's ability to meet its debts as and when they are due for payment depends on future performance and cash flow from its operations. These cash flows may be affected by broader economic, financial, competitive, legislative and other factors, many of which are beyond the control of the Board of Directors.

*Exploration Risk*

By its nature, exploration is an extremely high risk business. Most exploration activity, in particular seismic and drilling, is conducted in joint venture, thus enabling the joint venture participants to spread that risk, and reward. The risks include, but are not limited to, land access risk, geological risk, drilling operations risk, safety and environmental risks. Central's activities are subject to extensive government regulation in areas such as exploration rights, drilling practices, environmental performance and workplace health and safety. Central regularly monitors changes in government regulation.

Exploration is typically funded with risk capital. Debt capital is normally only available for development activities such as facility and pipeline construction.

*Oil & Gas estimates*

Reservoir engineering is subjective and can only provide an educated estimate of the extent of oil and gas reserves in place. Estimates are not precise and are based not only on knowledge, but experience, interpretation and accepted industry practice. There are a number of variables that can impact economically recoverable reserves, including changes to government regulations, commodity prices and taxes.

*Environmental Risk*

Central is subject to laws and regulations to minimise the impact of environmental damage arising from its operations. Non-compliance with these laws and regulations can result in substantial penalties and remediation costs. Any change in the laws or regulation may adversely affect Central's business.

*Operating and insurance risks*

Central's key operating risks include governmental regulatory compliance, changes in operating costs, changes in capital maintenance and replacement costs, plant availability and sub-surface extraction. In addition, Central is exposed to changes in $A commodity prices with respect to crude oil sales which are benchmarked against $US international markets. The majority of Central's revenues, however, are generated by gas sales which effectively mitigates $A commodity price risk through the use of long-term, $A fixed price gas sales agreements with credit worthy customers.

The oil and gas industry is hazardous by nature with many inherent risks including potential well blowouts, spills and leaks, ruptures and pollutants. Central maintains insurance cover for the key risks, however full insurance cover may not be available or may be cost prohibitive and as a result any losses Central sustains may only be partially covered by insurance, if at all.

# Operating and Financial Review (*continued*)

## Risks *(continued)*

*Competition and human resource Risk*

Central competes with numerous other oil and gas producers that have substantially greater financial resources, staff and facilities. The ability to secure transportation of its product remains a kay factor in its competitiveness within the industry.

Central's credentials as an oil and gas explorer and producer are reliant on its ability to attract talented staff and professional service contractors, competing with other larger organisations. Any growth in demand for skilled employees and professional service contractors may adversely impact Central's ability to attract these people.

*Health, safety and security risks*

The oil and gas industry by its nature has many inherent health and safety risks. Central maintains a strong focus on the health and safety of all those involved or affected by it operations, however the risk of personal injury is always present.

In addition to personal harm, a serious incident may result in reputational damage, the ability to attract and retain employees as well as compensation, regulatory fines and penalties.

*Pipeline tariff risk*

Central is continually seeking to access new and higher value markets like the east coast gas market via the Northern Gas Pipeline (NGP). The east coast gas market, however, is currently undergoing a substantive restructuring of supply and demand following commencement of 3 LNG projects in Queensland. This has placed significant upward pressure on delivered gas prices in the east coast. Central's ex-field gas price for sales into the east coast, however will, in part, depend upon pipeline tariffs which are themselves undergoing substantive regulatory review and reform by Federal Government agencies. The outcome of these reviews will be material to Central's ex-field gas pricing received from east coast customers.

## Business Strategy

Over the past four years, Central has developed and successfully pursued a strategy to take advantage of a tightening domestic gas market to gain critical mass in conventional gas production and uncontracted gas reserves. This strategy first crystallised through the acquisition of the Palm Valley and Dingo gas fields from Magellan in April 2014, marking Central's entry into commercial gas production.

Central's business strategy was bolstered significantly on 1 September 2015 when Central completed the acquisition of 50% of Mereenie from Santos and became Operator for the Joint Venture. This was subsequently bolstered through the EDL Gas Supply Agreement which commenced 1 June 2017. The implementation of this business strategy has made Central a substantive onshore domestic gas producer, with approximately 15 TJ/d contracted sales equity accounted (~5.5PJ p.a.) and growing uncontracted conventional gas reserves from proven fields. Central is currently undertaking a 3-field drilling program with an ultimate target of tripling our uncontracted 2P reserves from existing producing fields to between 300 PJ and 400PJ (equity accounted). Whilst available for delivery in late 2018 for the domestic gas shortfall, which continues to appear very tight, completion of certification of the full reserves upgrade will take longer and occur over time.

With the Mereenie, Palm Valley and Dingo fields under our common operatorship, Central is now in a unique position to capitalise on the Northern Gas Pipeline ("NGP"), which will connect the Northern Territory to the eastern seaboard in late 2018. This project is driven by clear fundamentals of a domestic gas shortfall on the east coast and underexplored onshore gas potential in the Northern Territory. In linking supply and demand, Central's sound business strategy of acquiring gas assets and uncontracted reserves in advance of the NGP pipeline has positioned it to be a direct and substantive beneficiary.

## Operating and Financial Review (*continued*)

### Business Strategy *(continued)*

Whilst the implementation of Central's Business Strategy has been relatively swift, the volatility in oil prices has served to justify our transition into gas starting four years ago. The acquisition of Palm Valley, Dingo, and Mereenie have all been acquired based on existing gas contracts which are structured as long-term fixed price, CPI escalated. This provides a solid revenue stream going forward to cover Central's operating activities and debt financing arrangements secured on long term gas contracts that are not affected by oil price or currency movements and, therefore, largely unaffected by turmoil in international oil or LNG markets. Future reserve additions and new gas sales agreements (such as the EDL GSA) result in substantive value accretion to those assets.

Accessing new and higher-value markets for our gas should materially re-rate our significant under-explored permits throughout the Amadeus, Southern Georgina, Pedirka and Wiso basins in Central Australia. Going forward, our operations now allow Central to be cash flow positive after debt service and all other corporate obligations which means that any new capital raising (such as the recent equity raise) can be fully dedicated to growing high value conventional gas reserves throughout our various permits.

### Key Financial and Operating Data (Segment Reporting)

Central derives its revenues and profits from its producing assets segment; specifically the production and sales of natural gas from Palm Valley and Dingo, and natural gas and crude oil from Mereenie.

Central continues to explore for hydrocarbons which are reported in the exploration segment.

The Group recorded $17.7 million of operating revenue for the period compared to $12.6 million for the previous corresponding period, an increase of 39.8%. The increase reflects the supply of gas under the gas sales agreement with EDL which commenced in June 2017.

Gross Profit increased from $4.7 million for the half year ended 31 December 2016 to $8.7 million for the current half year, an increase of 83%. The result does not include amounts from take or pay gas contracts until the gas is taken or forfeited by the customer.

A summary of consolidated revenues and results for the half-year by segment is set out below:

| | Segment Revenues | | Segment EBITDAX[1] | | Segment Results | |
|---|---|---|---|---|---|---|
| ***Financial Data*** | 31 Dec 17 $ | 31 Dec 16 $ | 31 Dec 17 $ | 31 Dec 16 $ | 31 Dec 17 $ | 31 Dec 16 $ |
| Producing Assets | 17,673,716 | 12,639,411 | 8,727,069 | 4,804,312 | 189,401 | (2,720,107) |
| Development Assets | - | - | - | - | - | - |
| Exploration Assets | - | - | 280,000 | 279,816 | (875,814) | (178,381) |
| Unallocated Items | - | - | (2,854,577) | (2,863,112) | (3,232,215) | (3,247,975) |
| ***Total Group*** | 17,673,716 | 12,639,411 | 6,152,492 | 2,221,016 | (3,918,628) | (6,146,463) |

| ***Sales Data[2]*** | 31 Dec 17 | 31 Dec 16 |
|---|---|---|
| **Gas Sales (GJs)** | | |
| Dingo Gas Field | 374,586 | 421,387 |
| Mereenie Gas Field | 2,170,369 | 1,215,457 |
| Palm Valley Gas Field | - | 52,493 |
| **Total Gas Sales (GJs)** | **2,544,955** | **1,689,337** |
| **Oil Sales (Bbls)** | | |
| Mereenie Oil | 54,000 | 56,663 |
| **Total Oil Sales (Bbls)** | **54,000** | **56,663** |

[1] *Earnings before Interest, tax, depreciation, amortisation, impairment and exploration expense*

[2] *Sales volumes include gas physically supplied or forfeited under take or pay contracts. The volumes do not include quantities able to be invoiced under take or pay contracts where a future right to take gas still exists.*

## Operating and Financial Review (*continued*)

### Segment Results

Segment EBITDAX are earnings before interest, tax depreciation, amortisation, impairment and exploration. EBITDAX is used by management as an indicative measure of underlying cash profit from operations as it excludes non-cash items and the costs of finance. It should be noted however that share based payments (2017: $1,049,130 2016: $1,138,885) are not excluded from the unallocated items in the tables above but are also non-cash items.

Segment results are earnings after tax, which is the measure of segment result that is reported to the executive management team to assess the performance of the operating segments against total reported accounting profit.

EBITDAX increased by 177% from $2,221,016 for the previous corresponding period to $6,152,492 for the current period, reflecting a full 6 months of gas supplied under the EDL contract. EBITDAX from the Producing Assets segment increased from $4.8 million to $8.7 million, period on period. The Company maintained its focus on responsible cost management during the period.

Realised average oil prices increased from A$68 per barrel in the six months to December 2016 to A$82 per barrel for the current interim reporting period, reflecting the increase in world crude oil prices.

The prior year period included an R&D tax refund as Other Income amounting to $634,167.

### Other

The Group recorded a $0.3 million gain from the disposal of interests in exploration application areas.

## Events since the end of the Half Year

No matter or circumstance has arisen that will affect the Group's operations, results or state of affairs.

## Auditor's Independence Declaration

A copy of the auditor's independence declaration as required under section 307C of the Corporations Act 2001 is set out on page 12.

This report is made in accordance with a resolution of directors.

**Richard Cottee**
Managing Director

26 February 2018

**Forward-looking statements**

This report contains forward-looking statements, including statements of current intention, statements of opinion and expectations regarding Central Petroleum Limited's ("**Central Petroleum**") present and future operations, possible future events and future financial prospects. Such statements are not statements of fact and may be affected by a variety of known and unknown risks, uncertainties, variables and changes in underlying assumptions or strategy that could cause Central Petroleum'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, and the outcomes are not all within the control of Central Petroleum. Some matters are subject to approval of joint venture participants and governmental authorities.

Central Petroleum makes no representation, assurance or guarantee as to the accuracy or likelihood of fulfilment of any forward looking statement or any outcomes expressed or implied in any forward-looking statement. The forward-looking statements in this report reflect expectations held at the date of this report. Except as required by applicable law or the Australian Securities Exchange (ASX) Listing Rules, Central Petroleum disclaims any obligation or undertaking to publicly update any forward-looking statements, or discussion of future financial prospects, whether as a result of new information or of future events.

## Auditor's Independence Declaration

As lead auditor for the review of Central Petroleum Limited for the half-year ended 31 December 2017, 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 review; and

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

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

Michael Shewan
Partner
PricewaterhouseCoopers

Brisbane
26 February 2018

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# CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

For the half-year ended 31 December 2017

| | Notes | 2017<br>$ | 2016<br>$ |
|---|---|---|---|
| Operating revenue | | 17,673,716 | 12,639,411 |
| Cost of sales | | (8,996,266) | (7,899,120) |
| Gross profit | | 8,677,450 | 4,740,291 |
| Other income | 4 | 530,059 | 1,021,112 |
| Share based employment benefits | | (1,049,130) | (1,138,885) |
| General and administrative expenses | | (358,261) | (257,662) |
| Depreciation and amortisation | | (4,021,100) | (3,849,344) |
| Employee benefits and associated costs | | (1,647,626) | (2,143,840) |
| Exploration expenditure | | (1,704,973) | (576,568) |
| Finance costs | | (4,345,047) | (3,941,567) |
| Loss before income tax | | (3,918,628) | (6,146,463) |
| Income tax credit | | - | - |
| Loss for the half-year | | (3,918,628) | (6,146,463) |
| Other comprehensive loss for the half-year, net of tax | | - | - |
| Total comprehensive loss for the half-year | | (3,918,628) | (6,146,463) |
| **Total comprehensive loss attributable to members of the parent entity** | | (3,918,628) | (6,146,463) |
| **Earnings per share** | | | |
| Basic and diluted loss per share (cents) | | (0.64) | (1.42) |

The above consolidated statement of comprehensive income should be read in conjunction with the accompanying notes.

# CONSOLIDATED BALANCE SHEET

As at 31 December 2017

| | Notes | 31 Dec 2017 $ | 30 Jun 2017 $ |
|---|---|---|---|
| **ASSETS** | | | |
| **Current assets** | | | |
| Cash and cash equivalents | 5 | 28,591,601 | 5,478,140 |
| Trade and other receivables | | 12,097,731 | 4,996,216 |
| Inventories | | 3,626,498 | 3,273,014 |
| Total current assets | | 44,315,830 | 13,747,370 |
| **Non-current assets** | | | |
| Property, plant and equipment | 6 | 103,782,840 | 106,816,359 |
| Exploration assets | | 8,898,767 | 8,898,767 |
| Intangible assets | | 112,284 | 82,157 |
| Other financial assets | | 2,431,134 | 2,501,947 |
| Goodwill | | 3,906,270 | 3,906,270 |
| Total non-current assets | | 119,131,295 | 122,205,500 |
| **Total assets** | | **163,447,125** | **135,952,870** |
| **LIABILITIES** | | | |
| **Current liabilities** | | | |
| Trade and other payables | | 3,712,895 | 3,239,168 |
| Deferred revenue | | 2,714,334 | 2,714,334 |
| Interest-bearing liabilities | 7 | 3,705,327 | 3,859,747 |
| Other financial liabilities | 8 | 38,600 | 38,600 |
| Provisions | 9 | 2,399,133 | 3,161,454 |
| Total current liabilities | | 12,570,289 | 13,013,303 |
| **Non-current liabilities** | | | |
| Deferred revenue | | 10,335,299 | 5,283,741 |
| Interest-bearing liabilities | 7 | 76,467,933 | 78,310,007 |
| Other financial liabilities | 8 | 22,741,981 | 21,914,537 |
| Provisions | 9 | 24,684,012 | 23,389,129 |
| Total non-current liabilities | | 134,229,225 | 128,897,414 |
| **Total liabilities** | | **146,799,514** | **141,910,717** |
| **Net assets** | | **16,647,611** | **(5,957,847)** |
| **EQUITY** | | | |
| Contributed equity | 10 | 197,776,488 | 172,301,532 |
| Reserves | 10 | 22,890,585 | 21,841,455 |
| Accumulated losses | | (204,019,462) | (200,100,834) |
| **Total equity** | | **16,647,611** | **(5,957,847)** |

*The above consolidated balance sheet should be read in conjunction with the accompanying notes.*

# CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

For the half-year ended 31 December 2017

| | | Attributable to owners of Central Petroleum Limited | | | |
|---|---|---|---|---|---|
| | Notes | **Contributed Equity** | **Option Reserve** | **Accumulated Losses** | **Total** |
| | | **$** | **$** | **$** | **$** |
| **Balance at 1 July 2016** | | **172,301,532** | **19,590,431** | **(175,374,353)** | **16,517,610** |
| Loss for the half-year | | - | - | (6,146,463) | (6,146,463) |
| Other comprehensive income | | - | - | - | - |
| Total comprehensive loss for the half-year | | - | - | (6,146,463) | (6,146,463) |
| **Transactions with owners in their capacity as owners** | | | | | |
| Contributions of equity, net of transaction costs | | - | - | - | - |
| Share based payments | | - | 1,138,885 | - | 1,138,885 |
| Share and option issue | | - | - | - | - |
| Share issue costs | | - | - | - | - |
| Total transactions with owners | | - | 1,138,885 | - | 1,138,885 |
| **Balance at 31 December 2016** | | **172,301,532** | **20,729,316** | **(181,520,816)** | **11,510,032** |
| **Balance at 1 July 2017** | | **172,301,532** | **21,841,455** | **(200,100,834)** | **(5,957,847)** |
| Loss for the half-year | | - | - | (3,918,628) | (3,918,628) |
| Other comprehensive income | | - | - | - | - |
| Total comprehensive loss for the half-year | | - | - | (3,918,628) | (3,918,628) |
| **Transactions with owners in their capacity as owners** | | | | | |
| Share based payments | | - | 1,049,130 | - | 1,049,130 |
| Share issues | | 27,250,000 | - | - | 27,250,000 |
| Share issue costs | | (1,775,044) | - | - | (1,775,044) |
| Total transactions with owners | | 25,474,956 | 1,049,130 | - | 26,524,086 |
| **Balance at 31 December 2017** | | **197,776,488** | **22,890,585** | **(204,019,462)** | **16,647,611** |

*The above consolidated statement of changes in equity should be read in conjunction with the accompanying notes.*

# CONSOLIDATED STATEMENT OF CASH FLOWS

For the half-year ended 31 December 2017

| | 2017<br>$ | 2016<br>$ |
|---|---|---|
| **Cash flows from operating activities** | | |
| Receipts from customers | 16,656,043 | 10,783,302 |
| Interest received | 199,385 | 93,650 |
| Other income received | 19,576 | 27,559 |
| Interest and borrowing costs | (2,993,187) | (3,228,905) |
| Proceeds from research and development refund | - | 634,167 |
| Payments to suppliers and employees (inclusive of GST) | (13,666,293) | (11,060,738) |
| Lease incentive received | - | 193,000 |
| Net cash inflow/(outflow) from operating activities | 215,524 | (2,557,965) |
| **Cash flows from investing activities** | | |
| Payments for interest in Mereenie assets | - | (3,342,446) |
| Payments for property, plant and equipment | (957,832) | (926,778) |
| Payment for interest bearing security bonds | - | (270,237) |
| Redemption of interest bearing security bonds | 70,813 | 170,170 |
| Proceeds from the sale of interests in exploration permits | 280,000 | 80,000 |
| Deposits received for sale of exploration permits | 30,000 | - |
| Net cash outflow from investing activities | (577,019) | (4,289,291) |
| **Cash flow from financing activities** | | |
| Proceeds from contributed equity | 27,250,000 | - |
| Repayment of borrowings | (2,000,000) | (2,327,722) |
| Payments for capital raising costs | (1,775,044) | - |
| Net cash inflow/(outflow) from financing activities | 23,474,956 | (2,327,722) |
| **Net increase/(decrease) in cash and cash equivalents** | **23,113,461** | **(9,174,978)** |
| **Cash and cash equivalents at the beginning of the half-year** | **5,478,140** | **15,115,699** |
| **Cash and cash equivalents at the end of the half-year** | **28,591,601** | **5,940,721** |

*The above consolidated statement of cash flows should be read in conjunction with the accompanying notes.*

# NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the half-year ended 31 December 2017

## 1. Basis of Preparation of Half-Year Report

This condensed consolidated interim financial report for the half-year reporting period ended 31 December 2017 has been prepared in accordance with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Act 2001 (Cth)*.

This condensed consolidated interim financial report does not include all the notes of the type normally included in an annual financial report. Accordingly, this report is to be read in conjunction with the annual report for the year ended 30 June 2017 and any public announcements made by Central Petroleum Limited during the interim reporting period in accordance with the continuous disclosure requirements of the Corporations Act 2001.

The accounting policies adopted are consistent with those of the previous financial year and corresponding interim reporting period unless otherwise stated.

### (a) Going Concern

The interim financial report has been prepared on a going concern basis which contemplates continuity of normal business activities and the realisation of assets and settlement of liabilities in the ordinary course of business.

During the period ended 31 December 2017, Central Petroleum Limited ("Central") incurred a Loss of $3,918,628 (2016: Loss of $6,146,463) and had a net cash inflow from operating activities of $215,524 (2016: outflow of $2,557,965).

The Directors continually monitor the Group's operations and asset portfolio and regularly review the cash flows requirements, budgets and forecasts, to ensure that it has sufficient funds to meet its contractual commitments.

In order to maintain sustained cash flows over the longer term, the primary focus for the Company is to secure new Gas Sales Agreements ("GSA") in either the Northern Territory or east coast via the Northern Gas Pipeline ("NGP"), which is due for completion in 2018.

Based on the cash assets at 31 December 2017, take and/or pay funds received in January 2018 amounting to $5,418,771 and receipts from ongoing take or pay gas sales contracts, the Directors believe that the Group will, over the next twelve months, have sufficient funds to pay its debts as and when they fall due and payable and, accordingly, have prepared the Financial Statements on a going concern basis.

### (b) New and Amended Standards Adopted by the Group

In the current period, the Group has adopted all new and revised Standards and Interpretations issued by the Australian Accounting Standards Board that are relevant to its operations and effective for reporting periods beginning on or after 1 July 2017. The adoption of these new and revised Standards and Interpretations has not resulted in any changes to the Group's accounting policies.

### (c) Impact of Standards Issued but not yet applied by the Entity

Certain new accounting standards and interpretations have been published that are not mandatory for the current reporting period. The Group has concluded these standards and interpretations are not expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

(i) AASB 15 Revenue from contracts with customers

The AASB has issued a new standard for the recognition of revenue. This will replace AASB 118 which covers contracts for goods and services and AASB 111 which covers construction contracts. The new standard is based on the principle that revenue is recognised when control of a good or service transfers to a customer – so the notion of control replaces the existing notion of risks and rewards. The new standard is mandatory for financial years commencing on or after 1 January 2018.

Management has undertaken an initial assessment of the effects of applying the new standard on the Group's financial statements and does not expect the changes will have any material impact on the way revenue is currently recognised.

## 1. Basis of Preparation of Half-Year Report (*continued*)

### (c) Impact of Standards Issued but not yet applied by the Entity (*continued*)

(ii) AASB 9 Financial Instruments

AASB 9 Financial Instruments addresses the classification, measurement and derecognition of financial assets and financial liabilities, introduces new rules for hedge accounting and a new impairment model. The standard is not applicable until 1 January 2018 but is available for early adoption.

The Group does not expect any impact from the new classification, measurement and derecognition rules on the Group's financial assets and financial liabilities. The Group does not currently enter into any hedge transactions and will not be affected by the new rules. The new impairment model is an expected credit loss (ECL) model which is not expected to have any impact on the group.

(iii) AASB 16 Leases

AASB 16 was issued in February 2016. It will result in almost all leases being recognised on the balance sheet, as the distinction between operating and finance leases is removed. Under the new standard, an asset (the right to use the leased item) and a financial liability to pay rentals are recognised. The only exceptions are short-term and low-value leases.

The standard will affect primarily the accounting for the group's operating leases. As at the reporting date, the Group has operating lease commitments of $2,016,792. The group has not yet determined to what extent these commitments will result in the recognition of an asset and a liability for future payments and how this will affect the group's profit and classification of cash flows.

Some of the commitments may be covered by the exception for short-term and low-value leases and some commitments may relate to arrangements that will not qualify as leases under AASB 16.

The standard is mandatory for annual reporting periods beginning on or after 1 January 2019. At this stage, the group does not intend to early adopt the standard.

### (d) 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.

## 2. Significant Changes in the Current Reporting Period

The financial position and performance of the group was particularly affected by the following events and transactions during the half-year ended 31 December 2017:

- The Company made a fully underwritten institutional and sophisticated investor placement of 92,000,980 shares at an issue price of $0.10c per share. In addition the Company undertook a 5 for 12 traditional non-renounceable entitlement offer, issuing a further 180,499,020 shares also at $0.10c per share. These raised gross contributions of $27,250,000 before equity raising costs of $1,775,044.
- The half year results and cash flows include revenue from the supply of gas under a Gas Sales Agreement with Energy Developments ("EDL") which commenced in June 2017.

For a detailed discussion about the group's performance and financial position please refer to our review of operations on pages 3 to 8.

## 3. 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) Gas and Oil Producing Assets

The production and sale of natural gas and crude oil.

### (b) Development Assets

The development of oil and gas fields.

### (c) Exploration Assets

The 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. Financing requirements, finance income, finance costs and taxes are managed at a Group level. The consolidated entity's operations are wholly in one geographical location being Australia.

## 3. Segment Reporting (*continued*)

### (e) Performance Monitoring and Evaluation (*continued*)

| | Producing Assets 31 Dec 2017 $ | Exploration Assets 31 Dec 2017 $ | Unallocated Items 31 Dec 2017 $ | Consolidated 31 Dec 2017 $ |
|---|---|---|---|---|
| **Revenue** | 17,673,716 | - | - | 17,673,716 |
| **Cost of sales** | (8,996,266) | - | - | (8,996,266) |
| **Gross profit** | **8,677,450** | **-** | **-** | **8,677,450** |
| Other income | 49,619 | 280,000 | 200,440 | 530,059 |
| Share based employment benefits[1] | - | - | (1,049,130) | (1,049,130) |
| General and administrative expenses | - | - | (358,261) | (358,261) |
| Employee benefits and associated costs | - | - | (1,647,626) | (1,647,626) |
| **EBITDAX[2]** | **8,727,069** | **280,000** | **(2,854,577)** | **6,152,492** |
| Depreciation and amortisation | (3,894,765) | - | (126,335) | (4,021,100) |
| Exploration expenditure | (569,912) | (1,135,061) | - | (1,704,973) |
| Finance costs | (4,072,991) | (20,753) | (251,303) | (4,345,047) |
| **Profit/(loss) before income tax** | **189,401** | **(875,814)** | **(3,232,215)** | **(3,918,628)** |
| Taxes | - | - | - | - |
| **Profit / (Loss) for the period** | **189,401** | **(875,814)** | **(3,232,215)** | **(3,918,628)** |

*[1] Share based employment benefits are a non-cash item.*
*[2] EBITDAX is Earnings before Interest, Taxation, Depreciation and Amortisation, Impairment and Exploration expense.*

| | Producing Assets 31 Dec 2016 $ | Exploration Assets 31 Dec 2016 $ | Unallocated Items 31 Dec 2016 $ | Consolidated 31 Dec 2016 $ |
|---|---|---|---|---|
| **Revenue** | 12,639,411 | - | - | 12,639,411 |
| **Cost of sales** | (7,899,120) | - | - | (7,899,120) |
| **Gross profit** | **4,740,291** | **-** | **-** | **4,740,291** |
| Other income | 64,021 | 280,451 | 676,640 | 1,021,112 |
| Share based employment benefits[1] | - | - | (1,138,885) | (1,138,885) |
| General and administrative expenses | - | (635) | (257,027) | (257,662) |
| Employee benefits and associated costs | - | - | (2,143,840) | (2,143,840) |
| **EBITDAX[2]** | **4,804,312** | **279,816** | **(2,863,112)** | **2,221,016** |
| Depreciation and amortisation | (3,725,196) | (6,066) | (118,082) | (3,849,344) |
| Exploration expenditure | (137,727) | (438,841) | - | (576,568) |
| Finance costs | (3,661,496) | (13,290) | (266,781) | (3,941,567) |
| **Profit/(loss) before income tax** | **(2,720,107)** | **(178,381)** | **(3,247,975)** | **(6,146,463)** |
| Taxes | - | - | - | - |
| **Profit / (Loss) for the period** | **(2,720,107)** | **(178,381)** | **(3,247,975)** | **(6,146,463)** |

*[1] Share based employment benefits are a non-cash item.*
*[2] EBITDAX is Earnings before Interest, Taxation, Depreciation and Amortisation, Impairment and Exploration expense*

# 3. Segment Reporting (*continued*)

## (e) Performance Monitoring and Evaluation (*continued*)

| | Producing Assets $ | Exploration Assets $ | Unallocated Items $ | Consolidated $ |
|---|---|---|---|---|
| **Total Segment Assets** | | | | |
| 31 December 2017 | 127,229,455 | 11,862,833 | 24,354,837 | 163,447,125 |
| 30 June 2017 | 119,923,785 | 11,408,488 | 4,620,597 | 135,952,870 |
| **Total Segment Liabilities** | | | | |
| 31 December 2017 | (132,845,679) | (1,994,017) | (11,959,818) | (146,799,514) |
| 30 June 2017 | (127,314,178) | (1,659,886) | (12,936,653) | (141,910,717) |

| Revenue from external customers by geographical location of production: | 31 Dec 2017 $ | 31 Dec 2016 $ |
|---|---|---|
| Australia | 17,673,716 | 12,639,411 |

| Non-current assets by geographical location: | 31 Dec 2017 $ | 30 Jun 2017 $ |
|---|---|---|
| Australia | 119,131,295 | 122,205,500 |

## (f) Major Customers

Customers with revenue exceeding 10% of the group's total oil and gas sales revenue are shown below.

| | 31 Dec 2017 $ | % of Sales Revenue | 31 Dec 2016 $ | % of Sales Revenue |
|---|---|---|---|---|
| Largest customer | 4,629,921 | 26% | 4,584,132 | 36% |
| Second largest customer | 3,838,840 | 22% | 3,609,811 | 29% |
| Third largest customer | 2,959,059 | 17% | 2,858,885 | 23% |
| Fourth largest customer | 2,419,102 | 14% | - | - |
| Fifth largest customer | 2,036,678 | 12% | - | - |

# 4. Other Income

| | 31 Dec 2017 $ | 31 Dec 2016 $ |
|---|---|---|
| Research and development refund | - | 634,167 |
| Profit on disposal of interests in Exploration tenements | 280,000 | 280,000 |
| Interest revenue | 230,483 | 79,386 |
| Other | 19,576 | 27,559 |
| | **530,059** | **1,021,112** |

## 5. Cash and Cash Equivalents

| Cash at bank and on hand comprising: | 31 Dec 2017 $ | 30 Jun 2017 $ |
|---|---|---|
| Corporate (a) | 27,927,447 | 5,081,168 |
| Joint arrangements (b) | 664,154 | 396,972 |
| | **28,591,601** | **5,478,140** |

(a) $1,653,361 of this balance relates to restricted cash held with Macquarie Bank Limited to be used for allowable purposes under the Facility Agreement (30 June 2017: $1,421,848), including, but not limited to, operating costs for the Palm Valley, Dingo and Mereenie fields, taxes, capital expenditure and debt servicing.

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

## 6. Property, Plant and Equipment

| | Freehold land and buildings $ | Producing assets $ | Plant and equipment $ | Total $ |
|---|---|---|---|---|
| **30 June 2017** | | | | |
| Cost | 3,868,743 | 84,443,566 | 44,844,266 | 133,156,575 |
| Accumulated depreciation and impairment | (639,526) | (8,334,418) | (17,366,272) | (26,340,216) |
| **Net book amount** | **3,229,217** | **76,109,148** | **27,477,994** | **106,816,359** |
| **31 December 2017** | | | | |
| Opening net book amount | 3,229,217 | 76,109,148 | 27,477,994 | 106,816,359 |
| Additions | - | - | 930,993 | 930,993 |
| Adjustment to restoration provisions | - | 38,270 | (1,176) | 37,094 |
| Disposals and write offs | - | - | - | - |
| Depreciation charge | (175,101) | (1,861,862) | (1,964,643) | (4,001,606) |
| **Closing net book amount** | **3,054,116** | **74,285,556** | **26,443,168** | **103,782,840** |
| **31 December 2017** | | | | |
| Cost | 3,868,743 | 84,481,836 | 45,774,083 | 134,124,662 |
| Accumulated depreciation and impairment | (814,627) | (10,196,280) | (19,330,915) | (30,341,822) |
| **Net book amount** | **3,054,116** | **74,285,556** | **26,443,168** | **103,782,840** |

## 7. Interest Bearing Liabilities

| | | 31 Dec 2017<br>$ | 30 Jun 2017<br>$ |
|---|---|---|---|
| (a) | Interest bearing liabilities (current) | | |
| | Debt facilities | 3,705,327 | 3,859,747 |
| | | **3,705,327** | **3,859,747** |
| (b) | Interest bearing liabilities (non-current)[1] | | |
| | Debt facilities | 76,467,933 | 78,310,007 |
| | | **76,467,933** | **78,310,007** |

The Macquarie Bank Facility consists of 4 tranches totalling $90 million. Tranches A and C total $20 million and were used for the acquisition of Palm Valley and Dingo gas fields and related assets from Magellan. Tranche B totals $30 million and was used to fund completion of the Dingo gas field, including all acquisition costs and capitalised interest expenses. Tranche D totals $40 million and was used primarily to fund the Mereenie acquisition.

All tranches are structured as 5 year partially amortising term loans with a maturity date of 30 September 2020. The interest costs are based on fixed spreads over the periodic Bank Bill Swap (BBSW) average bid rate. The Group does not have any interest rate hedging arrangements in place. The Group can repay the Facility in part or in whole at any time without a pre-payment penalty.

Under the terms of the Facility, the Group is required to comply with the following three key financial covenants:

1. The Group current ratio is at least 1:1, excluding amounts payable under the Macquarie debt facility.
2. PDP Cover Ratio is greater than 1.3:1. PDP Cover Ratio is defined as the net present value (using a 10% discount rate) of the proved, developed, producing reserves of the Palm Valley, Dingo and Mereenie oil and gas fields.
3. Financial indebtedness to trade creditors over 90 days from due date for payment does not exceed $5 million.

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

## 8. Other financial liabilities

| | 31 Dec 2017<br>$ | 30 Jun 2017<br>$ |
|---|---|---|
| **Current** | | |
| Lease incentives received | 38,600 | 38,600 |
| | 38,600 | 38,600 |
| **Non-Current** | | |
| Liabilities associated with forward gas sales agreements containing a cash settlement option | 22,639,048 | 21,792,304 |
| Lease incentives liabilities | 102,933 | 122,233 |
| Available to be taken after 12 months | 22,741,981 | 21,914,537 |
| **Total Other Financial Liabilities** | **22,780,581** | **21,953,137** |

## 9. Provisions

| | 31 December 2017 | | | 30 June 2017 | | |
|---|---|---|---|---|---|---|
| | Current | Non-current | Total | Current | Non-current | Total |
| | $ | $ | $ | $ | $ | $ |
| Employee entitlements (a) | 2,295,463 | 563,161 | 2,858,624 | 3,059,075 | 516,369 | 3,575,444 |
| Restoration and rehabilitation (b) | 103,670 | 21,460,965 | 21,564,635 | 102,379 | 21,160,338 | 21,262,717 |
| Joint Venture production over-lift (c) | - | 2,659,886 | 2,659,886 | - | 1,712,422 | 1,712,422 |
| **Total** | **2,399,133** | **24,684,012** | **27,083,145** | **3,161,454** | **23,389,129** | **26,550,583** |

### Movements in Provisions

| | Employee Entitlements (a)$ | Restoration and Rehabilitation (b) $ | Joint Venture production over-lift (c)$ | Total $ |
|---|---|---|---|---|
| Carrying amount at 1 July 2017 | 3,575,444 | 21,262,717 | 1,712,422 | 26,550,583 |
| Charged/(credited) to profit or loss | 603,156 | 888 | 947,464 | 1,551,508 |
| Changes to restoration assets | - | 37,094 | - | 37,094 |
| Unwinding of discount | - | 263,936 | - | 263,936 |
| Amounts used during the half-year | (1,319,976) | - | - | (1,319,976) |
| **Carrying amount at 31 December 2017** | **2,858,624** | **21,564,635** | **2,659,886** | **27,083,145** |

(a) *The current provision for employee entitlements includes accrued short term incentive plans, all 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 Group does not have an unconditional right to defer settlement of these obligations. However, based on past experience the consolidated entity does not expect all employees to take the full amount of accrued leave or require payment within the next 12 months. The following amounts reflect leave that is not expected to be taken within the next 12 months.*

| | 31 Dec 2017 | 30 Jun 2017 |
|---|---|---|
| Leave obligations expected to be settled after 12 months | 687,753 | 706,408 |

(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 Consolidated Entity 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.*

## 10. Contributed Equity and Reserves

| | 31 Dec 2017<br>$ | 30 Jun 2017<br>$ |
|---|---|---|
| **Share Capital** | | |
| 707,081,966 ordinary shares | 197,776,488 | 172,301,532 |
| (30 June 2017: 433,197,647 ordinary shares) | | |
| **Reserves** | | |
| Share Options Reserve | 22,890,585 | 21,841,455 |

| | Half-Year Ended 31 December<br>2017<br>$ | <br>2016<br>$ |
|---|---|---|
| **Movements in Share Capital:** | | |
| Balance at start of year | 172,301,532 | 172,301,532 |
| Issues of ordinary shares | 27,250,000 | - |
| Transaction costs | (1,775,044) | - |
| **Balance at the end of the half year** | **197,776,488** | **172,301,532** |
| **Movements in Share Options Reserve:** | | |
| Balance at start of year | 21,841,455 | 19,590,431 |
| Share based payments costs | 1,049,130 | 1,138,885 |
| **Balance at the end of the half year** | **22,890,585** | **20,729,316** |

| | 2017<br>No. of securities | 2016<br>No. of securities |
|---|---|---|
| **Movements in Ordinary Shares on Issue during the half-year:** | | |
| Balance at the beginning of the half-year | 433,197,647 | 433,197,647 |
| Share issues under placement and entitlement offers | 272,500,000 | - |
| Exercise of Employee Share Rights under LTIP | 1,384,319 | - |
| **Balance at the end of the half-year** | **707,081,966** | **433,197,647** |

## 10. Contributed Equity and Reserves *(continued)*

**Rights[1] granted during the period**

| Date of Issue | Class | Expiry Date | Value on issue | Number Issued |
|---|---|---|---|---|
| 29-Sep-2017 | Unlisted employee share rights | 22-Sep-2020 | $0.097 | 201,334 |
| 29-Sep-2017 | Unlisted employee share rights | 08-Dec-2022 | $0.097 | 38,222 |
| 03-Oct-2017 | Unlisted employee share rights | 03-Oct-2022 | $0.081 - $0.115 | 6,406,154 |
| 03-Oct-2017 | Unlisted employee share rights | 03-Oct-2022 | $0.056 | 327,000 |
| 03-Oct-2017 | Unlisted employee share rights | 03-Oct-2022 | $0.082 | 70,000 |
| 15-Dec-2017 | Unlisted employee share rights | 05-Jan-2021 | $0.084 | 18,319 |
| 18-Dec-2017 | Unlisted employee share rights | 18-Dec-2022 | $0.055 | 1,835,910 |

[1] The number of rights to vest will be determined in accordance with the performance conditions as detailed in the Company's 2014 Long Term Incentive Plan.

**Options and Rights expired or cancelled during the period**

| Class | Expiry Date | Exercise Price | Number |
|---|---|---|---|
| Unlisted employee share rights - cancelled | 08-Dec-2022 | Nil | 16,169 |
| Unlisted employee options – expired | 15-Nov-2017 | $0.45 | 28,168,035 |
| Unlisted employee options – expired | 15-Nov-2017 | $0.40 | 365,100 |
| Unlisted employee options - expired | 15-Nov-2017 | $0.65 | 27,300 |

**Options and Rights exercised during the period**

| Class | Exercise Date | Exercise Price | Number |
|---|---|---|---|
| Unlisted employee share rights | 31-Oct-2017 | Nil | 1,279,644 |
| Unlisted employee share rights | 15-Dec-2017 | Nil | 104,675 |

## 11. Contingencies and Commitments

### (a) Exploration and Capital Commitments

The Group has contingent exploration expenditure commitments on various permit areas held in Australia.

| | Consolidated | |
|---|---|---|
| | **31 Dec 2017** **$** | **30 Jun 2017** **$** |
| Within 1 year | 9,355,000 | 4,630,000 |
| Later than 1year but not later than 3 years | 16,055,000 | 25,180,000 |
| Later than 3 years but not later than 5 years | 12,550,000 | 2,400,000 |
| **Total** | **37,960,000** | **32,210,000** |

In the petroleum industry it is common practice for entities to farm-out, transfer or sell a portion of their rights to third parties and, as a result, obligations may be reduced or extinguished.

### (b) Operating Lease Commitments

Commitments for minimum lease payments in relation to non-cancellable operating leases are as follows:

| | Consolidated | |
|---|---|---|
| | **31 Dec 2017** **$** | **30 Jun 2017** **$** |
| Within 1 year | 567,802 | 465,421 |
| Later than 1 year but not later than 5 years | 1,448,990 | 1,404,222 |
| **Total** | **2,016,792** | **1,869,643** |

## 11. Contingencies and Commitments (*continued*)

### (c) Contingent Liabilities

(i) Mereenie Sales Bonus

In November 2017 the Group entered into an agreement with Macquarie Bank and Santos to provide a full and final release of Santos Entities and Central Petroleum group entities from all obligations and liabilities, rights and entitlements in relation to the Mereenie Sales Bonus payments.

Other than the above there were no changes to contingent liabilities in respect of certain other joint arrangements at 31 December 2017, as outlined in the previous annual financial report.

(ii) GRR Litigation

The Company is involved in litigation filed in the District Court of Harris County, located in Houston, Texas, by Geoscience Resource Recovery, LLC ("GRR") in respect of a farm-in deal negotiated between the Perth office of Total S.A. and the Company when it was headquartered in Perth. The Company's appeal from the order of the court denying the Company's objection to the court's jurisdiction was not successful. The Company has filed a Motion for Rehearing with the Court of Appeals. The Company has denied any liability.

The Company also filed proceedings in the Supreme Court of Queensland against GRR seeking, among other things, declarations, that the Company did not enter into and is not bound by an alleged agreement to pay GRR certain fees, and that the Company is not liable to GRR for a fee or any other sum in relation to the farm-in deal. GRR opposed jurisdiction of the Supreme Court of Queensland. GRR's application was dismissed in the Company's favour in October 2017. GRR has filed an appeal of the decision.

### (d) Contingent Assets

In November 2017 the Group entered into an agreement with Macquarie Bank and Santos to provide a full and final release of Santos Entities and Central Petroleum group entities from all obligations and liabilities, rights and entitlements in relation to the Mereenie Sales Bonus payments.

As a result, the Group has no contingent assets at 31 December 2017.

## 12. Post Balance Date Events

There were no events that occurred subsequent to 31 December 2017 other than noted above or elsewhere in these accounts.

## 13. Related Party Transactions

There were no related part transactions during the period.

# DIRECTORS' DECLARATION

## 31 December 2017

In the Directors' opinion:

The Financial Statements and notes set out on pages 14 to 28 are in accordance with the Corporations Act 2001, including:

(a) complying with Accounting Standards, the Corporations Regulations 2001 and other mandatory professional reporting requirements, and

(b) giving a true and fair view of the Consolidated Entity's financial position as at 31 December 2017 and of its performance for the half-year ended on that date, and

(b) there are reasonable grounds to believe that Central Petroleum Limited will be able to pay its debts as and when they become due and payable.

This declaration is made in accordance with a resolution of Directors.

Richard I Cottee – Managing Director
Brisbane, Queensland

26 February 2018

# Independent auditor's review report to the members of Central Petroleum Limited

## *Report on the Half-Year Financial Report*

We have reviewed the accompanying half-year financial report of Central Petroleum Limited (the Company), which comprises the consolidated balance sheet as at 31 December 2017, the consolidated statement of comprehensive income, consolidated statement of changes in equity and consolidated statement of cash flows for the half-year ended on that date, selected explanatory notes and the directors' declaration for Central Petroleum Limited. The consolidated entity comprises the Company and the entities it controlled during that half-year.

### *Directors' responsibility for the half-year financial report*

The directors of the Company are responsible for the preparation of the half-year 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 half-year financial report that is free from material misstatement whether due to fraud or error.

### *Auditor's responsibility*

Our responsibility is to express a conclusion on the half-year financial report based on our review. We conducted our review in accordance with Australian Auditing Standard on Review Engagements ASRE 2410 *Review of a Financial Report Performed by the Independent Auditor of the Entity*, in order to state whether, on the basis of the procedures described, we have become aware of any matter that makes us believe that the half-year financial report is not in accordance with the *Corporations Act 2001* including giving a true and fair view of the consolidated entity's financial position as at 31 December 2017 and its performance for the half-year ended on that date; and complying with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Regulations 2001*. As the auditor of Central Petroleum Limited, ASRE 2410 requires that we comply with the ethical requirements relevant to the audit of the annual financial report.

A review of a half-year financial report consists of making enquiries, primarily of persons responsible for financial and accounting matters, and applying analytical and other review procedures. A review is substantially less in scope than an audit conducted in accordance with Australian Auditing Standards and consequently does not enable us to obtain assurance that we would become aware of all significant matters that might be identified in an audit. Accordingly, we do not express an audit opinion.

### *Independence*

In conducting our review, we have complied with the independence requirements of the *Corporations Act 2001*.

***PricewaterhouseCoopers, ABN 52 780 433 757***
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*Conclusion*

Based on our review, which is not an audit, we have not become aware of any matter that makes us believe that the half-year financial report of Central Petroleum Limited is not in accordance with the *Corporations Act 2001* including:

1. giving a true and fair view of the consolidated entity's financial position as at 31 December 2017 and of its performance for the half-year ended on that date;

2. complying with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Regulations 2001*.

PricewaterhouseCoopers

PricewaterhouseCoopers

Michael Shewan

Michael Shewan
Partner

Brisbane
26 February 2018

# CORPORATE DIRECTORY

31 December 2017

## Directors

Robert Hubbard BA (Hons), FCA, Non-Executive Chairman
Richard I Cottee BA, LLB (Hons), Managing Director and Chief Executive Officer
Wrixon F Gasteen BE (Hons), MBA (Dist), Non-Executive Director
Prof. Peter S Moore BSc (Hons1), MBA, PhD, Non-Executive Director
Martin D Kriewaldt, FAICD (Life), Non-Executive Director
Dr Sarah Ryan, PhD, BSc (Hons1), Non-Executive Director
Timothy R Woodall, B.Ec, FCPA, GAICD, Non-Executive Director

## Company Secretaries

Joseph P Morfea, FAIM, GAICD, FAIM
Daniel C M White LLB, BCom, LLM

## Registered Office

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## Auditors

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117 Victoria Street
West End, QLD 4101
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## Stock Exchange Listing

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