Interim Financial Report

Half-year ended 31 December

2019

Central Petroleum Limited
ABN 72 083 254 308

CONTENTS

Forward-looking statements

The Directors' 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 the Directors' Report reflect expectations held at the date of that 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.

CHAIRMAN'S LETTER

Dear Fellow Shareholder,

The past six months have seen Central Petroleum demonstrate solid foundations for a new phase of growth by unlocking new resources from our portfolio of assets.

Strong gas sales during the half year have proven the value of our producing gas fields and confirmed Central's position as a credible supplier to gas markets in both the Northern Territory and the eastern seaboard.

Central has recorded four solid quarters of operating performance from our expanded gas fields in the Northern Territory and has recorded a statutory profit of $3.2 million for the half year to December. In comparison to the same period last year, the results reflect the overwhelming impact of the commissioning of the Northern Gas Pipeline in January 2019, with gas sales volumes up 135% and earnings before interest, tax, depreciation and exploration costs (EBITDAX) of $17.2 million, up from just $2.6 million a year earlier.

In the same period, a pathway for further growth has become clear, with the successful drilling programme at the Range coal seam gas project culminating in the certification of 270 PJ (135 PJ net to Central) of 2C contingent gas resources in August.

Our focus on the Range prospect in 2020 will be complimented by a renewed emphasis on exploration in the producing, yet underexplored Amadeus Basin. Our portfolio review has identified several new lower-risk targets in, and close to, our existing producing areas which could more than double our existing reserves if successful.

We are in active discussion with Santos for a forward plan with Dukas and remain committed to completion of the Dukas-1 exploration well in 2021. If successful, this prospect would not only be Company making, but market changing given the potential for look-alike sub-salt plays throughout the Amadeus Basin.

These growth initiatives have the potential to completely transform Central and we are now focused on unlocking this significant value for our shareholders.

The energy market is very challenging at the moment, but Central is well positioned to weather periods of low spot gas prices because of our solid long-term fixed-price contracts and take-or-pay arrangements.

We are actively managing these market conditions, with a continued emphasis on prudent balance sheet and cost management. In 2019, we paid-down $21.5 million of debt and our financial position has been strengthened further by extending the term of our loan facilities by 12 months to September 2021. The loan extension was finalised after the reporting date and our balance sheet is now considerably stronger than reported in this financial report –some $67.7 million of debt is now classified as 'non-current' after balance date and a further $7.7 million of cash was subsequently received in January to finalise Incitec Pivot's equity position in the Range project.

The long-term outlook for gas remains strong, and Central is well positioned to play a role in Australia's transition from coal to renewable energy sources. Underwritten by solid operating assets, our growth strategy has multiple opportunities to deliver significant shareholder wealth in the near future.

Yours faithfully

Wrixon Gasteen
Chairman
25 February 2020

DIRECTORS' REPORT

31 December 2019

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 2019.

Directors

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

Mr Stuart Baker
Mr Leon Devaney
Dr Julian Fowles
Mr Wrixon Gasteen (Chairman)
Ms Katherine Hirschfeld AM
Mr Martin Kriewaldt (resigned 2 September 2019)

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

Operating and Financial Review

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

- Step change in operating results compared to the previous corresponding period (half year to 31 December 2018):
    - Operating revenue increased by 78.4% from $20.0 million to $35.7 million.
    - Gas sales volumes increased 135%, reflecting the commencement of gas sales through the newly-commissioned Northern Gas Pipeline ("NGP") from January 2019.
    - Earnings before interest, tax, depreciation and exploration (EBITDAX) of $17.2 million for the half year, up from $2.6 million.
    - Net profit of $3.2 million compared to a loss of $19.1 million.
- Successful completion of the four well exploration programme at the Range gas project in Queensland's Surat Basin, resulting in the certification of 270PJ of 2C contingent gas resource (135 PJ net to Central). It is anticipated that the upcoming pilot well programme and front-end engineering and design will lead to a conversion of 2C contingent gas resource to certified 2P reserves.
- The Dukas-1 exploration well in the Northern Territory's Amadeus Basin was suspended at a depth of 3,704m after encountering hydrocarbon-bearing gas from an over-pressurised zone close to the primary target. A forward plan for Dukas-1 is being formulated.
- Commenced planning a major exploration programme in the Amadeus Basin for CY2020, consisting of five high-graded drillable prospects and two appraisal tests. The programme has an estimated mean prospective resource of 505 PJ of gas and 29 mmbbl of oil (risked: 205 PJ of gas and 9 mmbbl of oil). Funding is anticipated to be sourced through a farmout process which is currently underway.
- Executed a new joint gas sales agreement (GSA) for the supply of 21.9 PJ of 'firm' and 'as-available' gas over three years from 1 January 2020, partially replacing maturing contracts. Central has a 50% contractual obligation for gas supply under the GSA, but it expects to receive the benefit of the majority of the revenue during the first two contract years, under new portfolio balancing arrangements with its Mereenie JV partner.
- Announced the extension of the Group's $72.8 million finance facility for a further 12 months to 30 September 2021, subsequent to the end of the reporting period.

Operating and Financial Review *(continued)*

Safety and environment

Safety performance was excellent with no MTIs or LTIs recorded and there were no reportable environmental incidents in the half year.

As an outcome of the Pepper Fracking Inquiry, the Northern Territory (NT) Government has identified proposed 'no-go zones' within granted tenures to be declared as 'reserved blocks', subject to reaching agreement with the tenure holder. At this point, this regulation does not appear to impact Central's existing operations or any exploration activity in the CY2020 exploration programme. Some of Central's exploration tenements and areas under application may be affected. Any such arrangement is expected to require lengthy negotiations between the Government, Central and its Joint Venture partners. The Company continues to work closely with the NT Government as regulations change and evolve.

PRODUCTION

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

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

During the half-year:

- Gas production averaged 40.3 TJ/d over the half-year (100% JV).
- Central's share of gas sales averaged 20.2 TJ/d, down 24% from the preceding June half year due to lower production volumes and the cessation of gas overliftings. Central will gradually return 2.4 PJ of its current overlift balance over the next three years.
- Oil sales averaged 270 barrels of oil per day over the half-year (Central's share).
- In-field optimisation and well intervention activity continued throughout the period to partially offset the natural field decline. Field capacity was 42 TJ/d at 31 December.

A campaign of targeted recompletions and at least one production well is being planned for the second half of CY2020 to maintain and optimise field production capacity.

The CY2020 exploration and appraisal programme proposes to target the Stairway Formation, using laterals drilled from existing wells. There is currently 54 PJ (net to Central) of 2C contingent gas resources booked in the Stairway Formation. If successful, additional production could be quickly supplied through the existing Mereenie production facilities.

Palm Valley Gas Field (OL3) – Northern Territory

(CTP – 100% Interest)

Gas production averaged 10.8 TJ/d over the six months to December 2019, an increase of 37% from the preceding six months, reflecting commencement of the PV13 well which was commissioned in May 2019.

Following the success of the PV13 well, which has produced consistently at 7 TJ/d, planning has commenced for another horizontal production well (PV12) to be drilled using the wellbore of the proposed Palm Valley Deep exploration well which is part of the exploration programme planned for later this year.

The proposed CY2020 exploration programme includes targets in the Palm Valley area, with a potential 182 PJ of risked mean prospective resources which could be tied into the existing Palm Valley infrastructure if successful.

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

(CTP – 100% Interest)

The Dingo field supplies gas to the Owen Springs Power Station, with gas sales averaging 3.3 TJ/d over the half-year, an increase of 26% from the 2.6 T/day sold in the preceding six months. The balance of the contracted volume of 4.4 TJ/d is subject to take-or-pay provisions, and is paid annually to Central in January for the preceding year.

It is proposed that the Dingo-1 well will be re-entered to target the deeper Pioneer Sandstone formation as part of the CY2020 exploration programme. The target Pioneer Sandstones are estimated to contain 63 PJ of risked mean prospective resources.

Operating and Financial Review *(continued)*

APPRAISAL / DEVELOPMENT

Range Gas Project (ATP2031) - Queensland

(CTP – 50% interest, Incitec Pivot Queensland Gas Pty Ltd – 50% interest)

In August, Central booked a maiden 2C contingent gas resource of 270 Petajoules (PJ) (135 PJ Central share) of Coal Seam Gas (CSG) in ATP 2031 in Queensland's Surat Basin. The Range Gas Project is at the doorstep of the east coast gas market and could nearly double Central's reserve base within 15 months.

The resources, certified by international certifier NSAI, exceeded expectations and resulted from a successful four-well exploration programme conducted safely, on schedule and on budget during July and August 2019. These wells provided exciting results, demonstrating average coal thickness of 30m and drill stem tests indicated that permeability is in line with, or better than, expectations – including the deeper Taroom seams. The excellent permeability and coal thickness suggest that the area should be suitable for gas production from low-cost, un-fracked vertical wells.

Given these excellent results, Central and joint venture partner, Incitec, are proceeding immediately with an appraisal pilot, which is anticipated to consist of three wells producing gas and water to a local flare and above-ground tank. Drilling is planned to commence in the first half of CY2020.

The joint venture is now progressing towards a Final Investment Decision (FID) for a substantial CSG development in early 2021. These pre-FID activities include conducting environmental studies, securing approvals, undertaking engineering studies, selecting equipment and ordering long-lead items. First gas sales from the Range gas project are targeted for 2022.

It is anticipated that completion of the pre-FID activities and a successful appraisal pilot will lead to a conversion of 2C contingent resource to 2P certified reserves. The 2C is currently classified as "development pending", which is the highest category of contingent resource, requiring only satisfaction of FID milestones such as development plans, access to infrastructure and offtake agreements for conversion to certified 2P gas reserves.

The Range gas project is situated in Queensland's Surat Basin, a geological province whose CSG reserves have attracted billions of dollars of investment over the last decade and now supplies gas to both the domestic market and international consumers through Gladstone's LNG facilities. There are a number of CSG wells in adjacent blocks and areas within the Walloons coal fairway in the same depth band as the Range gas project have been successfully developed for production. The permit area covers 77km^2 and is located approximately 28km north-west of the town of Miles which lies halfway between the Wooleebee Creek and Bellevue CSG developments.

EXPLORATION

Dukas-1 (EP112) – Northern Territory

(CTP – 30% interest, Santos (Operator) – 70% (farm-in in progress))

Dukas-1 is located approximately 175km south west of Alice Springs and the prospect has multi-TCF gas potential (30% net to Central).

The Dukas-1 exploration well had a proposed total depth of 3,850m and reached a depth of 3,704m in August when it encountered formation pressures much higher than predicted in association with a combination of hydrocarbon and inert gasses. Santos (as operator) subsequently assessed that the technical requirements to drill forward were in in excess of the capabilities of the rig and surface equipment, with drilling activity suspended and the rig released.

The primary reservoir objective, the Heavitree Quartzite / fractured basement, is yet to be penetrated.

Central and Santos are actively exploring options and opportunities to complete the Dukas-1 well. While a forward plan for Dukas-1 is subject to JV approval, Central would like to complete this important and potentially market changing exploration well as soon as practicable in 2021. A forward plan for Dukas-1 remains under active discussion within the JV and will be announced as soon as it has been formally agreed by the parties.

Exploration Portfolio Review

The current Central portfolio encompasses opportunities within the Amadeus, Southern Georgina, Wiso and Surat Basins. The total area held by Central for exploration (both granted and under application) within these basins is 188,767 km^2 (76,318 km^2 granted and 112,450 km^2 under application).

Operating and Financial Review *(continued)*

Following connection to the east coast gas market via the NGP in January 2019, Central's NT exploration assets now have a clear pathway to an attractive east coast gas market. Recognising this new market dynamic, Central has significantly augmented its exploration capabilities with experienced personnel and new analytical tools to undertake a full updated exploration portfolio review.

The exploration portfolio review continued during the period and has enabled the definition of an attractive 2020 exploration drilling campaign targeting lower-risk, higher value targets. In addition, a basin-wide play-based analysis has been advanced in order to assess longer term and potentially transformational exploration programmes beyond 2020. Completion of this longer-term analysis is targeted for 2020.

CY2020 Exploration Programme

The proposed CY2020 exploration programme announced in October is a potentially Company-changing programme that consists of five high-graded drillable targets and two appraisal tests. These exploration targets range from lower to more moderate-risk opportunities with compelling investment justifications, including rapid commercialisation, attractive brownfield economics, proximity to existing infrastructure, and the potential to be ready in CY2020.

The CY2020 exploration programme targets natural fractures within conventional formations. No artificial stimulation (hydraulic fracturing) is proposed for this exploration programme.

Work on the CY2020 exploration programme progressed during the period, finalising well designs and progressing the approvals processes required for exploration in the Northern Territory. To date, applications for Aboriginal Areas Protection Authority (AAPA) Certificates for the exploration and development wells have been lodged, and AAPA's assessment process is underway. Ecological assessments were also undertaken at all sites in December, with no significant ecological constraints identified. Work on the Environmental Management Plans for NT Government approval of the exploration wells continues to progress.

The CY2020 exploration program is estimated to have a total cost of circa $50 million and target mean prospective resources of up to 505 PJ of gas (205 PJ risked mean) and 29 mmbbl of oil (9.5 mmbbl risked mean):

	Unit	Best estimate (P50)	Mean	Risked Mean
Gas	Petajoules	321	505	205
Oil	Million barrels	24	29	9.5

In addition to the exploration wells above, the proposed 2020 exploration programme also includes two appraisal tests that could provide a potential pathway for converting 2C contingent resources of 54 PJ (Central share) to reserves within the Mereenie Stairway formations. Optimal lateral drilling and completion techniques are currently under review, including horizontal drilling with coil tubing and radial jetting.

Contingent and prospective resources

The best estimate and mean volumes above represent the unrisked recoverable volumes derived from montecarlo probabilistic volumetric analysis for each prospect. Inputs required for these analyses have been derived from offset wells and fields relevant to each play and field. Recovery factors used have been derived from analogous field production data.

The Prospective Resources were first reported to ASX on 11 October 2019 and the Contingent Resources are as reported in the 30 June 2019 Annual Report. Central confirms that it is not aware of any new information or data that materially affects the information included in those announcements and all material assumptions and technical parameters underpinning the estimates continue to apply and have not materially changed.

Risked mean recoverable volumes have been derived by using the geological chance of success for each individual prospect and multiplying the mean recoverable volume and aggregating the result.

Cautionary statement: the estimated quantities of petroleum that may potentially be recovered by the application of a future development project(s) relate to undiscovered accumulations. These estimates have both an associated risk of discovery and a risk of development. Further exploration appraisal and evaluation is required to determine the existence of a significant quantity of potentially moveable hydrocarbons.

Central plans to fully fund the CY2020 exploration programme through a formal farmout process which is now underway. Central's current operating assets at Mereenie, Palm Valley, and Dingo have all benefitted from recent access to the east coast gas market via the NGP. Central believes this catalyst has generated an uplift in asset value that could be released efficiently through a sell-down.

Operating and Financial Review *(continued)*

Longer-term Exploration Targets

The Amadeus Basin is an extensive underexplored basin with five working hydrocarbon systems demonstrating proven oil and gas production. Central have identified many less-mature, but potentially company-changing, oil and gas prospects throughout the basin. Work has been progressing on a play-based basin mapping that will enable the Company to mature these opportunities into drillable prospects with much better technical understanding and focus. The play-based mapping of these prospects, including potential Dukas "look-a-likes", will allow these exploration targets to be graded and prioritised.

Other exploration activity during the half year included:

- **Amadeus Basin,** Granted and Application Permits, Northern Territory: Central began initial planning for 500km of seismic acquisition in EP115 during the period. The final layout has yet to be agreed on, and the result of the Dukas-1 and Mamlambo-1 wells will influence the location of the upcoming seismic program which was due to be acquired before December 2019. An application for permit suspension was granted to facilitate a more informed seismic program whilst still meeting schedules necessary to keep the permit in good standing.
- **Ooraminna**, Northern Territory (RL3 and RL4): Following the portfolio review, the proposed Ooraminna-3 well has been assessed as being less compelling on a risk-return basis than the identified CY2020 exploration targets. The DPIR have agreed in principal to the deferral of the Ooraminna-3 well and Central is awaiting a formal response to its deferral request.
- **Southern Georgina Basin**, Queensland (ATP909, ATP911 and ATP912): Conducted geology and geophysical studies focussing on the Ethabuka structure.

KEY FINANCIAL AND OPERATING DATA

The Consolidated Entity had an operating profit after income tax for the half year to 31 December 2019 of $3.2 million (Dec 2018: loss of $19.1 million).

The above result was after expensing exploration costs of $1.1 million (Dec 2018: $13.6 million). The previous year's exploration costs were largely associated with the drilling of the Palm Valley 13 well which was successfully tied-in to production in May 2019. The Group's policy is to expense all exploration costs as incurred. To assist understanding of the Group's underlying financial performance before exploration costs, earnings before interest, tax, depreciation, amortisation and exploration (EBITDAX) is reported below.

The connection of the Group's gas fields to east coast gas markets through the Northern Gas Pipeline (NGP) on 3 January 2019 has had a favourable impact on the Group's financial performance and resulted in a 568% increase in EBITDAX from $2.6 million in the corresponding half year period in 2018 to $17.2 million in 2019. The table below shows key metrics for the Group:

	Half year to December 2019	Half year to December 2018	Change	% Change
Net Sales Volumes				
- Natural Gas (TJ)	6,863	2,921	3,942	135%
- Oil & Condensate (Bbls)	49,701	43,727	5,974	14%
Sales Revenue ($ '000)	35,713	20,022	15,691	78%
Gross Profit ($ '000)	18,785	5,825	12,960	222%
EBITDAX[1] ($ '000)	17,159	2,568	14,591	568%
EBITDA[2] ($'000)	16,080	(11,073)	27,153	n/a
EBIT[3] ($ '000)	6,714	(15,427)	22,141	n/a
Statutory Profit / (Loss) after tax ($ '000)	3,201	(19,077)	22,278	n/a
Net cash inflow/(outflow) from Operations[4] ($'000)	8,292	(14,479)	22,771	n/a
Capital expenditure[5] ($ '000)	1,377	12,672	(11,295)	(89) %

Notes:

1. EBITDAX is Earnings before Interest, Tax, Depreciation, Amortisation and Exploration costs (refer reconciliation below).
2. EBITDA is Earnings before Interest, Tax, Depreciation and Amortisation.
3. EBIT is Earnings before Interest and Taxation.
4. Cashflow from Operations includes cash outflows associated with Exploration activities.
5. Capital expenditure on tangible assets

Operating and Financial Review *(continued)*

Revenue

The Group recorded $35.7 million of operating revenue for the period compared to $20.0 million for the previous corresponding period, an increase of 78.4%. The increase reflects a 135.0% increase in gas volumes associated with gas supplied via the Northern Gas Pipeline (“NGP”) which became fully operational in January 2019. Crude volumes increased by 13.7% but were largely offset by lower prices.

Cost of Sales

Cost of Sales increased by $2.7 million (19.2%) over the previous corresponding period reflecting the increased production volumes and related gas field operations.

EBITDAX

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, the costs of finance and expensed exploration costs and is reconciled to statutory profit below:

Reconciliation of statutory profit/(loss) before tax to EBITDAX

	31 Dec 2019 $	31 Dec 2018 $
Statutory profit / (loss) before tax	3,200,780	(19,077,165)
Net interest	3,513,354	3,650,427
EBIT	**6,714,134**	**(15,426,738)**
Depreciation and amortisation	9,365,958	4,353,775
EBITDA	**16,080,092**	**(11,072,963)**
Exploration expenses	1,078,745	13,640,645
EBITDAX	**17,158,837**	**2,567,682**

It should be noted however that EBITDAX is only an indicative measure of underlying cash profit from operations as there are other significant non-cash items included in EBITDAX, such as share based payments (2019: $1,150,821, 2018: $567,198) are included in the statutory profit / loss above but are also non-cash items. Revenues recognised may also not reflect actual cash receipts, as some gas revenues relate to presold gas for which cash was received in previous periods and amounts received under take or pay gas contracts are not recognised as revenue until the gas is taken or forfeited by the customer.

Other Expenses

Net employee costs (including share based benefits) for the half year were $2.1 million compared to $2.8 million for the prior corresponding period. The annual Short Term Incentive Plan amounts were awarded as share rights rather than cash in 2019 ($0.5 million). Recoveries of labour costs from external parties in relation to operating and exploration activities were $0.5 million higher than the prior year.

Net Assets/Liabilities

At 31 December 2019 the Group had a net liability position of $1.4 million compared to a net liability position at 30 June 2019 of $5.6 million. The improvement reflects the positive operating cash flows and debt repayments during the period.

The net asset position has improved further subsequent to the end of the period, with $7.7 million received in January 2020 as consideration for finalisation of the granting of a 50% interest in ATP 2031 to Incitec Pivot.

Included in liabilities on the Group’s balance sheet are amounts recognised in respect of deferred revenue amounting to $37.8 million. These liabilities will be transferred to revenue as gas is supplied to the customer or forfeited under take-or-pay contracts and therefore do not represent a cash liability to the Group.

Debt

The group’s accelerated debt repayments continued during the half year with $9.5 million of principal repaid during the period (2018: $2.0 million). There were no new borrowings during the period.

The balance of outstanding debt at 31 December 2019 was $72.7 million and is disclosed as a current liability as, at the balance date, the loan facility with Macquarie was due to expire on 30 September 2019. Subsequent to the end of the year, the loan facility was extended by 12 months to expire on 30 September 2021.

Operating and Financial Review (*continued*)

The table below illustrates the impact of the loan extension on the 31 December 2019 Consolidated Balance Sheet. The Group's net current asset position becomes $4,034,835 instead of the $63,666,128 net current liability position reported under Australian Accounting Standards.

Consolidated Balance Sheet As at 31 Dec 2019	Statutory balance sheet $	Impact of loan extension $	Balance sheet after loan extension $
Current assets	29,420,586	-	29,420,586
Non-current assets	133,692,376	-	133,692,376
Total assets	**163,112,962**	**-**	**163,112,962**
Current liabilities	(93,086,714)	67,700,963	(25,385,751)
Non-current liabilities	(71,440,967)	(67,700,963)	(139,141,930)
Total liabilities	**(164,527,681)**	**-**	**(164,527,681)**
Net assets	**(1,414,719)**	**-**	**(1,414,719)**

Net working capital

Cash decreased by $2.9 million to $14.9 million at 31 December 2019, with $9.5 million of accelerated loan repayments over the period. Loan repayments reduce to $5 million in the next 12 months.

Net working capital (current assets less current liabilities) at 31 December 2019 was negative $63.7 million (June 2019: $1.5 million) including $67.7 million of outstanding loan balances which have subsequently been extended for a further 12 months. The table below illustrates that after taking into account the new loan maturity, the net working capital position improves to $4.0 million.

Consolidated Balance Sheet As at 31 Dec 2019	Statutory balance sheet $	Impact of loan extension $	Balance sheet after loan extension $
Current assets	29,420,586	-	29,420,586
Current liabilities	(93,086,714)	67,700,963	(25,385,751)
Net current assets / (liabilities)	**(63,666,128)**	**67,700,963**	**4,034,835**

The net working capital position also includes $10.9 million of deferred revenue. These liabilities will be transferred to revenue as gas is supplied to the customer or forfeited under take-or-pay contracts and therefore do not represent a cash liability to the Group.

Net cashflow from operations

Net cashflow from operations was $8.3 million (2018 half year: net cash outflow of $14.5 million), reflecting higher sales volumes following commencement of the Northern Gas Pipeline in January 2019.

Events since the end of the Half Year

Cash settlement for sale of interest in ATP2031

In January 2020, subsequent to the end of the half year, Central received $7.7 million from its joint venturer in ATP 2031, Incitec Pivot Limited (IPL), to finalise the acquisition by IPL of its 50% interest in ATP2031. IPL had been carrying Central's share of the first $20 million of exploration and appraisal expenditure of the joint venture, with any amount not spent by 31 December 2019 being payable to Central. Each joint venturer will now fund 50% of any further expenditure in the area.

Loan extension

In February 2020, the loan facility with Macquarie Bank was extended for a further 12 months. The loan is now due for full repayment by 30 September 2021. The loan is disclosed as a current liability in the Consolidated Balance Sheet as, at the balance date, the loans were due for repayment within 12 months. If the Consolidated Balance Sheet had been prepared to reflect the new repayment schedule, $67.7 million would have been classified as a non-current liability, instead of as a current liability.

No other matters or circumstances have 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 11.

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

Wrixon Gasteen
Chairman
Brisbane
25 February 2020

AUDITOR'S DECLARATION OF INDEPENDENCE

31 December 2019

Auditor's Independence Declaration

As lead auditor for the review of Central Petroleum Limited for the half-year ended 31 December 2019, 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.

Tim Allman
Partner
PricewaterhouseCoopers

Brisbane
25 February 2020

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CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

For the half-year ended 31 December 2019

	Notes	**2019** **$**	**2018** **$**
Revenue from contracts with customers -sale of hydrocarbons	3(a)	35,712,962	20,022,261
Cost of sales		(16,928,321)	(14,197,269)
Gross profit		18,784,641	5,824,992
Other income	5	814,529	217,030
Share based employment benefits		(1,150,821)	(567,198)
General and administrative expenses		(269,509)	(481,708)
Depreciation and amortisation		(9,365,958)	(4,353,775)
Employee costs net of recoveries		(937,168)	(2,229,204)
Exploration expenditure		(1,078,745)	(13,640,645)
Finance costs		(3,596,189)	(3,846,657)
Profit/(Loss) before income tax		3,200,780	(19,077,165)
Income tax credit		-	-
Profit/(Loss) for the half-year		3,200,780	(19,077,165)
Other comprehensive income/(loss) for the half-year, net of tax		-	-
Total comprehensive income/(loss) for the half-year		3,200,780	(19,077,165)
Total comprehensive income/(loss) attributable to members of the parent entity		3,200,780	(19,077,165)

Earnings per share

		2019	2018
Basic earnings/(loss) per share (cents)		0.45	(2.70)
Diluted earnings/(loss) per share (cents)		0.41	(2.70)

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

CONSOLIDATED BALANCE SHEET

As at 31 December 2019

	Notes	31 Dec 2019 $	30 Jun 2019 $
ASSETS			
Current assets			
Cash and cash equivalents	6	14,864,338	17,805,869
Trade and other receivables		11,751,278	9,060,155
Inventories		2,804,970	2,719,526
Total current assets		29,420,586	29,585,550
Non-current assets			
Property, plant and equipment	7	116,776,798	123,475,413
Right-of-use assets	8	1,230,208	-
Exploration assets		8,898,767	8,898,767
Intangible assets		109,551	113,365
Other financial assets		2,770,782	2,770,782
Goodwill		3,906,270	3,906,270
Total non-current assets		133,692,376	139,164,597
Total assets		**163,112,962**	**168,750,147**
LIABILITIES			
Current liabilities			
Trade and other payables		4,562,179	6,006,532
Deferred revenue	3(b)	10,912,821	6,752,568
Interest-bearing liabilities	9	72,700,963	10,956,896
Lease liabilities	8	568,875	-
Other financial liabilities	10	-	2,025,014
Provisions	11	4,341,876	5,375,799
Total current liabilities		93,086,714	31,116,809
Non-current liabilities			
Deferred revenue	3(b)	26,881,399	15,559,186
Interest-bearing liabilities	9	-	70,773,157
Lease liabilities	8	827,758	-
Other financial liabilities	10	-	13,823,493
Provisions	11	43,731,810	43,094,230
Total non-current liabilities		71,440,967	143,250,066
Total liabilities		**164,527,681**	**174,366,875**
Net assets		**(1,414,719)**	**(5,616,728)**
EQUITY			
Contributed equity	12	197,776,487	197,776,487
Reserves	12	26,451,053	25,310,162
Accumulated losses		(225,642,259)	(228,703,377)
Total equity		**(1,414,719)**	**(5,616,728)**

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 2019

		Attributable to owners of Central Petroleum Limited			
	Notes	**Contributed Equity**	**Option Reserve**	**Accumulated Losses**	**Total**
		$	**$**	**$**	**$**
Balance at 1 July 2018		**197,776,487**	**23,463,784**	**(214,176,963)**	**7,063,308**
Loss for the half-year		-	-	(19,077,165)	(19,077,165)
Other comprehensive income		-	-	-	**-**
Total comprehensive loss for the half-year		-	-	(19,077,165)	(19,077,165)
Transactions with owners in their capacity as owners					
Share based payments		-	567,198	-	567,198
Options issued for financing		-	258,188	-	258,188
Total transactions with owners		-	825,386	-	825,386
Balance at 31 December 2018		**197,776,487**	**24,289,170**	**(233,254,128)**	**(11,188,471)**
Balance at 1 July 2019		**197,776,487**	**25,310,162**	**(228,703,377)**	**(5,616,728)**
Change in accounting policy	1(b)	-	-	(139,662)	(139,662)
Profit for the half-year		-	-	3,200,780	3,200,780
Other comprehensive income		-	-	-	**-**
Total comprehensive profit for the half-year		-	-	3,200,780	3,200,780
Transactions with owners in their capacity as owners					
Share based payments		-	1,150,821	-	1,150,821
Share issue costs			(9,930)		(9,930)
Options issued for financing		-	-	-	-
Total transactions with owners		-	1,140,891	-	1,140,891
Balance at 31 December 2019		**197,776,487**	**26,451,053**	**(225,642,259)**	**(1,414,719)**

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 2019

	2019 $	2018 $
Cash flows from operating activities		
Receipts from customers	32,167,902	18,022,287
Interest received	96,657	211,692
Other income received	399	22,175
Tax related payments	(634,167)	-
Interest and borrowing costs	(2,820,604)	(3,117,010)
Payments for exploration expenditure	(1,257,367)	(15,935,187)
Payments to suppliers and employees (inclusive of GST)	(19,260,557)	(13,683,009)
Net cash inflow/(outflow) from operating activities	8,292,263	(14,479,052)
Cash flows from investing activities		
Payments for property, plant and equipment	(1,476,817)	(11,946,955)
Payment for security bonds	-	(188,324)
Redemption of security bonds	-	2,333,333
Proceeds from the sale of property, plant and equipment	54,351	-
Net cash outflow from investing activities	(1,422,466)	(9,801,946)
Cash flow from financing activities		
Payments for issue of securities	(9,929)	-
Proceeds from borrowings	-	10,000,000
Repayment of borrowings	(9,501,000)	(2,000,000)
Principal elements of lease payments (2018: Principal elements of finance lease payments)	(300,399)	-
Net cash (outflow)/inflow from financing activities	(9,811,328)	8,000,000
Net decrease in cash and cash equivalents	**(2,941,531)**	**(16,280,998)**
Cash and cash equivalents at the beginning of the half-year	**17,805,869**	**27,222,845**
Cash and cash equivalents at the end of the half-year	**14,864,338**	**10,941,847**

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 2019

1. Basis of Preparation of Half-Year Report

This consolidated interim financial report for the half-year reporting period ended 31 December 2019 has been prepared in accordance with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Act 2001 (Cth)*. They present reclassified comparative information where required for consistency with the current reporting period's presentation or where otherwise stated. Central Petroleum Limited is a for-profit entity for the purpose of preparing the financial statements.

This 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 2019 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 2019, Central Petroleum Limited ("Central") recorded a net profit of $3,200,780 (2018: Loss of $19,077,165) and had a net cash flow from operating activities (including exploration) of $8,292,263 (2018: net cash outflow of $14,479,052).

At 31 December 2019 the Group has reported an overall net liability position of $1,414,719 (30 June 2019: $5,616,728) and net current liabilities of $63,666,128 (30 June 2019: $1,531,259). Net current liabilities at 31 December 2019 include the full amount owing on the loan facility with Macquarie Bank, which at that time was due for full repayment by 30 September 2020. Subsequent to the period end, the facility was extended by 12 months. If this new maturity date could be reflected in the classification of current and non-current liabilities as at the balance date, then the reported net current asset/liability position would instead disclose net current assets of $4,034,835.

The overall net liability position has arisen due to a combination of factors and includes recognition of deferred contract revenues of $37,794,220 which will either be settled by the physical delivery of gas or forfeited by the buyer under the contract. There will be no settlement in cash and no associated cash outflow other than marginal production costs. The net asset position has improved further subsequent to year end, with $7,712,831 received in January as final settlement for the proceeds from the farm-out of a 50% interest in the Range Gas Project.

The Board and management monitor the Group's cash flow requirements to ensure it has sufficient funds to meet its contractual commitments and adjusts its spending, particularly with respect to discretionary exploration activity and corporate overhead.

Supported by the cash assets at 31 December 2019 of $14,864,338 and operating cash flow forecasts, the Group forecasts that over at least the next 12 months, it will have sufficient funds to meet its commitments and continue to pay its debts as and when they fall due

The following matters have also been considered by Directors in determining the appropriateness of the going concern basis of preparation of the financial statements:

i. In February 2020, the loan facility with Macquarie Bank, which is shown as a $72.7 million current liability at 31 December 2019, was extended for a further 12 months to 30 September 2021. As a result, $67.7 million is now due for repayment beyond 12 months of balance date.

ii. The Company has a $10 million Equity Line of Credit with Long State Investment Limited which remains undrawn.

Accordingly, the Directors believe the going concern assumption is appropriate.

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

(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 2019.

(i) AASB 16 Leases and Accounting Policy

The Group has adopted AASB 16 *Leases* using the modified retrospective approach from 1 July 2019, and as a result has not restated comparatives for the 2018 reporting period as permitted under the specific transitional provisions in the standard. The reclassifications and adjustments arising from the new leasing rules are therefore recognised in the opening balance sheet on 1 July 2019.

The group leases office space, property easements, equipment and vehicles. Rental contracts are typically made for fixed periods of 3 to 8 years but may have extension options as described below. Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions. The lease agreements do not impose any covenants, but leased assets may not be used as security for borrowing purposes.

Until the 2019 financial year, all of the Group's leases of property, plant and equipment were classified as operating leases. Payments made under operating leases (net of any incentives received from the lessor) were charged to profit or loss on a straight-line basis over the period of the lease.

From 1 July 2019, leases are recognised as a right-of-use asset and a corresponding liability at the date at which the leased asset is available for use by the group. Each lease payment is allocated between the liability and finance cost. The finance cost is charged to profit or loss over the lease period so as to produce a constant periodic rate of interest on the remaining balance of the liability for each period. The right-of-use asset is depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis.

Assets and liabilities arising from a lease are initially measured on a present value basis. Lease liabilities include the net present value of the following lease payments:

- fixed payments (including in-substance fixed payments), less any lease incentives receivable
- variable lease payment that are based on an index or a rate
- amounts expected to be payable by the lessee under residual value guarantees
- the exercise price of a purchase option if the lessee is reasonably certain to exercise that option, and
- payments of penalties for terminating the lease, if the lease term reflects the lessee exercising that option.

The lease payments are discounted using the interest rate implicit in the lease. If that rate cannot be determined, the lessee's incremental borrowing rate is used, being the rate that the lessee would have to pay to borrow the funds necessary to obtain an asset of similar value in a similar economic environment with similar terms and conditions.

Right-of-use assets are measured at cost comprising the following:

- the amount of the initial measurement of lease liability
- any lease payments made at or before the commencement date less any lease incentives received
- any initial direct costs, and
- the present value of estimated future restoration costs.

Payments associated with short-term leases and leases of low-value assets are recognised on a straight-line basis as an expense in profit or loss. Short-term leases are leases with a lease term of 12 months or less.

If there is a modification to a lease arrangement, a determination of whether the modification results in a separate lease arrangement being recognised needs to be made.

Where the modification does result in a separate lease arrangement needing to be recognised, due to an increase in scope of a lease through additional underlying leased assets and a commensurate increase in lease payments, the measurement requirements as described above need to be applied.

Where the modification does not result in a separate lease arrangement, from the effective date of the modification, the Group will remeasure the lease liability using the redetermined lease term, lease payments and applicable discount rate. A corresponding adjustment will be made to the carrying amount of the associated right-of-use asset. Additionally, where there has been a partial or full termination of a lease, the Group will recognise any resulting gain or loss in the income statement.

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

(b) New and /amended Standards Adopted by the Group (continued)

(ii) Adjustments recognised on adoption of AASB 16

On adoption of AASB 16, the group recognised lease liabilities in relation to leases which had previously been classified as 'operating leases' under the principles of AASB117 Leases. These liabilities were measured at the present value of the remaining lease payments, discounted using the lessee's incremental borrowing rate as of 1 July 2019. The weighted average lessee's incremental borrowing rate applied to the lease liabilities on 1 July 2019 was 7.3%.

Operating lease commitments disclosed as at 30 June 2019	1,898,431
(Less): short-term leases recognised on a straight-line basis as expense	(30,294)
Gross lease liabilities at 1 July 2019	1,868,137
Effect of discounting	(253,178)
Lease liability recognised as at 1 July 2019	**1,614,959**
Comprising:	
Current lease liabilities	531,677
Non-current lease liabilities	1,083,282
	1,614,959

The associated right-of-use assets for property leases were measured on a retrospective basis as if the new rules had always been applied. Other right-of use assets were measured at the amount equal to the lease liability, adjusted by the amount of any prepaid or accrued lease payments relating to that lease recognised in the balance sheet as at 30 June 2019. There were no onerous lease contracts that would have required an adjustment to the right-of-use assets at the date of initial application.

The recognised right-of-use assets relate to the following types of assets:

	1 July 2019 **$**
Land and buildings	1,029,705
Plant and equipment	361,959
Total right-of-use assets	1,391,664

The change in accounting policy affected the following items in the balance sheet on 1 July 2019:

- right-of-use assets increased by $1,391,664
- lease liabilities increased by $1,614,959
- other financial liabilities decreased by $83,633

The net impact on retained earnings on 1 July 2019 was a decrease of $139,662.

(iii) Impact on segment disclosures and earnings per share

EBITDA, segment assets and segment liabilities for December 2019 all increased as a result of the change in accounting policy. Lease liabilities are now included in segment liabilities, whereas finance leases, if any, were previously excluded from segment liabilities. The following segments were affected by the change in policy:

	EBITDA[1] **$**	**Segment Assets** **$**	**Segment liabilities** **$**
Producing Assets	75,412	366,951	337,853
Unallocated items	279,861	863,257	1,058,780
	355,273	1,230,208	1,396,633

There was no impact on reported earnings per share.

[1]EBITDA is Earnings before Interest, Taxation, Depreciation and Amortisation expense.

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

(b) New and /amended Standards Adopted by the Group (continued)

Practical expedients applied

In applying AASB 16 for the first time, the group has used the following practical expedients permitted by the standard:

- the use of a single discount rate to a portfolio of leases with reasonably similar characteristics
- reliance on previous assessments on whether leases are onerous
- the accounting for operating leases with a remaining lease term of less than 12 months as at 1 July 2019 as short-term leases
- the exclusion of initial direct costs for the measurement of the right-of-use asset at the date of initial application, and
- the use of hindsight in determining the lease term where the contract contains options to extend or terminate the lease.

The group has also elected not to reassess whether a contract is or contains a lease at the date of initial application. Instead, for contracts entered into before the transition date the group relied on its assessment made applying AASB 117 and Interpretation 4 *Determining whether an Arrangement contains a Lease.*

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 2019:

- Successfully completed the four well exploration programme at the Range gas project in Queensland's Surat Basin, resulting in the certification of 270PJ of 2C contingent gas resource (135 PJ net to Central).
- The Dukas-1 exploration well in the Northern Territory's Amadeus Basin was suspended at a depth of 3,704m after encountering hydrocarbon-bearing gas from an over-pressurised zone close to the primary target.
- Commenced planning a major exploration programme in the Amadeus Basin for CY2020, consisting of five high-graded drillable prospects and two appraisal tests. The programme has a risked estimated mean prospective resource of 205 PJ of gas and 9 mmboe of oil. Funding is anticipated to be sourced through a farmout process which is currently underway.
- The Group made $9.5 million in principal repayments under its debt facility with Macquarie Bank during the six months to 31 December 2019
- The Group entered into a new gas sales agreement with AGL commencing 1 January 2020.

For a detailed discussion about the group's performance and financial position please refer to our review of operations contained in the Directors' Report on pages 3 to 10.

3. Revenue from contracts with customers

(a) Revenue from contracts with customers

	2019 $	2018 $
Sale of hydrocarbon products – point in time		
Natural gas	31,683,852	15,695,306
Crude oil and condensate	4,029,110	4,326,955
	35,712,962	**20,022,261**

3. Revenue from contracts with customers *(continued)*

(b) Contract liabilities

	31 December 2019			30 June 2019		
	Current	Non-current	Total	Current	Non-current	Total
	$	$	$	$	$	$
Deferred Revenue from take or pay contracts (a)	2,714,334	18,972,003	21,686,337	2,714,334	15,559,186	18,273,520
Deferred Revenue from other contracts (b)	8,198,487	7,909,396	16,107,883	4,038,234	-	4,038,234
Total	**10,912,821**	**26,881,399**	**37,794,220**	**6,752,568**	**15,559,186**	**22,311,754**

Movements in Contract Liabilities

	Deferred Revenue from take or pay Contracts $	Deferred Revenue from other contracts $	Total $
Carrying amount at 1 July 2019	18,273,520	4,038,234	22,311,754
Revenue recognised from the delivery of gas (c)	-	(3,749,144)	(3,749,144)
Gas paid for but not taken during the period	3,412,817	-	3,412,817
Amounts transferred from Other Financial Liabilities (d)	-	15,818,793	15,818,793
Carrying amount at 31 December 2019	**21,686,337**	**16,107,883**	**37,794,220**

(a) Take or Pay proceeds received are taken to revenue at the earlier of physical delivery of the gas to the customer, or upon forfeiture of the right to gas under the contract. No revenue has been recognised during the half year ended 31 December 2019 for gas forfeited under take or pay contracts.

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

(c) There were no cash inflows during the period associated with the delivery of this gas as the Group received up-front payment for the gas in 2016.

(d) In July 2019, Macquarie Bank Limited novated its rights and obligations under the Second and Third Contract Years of the MBL Gas Sale and Prepayment Agreement, to another party who will take physical delivery of the gas. As there is no cash settlement option under the novation agreement, there is no longer a financial liability, and as a result, amounts previously recognised as Other Financial Liabilities have been transferred to Deferred Revenue. Classification of current and non-current Deferred Revenue is based on the contractual rights of the customer to take gas in each Contract Year.

4. Segment Reporting

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

(a) Producing Assets

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

(b) Development Assets

Fields under development in preparation for the sale of petroleum products. There were no fields under development during the current or comparative reporting period.

4. Segment Reporting *(continued)*

(c) Exploration Assets

Exploration and evaluation of permit areas.

(d) Unallocated Items

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

(e) Performance Monitoring and Evaluation

Management monitors the operating results of the operating segments separately for the purpose of making decisions about resource allocation and performance assessment. The consolidated entity's operations are wholly in one geographical location being Australia.

2019	Producing Assets 31 Dec 2019 $	Exploration Assets 31 Dec 2019 $	Unallocated Items 31 Dec 2019 $	Consolidated 31 Dec 2019 $
Revenue from contracts with customers				
Natural Gas	31,683,852	-	-	31,683,852
Crude oil and condensate	4,029,110			4,029,110
Total revenue from contracts with customers	35,712,962	-	-	35,712,962
Cost of sales	(16,928,321)	-	-	(16,928,321)
Gross profit	**18,784,641**	**-**	**-**	**18,784,641**
Other income excluding interest	135	724,032	7,527	731,694
Share based employment benefits[1]	-	-	(1,150,821)	(1,150,821)
General and administrative expenses	-	-	(269,509)	(269,509)
Employee benefits and associated costs	-	-	(937,168)	(937,168)
EBITDAX[2]	**18,784,776**	**724,032**	**(2,349,971)**	**17,158,837**
Depreciation and amortisation	(9,015,302)	-	(350,656)	(9,365,958)
Exploration expenditure	(236,218)	(842,527)	-	(1,078,745)
Net finance costs	(3,221,742)	(9,734)	(281,878)	(3,513,354)
Profit/(loss) before income tax	**6,311,514**	**(128,229)**	**(2,982,505)**	**3,200,780**
Taxes	-	-	-	-
Profit / (Loss) for the period	**6,311,514**	**(128,229)**	**(2,982,505)**	**3,200,780**

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

4. Segment Reporting *(continued)*

2018	Producing Assets 31 Dec 2018 $	Exploration Assets 31 Dec 2018 $	Unallocated Items 31 Dec 2018 $	Consolidated 31 Dec 2018 $
Revenue from contracts with customers				
Natural Gas	15,695,306	-	-	15,695,306
Crude oil and condensate	4,326,955			4,326,955
Total revenue from contracts with customers	20,022,261	-	-	20,022,261
Cost of sales	(14,197,269)	-	-	(14,197,269)
Gross profit	**5,824,992**	**-**	**-**	**5,824,992**
Other income excluding interest	8,306	-	12,494	20,800
Share based employment benefits[1]	-	-	(567,198)	(567,198)
General and administrative expenses	-	-	(481,708)	(481,708)
Employee benefits and associated costs	-	-	(2,229,204)	(2,229,204)
EBITDAX[2]	**5,833,298**	**-**	**(3,265,616)**	**2,567,682**
Depreciation and amortisation	(4,203,085)	-	(150,690)	(4,353,775)
Exploration expenditure	(13,192,606)	(448,039)	-	(13,640,645)
Net finance costs	(3,479,898)	(22,330)	(148,199)	(3,650,427)
Profit/(loss) before income tax	**(15,042,291)**	**(470,369)**	**(3,564,505)**	**(19,077,165)**
Taxes	-	-	-	-
Loss for the period	**(15,042,291)**	**(470,369)**	**(3,564,505)**	**(19,077,165)**

[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 $	Exploration Assets $	Corporate Items $	Consolidated $
Total Segment Assets				
31 December 2019	142,385,049	10,967,170	9,760,743	163,112,962
30 June 2019	143,022,770	11,067,874	14,659,503	168,750,147
Total Segment Liabilities				
31 December 2019	(153,051,106)	(2,003,160)	(9,473,415)	(164,527,681)
30 June 2019	(158,284,408)	(2,991,402)	(13,091,065)	(174,366,875)

5. Other Income

	2019 $	2018 $
Profit on disposal of interests in Exploration tenements	679,681	-
Profit on disposal of property, plant and equipment	51,613	-
Interest revenue	82,835	196,230
Other	400	20,800
	814,529	**217,030**

6. Cash and Cash Equivalents

Cash at bank and on hand comprising:	31 Dec 2019 $	30 Jun 2019 $
Corporate (a)	14,451,589	17,296,319
Joint arrangements (b)	412,749	509,550
	14,864,338	**17,805,869**

(a) $2,307,487 of this balance relates to restricted cash held with Macquarie Bank Limited to be used for allowable purposes under the Facility Agreement (30 June 2019: $3,084,832), 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.

7. Property, Plant and Equipment

	Freehold land and buildings $	Producing assets $	Plant and equipment $	Total $
30 June 2019				
Cost	3,868,743	100,889,665	65,546,087	170,304,495
Accumulated depreciation and impairment	(1,339,931)	(19,843,101)	(25,646,050)	(46,829,082)
Net book amount	**2,528,812**	**81,046,564**	**39,900,037**	**123,475,413**
31 December 2019				
Opening net book amount	2,528,812	81,046,564	39,900,037	123,475,413
Additions	-	91,377	1,285,197	1,376,574
Adjustment to restoration provisions	-	1,025,164	216	1,025,380
Disposals and write offs	-	-	(9,375)	(9,375)
Depreciation charge	(175,101)	(6,262,991)	(2,653,102)	(9,091,194)
Closing net book amount	**2,353,711**	**75,900,114**	**38,522,973**	**116,776,798**
31 December 2019				
Cost	3,868,743	102,006,205	66,632,473	172,507,421
Accumulated depreciation and impairment	(1,515,032)	(26,106,091)	(28,109,500)	(55,730,623)
Net book amount	**2,353,711**	**75,900,114**	**38,522,973**	**116,776,798**

8. Leases

(a) Amounts recognised in the balance sheet

	31 Dec 2019 $	30 Jun 2019 $
(i) Right-of-use assets		
Land and buildings	852,188	-
Plant and equipment	378,020	-
	1,230,208	**-**
(ii) Lease liabilities		
Current	568,875	-
Non-current	827,758	-
	1,396,633	**-**

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

	2019 $	2018 $
Depreciation charge of right-of-use assets		
Land and buildings	179,320	-
Plant and equipment	64,209	-
	243,529	-
Interest expense (included in finance costs)	54,873	-
Expense related to short-term leases (included in cost of sales and general and administrative expenses)	17,508	-
Expense related to low value assets not shown as short-term leases (included in cost of sales and general and administrative expenses)	-	-
Cash outflow for leases	355,273	-

9. Interest Bearing Liabilities

		31 Dec 2019 $	30 Jun 2019 $
(a)	Interest bearing liabilities (current)		
	Debt facilities	72,700,963	10,956,896
		72,700,963	**10,956,896**
(b)	Interest bearing liabilities (non-current)		
	Debt facilities	-	70,773,157
		-	**70,773,157**

The Macquarie Bank Facility consists of a number of tranches. Tranches A to D 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.

Subsequent to the balance date, in February 2020 the maturity date of the Macquarie Bank Facility was extended by 12 months to 30 September 2021. If the new maturity date had applied at balance date, then $67,700,963 of the current liability would have been classified as non-current.

10. Other financial liabilities

	31 Dec 2019 $	30 Jun 2019 $
Current		
Lease incentives received	-	38,600
Liabilities associated with forward gas sales agreements containing a cash settlement option (a)	-	1,986,414
	-	**2,025,014**
Non-Current		
Lease incentives received	-	45,033
Liabilities associated with forward gas sales agreements containing a cash settlement option (a)	-	13,778,460
Available to be taken after 12 months	**-**	**13,823,493**

(a) In July 2019, Macquarie Bank Limited novated its rights and obligations under the Second and Third Contract Years of the MBL Gas Sale and Prepayment Agreement, to another party who will take physical delivery of the gas and no cash settlement will apply. This resulted in an amount of $15,818,793 being reclassified from Other Financial Liabilities to Deferred Revenue.

11. Provisions

	31 December 2019			30 June 2019		
	Current	Non-current	Total	Current	Non-current	Total
	$	$	$	$	$	$
Employee entitlements (a)	2,485,630	756,082	3,241,712	3,529,565	763,299	4,292,864
Restoration and rehabilitation (b)	-	39,588,282	39,588,282	529,681	38,322,469	38,852,150
Other:						
Joint Venture production over-lift (c)	847,244	3,387,446	4,234,690	-	4,008,462	4,008,462
Other provisions (d)	1,009,002	-	1,009,002	1,316,553	-	1,316,553
Total	**4,341,876**	**43,731,810**	**48,073,686**	**5,375,799**	**43,094,230**	**48,470,029**

Movements in Provisions

	Employee Entitlements (a) $	Restoration and Rehabilitation (b) $	Other (c) $	Total $
Carrying amount at 1 July 2019	4,292,864	38,852,150	5,325,015	48,470,029
Charged/(credited) to profit or loss	686,499	(539,004)	239,510	387,005
Changes to restoration assets	-	1,025,380	-	1,025,380
Unwinding of discount	-	249,756	-	249,756
Amounts used during the half-year	(1,737,651)	-	(320,833)	(2,058,484)
Carrying amount at 31 December 2019	**3,241,712**	**39,588,282**	**5,243,692**	**48,073,686**

(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. Current leave obligations that are not expected to be taken or paid within the next 12 months amount to $710,595 (30 June 2019: $738,952)*

(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) *Other Provisions comprises:*
  (i) *Estimated future production costs to supply over-lifted gas. 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.*
  (ii) *provisions for liquidated damages under gas sales agreements and settlement of legal matters (which were nil at 31 December 2019).*

12. Contributed Equity and Reserves

	31 Dec 2019 $	30 Jun 2019 $
Share capital		
723,057,206 ordinary shares	197,776,487	197,776,487
(30 June 2019: 713,355,716 ordinary shares)		
Reserves		
Share options reserve	26,451,053	25,310,162

	Half-Year Ended 31 December	
	2019 $	2018 $
Movements in share capital:		
Balance at start of half year	197,776,487	197,776,487
Issues of ordinary shares	-	-
Transaction costs	-	-
Balance at the end of the half year	**197,776,487**	**197,776,487**
Movements in share options reserve:		
Balance at start of the half year	25,310,162	23,463,784
Share based payments costs	1,150,821	567,198
Transaction costs	(9,930)	-
Options issued for financing	-	258,188
Balance at the end of the half year	**26,451,053**	**24,289,170**

	2019 No. of securities	2018 No. of securities
Movements in ordinary shares on Issue during the half-year:		
Balance at the beginning of the half-year	713,355,716	707,115,793
Exercise of employee share rights under LTIP	9,701,490	2,876,183
Balance at the end of the half-year	**723,057,206**	**709,991,976**

Share rights granted during the period

Date of Issue	Class	Expiry Date	Value at grant date	Number Issued
13-Sep-2019	Unlisted employee share rights[1]	08-Dec-2022	$0.15	618,276
13-Sep-2019	Unlisted employee share rights[1]	08-Feb-2022	$0.15	2,428
13-Sep-2019	Unlisted employee share rights[1]	03-Oct-2022	$0.15	6,713
13-Sep-2019	Unlisted employee share rights[1]	30-Jun-2024	$0.155-$0.19	7,804,260
13-Sep-2019	Unlisted employee share rights[2]	13-Sep-2024	$0.142	3,311,771
12-Nov-2019	Unlisted employee share rights[1]	12-Nov-2024	$0.119	1,837,109
Total share rights granted during the period				**13,580,557**

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

[2] *Rights issued under the Short-Term Incentive Plan in lieu of cash*

12. Contributed Equity and Reserves *(continued)*

Share rights expired or cancelled during the period

Class	Expiry Date	Exercise Price	Number Cancelled
Unlisted employee share rights - cancelled	-	-	2,245,532

Share rights exercised during the period

Class	Share Issue Date	Exercise Price	Number Exercised
Unlisted employee share rights	18-Sep-2019	Nil	9,053,720
Unlisted employee share rights	30-Oct-2019	Nil	647,770
Total share rights exercised during the period			**9,701,490**

Options granted during the period

Date of Issue	Class	Expiry Date	Exercise Price	Value on Issue	Number Issued
20-Aug-2019	Executive options[1]	30-Jun-2023	$0.20	$0.120	13,046,116
12-Nov-2019	Executive options[1]	30-Jun-2023	$0.20	$0.087	5,105,000
Total options granted during the period					**18,151,116**

[1] *The Executive Options are exercisable from 1 July 2022. Some or all of an executive's options will lapse on a pro-rata basis if employment is terminated by reason of dismissal or resignation before that date. The options may become exercisable earlier where certain change of control events occur*.

Options expired or cancelled during the period

Class	Expiry Date	Exercise Price	Number Expired
Unlisted options issued to financiers	01-Sep-2019	$0.20	30,000,000
Unlisted options issued to financiers	31-Dec-2019	$0.14	22,500,000
Total options expired or cancelled during the period			**52,500,000**

13. Contingencies and Commitments

(a) Exploration and Capital Commitments

The Group has the following capital expenditure commitments:

	Consolidated	
	31 Dec 2019 $	**30 Jun 2019 $**
Within 1 year	474,903	608,787
Later than 1 year but not later than 3 years	-	-
Later than 3 years but not later than 5 years	-	-
Total	**474,903**	**608,787**

13. Contingencies and Commitments (*continued*)

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

	Consolidated	
	31 Dec 2019 **$**	**30 Jun 2019** **$**
Within one year	21,130,000	12,175,000
Later than one year but not later than three years	42,150,000	46,105,000
Later than three years but not later than five years	3,800,000	4,450,000
Later than five years	6,000,000	6,000,000
Total	**73,080,000**	**68,730,000**

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) Contingent Liabilities

There were no changes to contingent liabilities as outlined in the previous annual financial report to 30 June 2019.

14. Post Balance Date Events

(a) Cash settlement for sale of interest in ATP2031

In January 2020, subsequent to the end of the half year, Central received $7.7 million from its joint venturer in ATP 2031, Incitec Pivot Limited (IPL), to finalise the acquisition by IPL of its 50% interest in ATP2031. IPL had been carrying Central's share of the first $20 million of exploration and appraisal expenditure of the joint venture, with any amount not spent by 31 December 2019 being payable to Central. Each joint venturer will now fund 50% of any further expenditure in the area.

(b) Loan extension

In February 2020, the loan facility with Macquarie Bank was extended for a further 12 months. The loan is now due for full repayment by 30 September 2021. The loan is disclosed as a current liability in the Consolidated Balance Sheet as, at the balance date, the loans were due for repayment within 12 months. If the Consolidated Balance Sheet had been prepared to reflect the new repayment schedule, $67.7 million would have been classified as a non-current liability, instead of as a current liability.

There were no other events that occurred subsequent to 31 December 2019 other than noted above or elsewhere in these accounts.

15. Related Party Transactions

There were no related party transactions during the period.

DIRECTORS' DECLARATION

31 December 2019

In the Directors' opinion:

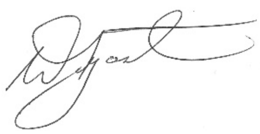
(a) the financial statements and notes set out on pages 12 to 29 are in accordance with the Corporations Act 2001, including:

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

  (ii) giving a true and fair view of the Consolidated Entity's financial position as at 31 December 2019 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, and

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



Wrixon Gasteen
Chairman
Brisbane

25 February 2020

INDEPENDENT AUDITOR'S REVIEW

pwc

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) and the entities it controlled during the half-year (together the Group), which comprises the consolidated balance sheet as at 31 December 2019, 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 other explanatory notes and the directors' declaration.

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 gives a true and fair view and 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 Group's financial position as at 31 December 2019 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*.

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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 Group's financial position as at 31 December 2019 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

Tim Allman
Partner

Brisbane
25 February 2020

CORPORATE DIRECTORY

31 December 2019

Directors

Mr Stuart Baker BE(Elec), MBA, AICD
Non-Executive Director

Mr Leon Devaney BSc, MBA
Managing Director and Chief Executive Officer

Dr Julian Fowles PhD, BSc (Hons), GDipAFI, GAICD
Non-Executive Director

Mr Wrixon F Gasteen BE (Mining) (Hons), MBA (Distinction)
Non-Executive Director and Chairman

Ms Katherine Hirschfeld AM, BE (Chem), HonFIEAust, FTSE, FIChemE, CEng, FAICD
Non-Executive Director

Company Secretaries

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

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Stock Exchange Listing

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