2019

ANNUAL REPORT

Central Petroleum

Central Petroleum Limited
ACN 083 254 308

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CORPORATE DIRECTORY

CENTRAL PETROLEUM LIMITED

ABN 72 083 254 308

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

GROUP GENERAL COUNSEL AND JOINT COMPANY SECRETARY
Mr Daniel C M White LLB, BCom, LLM

JOINT COMPANY SECRETARY
Mr Joseph P Morfea FAIM, GAICD

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

CHAIRMAN'S LETTER

Dear Fellow Shareholders

There is little doubt that the past year will be remembered as a watershed year for Central Petroleum. Many years of strategic positioning and successfully executing on that strategy have started to bear fruit.

Impact of NGP commissioning

Our expanded gas production facilities at Mereenie and Palm Valley, completed on time and within our funding, are now supplying gas to customers on the gas-short eastern seaboard via the new Northern Gas Pipeline which was commissioned in January. Contracted sales volumes have almost tripled since January and the resulting cash flow has been applied to reducing debt and provides an operating cash flow to help unlock the enormous potential of our exploration portfolio.

The production base re-positions Central as a credible, and not insignificant, supplier to gas markets in both the Northern Territory and the eastern seaboard. Quality conventional assets with low operating costs, combined with a buoyant gas market mean that our gas can be supplied profitably at competitive prices to customers in Queensland and the Northern Territory.

Exploration – Dukas and Range

With this stable base to underpin us, our next phase of exploration activity has already begun to provide a glimpse of the value that could lie within our asset portfolio. This will require significant investment. The early signs from the Dukas-1 well in the Amadeus Basin can only increase the likelihood of a huge gas play in the basin.

The immediate success at the Range project in the heart of Queensland's proven coal seam gas province demonstrates what our team can achieve in a short timeframe, with 2C gas resources certified within 12 months from the award of the tenement. This is a clear example of the positive impact that Government policy can have in alleviating the east coast gas market shortages and provides us with a material development-ready gas resource adjacent to transportation infrastructure.

Stakeholder Engagement and Climate Change

Stakeholder engagement remains a key focus for us. We thank the traditional owners for working with us over the past year. Our relations with the stakeholders in our areas of operations are important and our emphasis on employing local people and traditional owners continues to deliver positive outcomes for the communities touched by our operations.

This year we established a Community Affairs Committee as a Board Committee. The Committee elected Mr Bob Liddle OAM, a Traditional Owner originally from the Alice Springs region. Our whole Board visited and met with the Traditional Owners at Santa Teresa, Mereenie and Palm Valley.

At Central we recognise that we don't have all the answers to solve the Global Climate Change challenge. However, we are a supplier of a transition fuel significantly lower in CO_2 emissions than coal, and a highly sought after bridge between coal and renewables to reinforce a more stable electricity and energy system in the Northern Territory and on the East Coast.

Board & Management

The achievements of the past year are a testament to the vision of many at Central Petroleum over several years. It has not been an easy year corporately – the growing pains have resulted in changes at management and Board levels. We have seen the departure of influential characters, and particularly recognise Richard Cottee for his energy, advocacy and strategic courage in setting Central Petroleum on its current course. More recently we have accepted the resignation of Martin Kriewaldt as Chairman and thank him for his efforts in guiding the company through this transition.

I firmly believe that we emerge from the past year a far stronger and more valuable company. Certainly, the broader market is starting to recognise this with the Company's share price recently breaking free of the restrictive price range of recent years. We have built an experienced and capable management team, led by a very talented Managing Director, Leon Devaney.

Our new Board offers a diverse range of industry-specific experience. We welcomed Stuart Baker, Kathy Hirschfeld and Julian Fowles to the Board this year and I wholeheartedly recommend them for election at this year's AGM. The Board is implementing the best in Corporate Governance practices and transparency.

I see this as the beginning of a new era for Central. We appreciate the support of our shareholders during this year of transformation and enter the next year with a determination to learn from the past. Your new Board fully acknowledges that trust between the Company and its stakeholders is a function of transparency and stakeholder engagement – and we will be working to deliver.

I am confident that with stability at Board level and Leon's committed management team, in the coming year we will make significant progress in implementing our near term exploration programme to unlock further value from Central's impressive asset portfolio.

Wrixon Gasteen, Chairman
25 September 2019

CHIEF EXECUTIVE OFFICER'S LETTER

Dear Fellow Shareholders

In my Letter to Shareholders for the 2018 Annual Report, I highlighted the immediate challenges and fundamental changes facing the Company this time last year. We were focused on delivering our Gas Acceleration Programme (GAP) in time to meet significant firm gas supply commitments that were tied to the commencement of the Northern Gas Pipeline (NGP). At the same time, we were preparing for a step change increase in the level of operations and planning for a new future as an E&P company with exploration and production assets now unconstrained by market.

Today we can look back at the last 12 months having not only delivered those core objectives, but in doing so successfully emerging as a company much more capable of delivering growth and shareholder value. Commencement of the NGP on 3 January 2019 was the catalyst, connecting for the first time our recently acquired production assets and vast exploration portfolio in the Northern Territory to the east coast gas market. Sales nearly tripled, leading to a strong 2^{nd} half FY2019 operating cash flow. We strengthened our balance sheet through accelerated debt repayments, with net gearing already down to around 32% in September 2019. For the first time in the history of Central, we are operating from a foundation of new financial optionality.

Increased sales are only part of the story. In the midst of this financial and operational transformation, we reignited a core opportunity to create a step-change in shareholder wealth - exploration of our dominant position in the Amadeus Basin, one of Australia's most significant underexplored onshore basins with five proven hydrocarbon systems and long-term production history.

First, the Dukas-1 exploration well was drilled to within near proximity of the prognosed primary target, before being suspended due to excessive formation pressures. There were two positive indicators relating to an effective seal and a working hydrocarbon system, so these were encouraging results, notwithstanding the delay resulting from the technically difficult drilling conditions. It remains a pure exploration play, but under a success scenario it will be a game-changer for Central and potentially the east coast gas market. We continue to work closely with operator, Santos, whose technical input and financial contribution have been critical to the Dukas programme. A forward plan for the well will be outlined as soon as it is fully considered by the Joint Venture.

Second, and less visible than Dukas-1, we made key changes to our exploration team, including a new GM Exploration. Over the past six months, this team has been undertaking a full portfolio review using additional and updated data and analysis to progress a near-term exploration plan, including attractive drill-ready prospects that don't require further analysis. In addition, and a first for Central, the team initiated a basin-wide play-based analysis so that we can strategically approach a long list of less-mature, but potentially company-changing, oil and gas targets. This work is fundamental to successfully unlocking the huge potential in Central's large and complex exploration portfolio.

More recently, the Range gas project (ATP 2031) exploration programme provided a massive shot of momentum for the Company. With a maiden 2C resource far exceeding our high-side expectations at 270PJ (135PJ net to Central), the Range gas project could approximately double our reserve base in the heart of the east coast gas market. The Range gas project is emerging as a major new asset for Central, with the significance of this exploration result becoming increasingly apparent as we accelerate toward a final investment decision (FID) in early 2021 in conjunction with our partner Incitec Pivot.

The year was not without setbacks, detours and "opportunities to learn". Lower than anticipated field production at Palm Valley, a disappointing result from our Mereenie appraisal well (WM26) and suspension in our Dukas-1 drilling campaign being some obvious examples. Safety and environment remain priorities for the Company. Although this year's results did not meet our internal benchmarks, we have implemented several new health, safety and environment initiatives and processes in order to improve our performance. There was also significant change internally, including four Board members replaced and my appointment as CEO in February. Whilst challenges and changes of this nature could easily trip up small companies trying to deliver across multiple and complex objectives, we maintained momentum and continuity through the year.

Looking forward to the next 12 months our focus will be on driving value from our operating assets, implementing a well-informed exploration strategy and development planning for Project Range. These are not easily-achieved objectives, particularly for a junior E&P Company, but with our executive team now complete with very experienced professionals, we move forward with renewed confidence that we can punch well above our weight, much as we have done over the past 12 months. The achievements to date are a result of the dedication of our staff here at Central, and I extend my thanks to our team for their tireless efforts in delivering the strategy.

Capital is naturally a key consideration in our forward plans. New exploration, appraisal and development all require capital. We have already demonstrated that we can effectively utilise project finance (debt) to minimise any equity requirements. Fortunately, our strengthened financial position offers us a level of financial optionality we have never had before. Whilst the equity market appears open to quality oil and gas investments, we have other viable equity alternatives, including application of cash flow from operations, potential sell-down of a minority interest in our operating or development assets, strategically farming-out exploration activity with a promote, and structured pre-sale agreements. Ultimately, we will seek the most effective combination of funding options to drive shareholder value from growth.

In closing, I'd like to take this opportunity to thank shareholders for their trust, patience and continued support. After the last 12 months, Central has emerged as a much stronger company, with a clear vision and growing momentum to write a new and very rewarding chapter for our shareholders.

Leon Devaney

Leon Devaney, CEO
25 September 2019

DIRECTORS' REPORT
FOR THE YEAR ENDED 30 JUNE 2019

Your Directors present their report on the consolidated entity, consisting of Central Petroleum Limited ("the Company", "Central" or "CTP") and the entities it controlled (collectively "the Group" or "the Consolidated Entity") at the end of, or during, the year ended 30 June 2019.

DIRECTORS

The names of the Directors of the Company in office during the financial year and until the date of this report are set out below. Directors were in office for this entire period unless otherwise stated.

Current Directors:

Mr Stuart Baker (appointed 7 December 2018)
Mr Leon Devaney (appointed 14 November 2018)
Dr Julian Fowles (appointed 28 June 2019)
Mr Wrixon Gasteen (Chairman)
Ms Katherine Hirschfeld AM (appointed 7 December 2018)

Former Directors:

Mr Richard Cottee (resigned 5 February 2019)
Mr Martin Kriewaldt (resigned 2 September 2019)
Dr Peter Moore (resigned 13 November 2018)
Dr Sarah Ryan (resigned 13 November 2018)
Mr Timothy Woodall (resigned 29 September 2018)

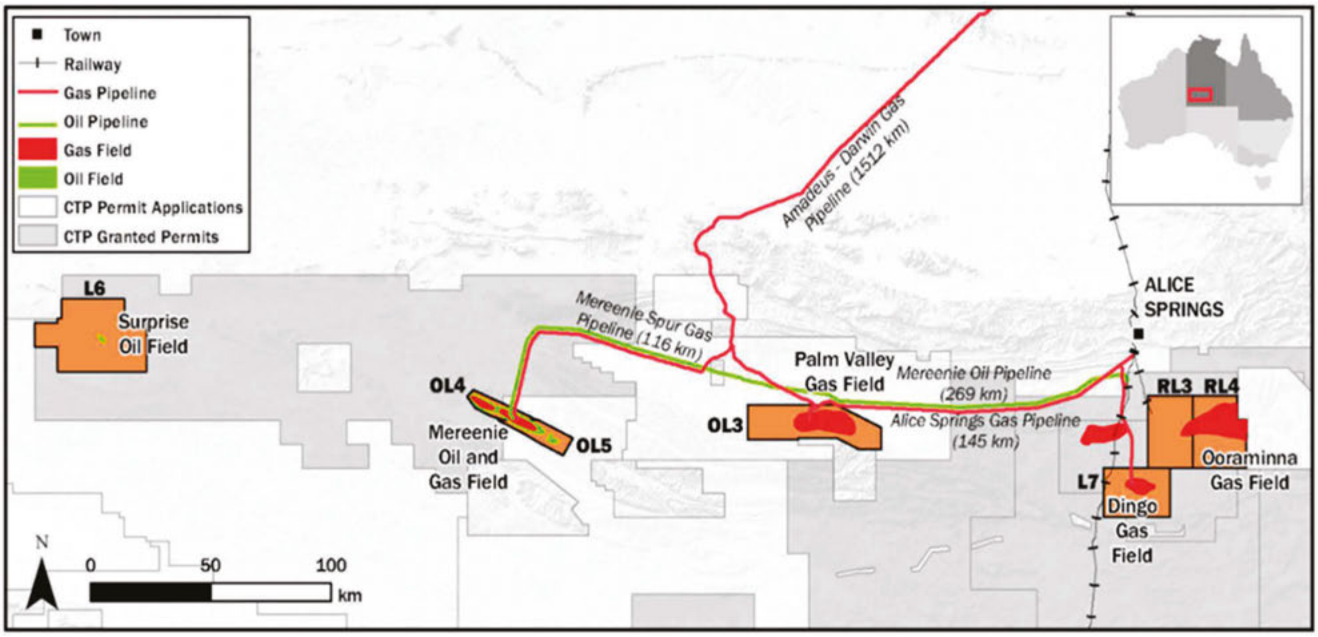
PRINCIPAL ACTIVITIES

The principal activities of the Consolidated Entity constituting Central Petroleum Limited and the entities it controls consists of development, production, processing and marketing of hydrocarbons and associated exploration.

DIVIDENDS

No dividends were paid or declared during the financial year (2018: $Nil). No recommendation for payment of dividends has been made.

OPERATING AND FINANCIAL REVIEW



Granted Petroleum Production and Retention Licences in which the Company has an interest.

Operating Highlights

The Company's achievements for the year were as follows:

- Second half gas sales volumes increased 150% and total sales revenue increased 96% over the first half. Year on year, a 111% increase in gas sales volumes and a 70% increase in total sales revenue;
- Palm Valley gas field successfully restarted, although at lower than anticipated rates resulting in reduced reserves and lower production plateaus;
- Palm Valley 13 well successfully drilled to 2,242 metres and tied into production facilities in May 2019;
- West Mereenie 26 appraisal well was successfully drilled but encountered minimal gas flow due to mineralisation. Material 2C resources are currently booked in the Stairway formation, which overlies the existing production zones. Evaluation of alternative approaches to recover gas from the Stairway formation remains ongoing;
- The Queensland Government formally awarded ATP 2031 to Central's wholly owned subsidiary, Central Petroleum Eastern Pty Ltd, for a period of 12 years. The permit lies within the north-eastern Walloon Coals Fairway, surrounded by acreage held by QGC, Arrow and APLNG:
  - Partnered with Incitec Pivot (IPL) as 50% joint venturer in the permit, with IPL carrying the first $20 million of exploration costs;
  - Range 4 well spudded on 30 June 2019 as the first in a four well exploration programme in ATP 2031 (Incitec Pivot free carry for first $20 million); and
  - Certified 270PJ of 2C gas resource (135PJ net to Central) in ATP 2031 after completing the four well exploration programme subsequent to year end;
- Mereenie Expansion Project was successfully delivered on schedule with firm plant capacity of 44TJ/day;
- Sales through the Northern Gas Pipeline commenced January 2019; and
- Santos elected to proceed to Stage 3 of the Southern Amadeus farmout and the Dukas 1 exploration well in EP 112 spudded on 16 April 2019 reaching a depth of 3,391m at 30 June 2019, and subsequently suspended at 3,704m after encountering hydrocarbon-bearing gas from an overpressured zone close to the primary target.

Financial Review

The Consolidated Entity had an operating loss after income tax for the year ended 30 June 2019 of $14.5 million (2018: loss of $14.1 million).

The above result was after expensing exploration costs of $15.8 million (2018: $8.8 million) largely associated with the drilling of the Palm Valley 13 well which was successfully tied-in to production during the year. The Group's policy is to expense all exploration costs as incurred.

The connection of the Group's gas fields to east coast gas markets through the Northern Gas Pipeline (NGP) on 3 January 2019 has resulted in a 105% increase in earnings before interest, tax, depreciation, amortisation and exploration (EBITDAX) from $11.0 million in 2018 to $22.5 million in 2019. The table below shows key metrics for the Group based on a comparison of first half and second half performance for 2019, which clearly highlights this inflection point, as well as a comparison to full year 2018.

Key Metrics

	1st Half 2019	2nd Half 2019	Total 2019	Total 2018	$ Change (Year)	% Change (Year)
Net Sales Volumes						
- Natural Gas (TJ)	2,921	7,308	10,229	4,842	5,387	111%
- Oil & Condensate (Bbls)	43,728	53,664	97,392	105,619	(8,227)	(8)%
Sales Revenue ($ '000)	20,022	39,336	59,358	34,939	24,419	70%
Gross Profit ($ '000)	5,825	23,164	28,989	16,235	12,754	79%
EBITDAX[1] ($ '000)	2,764	19,782	22,546	11,010	11,536	105%
EBITDA[2] ($'000)	(10,877)	17,621	6,744	2,221	4,523	204%
EBIT[3] ($ '000)	(15,231)	9,279	(5,952)	(5,813)	(139)	(2)%
Statutory Loss after tax ($ '000)	(19,077)	4,551	(14,526)	(14,076)	(450)	(3)%
Net cash inflow/(outflow) from Operations[4] ($'000)	(14,479)	16,944	2,465	5,173	(2,708)	(52%)
Capital expenditure[5] ($ '000)	12,672	3,516	16,188	4,668	11,520	247%

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.*

Reconciliation of statutory loss before tax to EBITDAX

	2019 $	2018 $
Statutory loss before tax	(14,526,414)	(14,076,129)
Finance costs	8,574,831	8,263,308
EBIT	**(5,951,583)**	**(5,812,821)**
Depreciation and amortisation	12,695,238	8,033,092
EBITDA	**6,743,655**	**2,220,271**
Exploration expenses	15,802,075	8,790,052
EBITDAX	**22,545,730**	**11,010,323**

Sales volumes

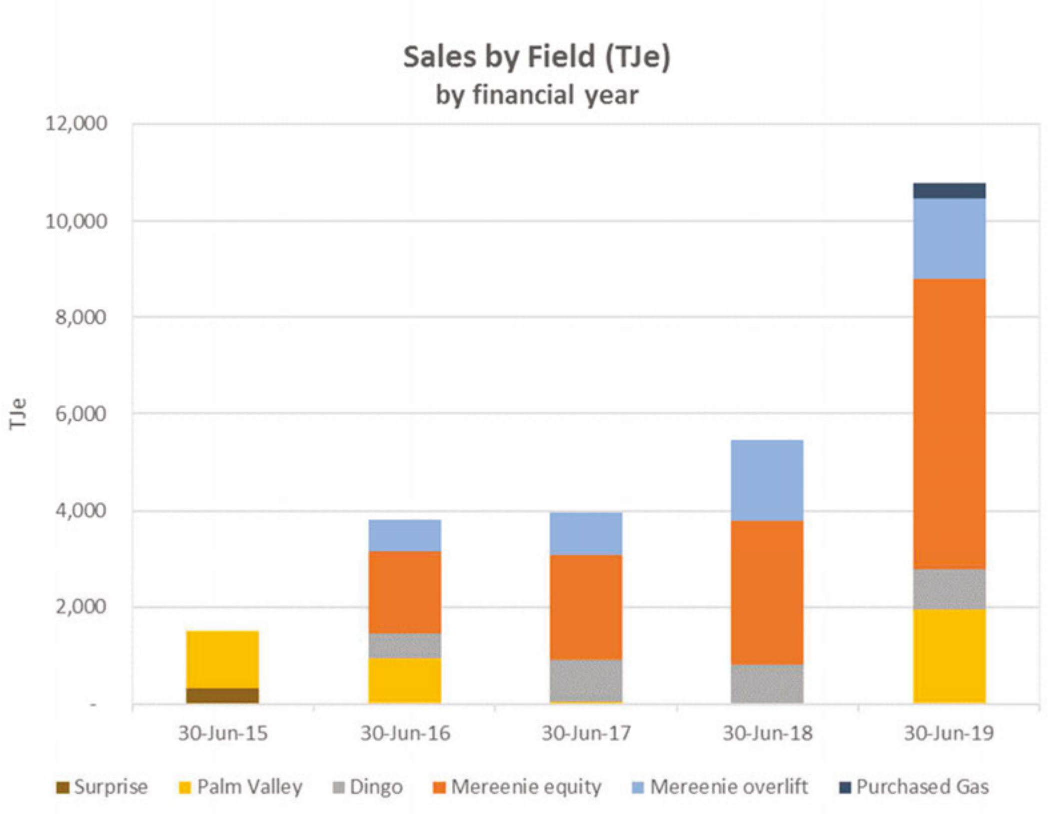
Gas volumes in 2019 increased 111% from 2018, taking advantage of the new NGP connection. The Palm Valley gas field was successfully restarted in October 2018 and the Mereenie facility upgrade was completed on schedule resulting in a 44 TJ/day firm plant capacity (100% JV).

Gas sales from the Dingo field did not achieve full contracted volumes as the customer continued to take gas below the annual contract quantity, resulting in an annual take or pay receipt of $5.1 million.

Sales revenue

Sales revenue increased 70% reflecting the upgraded field capacity and resulting increased gas volumes sold through the NGP. Realised oil prices were up 11% on 2018 but were partly offset by lower volumes.

Sales revenue does not include receipts from take or pay contracts until such time as gas is delivered or forfeited by the buyer. During the year, the Company received take or pay payments of $5.2m in respect of the 2018 calendar year which have not been reflected in revenue.



Additional Information:

1 *Mereenie oil converted at 5.816 GJ/BOE*

2 *Central had no production prior to April 2014*

Gross Profit

Gross profit from operations increased 79% year on year as increased production provided increased economies of scale to production operations.

Depreciation and Amortisation

Non-cash depreciation and amortisation costs increased from $8.0 million to $12.7 million, reflecting the increase in production and larger depreciable asset base following the Gas Acceleration Program (GAP).

Capital Expenditure

The increase in capital expenditure was a result of the investment in the GAP to expand capacity in time to meet the NGP connection as well as the successful tie in of the Palm Valley 13 well to the Palm Valley production facilities.

Net Assets/Liabilities

At 30 June 2019 the Group had a net liability position of $5.6 million compared to a net asset position at 30 June 2018 of $7.1 million. The net liability position improved from $11.2 million at 31 December 2018, reflecting the impact of the NGP commissioning resulting in increased operating cash flows.

Over the year cash balances have reduced by $9.4 million as the funds remaining from the 2017 capital raising were applied to exploration activities, mainly the drilling of Palm Valley 13 which was successfully tied into production.

Included in liabilities on the Group's balance sheet are amounts recognised in respect of deferred revenue amounting to $22.3 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.

In addition, $15.8 million in liabilities are recognised relating to the second and third years of the Macquarie Gas Sale and Prepayment Agreement which contains a financial settlement option. Ultimately this liability will be settled by either the physical delivery of gas or from the proceeds of gas sold to third parties for which no corresponding asset is currently recognised and therefore no net cash outflow is expected to result.

Debt

The Group borrowed a total of $17.5 million in additional funds during the year for its investment in the GAP, of which $10 million has been repaid from the increased cashflow during the six months following connection of the NGP. A further $10 million in debt is scheduled for repayment by December 2019.

The consolidated debt ratio at 30 June 2019 was 0.48 (2018: 0.49). Debt ratio is defined as: Total Debt/Total Assets. Net gearing at 30 June 2019 was 40% (2018: 33%). Net gearing is calculated as: Net Debt / (Market capitalisation + Net Debt). Debt funding is supported by long term gas sales contracts and the Group's certified 2P reserves.

Net Working Capital

Cash decreased by $9.4 million to $17.8 million at 30 June 2019, reflecting the significant investment in the GAP and Palm Valley 13 exploration costs during the year.

Net working capital at 30 June 2019 was negative $1.5 million (2018: positive $17.2 million) after recognition of $6.0 million in current liabilities associated with the Macquarie Gas Sale and Prepayment Agreement. These liabilities will be settled either by the physical delivery of gas to Macquarie or where physical delivery is not requested, out of the proceeds of the sale of that gas to third parties.

Net Cashflow from Operations

Net cashflow from operations decreased from $5.2 million in 2018 to $2.5 million for 2019. Cashflow from operations includes $18.1 million of cash outflows associated with the Group's exploration activities, which during 2019 included the Palm Valley 13 exploration well.

Second half net cashflow from operations was $16.9 million compared to the first half cash outflow of $(14.5) million, reflecting completion of the GAP, exploration activity and commencement of gas supplies into the NGP in January 2019.

Excluding payment for exploration activities, cashflow from production operations for 2019 was $20.6 million compared to $10.4 million for 2018.

Five Year Comparative Data

The following table and discussion is a one year (and five year) comparative analysis of the Consolidated Entity's key financial information. The Statement of Financial Position information is as at 30 June each year and all other data is for the years then ended.

	2019 $ MILLION	2018 $ MILLION	2017 $ MILLION	2016 $ MILLION	2015 $ MILLION
Financial Data					
Operating revenue	59.36	34.94	24.79	23.86	10.31
Exploration expenditure	15.80	8.79	1.90	4.03	7.66
Loss after income tax	14.53	14.08	24.73	21.04	27.73
Equity issued during year	—	25.47	—	11.52	5.56
Property, plant and equipment	123.48	103.85	106.82	113.78	58.58
Borrowings	(81.73)	(78.33)	(82.17)	(85.70)	(47.46)
Net Assets (Total Equity)	(5.62)	7.06	(5.96)	16.52	23.15
Net Working Capital	(1.53)	17.19	0.73	5.33	(4.41)

	2019	2018	2017	2016	2015
Operating Data					
Gas Sales (TJ)	10,229	4,842	3,322	3,230	1,194
Oil Sales (barrels)	97,392	105,619	111,380	98,635	53,925
No. of employees at 30 June	99	89	83	83	58

Risk Management

Central Petroleum maintains a robust and disciplined focus on effective risk management. We do this so that we better understand uncertainty and manage risks, to help achieve our objectives.

Our risk management process is designed to recognise and manage risks that have the potential to materially impact on Central's business objectives. This process is aligned to the international standard ISO31000 for risk management and assesses potential risks across our business and considers impacts on the health and safety of our employees, the environment and communities in which we operate, our financial stability, our reputation and legal and compliance obligations.

Principal risks and uncertainties at 30 June 2019

The principal risks and uncertainties outlined in this section may materialise independently, concurrently or in combination. These risks and uncertainties may impact Central's ability to meet its strategic objectives.

Context	Risk	Mitigation
Exploration and Appraisal		
Our future growth depends on our ability to identify, acquire, explore and develop reserves.	Unsuccessful exploration and renewal of upstream resources may impede delivery of our strategy.	Exposure to reserve depletion is addressed through our exploration strategy. We continue to analyse existing acreage for exploration drilling prospects and undertake extensive subsurface modelling and uncertainty analysis to determine the most likely production outcomes across our fields. Our disciplined management of opportunities and acquisitions, together with the application of existing technologies and recovery processes, further addresses this risk.

Context	Risk	Mitigation
Oil and Gas Reserves		
Commercialisation of hydrocarbons reserves is a key contributor to our long-term success.	Uncertainty in hydrocarbon reserve estimation and the broad range of possible recovery scenarios from existing resources could have a material adverse effect on our operations and financial performance.	Our reserve and resource estimates are prepared in accordance with the guidelines set forth in the 2018 Petroleum Resources Management System (PRMS). We proactively analyse reservoir performance and undertake comprehensive production and economic modelling to determine the most likely outcomes across our fields.
Operating		
Production and delivery of hydrocarbon products to plan are key elements of our operational and financial performance and directly impact shareholder returns.	Reservoir / field performance is subject to subsurface uncertainty. The actual performance could vary from those forecasted, which may result in diminished production and / or additional development costs. Our facilities are subject to hazards associated with the production of gas and petroleum, including major accident events such as spills and leaks which can result in a loss of hydrocarbon containment, diminished production, additional costs, environmental damage or harm to our people, reputation or brand.	We continually monitor field performance and schedule production optimisation and development activities to extract maximum value from the field and to mitigate any potential reservoir under-performance. Our operational performance is based on a framework of controls which enable the management of these risks. We have in place asset integrity management processes, inspections, maintenance procedures and performance standards across all infrastructure to ensure reliable and safe operations. Central maintains insurance in line with industry practice and sufficient to cover normal operational risks. However, Central is not insured against all potential risks because not all risks can be insured. Insurance coverage is determined by the availability of commercial options and cost / benefit analysis, considering Central's risk management program.
Financial		
Central's financial strength and performance underpins our strategy and future growth.	Insufficient liquidity to meet financial commitments and fund growth opportunities could have a material adverse effect on our operations and financial performance.	We have a robust internal expenditure management and forecasting process which is monitored against a Board approved budget to ensure our strategy is appropriately funded. We prioritise debt reduction which strengthens our balance sheet and supports the ability to access suitable additional funding where required to support growth. We also actively seek partnering opportunities to share risks and assist in funding key activities on a project-by-project basis.

Context	Risk	Mitigation
Financial		
Central's revenue is from the sale of hydrocarbons. This underpins Central's financial performance.	Central is exposed to USD commodity price variability with respect to crude oil sales which are impacted by broader economic factors beyond our control. Central is exposed to gas commodity prices with respect to gas sales, all of which are to the Northern Territory and Australian east coast markets. In addition to normal demand and supply forces, gas prices in these markets are subject to risk of Government intervention in the form of the Australian Domestic Gas Supply Mechanism; although this mechanism is focussed on availability of supply and is not considered to have significant potential impact on price.	Oil revenue represented less than 20% of consolidated sales revenue in FY2019 and this is expected to decrease further with a full year of post NGP gas sales. The majority of Central's revenue is from natural gas sales denominated in AUD and the uncertainty with this commodity is mitigated through long term fixed-price gas sales agreements with 'take-or-pay' provisions.
Health and Safety		
Health and Safety is at the heart of all activities and decisions at Central.	Health and Safety incidents or accidents may adversely impact our people, the communities in which we operate, our reputation and/or our licence to operate.	Health and Safety is an area of focus for Central and through our risk management framework we are implementing plans that include auditing and verification processes for our critical controls. We also regularly review our operations and activities to ensure we operate with the required standards of safety management.
Environment		
Our environmental performance underpins our licence to operate.	Our operations by their nature have the potential to impact air quality, biodiversity, land and water resources and related ecosystems. A failure to manage these leading to an incident may adversely impact not just the environment, but our people, the communities in which we operate, our reputation and our licence to operate.	Environmental management is a very high priority for Central. We operate under approved Field Environmental Management Plans and have a program of regular environmental inspections and audits in place to ensure compliance. We also continue to assess and develop our standards to prevent, monitor and limit the impact of our operations on the environment. We carry third party environmental liability insurance in addition to well control insurance to mitigate financial impacts should an event occur.
Information Technology		
Central is reliant upon our systems and infrastructure availability and reliability to support the business operating safely and effectively.	The integrity, availability and reliability of data and intellectual property within Central's information technology systems may be subject to intentional or unintentional disruption (e.g. cyber security attack).	Our exposure to cyber security risk is managed by a proactive and continuing focus on system controls such as firewalls, restricted points of entry, multiple data back-ups and security monitoring software. We are also bolstering our system processes and policy controls.

Context	Risk	Mitigation
Human Resources		
Central must have the right capability and capacity, within our personnel to perform in line with expectations to support our business.	Failure to establish and develop sufficient capability to support our operations and advance our organisational culture may impact achievement of our objectives.	Central's focus remains on securing and developing the right people to support the development of our portfolio of assets and opportunities. Our focus remains on creating a positive employer value proposition, planning our resource requirements and attracting talented individuals. We also proactively engage contractors to supplement any short term gaps in capability and capacity to support the execution of our business plans.
Regulatory Compliance / Change		
Our business activities are subject to extensive regulation and government policy. Our business performance is underpinned by our licence to operate.	Central is subject to various national and local laws, regulations and approvals, which are subject to change - such as the proposed reserved blocks (no-go zones) for petroleum activities in the Northern Territory. These, along with other changes, could impact the exploration, development, production, transportation and storage of our products and along with it our future prospects.	We have a robust framework in place to support our regulatory and compliance obligations and we continue to strengthen our regulatory compliance framework and supporting tools. We also proactively maintain relationships with governments, regulators and stakeholders within jurisdictions in which we operate.
Climate Change		
Central faces risks associated with climate change including fluctuations in product demand, carbon pricing and increased stakeholder expectations.	Demand for oil and gas may subside over the longer term as lower carbon substitutes take market share. Global climate change policy remains uncertain and has the potential to constrain Central's ability to create and deliver stakeholder value from the commercialisation of our hydrocarbons.	We are focused on ensuring our portfolio is robust in a potentially carbon constrained market and engage proactively with key industry and government stakeholders. We also note that demand for natural gas could increase as part of a clean energy future compared to other energy sources.
Geographic Concentration		
Central faces risks associated with the concentration of its production assets.	Central's revenue is derived from oil and gas production in the Amadeus Basin leaving Central exposed to downsides associated with weather conditions and infrastructure failure.	We ensure that appropriate insurance is in place to mitigate the impact of any extended business interruption. The Range coal seam gas project in the Surat Basin aims to begin to diversify our business. We are also investigating other new ventures outside of the Amadeus Basin.
Access to Infrastructure		
Our financial performance and growth strategy are dependent on access to third party owned infrastructure.	Negative impacts to revenue as a result of infrastructure failure, increased tariffs or restricted access to third party owned infrastructure.	We seek to work closely with customers and suppliers of infrastructure to mitigate the risk of delays or failure. We continue to explore alternative routes to market to diversify risk where possible.

Context	Risk	Mitigation
Community		
Our proactive engagement and support of local and indigenous communities is at the core of how we operate.	Our interactions with, and decisions involving landholders, traditional owners, suppliers and the community fails to attract and maintain the continued support of the communities in which we operate, impacting our social licence to operate.	We work in conjunction with our key stakeholders and have established programs to support and assist the communities in which we operate through donations, sponsorships, local procurement, training and providing ongoing local employment opportunities.

Business Strategy

Over the past five years, Central has successfully implemented its strategy to gain critical mass in conventional gas production and uncontracted gas reserves in order to take advantage of a tightening domestic gas market. This strategy encompassed:

- the acquisition of the Palm Valley and Dingo gas fields from Magellan in April 2014;
- the acquisition of 50% of Mereenie from Santos (including becoming Operator for the Joint Venture) in September 2015;
- the substantial upgrade of the Mereenie and Palm Valley gas fields' surface facilities to maximise sales capacity and accelerate delivery of existing reserves; and
- the commencement of gas supply to the critically short east coast market with the commencement of the operation of the NGP operations on 3 January 2019.

This has transformed Central into a substantial onshore domestic gas producer, with 10.2 PJ of gas sales during the 2019 financial year, and 7.3PJ of gas sales since the connection of the NGP in the 2nd half of 2019.

Central also undertook an appraisal drilling programme to increase uncontracted 2P reserves. Whilst the results of the first appraisal well (WM 26 at Mereenie) were disappointing, the PV 13 appraisal well at Palm Valley encountered commercial flow rates and is supplying sales gas after being tied in to existing production facilities on 17 May 2019. Central had 144.7 PJ of 2P gas reserves across all producing fields as at 30 June 2019.

With the Mereenie, Palm Valley and Dingo fields under Central's operatorship, Central is now in a unique position to benefit from the additional market access provided by the NGP. This strategy was driven by the clear fundamentals of leveraging a connection of a domestic gas shortfall on the east coast with the underexplored onshore gas potential in the Northern Territory. Central's strategy of acquiring previously market-limited gas assets and uncontracted gas reserves, in advance of the connection of the NGP, has positioned the Company as a direct beneficiary of the subsequent market expansion.

The acquisition of Palm Valley, Dingo and Mereenie were underpinned by existing long-term gas sale agreements (GSAs) which incorporate fixed prices with CPI escalation. More recent GSAs have been structured on a similar fixed price basis. This provides a solid revenue stream to support Central's operating activities and debt financing arrangements. These fixed price contracts are not affected by oil price or currency movements, shielding these commitments from volatility in international oil or LNG markets. Any future reserve additions and gas sales agreements are expected to result in value accretion to those assets, as will potential improved debt financing terms as Central's operations mature with greater gas sales to the newly connected east coast gas market.

Central is currently well advanced in marketing gas which is becoming available for the period commencing January 2020 as legacy contracts are completed. The market, newly connected to the east coast by the NGP, is demonstrating strong demand and pricing.

Exploration and appraisal

Central's exploration footprint represents a rare opportunity in Australia, covering largely under-explored hydrocarbon-bearing basins with enormous potential. The strong cash flow generated from the producing oil and gas fields provides a firm base from which Central can enter the next phase of its growth strategy and focus capital on value accretive exploration and appraisal activities.

In the past year, the exploration program has delivered promising results in the Amadeus Basin in Central Australia through the Dukas-1 well and substantial certified 2C coal seam gas resources at the Range gas project in Queensland's Surat Basin.

Dukas-1 exploration well

As part of testing Central's very substantial portfolio of significant high-risk opportunities that have the potential to become substantial gas fields - in this case pre-salt plays in the Amadeus basin, Central's joint venture (JV) partner Santos drilled the Dukas-1 exploration well commencing in April 2019. Santos is operating the Dukas-1 well drilling programme, carrying 100% of the cost of the well to earn a 70% share of EP112.

In August 2019 at 3,700m, just above the currently prognosed primary target, the well encountered extremely high pressures in excess of the capabilities of the drill rig and surface equipment. Drilling was suspended, logging was completed, and the rig was released from site. Although the target formations were not reached at this time, there are positive indicators for a working petroleum system with an efficient regional seal. The testing and drilling data will be analysed before a forward plan is determined.

These are encouraging results and Central looks forward to working with Santos to further develop this opportunity.

Range gas project

In addition to leveraging its Northern Territory gas assets and taking advantage of the recent connection to the east coast gas market, Central secured highly sought-after exploration acreage in the heart of the intensively developed Queensland coal seam gas production area, known as the Walloons Fairway, in a creatively crafted bid with Incitec Pivot Limited (IPL). Central was granted ATP 2031 on 29 August 2018 as successful tenderer in a Queensland Government tender process. The tender committed a 4-year programme, comprising nine wells and at least one production test pilot. IPL joined Central as a 50/50 JV partner and committed to contributing up to $20 million of the exploration and appraisal costs.

A four well exploration programme was completed in August 2019 with exciting results showing net coal thickness on prognosis and permeability in line with, or better than, expectations throughout the permit. These results underpinned a similarly exciting maiden 2C resource which exceeded high-side expectations at 270PJ (135PJ net to Central) certified by Netherland, Sewell & Associates. These 2C resources were certified after year end and are not included in the reported reserves and resources at 30 June set out on page 22 of this report.

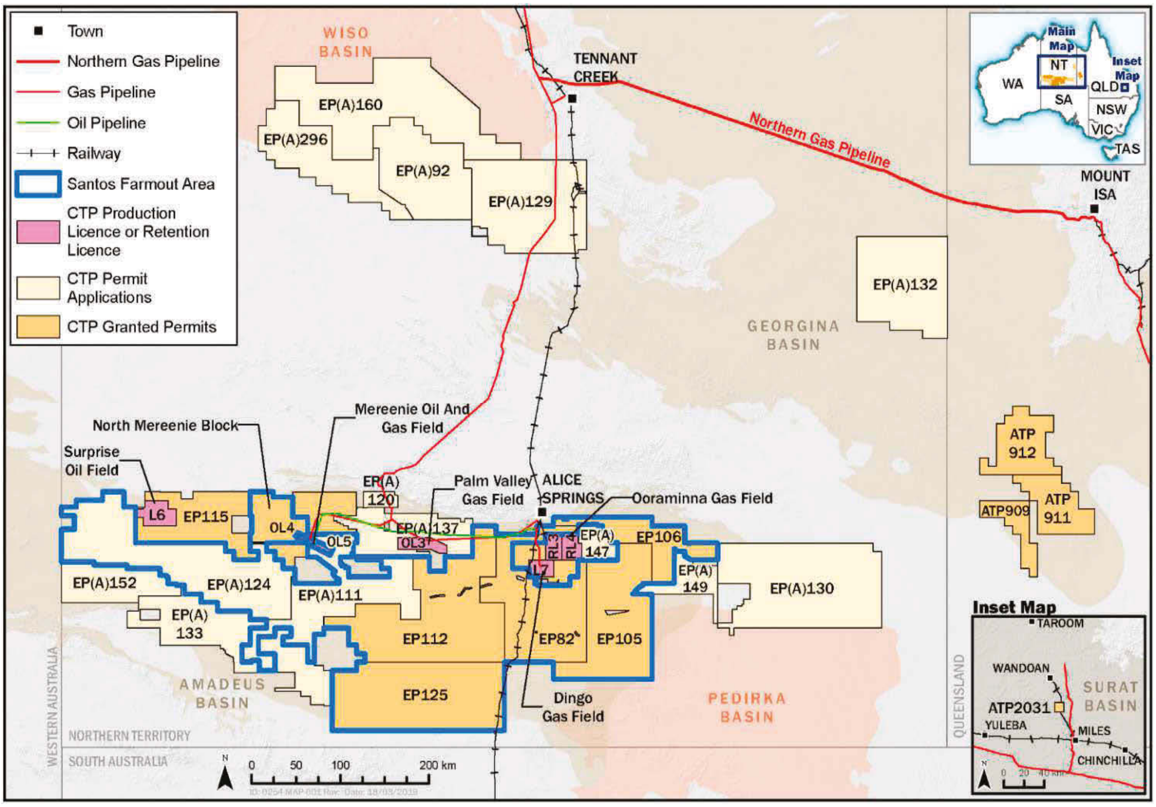
The Joint Venture is now selecting a location for a production pilot to demonstrate gas flows to surface and Central looks forward to expediting development, targeting a final investment decision in early 2021 and first gas in late 2022.

New exploration strategy

Central is finalising a near-term exploration programme for prospects that can be advanced in one to two years without significant additional analysis. Priority will be given to lower risk prospects which are 100% held by Central, have no regulatory barriers, do not require additional seismic work, and are in proven plays and close to existing facilities and infrastructure.

Detailed play-based exploration analysis is being carried out for medium to long-term prospects spread over the five complex working petroleum systems which lie within Central's 188,000km^2 of exploration permits. This analysis will form the basis for the medium to long-term exploration strategy. We anticipate this important analysis to be completed this year with an exploration strategy for the medium to long term targets to be finalised in early CY2020.

Operations and Activities



Granted Petroleum Permits, Licences and Application Interests

Sales Volumes (Central Petroleum's Share)

Product	Unit	FY 2018/19	FY 2017/18
Gas	PJ	10.2	4.8
Crude and Condensate	bbls	97,392	105,619

Producing assets

Mereenie Oil and Gas Field (OL4 and OL5)

Northern Territory

(CTP—50% Interest (Operator), Macquarie Mereenie Pty Ltd—50% Interest)

Sales volumes (CTP share)	Unit	FY 2018/19	FY 2017/18
Gas	PJ	7.1	4.0
Crude and Condensate	bbl	97,392	105,619

Reserves (CTP share)	Unit	1P	2P	2C
Gas	PJ	71.19	81.55	91.20
Oil	MMbbl	0.68	0.87	0.10

The Mereenie oil and gas field was discovered in 1963 and commenced production in 1984, delivering hydrocarbon liquids for sale in South Australia and gas to Northern Territory markets. During the year the Northern Gas Pipeline commenced operations, enabling Mereenie gas to access the east coast market for the first time.

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

During the year, the Mereenie Expansion Project (part of the GAP) was successfully delivered on schedule and on budget. This was an excellent outcome given that the project was delivered on an accelerated schedule only six months after major equipment was procured. Due to the expansion, the facilities can now deliver firm plant capacity of 44 TJ/d.

New equipment installed as part of the Mereenie Facility Upgrade

The focus at Mereenie has now shifted to field production and plateau maintenance. To offset ongoing natural field decline, a series of minor projects are being identified for implementation over the coming year. In particular, this includes a series of turnarounds involving the conversion of injector wells into production wells. In addition, planning has commenced for a significant recompletion campaign to access gas currently behind pipe. This campaign is expected to be executed in mid-2020 after the various approvals have been obtained. This provides an opportunity to further appraise the Stairway via a series of targeted recompletions which will aim to demonstrate commercial gas flows from the Stairway formation. It is anticipated that new development wells will be required to maintain production levels, with the number and timing to be driven by field performance.

Palm Valley Gas Field (OL3)

Northern Territory
(CTP—100% Interest)

Sales volumes (CTP share)	Unit	FY 2018/19	FY 2017/18
Gas	PJ	1.9	-

Reserves (CTP share)	Unit	1P	2P	2C
Gas	PJ	18.49	25.83	13.58

Gas was first discovered at Palm Valley in 1965 and is primarily reservoired in an extensive fracture system in the lower Stairway Sandstone, Horn Valley Siltstone and Pacoota Sandstone. The anticlinal structure is approximately 29km in length and 14km in width.

During the year, the field was successfully restarted in order to deliver gas into the broader gas market available via the NGP connection and now has four producing wells. Unfortunately, field performance was less than anticipated and this resulted in a downwards adjustment to reserves during the year. However, the Palm Valley 13 well was successfully drilled and brought on-line which has enabled the field to deliver up to 13 TJ/d of sales gas. A gradual decline in production is anticipated from the Palm Valley field in coming years to circa 5 – 7 TJ/d.

The focus has now shifted to increasing field production capacity through the installation of either additional compressors or via reconfiguring the existing compressors. If successful, this project would help mitigate some of the natural field decline.

Palm Valley appraisal

Planning is continuing for additional appraisal and production wells in the Palm Valley field to target previously undrilled areas. If successful, this could see an upgrade of the 2C resources to 2P and the introduction of additional new production capacity.

Palm Valley-13 well during commissioning

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

Northern Territory
(CTP—100% Interest)

Sales volumes (CTP share)	Unit	FY 2018/19	FY 2017/18
Gas	PJ	0.9	0.8

Reserves (CTP share)	Unit	1P	2P	2C
Gas	PJ	30.49	37.32	-

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

The Dingo Gas Field development, completed in April 2015, comprised the construction of wellhead facilities, gathering pipelines, gas conditioning facilities, a 50km gas pipeline to Brewer Estate in Alice Springs and custody transfer metering facilities. It was designed to service a gas sales contract with Territory Generation.

During the year, a water bath heater was installed to improve production stability and reduce methanol consumption. The field continued to supply the Owen Springs Power Station from two producing wells. Gas sales to Owen Springs are expected to increase when the Northern Territory Government decommissions the existing Ron Goodin power station.

Surprise Oil Field (L6)

Northern Territory
(CTP—100% Interest)

In February 2014, Central was granted the Petroleum Production Licence (L6) for the Surprise Oil Field Development. Initial production and storage facilities were installed to allow production to commence in March 2014, and additional storage tanks and ancillary equipment were completed in 2015. The Surprise West well produced approximately 88,650 barrels of oil between March 2014 to August 2016 when it was shut in due to low oil prices and to obtain long term pressure data.

The field remains shut-in. The potential for a restart is being reviewed alongside a broader review of exploration and appraisal opportunities in the portfolio. Environmental and reservoir monitoring continued throughout the year.

Range gas project (ATP 2031)

Surat Basin, Queensland

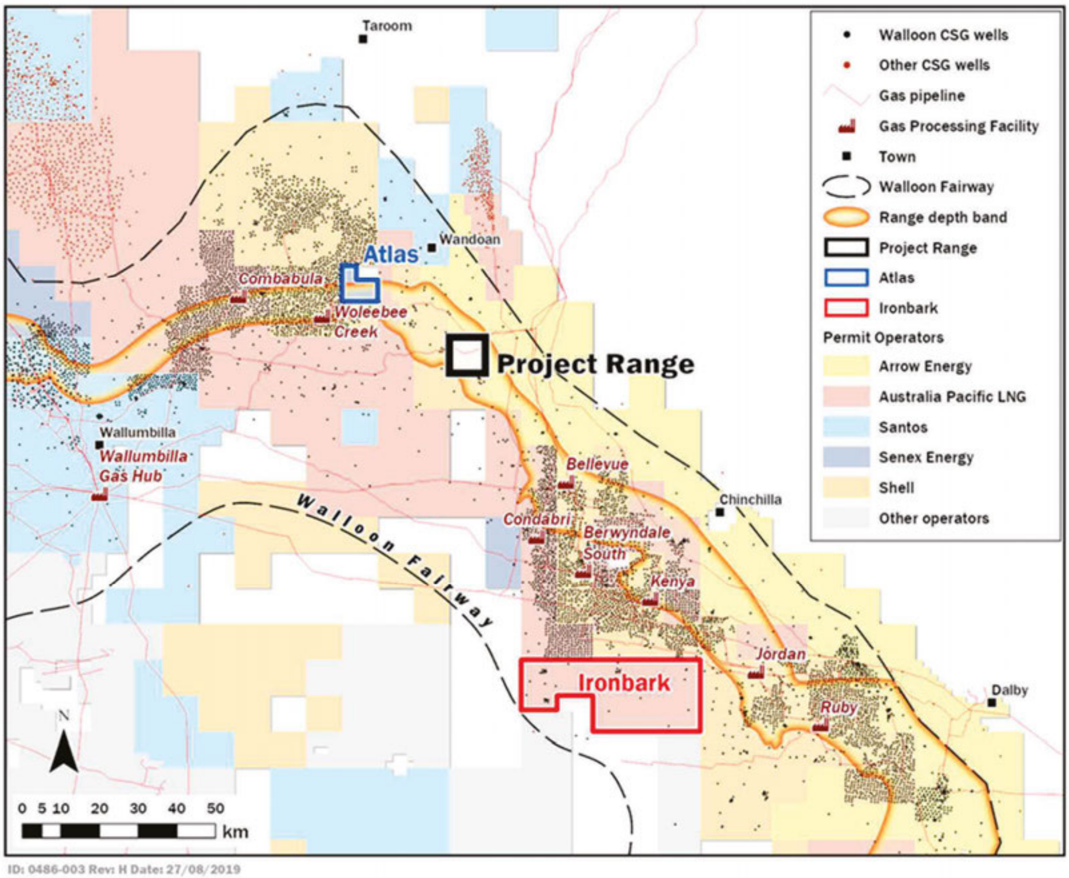
(CTP—50% Interest, Incitec Pivot Queensland Gas Ltd (IPL) – 50%)

Reserves (CTP share)	Unit	1P	2P	2C
Gas	PJ	-	-	135

The Company's wholly-owned subsidiary Central Petroleum Eastern Pty Ltd was formally granted the Authority to Prospect (ATP) 2031 in Queensland's gas-rich Surat Basin on 28 August 2018 for a term of 12 years. The exploration and appraisal program is being undertaken through a 50:50 joint venture arrangement with IPL. Under the arrangement in place, IPL will free carry the Company by contributing up to $20 million of the exploration programme costs for the initial exploration period. Gas production from this permit is to be dedicated to the east coast domestic gas market.

During the year, the parties commenced exploration drilling with the spudding of the Range 4 exploration well, only 10 months after the grant of the permit. The exploration programme consisted of four wells, with each well being drilled to gather geological data including coal depth, thickness and permeability. To minimise costs, the wells were drilled as slimholes and are planned to be plugged and abandoned.

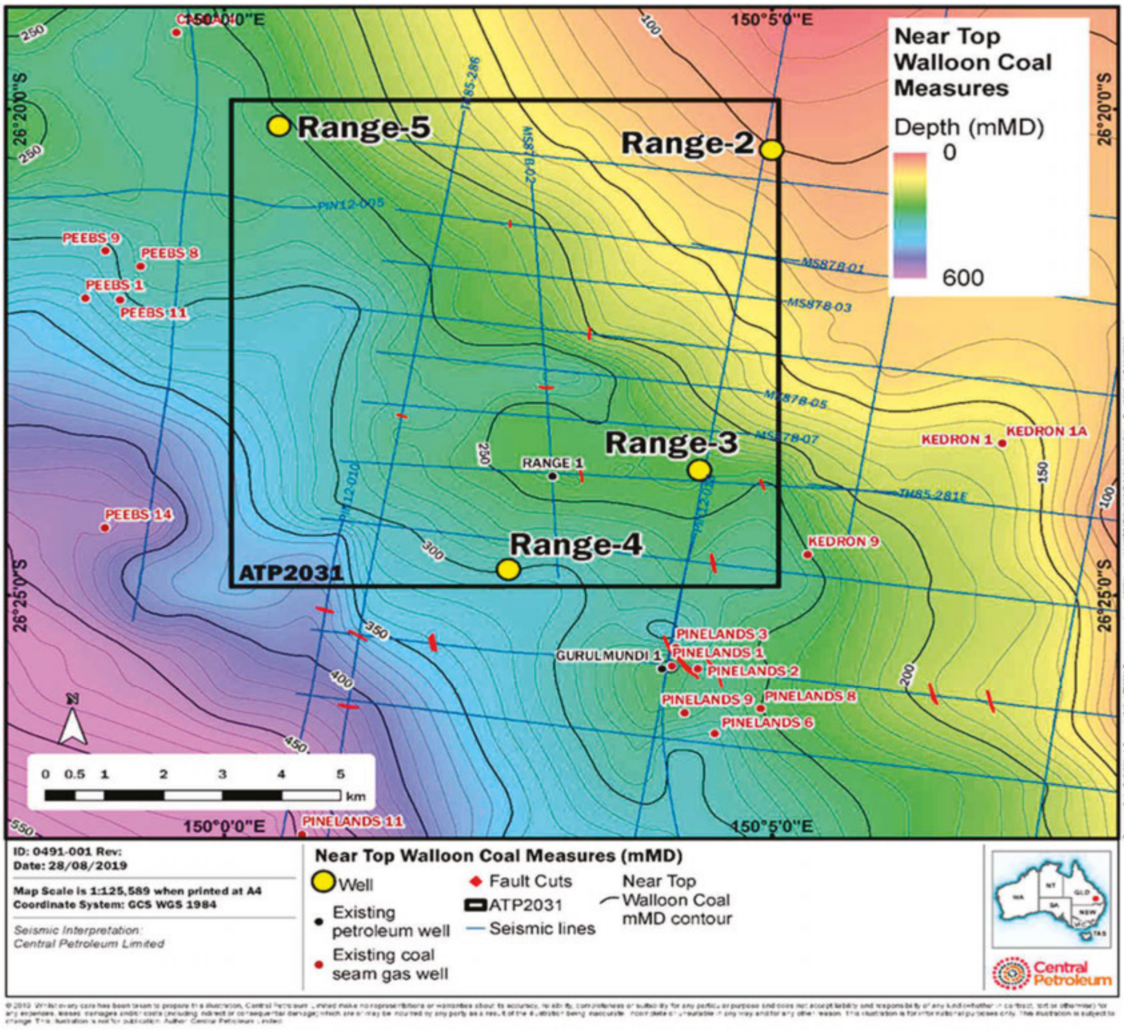
The block is situated in the Surat Basin, a geological province that has been developed extensively over the last decade. No coal seam gas wells were previously drilled in the permit, but there are a number of coal seam gas wells in adjacent blocks. The permit area covers 77km^2 and is located approximately 28km North-West of the town of Miles which is estimated to be half way between the Wooleebee Creek and Bellevue coal seam gas developments.



Location of Project Range (ATP 2031) in relation to other coal seam gas projects in the Surat Basin

The four well exploration programme was completed in August 2019, encountering average net coal thickness of 30m and permeability in line with, or better than expected, recorded in all wells, including in the deeper Taroom coal seams. The results enabled reserves and resources certifier, Netherland Sewell & Associates to certify 270 PJs (100% JV) of 2C Resources in August 2019.

The certified 2C resources significantly exceeded expectations, and the results indicate that the area is suited to low-cost un-fracked vertical well development. Given the production history of gas fields in the surrounding area, the Company has a high degree of confidence that the 2C resources can be converted into 2P reserves to support a final investment decision in 2021.



Map of ATP 2031 and the four Project Range exploration wells

Exploration assets

Exploration Portfolio Review and High-grade Seriatim

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). The Amadeus Basin has, to date, been a focus for the majority of Central's exploration activity, with ~170,000km^2 of areal extent, five known working petroleum systems and four fields having produced significant quantities of oil and gas (one oil field currently suspended).

Notwithstanding this production history, the Amadeus Basin is by any standard underexplored with only a total of 39 exploration wells and ~14,500km of 2D seismic acquired across the entire basin. This can in part be attributed to the small and historically oversupplied Northern Territory gas market which has limited investment in the region.

Following connection to the east coast gas market via the NGP in January of this year, Central's Northern Territory 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, including a new GM Exploration (April 2019) and a new experienced Reservoir Engineer (March 2019).

With augmentation of exploration capabilities complete, the Company initiated a full exploration portfolio review and update, incorporating historical and recently acquired technical data in order to generate a systematic and consistent play-based approach to drive new exploration strategies. Play-based exploration methodologies, incorporating the integration of seismic data, log and palynological data, structural analysis, geochemistry, 3D basin modelling, consistent well failure analysis and gross depositional environment maps will allow the systematic creation of common risk segment maps at all play levels. This information will be actively utilised in the future for permit management, business development, work program creation and portfolio management.

Initial indications from this portfolio review show that the Amadeus Basin is one of the few remaining large under-explored on-shore working hydrocarbon systems in Australia. A total of 115 potential targets (65 gas and 50 oil) have been identified at this point within Central's permits and applications in the Amadeus Basin.

With the initial phase of this portfolio review now nearing completion, the Company is constructing a high-grade seriatim and exploration strategy for short, medium and longer-term maturation of leads and prospects. This is fundamental to the future growth of the Company.

Ooraminna Field (RL3 and RL4)

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, 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 and outcrop mapping. A decision on drilling the Ooraminna commitment well will be made upon completion of the exploration portfolio review and finalisation of a near-term exploration plan.

Tenure Update

Grant of renewal for both retention licences were received from the Northern Territory Department of Primary Industry and Resources ("DPIR") on 9 August 2018 with a suspension of Year 1 approved on 3 April 2019. Technical work continues within the leases.

ATP909, ATP911 and ATP912

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

Central received approval for Project Status and applied to renew the permits with the Queensland Department of Natural Resources, Mines and Energy. The Permit renewals have subsequently been granted. Central is currently conducting Year 1 permit obligations of geology and geophysical studies focusing on the Ethabuka structure. Ethabuka-1 was drilled in 1973 and tested gas at ~0.2 mmscfd from the Coolibah Formation, the well was abandoned prematurely due to mechanical difficulties and weather. As such, the large Ethabuka anticline remains to be fully tested at multiple levels. Work also continues on the development of a large hydrothermal dolomite play in the blocks.

Dukas-1 (EP112)

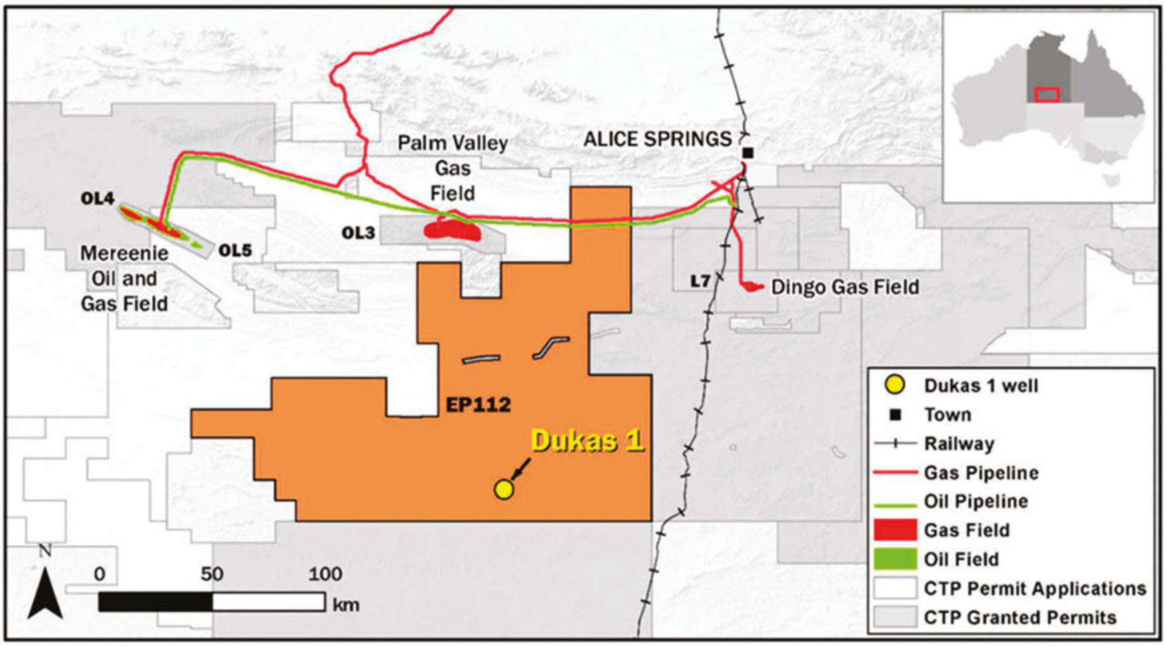
Southern Amadeus Basin, Northern Territory
(CTP – 30% interest, Santos earning 70%)

The Dukas-1 well was selected for drilling by the Joint Venture for the EP112 3rd (and final) farm-out completion phase. Santos is carrying 100% of the cost of this well and will earn a 70% interest in EP112 as a result. Dukas-1 is designed to test a large regional high optimally located to receive charge from an interpreted Neoproterozoic depocenter. The primary reservoir objective is the Heavitree Quartzite/fractured basement, a petroleum system which has been proven to be hydrocarbon bearing at Mt. Kitty-1 and McGee-1.

Dukas-1 is located approximately 175km south west of Alice Springs and the prospect has multi-TCF gas potential.

The Dukas gas prospect is a large structure and, given the potential size, success at Dukas would be company changing. In addition, several other large 'lookalike" sub-salt closures have been identified from interpretation of seismic acquired in the Southern Amadeus basin between 2016 and 2018. As such, success at Dukas-1 has the potential to unlock a significant new hydrocarbon province in the Southern Amadeus Basin and become a major new source of gas for the east coast market.

Dukas-1 was spudded on the 16th April 2019 with a proposed total depth of 3,850m. The air-drilling assembly became stuck while drilling and the well was subsequently side-tracked on the 16th May 2019. Drilling continued to 2,604m into the Gillen Formation where the 10 ¾" surface casing was set. Drilling then resumed. As at the 30th June the well was at a depth of 3,391m.



Location map of Dukas-1 and EP112

In August 2019, the well encountered formation pressure much higher than expected at a depth of 3,704m. The existence of highly-pressured hydrocarbon-bearing gas close to the target formation provides strong evidence of a working petroleum system with an effective seal, increasing the chance of a material gas resource at Dukas. The high pressures encountered were in excess of rig capacity and the well was suspended after wireline logs were run, sidewall cores obtained, and vertical seismic profiling conducted. The data acquired will be analysed and a forward plan will be developed. It is likely that equipment capable of safely drilling in the higher pressure environment will be required.

Southern Amadeus Basin, Northern Territory

Various Exploration Permits (see table on page 102)

Santos Stage 3 Farm out

The joint venture's primary exploration objective within these permits is maturing large sub-salt leads in the Neoproterozoic. Potential secondary reservoir objectives are developed within the post-salt units including the Areyonga Formation and Pioneer Sandstone, both of which are gas bearing in the Dingo and Ooraminna fields, respectively.

In addition to the sub-salt prospects, Central continues to mature its geological interpretations in these permits, seeking to identify a variety of other exploration play types and targets which could be prospective for hydrocarbons and/or helium. A full play-based-exploration review is underway with the objective of identifying new plays and fully understanding existing plays. Santos has also requested an additional five-month extension on the Stage 3 end date to 3 November 2019 to which Central has agreed.

Southern Amadeus Area	Total Central Participating Interest after completion of Stage 3 Farmout to Santos
EP 82 (excluding EP 82 Sub-Blocks) **	60%
EP 105**	60%
EP 106 * & **	60%
EP 112	30%
EP 125 **	30%
EP 115 (North Mereenie Block) **	60%

* 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.

** Santos' right to earn and retain participating interests in the permit is subject to satisfying various obligations in their farmout agreement with Central. The participating interests as stated assume such obligations will be met or otherwise may be subject to change.

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

Exploration objectives have recently been prioritised to determine Central's exploration strategy with a play-based approach. The block has proven oil at the Larapintine system level (Pacoota Formation - Surprise Oil Field), and also contains a number of significant gravity highs which provide potential large gas and associated Helium pre-salt targets at both the Heavitree Formation and fractured Basement levels. A number of potentially large leads with oil potential have been identified in the vicinity of the Surprise oil field and work continues to progress these to potentially drillable status.

Central began initial planning for the Year 3 permit commitment of 500km of seismic acquisition in EP115. The final layout has yet to be agreed on, however the targets will include leads at the Ordovician (Stairway and Pacoota Sandstone), Arumbera, Pioneer, Areyonga and Heavitree/ basement horizons. The data gathered in the Dukas-1 well is likely to influence the location of the upcoming seismic program which is due to be acquired before December 2019. Therefore, an application for permit suspension is in progress to facilitate a more informed seismic program whilst still meeting schedules necessary to keep the permit in good standing.

The Company continues to interpret in these permits, seeking to identify a variety of exploration play types and targets which could be prospective for hydrocarbons and/or helium.

Exploration Application Areas, Northern Territory

Amadeus, Pedirka and Wiso Basins — Various Areas (see table on page 102)

The Company continued to evaluate a number of these areas and has been working to gain Native Title/ALRA clearance and secure the other necessary approvals in advance of the award of exploration permit status.

Across the Amadeus Basin, further review of the seismic, well, magnetic and recently acquired gravity data was completed resulting in an inventory of leads and prospects. Play types and leads are also being developed for the under-explored section underlying the proven Ordovician Larapintine system which is believed to be prospective for gas. In the western Amadeus a preliminary seismic programme that targets identified structural trends and leads with the aim of defining areas for follow up infill seismic has been designed.

In the Wiso Basin, a gravity survey was conducted by Geoscience Australia and Northern Territory Geologic Survey in 2013, which has provided Central with improved detail of structural trends. Interpretation and forward modelling in conjunction with magnetic, borehole and outcrop data has led to the generation of a depth to basement map which will help with the planning of a proposed seismic acquisition which will form part of the first phase of exploration once tenure is granted.

RESERVES & RESOURCES INFORMATION

Net proved ("1P") gas reserves were 120.2 PJ and net proved ("1P") oil reserves were 0.68 MMbbl at 30 June 2019. 1P gas reserves decreased by 13.61 PJ through production and an adjustment at Palm Valley while 1P oil reserves decreased 0.10 MMbbl, through continued production.

Net proved plus probable ("2P") gas reserves were 144.69 PJ and net proved plus probable ("2P") oil reserves were 0.87 MMbbl at 30 June 2019.

Reserves and contingent resources for Mereenie and Dingo are based on volumes provided by independent expert Netherland, Sewell & Associates Inc ("NSAI") for the respective Petroleum Resources Management System compliant categories dated 30 June 2018. Reserves and contingent resources for Palm Valley, are based on an internal assessment of recoverable volumes reported externally on 12 June 2019.

AGGREGATE RESERVES (Central Petroleum Share)

	Unit	30/06/2018	Production for the period 01/07/2018 - 30/06/2019	Adjustments for the period 01/07/2018 - 30/06/2019	30/06/2019
Oil					
Proved reserves	MMbbl	0.78	(0.10)	-	**0.68**
Proved plus probable reserves	MMbbl	0.97	(0.10)	-	**0.87**
Contingent Resources 2C	MMbbl	0.10	-	-	**0.10**
Gas					
Proved reserves	PJ	133.79	(9.82)	(3.80)	**120.18**
Proved plus probable reserves	PJ	168.73	(9.82)	(14.22)	**144.69**
Contingent Resources 2C	PJ	91.20	-	13.58	**104.78**

RESERVES PER ENTITY (Central Petroleum Share)

	Unit	30/06/2018	Production for the period 01/07/2018 - 30/06/2019	Adjustments for the period 01/07/2018 - 30/06/2019	30/06/2019
Mereenie, oil					
Proved reserves	MMbbl	0.78	(0.10)	-	**0.68**
Proved plus probable reserves	MMbbl	0.97	(0.10)	-	**0.87**
Contingent Resources 2C	MMbbl	0.10	-	-	**0.10**
Mereenie, gas					
Proved reserves	PJ	78.20	(7.01)	-	**71.19**
Proved plus probable reserves	PJ	88.55	(7.01)	-	**81.55**
Contingent Resources 2C	PJ	91.20	-	-	**91.20**
Palm Valley					
Proved reserves	PJ	24.24	(1.95)	(3.80)	**18.49**
Proved plus probable reserves	PJ	42.00	(1.95)	(14.22)	**25.83**
Contingent Resources 2C	PJ	-	-	13.58	**13.58**
Dingo					
Proved reserves	PJ	31.35	(0.86)	-	**30.49**
Proved plus probable reserves	PJ	38.18	(0.86)	-	**37.32**
Contingent Resources 2C	PJ	-	-	-	-

Note: Estimates may not arithmetically balance due to rounding

QUALIFIED PETROLEUM RESERVES AND RESOURCES EVALUATOR STATEMENT

The information contained in this report regarding the Central Petroleum reserves and contingent resources is based on, and fairly represents, information and supporting documentation reviewed by Mr Kevan Quammie who is a full-time employee of Central Petroleum holding the position of Development & Appraisal Manager. Mr. Quammie holds an M.Sc. Petroleum and Natural Gas Engineering from the Pennsylvania State University, is a member in good standing of the Society of Petroleum Engineers, is qualified in accordance with ASX listing rule 5.41. and has consented to the inclusion of this information in the form and context in which it appears.

SIGNIFICANT CHANGES IN THE STATE OF AFFAIRS

The financial position and performance of the group was particularly affected by the following events and transactions during the year ended 30 June 2019:

- The Gas Acceleration Programme was completed in time for NGP connection;
- The NGP was commissioned and commenced 3 January 2019, connecting the Northern Territory to east coast gas markets;
- Gas deliveries under the Incitec Pivot GSA commenced in January 2019, representing a significant increase in gas sales;
- The Palm Valley field was restarted, albeit at rates below expectations leading to a reduction of 14.2PJ of 2P reserves;
- Palm Valley 13 well successfully drilled and tied into production;
- Commenced drilling the Dukas 1 exploration well targeting material gas resources; and
- Granted exploration ATP 2031 in Queensland's gas-rich Surat Basin and commenced a four well exploration program, funded by a joint venture partner.

There were no other significant events that will have a forward impact on the state of affairs of the group.

EVENTS SINCE THE END OF THE FINANCIAL YEAR

The Queensland and Texas court proceedings with Geoscience Resource Recovery, LLC (GRR) have settled. The parties filed the relevant paperwork with the Queensland and Texas courts to finalise ending the legal proceedings. The Group has included a provision for the settlement of this matter in the financial statements.

The Dukas exploration well in EP112 (100% free carry by Santos) was suspended after encountering much higher than predicted formation pressures. A forward plan is to be developed over the coming months.

The four well exploration programme in ATP 2031 concluded with encouraging results. Netherland, Sewell & Associates has independently certified 2C contingent resources of 270PJs (100% JV) of Walloons coal seam gas.

INFORMATION ON DIRECTORS

Mr Leon Devaney, BSc, MBA

Managing Director and Chief Executive Officer

Mr Devaney has 19 years of commercial and finance experience within the Australian oil and gas sector and holds an MBA and BSc (Finance) from the University of Southern California, USA.

He joined Central Petroleum in 2012 and has been responsible for commercial, finance and business development activities in various senior roles. He was instrumental in negotiating the Mereenie acquisition from Santos in 2015, as well as the Palm Valley and Dingo Gas Field acquisition from Magellan Petroleum in 2014. Mr Devaney was appointed Chief Executive Officer, effective 21 February 2019, after serving as Acting CEO since July 2018.

Prior to joining Central Petroleum, he worked at QGC and played a pivotal role in its growth from a small cap gas exploration company into a multi-billion dollar takeover target by the BG Group in 2008. He continued with BG following the QGC takeover, where he served as General Manager, Gas and Power, responsible for the domestic gas and electricity portfolio.

Prior to QGC, Mr Devaney held senior roles at Deloitte in the Corporate Finance Advisory group where he was active in structuring and implementing commercial and financing transactions for major energy and infrastructure projects throughout Australia.

Mr Stuart Baker, BE(Elec), MBA, AICD

Independent Non-executive Director

Mr Baker was appointed as a Director on 7 December 2018 and has more than four decades of experience in the oil and gas sector and currently provides independent advice to corporates and investors in the Australian oil and gas industry.

Previously he was Executive Director, Morgan Stanley with dual roles as Co-Head Asia Oil, Gas and Chemicals Research and team leader, Australian energy, mining and utility research, with positions held over a 13-year period. He also held senior equity research positions in oil and gas, at Macquarie Bank and Bankers Trust, and as a Petrophysical Engineer at Schlumberger Inc. based in South-east Asia, rising to General Field Engineer.

Mr Baker is currently a member of the investment committee of resource focused ASX listed Lowell Resources Fund, is a strategic advisor to Karoon Gas Australia Ltd and a Member of the Board of Governors, Shelford Girls Grammar School, Melbourne.

Mr Baker is a member of the Australian Institute of Company Directors and holds a BE(Elec) from the University of Melbourne and an MBA from the Melbourne School of Management.

Dr Julian Fowles, PhD, BSc (Hons), GDipAFI, GAICD

Independent Non-executive Director

Dr Fowles was appointed as a Director on 28 June 2019 and is a petroleum industry professional with over 30 years in international leadership roles, including 17 years with Shell International, as well as positions with other major listed companies. He has extensive board, shareholder and analyst engagement experience.

Most recently Dr Fowles was a senior executive with Oil Search limited, leading the PNG operated and non-operated oil and LNG production and development businesses. He was previously the executive leading Oil Search's Exploration and New Business teams and has also been involved in the development and implementation of Oil Search's opportunity development framework, targeting major projects through key assurance processes from pre-concept to FID.

Dr Fowles is a Graduate of the Australian Institute of Company Directors and holds a BSc (Hons) from the University of Edinburgh and a PhD from the University of Cambridge. Dr Fowles also holds a Graduate Diploma in Applied Finance and Investment.

Mr Wrixon F Gasteen, BE (Mining) (Hons) QLD, MBA (Distinction) Geneva

Independent Non-executive Chairman

Wrix Gasteen has over 30 years' experience in mining, oil and gas, and manufacturing industries in Australia and Asia.

He is an experienced Managing Director and CEO, Executive Director, Independent Non-Executive Director and Chairman of both listed and private companies in Australia, Singapore, Malaysia, and the United States. He is a Senior Advisor to Australian companies.

He has held senior management positions in the Resources Industry in Australia. As Chief Mining Engineer, he led the Exploration and Engineering team that discovered and then developed the Boundary Hill Coal Mine in Central Queensland. He became its inaugural Mine Manager.

As Managing Director and CEO of Hong Leong Asia Limited, listed on the Singapore Stock Exchange (SGX: HLA), he transformed and grew the company 7 fold, through acquisitions and organic growth, from a loss making company to a highly profitable conglomerate with $2.2 billion in sales, 80% of which were in China and SE Asia. Mr Gasteen was also Director of Tasek Corporation (cement) listed on Kuala Lumpur Stock Exchange (KLSE) and Chairman and President of China Yuchai International (diesel engines) listed on the New York Stock Exchange (NYSE).

During his term as Managing Director and CEO of HLA, he was presented with two successive annual awards by the Securities Investors Association of Singapore (SIAS) for Corporate Transparency. The BRW ranked Mr Gasteen No.3 in their Top 20 Australians Managing in Asia.

Mr Gasteen is an Executive Director of Australian dairy milk powder products company, CBS International. He is a Director and co-founder of Ikon Corporate (Singapore), established in 2007 to provide corporate advisory, capital raising and management consulting services.

Ms Katherine Hirschfeld AM, BE(Chem) UQ, HonFIEAust, FTSE, FIChemE, CEng, FAICD

Independent Non-executive Director

Ms Hirschfeld was appointed as a Director on 7 December 2018 and is a highly regarded non-executive director, having served on company boards listed on the ASX, NZX and NYSE, as well as government and private company boards. She is currently the Chair of Powerlink, Senator at the University of Queensland and a board member of Qld Urban Utilities and Tellus Holdings Ltd.

Ms Hirschfeld has also been a board member and President of UN Women National Committee Australia and non-executive director of Energy Queensland, Tox Free Solutions, InterOil Corporation, Broadspectrum and Snowy Hydro. Previously she had leadership roles with BP in oil refining, logistics, exploration and production located in Australia, UK and Turkey.

Ms Hirschfeld was recognised in the AFR/Westpac 100 Women of Influence 2015, by Engineers Australia as one of Australia's Top 100 Most Influential Engineers 2015 and as an Honorary Fellow in 2014. She is a member of Chief Executive Women and a Fellow of the Australian Institute of Company Directors and the Academy of Engineering and Technology. She is also an executive mentor/coach with Merryck & co.

In 2019 Ms Hirschfeld was appointed a Member of the Order of Australia (AM) for significant service to engineering, to women, and to business.

COMPANY SECRETARIES

Mr Daniel C M White, LLB, BCom, LLM

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

Mr Joseph P Morfea, FAIM, GAICD

Mr Morfea has over 40 years of experience in the resource industry having held key financial positions with both Australian and international based companies. He was previously the chief financial officer of Magellan Petroleum Australia Pty Ltd, a wholly owned subsidiary of Denver based Magellan Petroleum Corporation and has also held board and advisory committee positions. Prior to Magellan, Mr Morfea worked for Santos Limited and Thiess Dampier Mitsui Coal Pty Ltd.

DIRECTORS' MEETINGS

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

Director	Full Meeting of Directors		Audit Committee		Risk Committee		Remuneration & Nominations Committee		Community Affairs Committee	
	Eligible[1]	Attended	Eligible[1]	Attended[2]	Eligible[1]	Attended[2]	Eligible[1]	Attended[2]	Eligible[1]	Attended[2]
Mr Stuart Baker[3]	4	4	1	2	1	2	1	2	2	2
Mr Richard Cottee[4]	14	—	—	—	—	—	—	—	—	—
Mr Leon Devaney[5]	4	4	—	2	—	2	—	2	—	2
Mr Wrixon Gasteen	18	18	5	5	3	3	4	5	2	2
Ms Katherine Hirschfeld AM[3]	4	4	1	2	1	2	1	2		
Mr Martin Kriewaldt	18	17	2	5	3	3	4	5	2	2
Mr Peter Moore[6]	11	11	—	3	1	1	2	2	—	—
Dr Sarah Ryan[6]	11	11	3	3	1	1	2	2	—	—
Mr Timothy Woodall[7]	9	9	2	2	1	1	1	1	—	—

1 *Number of meetings held during the time the director held office or was a member of the committee during the year.*

2 *The number of meetings attended includes those attended by invitation.*

3 *Stuart Baker and Katherine Hirschfeld were appointed 7 December 2018.*

4 *Richard Cottee resigned as Director 5 February 2019.*

5 *Leon Devaney was appointed as a Director 14 November 2018.*

6 *Peter Moore and Sarah Ryan resigned 13 November 2018.*

7 *Timothy Woodall resigned 29 September 2018.*

ENVIRONMENTAL REGULATION

The Consolidated Entity is subject to significant environmental regulation.

The Consolidated Entity aims to ensure the appropriate standard of environmental care is achieved and, in doing so, that it is aware of and is in compliance with all environmental legislation. The Directors of the Company and the Consolidated Entity are not aware of any breach of environmental legislation for the year under review.

SHARES UNDER OPTION

(a) Options granted during or since the end of the financial year to officers of the Company as part of their remuneration:

Name of officer	Date granted	Vesting Date	Exercise Price	Expiry Date	Number of options granted
Ross Evans	20 Aug 2019	30 Jun 2022	$0.20	30 Jun 2032[1]	4,170,025
Damian Galvin	20 Aug 2019	30 Jun 2022	$0.20	30 Jun 2032[1]	2,750,000
Duncan Lockhart	20 Aug 2019	30 Jun 2022	$0.20	30 Jun 2032[1]	3,333,333
Robin Polson	20 Aug 2019	30 Jun 2022	$0.20	30 Jun 2032[1]	2,792,758

1 *On 4 September 2019 the Directors announced their intention to change to the expiry date of these options to 30 June 2023 subject to shareholder approval at the Annual General Meeting.*

Details of share rights issued during the financial year the five most highly remunerated officers as part of their remuneration are included in Table 3 of Section H of the remuneration report contained on page 37.

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

Class	Issue Price	Exercise Price	Expiry Date	Number on issue
Unlisted options provided to financiers	Nil	$0.14	31 Dec 2019	22,500,000
Unlisted employee options	Nil	$0.20	30 Jun 2032	13,046,116
Unlisted employee share rights	Nil	Nil	05 Jan 2021	7,305
Unlisted employee share rights	Nil	Nil	03 Oct 2022	5,450,401
Unlisted employee share rights	Nil	Nil	08 Dec 2022	4,515,690
Unlisted employee share rights	Nil	Nil	23 May 2023	16,868
Unlisted employee share rights	Nil	Nil	28 Jun 2023	135,920
Unlisted employee share rights	Nil	Nil	22 May 2024	7,000,371
Unlisted employee share rights	Nil	Nil	30 Jun 2024	7,804,260
Unlisted employee share rights	Nil	Nil	13 Sep 2024	23,429
				60,500,360

(c) Shares issued by Central Petroleum Limited during or since the end of the year on the exercise of options or on the exercise of rights issued to employees under the Long Term Incentive Plan are set out below. No amounts are unpaid on any of the shares.

Class	Exercise Price	Share issue Date	Number exercised and issued as shares
Unlisted employee share rights	Nil	28 Nov 2018	2,876,183
Unlisted employee share rights	Nil	07 Feb 2019	1,038,000
Unlisted employee share rights	Nil	10 Apr 2019	266,355
Unlisted employee share rights	Nil	12 Apr 2019	1,634,631
Unlisted employee share rights	Nil	04 Jun 2019	424,754
Unlisted employee share rights	Nil	18 Sep 2019	9,053,720
			15,293,643

INSURANCE OF DIRECTORS AND OFFICERS

During the financial year, the Group paid premiums to insure Directors and officers of the Group. The contracts include a prohibition on disclosure of the premium paid and nature of the liabilities covered under the policy.

STAFF AND MANAGEMENT

The Directors wish to acknowledge the contributions made by the Company's staff and management. The skills and dedication of all of Central's personnel both in the field and at Head Office are greatly appreciated and valued.

AUDITOR'S INDEPENDENCE

A copy of the Auditor's Independence Declaration as required under section 307C of the *Corporations Act 2001* is set out on page 42.

NON-AUDIT SERVICES

During the year the Company engaged the auditor, PricewaterhouseCoopers ("PwC"), on assignments additional to their statutory audit duties where the auditor's expertise and experience with the Company and/or the Consolidated Entity was important.

Details of amounts paid or payable to the auditor (PwC) for non-audit services provided during the year are set out below.

The Board of Directors is satisfied that the provision of the non-audit services is compatible with the general standard of independence for auditors imposed by the *Corporations Act 2001*. The Directors are satisfied that the provision of non-audit services by the auditor, as set out below, did not compromise the auditor independence requirements of the *Corporations Act 2001* and did not compromise the general principles relating to auditor independence in accordance with APES 110 Code of Ethics for Professional Accountants set by the Accounting Professional and Ethical Standards Board.

	CONSOLIDATED	
	2019	2018
PwC Australian firm:	**$**	$
(i) Taxation services		
Income tax compliance	8,670	8,160
R&D Services	35,350	—
Other tax related services	44,752	26,259
	88,772	**34,419**
(ii) Other services		
Consulting services	8,865	—
	8,865	**—**
Total remuneration for non-audit services	**97,637**	**34,419**

EXECUTIVE SUMMARY - REMUNERATION

Dear Shareholders,

Over the last few years - and in particular the last year, Central Petroleum's Board, management and staff have been focussed on transforming the Company into a leading supplier of oil and gas to the Northern Territory and east coast energy markets. FY19 was a year when we have seen positive signs that the Company's strategy is working, with a 70% increase in revenues and the certification of an additional 270PJ of 2C gas resources at the Range gas project subsequent to year end.

Critical to this strategy has been the installation of a professional and experienced management team. We have confidence that the re-vamped Board and management team have the skills, experience and dedication to unlock the full value of the Company's impressive asset portfolio.

It goes without saying that an appropriate remuneration structure is an important factor in attracting and retaining key personnel and in aligning the management team's interests with those of shareholders. There is nothing unusual about our remuneration structure - it is similar to many organisations, with remuneration divided into three components – Base (including superannuation), Short Term Incentive (STI) and Long Term Incentive (LTI).

Central engages external consultants (Guerdon Associates in both 2018 and 2019) to provide a scan of similar companies annually in respect of the remuneration levels of the CEO and those reporting to him by comparison with the market. Industry scans of the remaining positions are received during the year. Central's base remuneration tends to be a little higher than some of its peers, offset by a much lower STI (it is a maximum 10% of Base while other companies can range up to 30% and beyond).

Achievement of the Short Term Incentive depends upon achieving personal, departmental and corporate objectives over the year. The philosophy is that the base salary pays for effort and the STI pays for outcomes above the expected performance. There is an overriding Board discretion to modify the calculated STI outcome, and that discretion was exercised in FY18 to reduce the STI to zero for certain employees due to disappointing outcomes.

FY19 however, has been a watershed year for the Company and our staff have been successful in achieving many of the targets (refer section F of the following Remuneration Report), including:

- being awarded the new exploration tenement ATP2031 and drilling of appraisal wells that subsequently resulted in the certification of 270 PJ of 2C gas resources at the Range gas project; and
- successful mid-year completion of the Gas Acceleration Project (GAP) that has resulted in a 70% increase in revenues in FY19.

As a result, personnel received, on average, approximately 8.1% of their maximum 10% STI this year. Some key staff also received a one-off discretionary bonus for their efforts in completing the GAP on time and on budget. Shareholders too, have shared in the benefits of these results, with Central's share price breaking free of its recent price range – up approximately 50% to over 20 cents at the time of writing in early September.

For FY20, the STI targets for management and staff will cover critical aspects of our operational and growth plans, including: exploration programmes; reserve and resource growth; gas revenue; operating cost containment; traditional owner interaction; safety; and environmental outcomes.

The Long Term Incentive Plan (LTIP) pegs half of its reward outcomes to Central out-performing its comparator companies (Relative Total Shareholder Returns) and half to Absolute Total Shareholder Returns (TSR). Absolute TSR must exceed 10% per annum for three years to achieve any part of this second element and 25% per annum for three years to receive the whole of this element.

The LTIP's Absolute TSR performance for the three years from 1 July 2016 to 30 June 2019 achieved growth of 15.5% pa and the Relative TSR placed Central at the 88th percentile compared to its peers, resulting in approximately 75% of rights vesting for this three year performance period. This is a result shared with shareholders over the same three year period.

To address shareholder concerns regarding the complexity of our executive remuneration structure, Central will move key executives over to a simplified long-term incentive scheme which better aligns key management objectives with shareholder value. The Executive Share Option Plan will replace the LTIP for key executives for the next three years.

The contents of the following Remuneration Report are prepared in accordance with the requirements of the Corporations Act and Australian Accounting Standards. Unfortunately, these do not always reflect the actual value of remuneration received by senior executives each year. In the spirit of improved transparency and communication, and to assist readers of this report to understand the actual remuneration which the senior executives have received this year, we have added a new table which we hope you will find more clearly sets out the take home value of their remuneration. This "Realised Remuneration" table can be found at section G of the following Remuneration Report (Table 1).

Wrixon Gasteen
Remuneration and Nominations Committee Chairman

REMUNERATION REPORT (AUDITED)

This remuneration report for the year ended 30 June 2019 outlines the remuneration arrangements of the Group in accordance with the requirements of the *Corporations Act 2001* (Cth)*, as amended (the Act).* This information has been audited as required by section 308(3C) of the Act.

The remuneration report is presented under the following sections:

A	Directors and Key Management Personnel (KMP)
B	Remuneration Overview
C	Remuneration Policy
D	Remuneration Consultants
E	Long Term Incentive Plan (LTIP)
F	Short Term Incentive Plan (STIP)
G	Realised Remuneration
H	Remuneration Details
I	Executive Service Agreements
J	Non-Executive Director Fee Arrangements

Voting of shareholders at the 2018 Annual General Meeting

At the Company's 2018 Annual General Meeting, 71% of the votes cast were against the adoption of the Remuneration Report. A number of shareholders commented on the difficulty in understanding the remuneration of Directors and Key Management Personnel as presented in the Remuneration Report and called for increased transparency around the attainment of performance hurdles for the variable remuneration.

The Board has considered this feedback and has taken a number of steps to improve the understanding of this year's Remuneration Report, including:

- the inclusion of an executive summary from the Chairman of the Remuneration and Nominations Committee (refer previous page);
- the compilation of a simplified table of 'Realised Remuneration' (section G of this report); and
- the provision of additional information to explain the achievement of both the Long Term Incentive Plan hurdles (section E of the report) and the Short Term Incentive Plan targets (section F of this report).

The Board has also introduced a new Executive Share Option Plan from FY2020 to replace the Long Term Incentive Plan for certain executives to provide a more direct and transparent link between executive remuneration and shareholder value.

A. Directors and Key Management Personnel

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

Directors

Current Directors:	
Mr Stuart Baker	Non-executive Director (appointed 7 December 2018)
Mr Leon Devaney	Managing Director (appointed 14 November 2018) and Chief Executive Officer (from 21 February 2019, acting since July 2018)
Dr Julian Fowles	Non-executive Director (appointed 28 June 2019)
Mr Wrixon Gasteen	Non-executive Chairman (appointed as Chairman 2 September 2019)
Ms Katherine Hirschfeld AM	Non-executive Director (appointed 7 December 2018)
Former Directors:	
Mr Richard Cottee	Managing Director and CEO (resigned as Director 5 February 2019)
Mr Martin Kriewaldt	Non-executive Chairman (resigned 2 September 2019)
Dr Peter Moore	Non-executive Director (resigned 13 November 2018)
Dr Sarah Ryan	Non-executive Director (resigned 13 November 2018)
Mr Timothy Woodall	Non-executive Director (resigned 29 September 2018)

Remuneration Report (Continued)

Other Key Management Personnel

Mr Ross Evans	Chief Operations Officer
Mr Damian Galvin	Chief Financial Officer (commenced 5 August 2019)
Mr Michael Herrington	President - Operations and Chief Development Officer (to 29 January 2019)
Mr Duncan Lockhart	General Manager Exploration (commenced 8 April 2019)
Mr Robin Polson	Chief Commercial Officer
Mr Daniel White	Group General Counsel and Company Secretary

B. Remuneration Overview

Central's remuneration strategy is designed to attract, motivate and retain high performing individuals and is linked to the Group's objectives to build long-term shareholder value. In doing so, Central adopts a pay for performance culture which is balanced by a fair and equitable approach to the retention and motivation of its team. The remuneration strategy incorporates the following metrics:

a. Measuring Central's achievement of its targets and performance against its peers
b. Peer company comparative indicators such as market capitalisation, size, complexity of operations and market developments
c. Adjusting to remuneration best practice
d. Market movements and its impact on the alignment of internal relativities
e. Linking internal strategies for the achievement of improved shareholder value.

Financial Year 2019, summary of fixed and variable remuneration outcomes	
Inflation Salary average increases of 2%	Where appropriate, a pay rise was awarded to address inflation and on account of a change in role, responsibilities or other extenuating circumstances.
STIP	The Company's Short Term Incentive Plan payments were made in August 2019.
LTIP Vesting	Awards vested under the Long Term Incentive Plan for the three year period ending 30 June 2019 during fiscal year 2020.

C. Remuneration Policy

The remuneration policy of the Company is to pay its Directors and executives amounts in line with employment market conditions relevant to the oil and gas industry whilst reflecting the specific circumstances of Central. The Company's remuneration practices and, in particular, its short term and long term incentive plans are focussed on creating strong linkages between shareholder value as measured by shareholder returns and executive remuneration. Consequently, the major component of executive incentives will be the Long Term Incentive Plan ("LTIP") rather than the Short Term Incentive Plan ("STIP").

From FY2020, certain key executives will participate in an Executive Share Option Plan instead of the LTIP, as this will provide a more transparent alignment between executive remuneration and shareholder value.

D. Remuneration Consultants

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

The Board has appointed Guerdon Associates to provide remuneration advice to the Board and Remuneration Committee. The works undertaken comprised the following but the reports received did not include any specific recommendations as to the elements or amounts of Key Management Personnel remuneration:

- Executive KMP Market Reviews;
- Equity Plan design and modelling - Long Term Incentives; and
- Performance measurement of Absolute TSR as per the Performance Rights based Long Term Incentive Plan (LTIP) and proposed peer group of Companies to adopt for those future LTIP years from 1 July 2018.

Remuneration Report (Continued)

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

For periods up to and ending on 30 June 2019, the remuneration of directors and executives consisted of the following key elements:

Non-executive directors:

1. Fees including statutory superannuation; and
2. No further participation in short or long term incentive schemes.

Executives, including executive directors:

1. Annual salary and non-monetary benefits including statutory superannuation;
2. Participation in a Short Term Incentive Plan (performance measured over a 12 month period);
3. Participation in a Long Term Incentive Plan (Performance Rights or Options schemes, measured over a 3 year period); and
4. There are no guaranteed base pay increases included in any executive's contract.

E. Long Term Incentive Plan (LTIP)

In its 2014 Annual Report, Central announced that from 1 July 2014 it would change its remuneration practices and, in particular, the structure of its STIP and LTIP in line with market conditions relevant to the oil and gas exploration industry.

The LTIP is a major component of executive incentives and, in developing the LTIP, the Board of Central focused on creating strong linkages between shareholder value as measured by shareholder returns and executive remuneration. Consequently, vesting conditions are divided equally between relative shareholder return and absolute shareholder return. In doing this the Board has identified that it is not sufficient for Central to perform above its peer group for executives to receive their maximum entitlement to share rights but also to achieve levels of absolute share price growth that would be considered as superior returns. For example, for the absolute share price vesting condition to be met, the Central share price must increase by at least 25% per annum for three years, compound growth of 95%.

Key terms and vesting conditions

On 26 November 2014 and subsequently on 2 November 2015 and 14 November 2018, shareholders approved the Company's share based LTIP to incentivise eligible employees (Non-Executive Directors are not eligible to participate in the LTIP).

The maximum number of performance rights vested in any year is determined by measuring Central's share price performance over that year compared to a peer group of companies (relative measure) and compared to its absolute share price movement over a three year cycle.

The following table details the percentage of Share Rights which will vest (Vesting Percentage) as determined by the performance conditions:

HURDLE	DEFINITION	HURDLE BANDING	VESTING PERCENTAGE	RESULT FOR PLAN YEAR VESTING 30 JUNE 2019
Absolute TSR[1] growth **(50% weighting)**	Company's absolute TSR calculated as at vesting date. This looks to align eligible employee's rewards to shareholder superior returns	Company's Absolute TSR over 3 years	Share Rights Vesting	
		Below 10% pa	0%	
		10% to <15% pa	25%	
		15% to <20% pa	50%	
		20% to <25% pa	75%	
		25% pa plus	100%	

Remuneration Report (Continued)

HURDLE	DEFINITION	HURDLE BANDING	VESTING PERCENTAGE	RESULT FOR PLAN YEAR VESTING 30 JUNE 2019
Relative TSR – E&P[2] **(50% weighting)**	Company's TSR relative to a specific group of exploration and production companies (determined by the Board within its discretion) calculated as at vesting date.	<u>Company's Relative TSR</u>	<u>Share Rights Vesting</u>	
		Below 51st percentile	0%	
		51st percentile	50%	
		52nd to 75th percentile	51% to 99%	
		76th percentile and above	100%	

1 *Total shareholder return (i.e. growth in share price plus dividends reinvested)*

2 *Exploration and Production*

For the purposes of determining the maximum number of unvested Share Rights available for vesting, the Company will calculate the Company's absolute TSR (total shareholder return as measured by an independent company chosen by the Board) and relative TSR effective as at the vesting date in accordance with the above table to determine the relative hurdle band and Vesting Percentage met. The unvested Share Rights for the applicable hurdle met for the performance period are then multiplied by the Vesting Percentage achieved for that hurdle to determine the total number of unvested Share Rights which vest to become Share Rights on the vesting date, which may then be exercised in accordance with the Employee Rights Plan Rules.

Subject to the vesting of unvested Share Rights on the Vesting Date, the unvested Share Rights vest at the rate of one Share Right for one unvested Share Right.

Employees must be employed by the Company at the end of the performance period in order for the Performance Rights to vest. The maximum number of Share Rights that may vest (subject to share price performance hurdles) is a function of the employee's base salary, their LTIP percentage, and the 20 trading days daily volume weighted average sale price of company shares sold on the ASX ending on the trading day prior to 30 June.

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

Details of the LTIP Plan's Key Terms can be viewed on the Company's website at www.centralpetroleum.com.au.

This LTIP provides coverage for various levels of eligible employees which include:

a. The Managing Director who is principally responsible for achievement of Central's strategy may receive a LTIP percentage up to 50%, subject to shareholder approval;

b. The Executive Management Team (EMT) and eligible employees are those in roles which influence and drive the strategic direction of the Company's business. EMT eligible employees receive a LTIP percentage up to 30%;

c. Eligible employees who are senior managers that are charged with one or more defined functions, departments or outcomes. They are more likely to be involved in a balance of strategic and operational aspects of management. Some decision-making at this level would require approval from the EMT. These eligible employees receive a LTIP percentage up to 20%;

d. Eligible employees who are not part of the EMT and are in roles which are focused on the key drivers of the operational parts of the Company's business. These eligible employees receive a LTIP percentage up to 10%; and

e. All other eligible employees are integral to the success of the Company obtaining its goals and objectives may participate in the Central Petroleum $1,000.00 Exempt Plan.

Conditions of the Central Petroleum $1,000.00 Exempt Plan include:

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

Remuneration Report (Continued)

F. Short Term Incentive Plan (STIP)

From 1 July 2014, a performance based plan comprising a matrix of Corporate, Departmental and Individual Key Performance Indicators ("KPIs") for all eligible employees was implemented. The Company's Board of Directors determine the maximum amount of KPIs achievable in any year (normally expressed as a percentage of base salary). Achieving the maximum is contingent upon all of the KPIs in the matrix being met at the 100% level. The KPIs are reviewed at the beginning of each year and adjusted where necessary to reflect Central's strategic direction. Consistent with the Directors' focus on appreciation in shareholder value as the major form of incentive, STIP payments were limited to a maximum of 10% of base salary for the financial year ended 30 June 2019.

Key terms and conditions

The Financial Year 2019 STIP has been holistically designed to recognise and reward individual effort through connecting individual KPIs, departmental KPIs and corporate KPIs. These groups of KPIs are intrinsically linked and start by cascading from the corporate KPIs, to the departmental KPIs and then onto individual KPIs. Individual KPIs drive the success of achieving departmental KPIs, which are in turn aimed at effecting the desired outcome to be reached in the corporate KPIs.

It is the responsibility of the Board to set the strategic direction priorities and objectives of the Company. The existence of this STIP does not amend or take away that responsibility and, as such, the results of the STIP form part of the Board's deliberation in its decision on the bonus recommendation to be awarded.

The Managing Director approves KPIs after consultation with the Board. These KPIs can change having regard to aligning employees with the Company's strategic direction, the practice in the marketplace and any other factors which the Board deems relevant. Neither the Board nor the Company guarantee any payment from the STIP, nor do they guarantee any performance level of the Company in future years. If there is a change as a result of this, employees participating in the STIP will be notified.

	PERCENT ALLOCATION OF STIP	
KPI CATEGORY	Executive	All Other Employees
Corporate KPIs	30%	30%
Safety and Environment KPI's	10%	10%
Departmental KPIs	40%	30%
Individual KPIs	20%	30%

The Financial Year 2019 STIP percentage allocation is a maximum of up to 10% of the employee's Base Salary. The maximum is contingent upon all of the KPIs being met at 100% in the STIP. This formed the basis of the recommendation to the Board who decided the amount. This percentage will be annually reviewed by the Board through the Remuneration and Nominations Committee. At the Board's discretion the financial year 2019 STIP has been paid as a combination of cash and company securities.

Corporate KPIs included:

		Performance outcome for FY19			
OBJECTIVE	WEIGHTING	0%	50%	75%	100%
Qld Acreage Authority to Prospect (ATP) issued & work programme approved by Government & IPL and substantially commenced	10%				●
Drilling	10%			●	
Facilities capable of producing * By 1st December 2018, and within approved budget (firm supply on CTP's participating interest)	60%				●
Budget (Original submission approved by the Board, unless amended due to a Board approved change of scope)	20%				●

* *Eligibility to participate in the reward of all achieved Objectives within the Corporate KPI's is dependent on the successful achievement of the Facilities capable of producing.*

Remuneration Report (Continued)

Safety and Environment KPIs included:

OBJECTIVE	WEIGHTING	Performance outcome for FY19 0%	50%	75%	100%
Traditional Owner cultural heritage: No breach	20%				●
Safety: No Lost Time Injuries (LTI)	30%	●			
Environment: No breach regarding reportable environmental incidents	30%	●			
Alice Springs local and Indigenous employment	20%				●

Summary Performance of Corporate KPI's:

Corporate	100% (being 30% of STI)	96 out of 100 (or 29 out of a possible 30)
Safety and Environment	100% (being 10% of STI)	40 out of 100 (or 4 out of a possible 10)
Total		82.5 out of 100 (or 33 out of a possible 40)

The departmental KPIs vary from one department to the next, however, all are equally important to achieve in the pursuit of achieving 100% of the corporate KPIs which are re-set annually. Individual KPIs are linked to the departmental KPIs and as such provides significant relevance to the role that the employee is employed for in each department.

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

Details of the remuneration of the Directors and the key management personnel of Central Petroleum Limited and the Consolidated Entity are set out in section H of this report.

Gas Acceleration Program (GAP) – Outcomes Bonus

Separate to the STIP, at the board's discretion - acknowledged one of the most important activities and subsequent achievements to have occurred in the last two years. Delivered without injury, on time and on budget, the completion of the Gas Acceleration Program was an absolute success resulting in almost tripling the Company's gas sales. The project was completed in December 2018 – primarily due to those staff who joined with new management just before the beginning of the financial year.

The Board awarded a discretionary bonus to the principal staff who achieved this. The reward was appropriate in the context of what was achieved, the costs avoided and obviating the need for a significant capital raise. It was a mammoth effort from management and staff. The Board congratulates those directly involved and to the rest of the team for making this outcome possible.

G. Realised remuneration

Table 1 identifies the Actual Remuneration received in respect of the financial year. Realised Remuneration reflects the take home remuneration of the Executive and includes:

- Total fixed remuneration inclusive of company superannuation contributions;
- Any STI awarded as cash for the financial year but paid after the end of the financial year;
- Any STI awarded as share rights in lieu of cash for the financial year, and granted after the end of the financial year valued at the cash equivalent amount; and
- The value of LTI share rights vesting in respect of the three-year period ending 30 June, valued at the year-end share price (2019: 14 cents per share, 2018: 14.5 cents per share).

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

Table 1: Realised Remuneration

	YEAR	TOTAL FIXED REMUNERATION[1] $	STI (CASH) $	GAP BONUS (CASH) [2] $	OTHER BENEFITS[3] $	STI VESTED AS SHARES[4] $	LTI VESTED AS SHARES[5] $	Total $
Current Executive KMP – Senior Executives								
Leon Devaney	2019	565,939	49,162	41,600	5,159	—	150,917	812,777
	2018	523,863	—	—	5,460	—	61,589	590,912
Ross Evans[6]	2019	423,552	20,000	30,000	3,896	20,000	—	497,448
	2018	31,938	—	—	—	—	—	31,938
Duncan Lockhart[7]	2019	93,189	—	—	—	—	—	93,189
	2018	—	—	—	—	—	—	—
Robin Polson[8]	2019	331,400	13,433	24,400	4,293	13,433	—	386,959
	2018	54,750	—	—	—	—	—	54,750
Daniel White	2019	438,064	16,909	—	5,159	16,909	148,401	625,442
	2018	435,978	—	—	5,460	12,404	60,567	514,409
Former Executive KMP – Senior Executives								
Richard Cottee[9]	2019	364,220	—	—	10,105	—	—	374,325
	2018	607,540	—	—	16,550	—	150,510	774,600
Michael Herrington[10]	2019	314,380	—	—	4,668	—	102,906	421,954
	2018	524,846	—	—	6,280	—	73,152	604,278
Total Executive KMP	**2019**	**2,530,744**	**99,504**	**96,000**	**33,280**	**50,342**	**402,224**	**3,212,094**
	2018	2,178,915	—	—	33,750	12,404	345,818	2,570,887

1 *Total Fixed Remuneration includes salaries, fees and superannuation contributions*

2 *Directors' discretionary bonus in respect of the Gas Acceleration Project*

3 *Includes car parking and other fringe benefits*

4 *Short term incentive issued as share rights and issued after year end valued at cash equivalent STI*

5 *Long Term Incentive Vested as Shares comprises any LTI from prior years that was awarded or is expected to be awarded for the three-year period ending 30 June and valued at that date.*

6 *Ross Evans commenced 1 June 2018*

7 *Duncan Lockhart commenced 8 April 2019*

8 *Robin Polson commenced 1 May 2018*

9 *Richard Cottee ceased employment as CEO effective 31 January 2019*

10 *Michael Herrington ceased employment effective 29 January 2019*

Remuneration Report (Continued)

H. Remuneration Details – Statutory tables

Table 2: Remuneration of Directors and Key Management Personnel

		SHORT-TERM			POST-EMPLOYMENT		LONG-TERM BENEFITS	SHARE-BASED PAYMENTS		Value of Options& Rights as Proportion of Remuneration
		Salary / fees $	STI[1] $	Non-monetary benefits[1] $	Superannuation contributions $	Termination Benefits $	LSL $	(At Risk) Rights[2] $	Total $	%
Non-Executive Directors										
Stuart Baker[3]	2019	47,139	—	—	4,478	—	—	—	51,617	0%
	2018	—	—	—	—	—	—	—	—	—
Wrixon Gasteen	2019	113,750	—	—	10,806	—	—	—	124,556	0%
	2018	93,333	—	912	8,867	—	—	—	103,112	0%
Robert Hubbard[4]	2019	—	—	—	—	—	—	—	—	0%
	2018	104,710	—	—	9,947	—	—	—	114,657	0%
Katherine Hirschfeld[3]	2019	47,139	—	—	4,478	—	—	—	51,617	0%
	2018	—	—	—	—	—	—	—	—	—
Martin Kriewaldt[5]	2019	167,746	—	—	15,936	—	—	—	183,682	0%
	2018	59,362	—	—	5,639	—	—	—	65,001	0%
Peter Moore[6]	2019	53,333	—	—	5,067	—	—	—	58,400	0%
	2018	83,333	—	—	7,917	—	—	—	91,250	0%
Sarah Ryan[5,6]	2019	55,417	—	—	5,265	—	—	—	60,682	0%
	2018	52,670	—	—	5,004	—	—	—	57,674	0%
Timothy Woodall[7]	2019	20,000	—	—	1,900	—	—	—	21,900	0%
	2018	38,889	—	—	3,694	—	—	—	42,583	0%
Sub-total	2019	504,524	—	—	47,930	—	—	—	552,454	0%
	2018	432,297	—	912	41,068	—	—	—	474,277	0%
Executive Directors and Other Key Management Personnel										
Richard Cottee[8]	2019	314,975	—	10,105	15,005	52,542	(68,772)	(343,827)	(19,972)	N/A
	2018	565,954	—	16,550	20,049	—	16,988	713,704	1,333,245	54%
Leon Devaney	2019	551,385	90,762	5,159	22,765	—	20,947	76,358	767,376	10%
	2018	517,512	—	5,460	24,085	—	19,483	110,740	677,280	16%
Ross Evans[9]	2019	410,613	70,000	3,896	22,765	—	5,361	23,221	535,856	4%
	2018	31,411	—	—	2,771	—	316	—	34,498	0%
Michael Herrington[10]	2019	257,419	—	4,668	15,292	28,366	(53,199)	80,865	333,411	24%
	2018	523,557	—	6,280	23,634	—	13,696	149,623	716,790	21%
Duncan Lockhart[11]	2019	94,830	—	—	5,133	—	936	—	100,899	0%
	2018	—	—	—	—	—	—	—	—	N/A
Robin Polson[12]	2019	307,387	51,266	4,293	26,508	—	3,553	17,746	410,753	4%
	2018	53,846	—	—	4,750	—	543	—	59,139	0%
Daniel White	2019	418,188	15,918	5,159	24,139	—	9,855	124,249	597,508	21%
	2018	384,336	17,900	5,460	23,417	—	8,730	123,802	563,645	22%
Sub-total	2019	2,354,797	227,946	33,280	131,607	80,908	(81,319)	(21,388)	2,725,831	(1)%
	2018	2,076,616	17,900	33,750	98,706	—	59,756	1,097,869	3,384,597	32%
Total Remuneration	**2019**	**2,859,321**	**227,946**	**33,280**	**179,537**	**80,908**	**(81,319)**	**(21,388)**	**3,278,285**	**(1)%**
	2018	2,508,913	17,900	34,662	139,774	—	59,756	1,097,869	3,858,874	28%

1 *Short term incentives are unpaid at the end of the financial year. Amounts are shown in respect of the performance period to which they relate. The STI was subsequently settled partly in cash and partly in equity after year end.*

2 *The fair values of deferred share rights granted are valued using methodology that takes into account market and peer performance hurdles. The values are calculated at the date of grant using a Black Scholes valuation model and Monte Carlo simulations and an agreed comparator group to assess relative total shareholder return. The values are allocated to each reporting period evenly over the period from grant date to vesting date. In the event that rights are cancelled for failure to meet the required service period or are not retained on termination of employment, any amounts previously expensed as share based payments are reversed as negative amounts.*

3 *Stuart Baker and Katherine Hirschfeld AM were appointed 7 December 2018.*

4 *Robert Hubbard retired 14 May 2018.*

5 *Martin Kriewaldt and Sarah Ryan were appointed 23 October 2017.*

6 *Peter Moore and Sarah Ryan resigned 13 November 2018.*

7 *Timothy Woodall was appointed 20 December 2017 and resigned 29 September 2018.*

8 *Richard Cottee ceased employment effective 31 January 2019.*

9 *Ross Evans commenced 1 June 2018.*

10 *Michael Herrington ceased employment effective 29 January 2019.*

11 *Duncan Lockhart commenced 8 April 2019.*

12 *Robin Polson commenced 1 May 2018.*

Remuneration Report (Continued)

The following factors and assumptions were used in determining the fair value of rights granted to key management personnel during the 2019 year:

GRANT DATE	EXPIRY DATE	FAIR VALUE PER RIGHT	EXERCISE PRICE	PRICE OF SHARES AT GRANT DATE	ESTIMATED VOLATILITY	RISK FREE INTEREST RATE	DIVIDEND YIELD
24 Sep 2018	22 May 2024	\$0.087	Nil	\$0.120	86%	2.33%	0.00%
02 Oct 2018[1]	Various	\$0.067	Nil	\$0.135	N/A	N/A	0.00%
22 Mar 2019[2]	10 Apr 2024	\$0.130	Nil	\$0.130	N/A	N/A	0.00%

1 *Adjustment to number of LTIP Rights for plan year commencing 1 July 2015 – valued at the market price of the known vesting %*

2 *STIP Rights fully vested on issue – valued at market price on issue*

The following factors and assumptions were used in determining the fair value of share rights granted during the 2018 year:

GRANT DATE	EXPIRY DATE	FAIR VALUE PER RIGHT	EXERCISE PRICE	PRICE OF SHARES AT GRANT DATE	ESTIMATED VOLATILITY	RISK FREE INTEREST RATE	DIVIDEND YIELD
01 Sep 2017	3 Oct 2022	\$0.081	Nil	\$0.115	87%	2.22%	0.00%
29 Nov 2017	18 Dec 2022	\$0.055	Nil	\$0.084	87%	2.09%	0.00%
27 Jun 2018	28 Jun 2023	\$0.102	Nil	\$0.150	87%	2.30%	0.00%

Table 3: Share Based Compensation – Share Rights Granted during the Year

		NUMBER OF RIGHTS GRANTED	GRANT DATE	AVERAGE FAIR VALUE AT GRANT DATE	AVERAGE EXERCISE PRICE PER RIGHT	EXPIRY DATE
Richard Cottee[1]	2019	183,540	02 Oct 18	\$0.067	\$0.000	09 Feb 21
	2018	1,835,910	29 Nov 17	\$0.055	\$0.000	18 Dec 22
	2018	18,319	29 Nov 17	\$0.084	\$0.000	18 Dec 22
Leon Devaney	2019	75,089	02 Oct 18	\$0.067	\$0.000	05 Jan 21
	2018	754,705	01 Sep 17	\$0.081	\$0.000	03 Oct 22
	2018	26,714	29 Sep 17	\$0.097	\$0.000	22 Sep 20
	2018	135,920	27 Jun 18	\$0.102	\$0.000	28 Jun 23
Ross Evans[2]	2019	778,854	24 Sep 18	\$0.087	\$0.000	22 May 24
	2018	—	—	—	—	—
Michael Herrington[3]	2019	891,413	24 Sep 18	\$0.087	\$0.000	22 May 24
	2019	89,187	02 Oct 18	\$0.067	\$0.000	05 Jan 21
	2018	892,835	01 Sep 17	\$0.081	\$0.000	03 Oct 22
	2018	38,222	29 Sep 17	\$0.097	\$0.000	22 Sep 20
Robin Polson[4]	2019	603,491	24 Sep 18	\$0.087	\$0.000	22 May 24
	2018	—	—	—	—	—
Daniel White	2019	804,984	24 Sep 18	\$0.087	\$0.000	22 May 24
	2019	83,464	22 Mar 19	\$0.130	\$0.000	10 Apr 24
	2019	73,843	02 Oct 18	\$0.067	\$0.000	05 Jan 21
	2018	736,319	01 Sep 17	\$0.081	\$0.000	03 Oct 22
	2018	31,647	29 Sep 17	\$0.097	\$0.000	22 Sep 20

1 *Richard Cottee ceased employment effective 31 January 2019.*

2 *Ross Evans commenced 1 June 2018.*

3 *Michael Herrington ceased employment effective 29 January 2019.*

4 *Robin Polson commenced 1 May 2018*

Remuneration Report (Continued)

Table 4: Share Based Compensation – Share Rights Vested during the Year

		MAXIMUM NUMBER OF RIGHTS ELIGIBLE FOR VESTING	LTIP YEAR COMMENCING	STIP YEAR COMMENCING	NUMBER OF RIGHTS VESTED[1]	PROPORTION OF LTIP RIGHTS VESTED[2]
Richard Cottee	2019	2,097,413	01 Jul 15	N/A	1,038,219	49.5%
	2018	209,350	01 Jul 14	N/A	104,675	50.0%
Leon Devaney	2019	858,089	01 Jul 15	N/A	424,754	49.5%
	2018	305,285	01 Jul 14	N/A	152,642	50.0%
Michael Herrington	2019	1,019,187	01 Jul 15	N/A	504,497	49.5%
	2018	436,793	01 Jul 14	N/A	218,396	50.0%
Daniel White	2019	843,843	01 Jul 15	N/A	417,702	49.5%
	2019	83,464	N/A	01 Jul 17	83,464	N/A
	2018	361,647	01 Jul 14	N/A	180,823	49.6%

1 *The number of rights that vested during the year relates to rights granted in prior financial years under the Long Term Incentive Plan or rights granted in respect of the Short Term Incentive Plan*

2 *The proportion of rights vested represents the proportion of the maximum number of rights that were eligible for vesting during the financial year under the Long Term Incentive Plan*

Table 5: Shareholdings of Key Management Personnel

		HELD AT BEGINNING OF YEAR	HELD AT DATE OF APPOINTMENT	SPP & ON MARKET PURCHASE	RECEIVED ON EXERCISE OF RIGHTS	NET CHANGE OTHER	HELD AT DATE OF DEPARTURE	HELD AT END OF YEAR
Non-Executive Directors								
Stuart Baker[1]	2019	N/A	—	—	—	—	N/A	—
	2018	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Julian Fowles[6]	2019	N/A	—	—	—	—	N/A	—
	2018	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Wrixon Gasteen	2019	293,337	N/A	—	—	—	N/A	293,337
	2018	136,473	N/A	156,864	—	—	N/A	293,337
Katherine Hirschfeld[1]	2019	N/A	200,000	—	—	—	N/A	200,000
	2018	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Robert Hubbard[2]	2019	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	2018	298,947	N/A	365,667	—	—	664,614	N/A
Martin Kriewaldt[3]	2019	1,100,000	N/A	—	—	—	N/A	1,100,000
	2018	N/A	200,000	900,000	—	—	N/A	1,100,000
Peter Moore[4]	2019	265,000	—	50,000	—	—	315,000	N/A
	2018	—	N/A	265,000	—	—	N/A	265,000
Sarah Ryan[3,4]	2019	105,000	N/A	100,000	—	—	205,000	N/A
	2018	N/A	—	105,000	—	—	N/A	105,000
Timothy Woodall[5]	2019	1,500,000	N/A	250,000	—	—	1,750,000	N/A
	2018	N/A	1,000,000	500,000	—	—	N/A	1,500,000

1 *Stuart Baker and Katherine Hirschfeld AM were appointed Directors 7 December 2018*

2 *Robert Hubbard retired 14 May 2018*

3 *Martin Kriewaldt and Sarah Ryan were appointed Directors 23 October 2017*

4 *Sarah Ryan and Peter Moore resigned 13 November 2018*

5 *Timothy Woodall was appointed Director 20 December 2017 and resigned 29 September 2018*

6 *Dr Fowles was appointed Director 28 June 2019*

Remuneration Report (Continued)

Table 5: Shareholdings of Key Management Personnel (continued)

		HELD AT BEGINNING OF YEAR	HELD AT DATE OF APPOINTMENT	SPP & ON MARKET PURCHASE	RECEIVED ON EXERCISE OF RIGHTS	NET CHANGE OTHER	HELD AT DATE OF DEPARTURE	HELD AT END OF YEAR
Executive Directors and Other Key Management Personnel								
Richard Cottee[6]	2019	889,933	N/A	—	—	(47,700)	842,233	N/A
	2018	571,829	N/A	216,929	104,675	(3,500)	N/A	889,933
Leon Devaney	2019	629,022	N/A	—	424,754	—	N/A	1,053,776
	2018	210,000	N/A	266,380	152,642	—	N/A	629,022
Ross Evans[7]	2019	—	N/A	—	—	—	N/A	—
	2018	N/A	—	—	—	—	N/A	—
Michael Herrington[8]	2019	572,564	N/A	—	504,497	—	1,077,061	N/A
	2018	250,000	N/A	104,168	218,396	—	N/A	572,564
Duncan Lockhart[9]	2019	N/A	—	—	—	—	N/A	—
	2018	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Robin Polson[10]	2019	—	—	—	—	—	N/A	—
	2018	N/A	—	—	—	—	N/A	—
Daniel White	2019	628,823	N/A	—	501,166	—	N/A	1,129,989
	2018	288,000	N/A	160,000	180,823	—	N/A	628,823
Total KMP	2019	5,983,679	200,000	400,000	1,430,417	(47,700)	4,189,294	3,777,102
	2018	1,755,249	1,200,000	3,040,008	656,536	(3,500)	664,614	5,983,679

7 Richard Cottee ceased employment effective 31 January 2019

8 Ross Evans commenced 1 June 2018

9 Michael Herrington ceased employment effective 29 January 2019

10 Duncan Lockhart commenced 8 April 2019

11 Robin Polson commenced 1 May 2018

Deferred Share Holdings of Key Management Personnel

Under the Group's Employee Rights Plan, eligible employees may receive rights to deferred shares of Central Petroleum Limited. The rights are granted in respect of a plan year which commences 1 July each year. The share rights remain unvested until the end of the performance period, which is three years commencing from the start of each plan year. Eligible employees must still be in the employment of Central Petroleum Limited as at the vesting date for the rights to vest.

Final vesting percentages are determined by a combination of performance hurdles in respect of a combination of absolute total shareholder return and relative total shareholder return compared to a specific group of exploration and production companies as determined by the Board (refer section E of this report).

The number of rights to be granted to eligible employees is determined based on the maximum long term incentive amount applicable for each employee, being either a fixed dollar amount or a percentage of the employee's base salary, divided by the volume weighted average share price ("VWAP") at the start of the plan year.

The maximum number of rights to ordinary shares in the Company under the long term incentive plan held during the financial year by other key management personnel of the Consolidated Entity, including their personally related parties, are set out below:

Remuneration Report (Continued)

Table 6: Deferred Share Holdings of Key Management Personnel

		NUMBER OF RIGHTS HELD AT START OF YEAR	MAXIMUM NUMBER GRANTED AS COMPENSATION	CANCELLED DURING THE YEAR	CONVERTED TO SHARES	RETAINED ON DEPARTURE	NUMBER OF RIGHTS HELD AT END OF YEAR (UNVESTED)
Executive Directors and Other Key Management Personnel							
Richard Cottee[1]	2019	6,952,766	183,540	(6,098,087)	—	1,038,219	N/A
	2018	5,307,887	1,854,229	(104,675)	(104,675)	N/A	6,952,766
Leon Devaney	2019	2,985,158	75,089	(433,335)	(424,754)	N/A	2,202,158
	2018	2,373,104	917,339	(152,643)	(152,642)	N/A	2,985,158
Ross Evans	2019	—	778,854	—	—	N/A	778,854
	2018	—	—	—	—	N/A	—
Michael Herrington[2]	2019	3,380,501	980,600	(1,870,478)	(504,497)	1,986,126	N/A
	2018	2,886,237	931,057	(218,397)	(218,396)	N/A	3,380,501
Robin Polson	2019	—	603,491	—	—	N/A	603,491
	2018	—	—	—	—	N/A	—
Daniel White	2019	2,795,985	962,291	(426,141)	(501,166)	N/A	2,830,969
	2018	2,389,666	767,966	(180,824)	(180,823)	N/A	2,795,985
Total	**2019**	**16,114,410**	**3,583,865**	**(8,828,041)**	**(1,430,417)**	**3,024,345**	**6,415,472**
	2018	12,956,894	4,470,591	(656,539)	(656,536)	—	16,114,410

1 *Richard Cottee ceased employment effective 31 January 2019*

2 *Michael Herrington ceased employment effective 29 January 2019.*

I. Executive Service Agreements

The details of service agreements of the key management personnel of the Consolidated Entity are as follows:

Leon Devaney, Managing Director & Chief Executive Officer

- The term of the agreement expires 1 July 2022.
- Mr Devaney's Total Fixed Remuneration is presently $612,061 per annum inclusive of compulsory superannuation contribution requirements.
- In order to terminate employment, a 6 month period of notice is required by either party, except in certain exceptional circumstances (such as breach or gross misconduct) where a shorter time applies.

Ross Evans, Chief Operations Officer

- The term of the agreement expires 1 December 2022.
- Mr Evan's Total Fixed Remuneration is presently $500,403 per annum inclusive of compulsory superannuation contribution requirements.
- In order to terminate employment, a 6-month period of notice is required by either party, except in certain exceptional circumstances (such as breach or gross misconduct) where a shorter time applies.

Duncan Lockhart, General Manager Exploration (commenced 8 April 2019)

- The term of the agreement expires 8 July 2022.
- Dr Lockhart's Total Fixed Remuneration is presently $400,000 per annum inclusive of compulsory superannuation contribution requirements.
- In order to terminate employment, a 6 month period of notice is required by either party, except in certain exceptional circumstances (such as breach or gross misconduct) where a shorter time applies.

Remuneration Report (Continued)

Robin Polson, Chief Commercial Officer

- The term of the agreement expires 1 October 2022.
- Mr Polson's Total Fixed Remuneration is presently $335,131 per annum inclusive of compulsory superannuation contribution requirements.
- In order to terminate employment, a 6-month period of notice is required by either party, except in certain exceptional circumstances (such as breach or gross misconduct) where a shorter time applies.

Daniel White, Group General Counsel and Company Secretary

- The term of the agreement expires 30 November 2021.
- Mr White's Total Fixed Remuneration is presently $444,081 per annum inclusive of compulsory superannuation contribution requirements.
- In order to terminate employment, a 3-month period of notice is required by either party, except in certain exceptional circumstances (such as breach or gross misconduct) where a shorter time applies.

J. Non-Executive Director Fee Arrangements

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

The table below summarises the Non-Executive Director fees for 2019.

BOARD FEES (PER ANNUM)	
Chairman	$130,000
Non-Executive Director	$70,000

COMMITTEE FEES (PER ANNUM)		
Audit	Chair	$10,000
	Member	$5,000
Community Affairs	Chair	$10,000
	Member	$5,000
Remuneration & Nominations	Chair	$10,000
	Member	$ 5,000
Risk	Chair	$10,000
	Member	$5,000

The directors also receive superannuation benefits in accordance with legislative requirements.

Signed in accordance with a resolution of the directors:

Wrixon Gasteen
Chairman

25 September 2019

pwc

Auditor's Independence Declaration

As lead auditor for the audit of Central Petroleum Limited for the year ended 30 June 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 audit; and

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

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

Tim Allman
Partner
PricewaterhouseCoopers

Brisbane
25 September 2019

PricewaterhouseCoopers, ABN 52 780 433 757
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FINANCIAL REPORT

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

The Financial Statements are presented in Australian currency.

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

Level 7, 369 Ann Street
Brisbane, Queensland 4000

A description of the nature of the Consolidated Entity's operations and its principal activities is included in the review of operations and activities which forms part of the Directors' Report on pages 4 to 41. These pages are not part of these financial statements.

The financial statements were authorised for issue by the Directors on 25 September 2019. The Directors have the power to amend and reissue the financial statements.

Through the use of the internet we have ensured that our corporate reporting is timely and complete. Press releases, financial reports and other information are available via the links on our website: www.centralpetroleum.com.au.

CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME

FOR THE YEAR ENDED 30 JUNE 2019

	NOTE	2019 $	2018 $
Revenue from contracts with customers – sale of hydrocarbons	2	59,357,758	34,939,194
Cost of sales		(30,369,092)	(18,704,042)
Gross profit		28,988,666	16,235,152
Other income	3	384,728	1,055,184
Share based employment benefits	32(d)	(601,897)	(1,622,329)
General and administrative expenses		(1,031,636)	(595,925)
Depreciation and amortisation	4(a)	(12,695,238)	(8,033,092)
Employee benefits and associated costs		(5,194,131)	(4,061,759)
Exploration expenditure		(15,802,075)	(8,790,052)
Finance costs	4(a)	(8,574,831)	(8,263,308)
Loss before income tax		**(14,526,414)**	**(14,076,129)**
Income tax credit	5	—	—
Loss for the year		**(14,526,414)**	**(14,076,129)**
Other comprehensive loss for the year, net of tax		—	—
Total comprehensive loss for the year		**(14,526,414)**	**(14,076,129)**
Total comprehensive loss attributable to members of the parent entity		**(14,526,414)**	**(14,076,129)**
Basic and diluted loss per share (cents)	**22**	**(2.05)**	**(2.13)**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION
AS AT 30 JUNE 2019

	NOTE	2019 $	2018 $
ASSETS			
Current assets			
Cash and cash equivalents	7	17,805,869	27,222,845
Trade and other receivables	8	9,060,155	6,631,642
Inventories	9	2,719,526	3,575,480
Other financial assets	13	—	2,333,333
Total current assets		29,585,550	39,763,300
Non-current assets			
Property, plant and equipment	10	123,475,413	103,853,369
Exploration assets	11	8,898,767	8,898,767
Intangible assets	12	113,365	156,017
Other financial assets	13	2,770,782	2,535,915
Goodwill	14	3,906,270	3,906,270
Total non-current assets		139,164,597	119,350,338
Total assets		**168,750,147**	**159,113,638**
LIABILITIES			
Current liabilities			
Trade and other payables	15	6,006,532	8,113,667
Deferred revenue	2(b)	6,752,568	7,283,068
Interest-bearing liabilities	16	10,956,896	3,727,338
Other financial liabilities	18	2,025,014	38,600
Provisions	17	5,375,799	3,406,515
Total current liabilities		31,116,809	22,569,188
Non-current liabilities			
Deferred revenue	2(b)	15,559,186	13,678,980
Interest-bearing liabilities	16	70,773,157	74,599,221
Other financial liabilities	18	13,823,493	15,362,506
Provisions	17	43,094,230	25,840,435
Total non-current liabilities		143,250,066	129,481,142
Total liabilities		**174,366,875**	**152,050,330**
Net assets		**(5,616,728)**	**7,063,308**
EQUITY			
Contributed equity	19	197,776,487	197,776,487
Reserves	20	25,310,162	23,463,784
Accumulated losses	21	(228,703,377)	(214,176,963)
Total equity		**(5,616,728)**	**7,063,308**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
FOR THE YEAR ENDED 30 JUNE 2019

	CONTRIBUTED EQUITY $	RESERVES $	ACCUMULATED LOSSES $	TOTAL $
Balance at 1 July 2017	**172,301,532**	**21,841,455**	**(200,100,834)**	**(5,957,847)**
Total loss for the year	—	—	(14,076,129)	(14,076,129)
Other comprehensive loss	—	—	—	—
Total comprehensive loss for the year	—	—	(14,076,129)	(14,076,129)
Transactions with owners in their capacity as owners				
Share based payments	—	1,622,329	—	1,622,329
Share and option issues	27,250,000	—	—	27,250,000
Share issue costs	(1,775,045)	—	—	(1,775,045)
	25,474,955	1,622,329	—	27,097,284
Balance at 30 June 2018	**197,776,487**	**23,463,784**	**(214,176,963)**	**7,063,308**
Total loss for the year	—	—	(14,526,414)	(14,526,414)
Other comprehensive loss	—	—	—	—
Total comprehensive loss for the year	—	—	(14,526,414)	(14,526,414)
Transactions with owners in their capacity as owners				
Share based payments	—	601,897	—	601,897
Options issued for financing	—	1,244,481	—	1,244,481
	—	1,846,378	—	1,846,378
Balance at 30 June 2019	**197,776,487**	**25,310,162**	**(228,703,377)**	**(5,616,728)**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CASH FLOWS

FOR THE YEAR ENDED 30 JUNE 2019

	NOTE	2019 $	2018 $
Cash flows from operating activities			
Receipts from customers		58,924,286	39,285,428
Interest received		372,705	494,077
Other income		26,044	25,660
Interest and borrowing costs		(6,452,096)	(5,987,298)
Payments for exploration expenditure		(18,106,028)	(5,250,936)
Payments to other suppliers and employees		(32,299,549)	(23,393,701)
Net cash inflow from operating activities	28	2,465,362	5,173,230
Cash flows from investing activities			
Payments for property, plant and equipment		(17,481,804)	(2,999,815)
Proceeds from sale of property, plant and equipment		—	33,636
Proceeds and deposits for the disposal of exploration permits		—	430,000
Redemption/(Acquisition) of security deposits and bonds		2,098,466	(2,367,302)
Net cash outflow from investing activities		(15,383,338)	(4,903,481)
Cash flows from financing activities			
Proceeds from the issue of shares and options		—	27,250,000
Payments for capital raising costs		—	(1,775,044)
Proceeds from borrowings and other financing arrangements		17,500,000	—
Repayment of borrowings	29	(13,999,000)	(4,000,000)
Net cash inflow from financing activities		3,501,000	21,474,956
Net (decrease)/increase in cash and cash equivalents		**(9,416,976)**	**21,744,705**
Cash and cash equivalents at the beginning of the financial year		**27,222,845**	**5,478,140**
Cash and cash equivalents at the end of the financial year	7	**17,805,869**	**27,222,845**

The accompanying notes form part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

(a) Basis of Preparation

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

(i) Going Concern

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

The Group incurred a net loss for the year of $14,526,414, had a net positive cash flow from operations of $2,465,362 and had an overall net current liability position at 30 June 2019 of $1,531,259. The net current liabilities include $6,752,568 of deferred revenue which will not crystallise into a cash outflow and a further $1,986,414 relates to a financial liability which will either be settled by the physical delivery of gas or be satisfied from the proceeds of selling that gas under existing or future gas sales agreements (Note 4(b)). 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 30 June 2019 of $17,805,869, and expected operating cashflows, 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. To date the Group has been successful in funding new projects through a combination of borrowings, gas presales, farmouts and equity from new and existing shareholders. The following matters have also been considered by the Directors in determining the appropriateness of the going concern basis of preparation in the financial statements:

i. The Group's existing debt facilities are due to mature on 30 September 2020. The Group has received a number of term sheets from potential financiers and is in the process of assessing the proposals. Management and the Board are confident new arrangements will be in place before expiry of the current facility; and

ii. The Company has access to a $10 million Equity Line of Credit with Long State Investment Limited (refer Note 19(f)).

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

(ii) Compliance with IFRS

The consolidated financial statements of the Central Petroleum Limited Group also comply with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board ("IASB").

(iii) Early Adoption of Standards

The Group has not applied any pronouncements to the annual reporting period beginning on 1 July 2018 where such application would result in them being applied prior to them becoming mandatory.

(iv) Historical Cost Convention

These financial statements have been prepared under the historical cost convention.

(v) Critical Accounting Judgements and Key Sources of Estimate Uncertainty

In the application of the Group's accounting policies, management is required to make judgements, estimates and assumptions regarding carrying values of assets and liabilities that are not readily apparent from other sources. The estimates and assumptions are based on historical experience and various other factors that are believed to be reasonable under the circumstances, the results of which form the basis of making the judgements. Actual results may differ from these estimates. Key judgements in applying the entity's accounting policies are required in the following areas:

Rehabilitation

The Group recognises any obligations for removal and restoration that are incurred during a particular period as a consequence of having undertaken exploration and evaluation activity. The Group makes provision for future restoration expenditure relating to work previously undertaken based on management's estimation of the work required.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(a) Basis of Preparation (continued)

(v) Critical Accounting Judgements and Key Sources of Estimate Uncertainty (continued)

Share-based Payments

The Group is required to use assumptions in respect of its fair value models, and the variable elements in these models, used in attributing a value to share based payments. The Directors have used a model to value options and rights, which requires estimates and judgements to quantify the inputs used by the model.

Impairment of Capitalised Exploration and Evaluation Expenditure

The future recoverability of capitalised exploration and evaluation expenditure is dependent on a number of factors, including whether the Group decides to exploit the lease itself or, if not, whether it successfully recovers the related exploration and evaluation expenditure through sale. Factors that impact recoverability may include, but are not limited to, the level of resources and reserves, the cost of production, legal changes and commodity price changes. Acquisition expenditure is capitalised if activities in the area of interest have not yet reached a stage that permits a reasonable assessment of the existence or otherwise of economically recoverable reserves. To the extent that the capitalised acquisition expenditure is determined not to be recoverable in future, profits and net assets will be reduced in the period in which this determination is made.

Impairment of Other Non-financial Assets

Other non-financial assets, including property, plant and equipment and goodwill are tested for impairment annually or whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows which are largely independent of the cash inflows from other assets or groups of assets (cash-generating units). The Group is required to use assumptions in respect of future commodity prices, foreign exchange rates, interest rates and operating costs in determining expected future cash flows from operations.

Other Financial Liabilities

The group may be required to use assumptions in respect of expected future gas prices in respect of gas sales agreements that contain a financial settlement option. The expected future financial settlements reference expected future gas sales volumes and prices and the terms of individual agreements (refer to Note 18 for further details).

Taxation

The Group's accounting policy for taxation requires management's judgement in relation to the types of arrangements considered to be a tax on income in contrast to an operating cost. Judgement is also made in assessing whether deferred tax assets and certain deferred tax liabilities are recognised on the Consolidated Statement of Financial Position. Deferred tax assets, including those arising from un-recouped tax losses, capital losses, are recognised only where it is considered more likely than not they will be recovered, which is dependent on the generation of sufficient future taxable profits.

Judgements are also required about the application of income tax legislation. These judgements and assumptions are subject to risk and uncertainty, hence there is a possibility changes in circumstances will alter expectation, which may impact the amount of deferred tax assets and deferred tax liabilities recognised on the Consolidated Statement of Financial Position and the amount of other tax losses and temporary differences not yet recognised. In such circumstances, some or all of the carrying amounts of recognised deferred tax assets and liabilities may require adjustment, resulting in a corresponding credit or charge to the Consolidated Statement of Comprehensive Income.

(b) Principles of Consolidation

(i) Subsidiaries

The consolidated financial statements incorporate the assets and liabilities of all subsidiaries of Central Petroleum Limited ("the Company" or "Parent Entity") as at 30 June and the results of all subsidiaries for the year then ended. Central Petroleum Limited and its subsidiaries together are referred to in this financial report as "the Group" or "the Consolidated Entity".

Subsidiaries are all entities (including structured entities) over which the group has control. The group controls an entity when the group is exposed to, or has rights to, variable returns from its involvement with the entity and has the ability to affect those returns through its power to direct the activities of the entity. Subsidiaries are fully consolidated from the date on which control is transferred to the group.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(b) Principles of Consolidation (continued)

(i) Subsidiaries (continued)

They are deconsolidated from the date that control ceases. The acquisition method is used to account for business combinations by the Group.

Intercompany transactions, balances and unrealised gains on transactions between Group companies are eliminated. Unrealised losses are also eliminated unless the transaction provides evidence of the impairment of the asset transferred. Accounting policies of subsidiaries have been changed where necessary to ensure consistency with the policies adopted by the Group.

Non-controlling interests (if applicable) in the results and equity of subsidiaries are shown separately in the statement of comprehensive income, statement of changes in equity and statement of financial position respectively.

(ii) Joint Arrangements

The Group's investments in joint arrangements are classified as either joint operations or joint ventures; depending on the contractual rights and obligations each investor has, rather than the legal structure of the joint arrangement.

The Group's exploration and production activities are conducted through joint arrangements governed by joint operating agreements or similar contractual relationships.

A joint operation involves the joint control, and often the joint ownership, of one or more assets contributed to, or acquired for the purpose of, the joint operation and dedicated to the purposes of the joint operation. The assets are used to obtain benefits for the parties to the joint operation. Each party may take a share of the output from the assets and each bears an agreed share of expenses incurred. Each party has control over its share of future economic benefits through its share of the joint operation. The interests of the Group in joint operations are brought to account by recognising in the financial statements the Group's share of jointly controlled assets, share of expenses and liabilities incurred, and the income from the sale or use of its share of the production of the joint operation in accordance with the revenue policy in Note 1(e). Details of the joint operations are set out in Note 34.

(c) Segment Reporting

Operating segments are reported in Note 23 in a manner consistent with the internal reporting provided to the chief operating decision maker. The chief operating decision maker, who is responsible for allocating resources and assessing performance of the operating segments, has been identified as the Executive Management Team.

(d) Foreign Currency Translation

(i) Functional and Presentation Currency

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

(ii) Transactions and Balances

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

(e) Revenue Recognition

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(e) Revenue Recognition (continued)

(i) Revenue from the sale of hydrocarbons

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

(ii) Farmouts and terminations outside the exploration phase

Farmouts outside the exploration phase are accounted for by derecognition of the proportion of the asset disposed of, and recognition of the consideration received or receivable from the farmee. A gain or loss is recognised for the difference between the net disposal proceeds and the carrying value of the asset disposed. Consideration is initially recognised at fair value or the cash price equivalent where payment is deferred. Interest revenue is recognised for the difference between the nominal amount of the consideration and the cash price equivalent.

(iii) Contract Liabilities

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

(iv) Interest Income

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

(f) Government Grants

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

(g) Income Tax

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

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

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

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

Deferred tax liabilities are not recognised if they arise from the initial recognition of goodwill. Deferred tax is also not accounted for if it arises from initial recognition of an asset or liability in a transaction other than a business combination that, at the time of the transaction, affects neither accounting nor taxable profit or loss. Deferred income tax is determined using tax rates (and laws) that have been enacted or substantially enacted by the end of the reporting period and are expected to apply when the related deferred income tax asset is realised, or the deferred income tax liability is settled.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(g) Income Tax (continued)

Deferred tax assets and liabilities are offset when there is a legally enforceable right to offset current tax assets and liabilities and when the deferred tax balances relate to the same taxation authority. Current tax assets and tax liabilities are offset where the entity has a legally enforceable right to offset and intends either to settle on a net basis, or to realise the asset and settle the liability simultaneously.

(h) Leases

Leases of property, plant and equipment where the Group, as lessee, has substantially all the risks and rewards of ownership are classified as finance leases. Finance leases are capitalised at the lease's inception at the fair value of the leased property or, if lower, the present value of the minimum lease payments. The corresponding rental obligations, net of finance charges, are included in other short-term and long-term payables. Each lease payment is allocated between the liability and finance cost. The finance cost is charged to the 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 property, plant and equipment acquired under finance leases is depreciated over the asset's useful life or over the shorter of the asset's useful life and the lease term if there is no reasonable certainty that the Group will obtain ownership at the end of the lease term.

Capitalised leased assets are depreciated over the shorter of the estimated useful life of the asset and the lease term if there is no reasonable certainty that the Consolidated Entity will obtain ownership by the end of the lease term.

Leases in which a significant portion of the risks and rewards of ownership are not transferred to the Group as lessee are classified as operating leases (Note 31(c)). Payments made under operating leases (net of any incentives received from the lessor) are charged to profit or loss on a straight-line basis over the period of the lease.

(i) Impairment of Assets

Goodwill and intangible assets that have an indefinite useful life are not subject to amortisation and are tested annually for impairment, or more frequently if events or changes in circumstances indicate that they might be impaired. Other assets are tested for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognised for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value less costs to sell and value in use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows which are largely independent of the cash inflows from other assets or groups of assets (cash-generating units). Non-financial assets other than goodwill that suffered impairment are reviewed for possible reversal of the impairment at the end of each reporting period.

(j) Cash and Cash Equivalents

For the purpose of presentation in the statement of cash flows, cash and cash equivalents includes cash on hand, deposits held at call with financial institutions, other short-term, highly liquid investments with original maturities of 3-months or less that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value, and bank overdrafts. Bank overdrafts (if applicable) are shown within borrowings in current liabilities in the statement of financial position.

(k) Trade Receivables

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

The Group considers an allowance for expected credit losses (ECLs) for all receivables. The Group applies a simplified approach in calculating ECLs which is based on an assessment on its historical credit loss experience, adjusted for factors specific to the debtors and the economic environment. This includes, but is not limited to, financial difficulties of the debtor, probability that the debtor will enter bankruptcy or financial reorganisation and delinquency in payments.

Information about the impairment of trade receivables and the group’s exposure to credit risk, foreign currency risk and interest rate risk can be found in Note 33.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(l) Inventories

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

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

(m) Other Financial Assets

Classification

The Group's financial assets consist of receivables and security deposits. These are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. They are included in current assets, except for those with maturities greater than 12-months after the reporting period which are classified as non-current assets. Receivables are included in trade and other receivables (Note 8) in the statement of financial position. Amounts paid as performance bonds or amounts held as security for bank guarantees in satisfaction of performance bonds are classified as other financial assets (Note 13).

Measurement

At initial recognition, the Group measures a financial asset at its fair value plus, in the case of a financial asset not at fair value through profit or loss, transaction costs that are directly attributable to the acquisition of the financial asset. Transaction costs of financial assets carried at fair value through profit or loss are expensed in profit or loss. Loans and receivables are subsequently carried at amortised cost using the effective interest method.

The Group considers an allowance for expected credit losses (ECLs) for its financial assets. The Group applies a simplified approach in calculating ECLs which is based on an assessment on its historical credit loss experience, adjusted for factors specific to the counterparty and the economic environment.

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

Assets in Development

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

Producing Assets

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

Depreciation of producing assets is calculated using the units of production method for an asset or group of assets from the date of commencement of production. Depletion charges are calculated using the units of production method which will amortise the cost of carried forward exploration, evaluation, subsurface development expenditure ("subsurface assets") and capitalised restoration costs over the life of the estimated Proven plus Probable (2P) hydrocarbon reserves for an asset or group of assets, together with future subsurface costs necessary to develop the hydrocarbon reserves included in the calculation.

(o) Property, Plant and Equipment – Other than Development and Production Assets

All property, plant and equipment is stated at historical cost less depreciation. Historical cost includes expenditure that is directly attributable to the acquisition of the items. Cost may also include transfers from equity of any gains or losses on qualifying cash flow hedges of foreign currency purchases of property, plant and equipment.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(o) Property, Plant and Equipment – Other than Development and Production Assets (continued)

Subsequent costs are included in the asset's carrying amount or recognised as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably. The carrying amount of any component accounted for as a separate asset is derecognised when replaced. All other repairs and maintenance costs are charged to profit or loss during the reporting period in which they are incurred.

Land is not depreciated. Depreciation of plant and equipment is calculated on a reducing balance basis so as to write off the net costs of each asset over the expected useful life. The assets' residual values and useful lives are reviewed, and adjusted if appropriate, at each statement of financial position date.

An asset's carrying amount is written down immediately to its recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount. Gains and losses on disposals are determined by comparing proceeds with the carrying amount. These are included in the profit or loss.

The expected useful life for each class of depreciable assets is:

Class of Fixed Asset	Expected Useful Life
Buildings	40 years
Leasehold Improvements	2 – 6 years
Plant and Equipment	2 – 30 years
Motor Vehicles	5 – 10 years

(p) Exploration Expenditure

Exploration and evaluation costs are expensed as incurred. Acquisition costs of rights to explore are capitalised in respect of each separate area of interest and carried forward where right of tenure of the area of interest is current. These costs are expected to be recouped through sale or successful development and exploitation of the area of interest or where exploration and evaluation activities in the area of interest have not yet reached a stage that permits reasonable assessment of the existence of economically recoverable reserves. No amortisation is charged on acquisition costs capitalised under this policy.

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

(q) Goodwill

Goodwill arising on the acquisition of subsidiaries is not amortised but it is tested for impairment annually, or more frequently if events or changes in circumstances indicate a potential impairment. Goodwill is carried at cost less accumulated impairment losses.

Goodwill is allocated to cash generating units for the purpose of impairment testing. The allocation is made to those cash-generating units or groups of cash-generating units that are expected to benefit from the business combination in which the goodwill arose. The units or groups of units are identified at the lowest level at which goodwill is monitored for internal management purposes, being the operating segments (Note 23).

(r) Trade and Other Payables

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(s) Provisions

(i) Restoration

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

A restoration provision is recognised and updated at different stages of the development and construction of a facility and then reviewed on an annual basis. When the liability is initially recorded, the estimated cost is capitalised by increasing the carrying amount of the related exploration and evaluation assets or property plant and equipment. Over time, the liability is increased for the change in the present value based on a pre-tax discount rate appropriate to the risks inherent in the liability. The unwinding of the discount is recorded as an accretion charge within finance costs.

The carrying amount capitalised in property plant and equipment is depreciated over the useful life of the related producing asset (refer to Note 1(n)).

Costs incurred that relate to an existing condition caused by past operations and do not have a future economic benefit are expensed.

(ii) Onerous Contracts

An Onerous Contracts provision is recognised where the unavoidable costs of meeting obligations under the contract exceeds the value of the economic benefits expected to be received under the contract.

(iii) Other

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

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

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

(t) Employee Benefits

(i) Short-term Obligations

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

(ii) Other Long-term Employee Benefit Obligations

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

(iii) Share-based Payments

Share-based compensation benefits are provided to employees by Central Petroleum Limited.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(t) Employee Benefits (continued)

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

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

(iv) Termination Benefits

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

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

(u) Contributed Equity

Ordinary shares are classified as equity.

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

(v) Dividends

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

(w) Earnings Per Share

(i) Basic Earnings Per Share

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

(ii) Diluted Earnings Per Share

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

(x) Goods and Services Tax (GST)

Revenues, expenses and assets are recognised net of the amount of GST, unless the GST incurred is not recoverable from the taxation authority. In this case it is recognised as part of the cost of acquisition of the asset or as part of the expense.

Receivables and payables are stated inclusive of the amount of GST receivable or payable. The net amount of GST recoverable from, or payable to, the taxation authority is included with other receivables or payables in the statement of financial position.

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(y) Parent Entity Financial Information

The financial information for the Parent Entity, Central Petroleum Limited, disclosed in Note 24, has been prepared on the same basis as the consolidated financial statements except as set out below.

(i) Investments in Subsidiaries, Associates and Joint Venture Entities

Investments in subsidiaries, associates and joint venture entities are accounted for at cost in the financial statements of Central Petroleum Limited.

(z) Business Combinations

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

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

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

Acquisition related costs are expensed as incurred.

The excess of the:

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

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

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

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

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

(aa) Standards, Amendments and Interpretations

(i) 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 2018.

(a) AASB 15 Revenue from contracts with customers

AASB 15 establishes a comprehensive framework for determining whether, how much, and when revenue is recognised. AASB 15 establishes a five-step model to be applied to all contracts with customers. The new standard is based on the principle that revenue is recognised when control of a good or service transfers to a customer. The Group has adopted AASB 15 from 1 July 2018

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

(aa) Standards, Amendments and Interpretations (continued)

(i) New and Amended Standards Adopted by the Group *(continued)*

The Group undertook a detailed review of its revenue contracts and concluded that there were no adjustments required to net profit or opening retained earnings on transition. The Group has applied the practical expedient in paragraph 121 of AASB 15 and does not disclose information on the transaction price allocated to performance obligations that are unsatisfied.

The Group does not currently enter into any gas swap arrangements nor is it in any "under-lift" position which may impact revenue recognition.

(b) 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 was mandatory for the Group from 1 July 2018.

The Group has undertaken an assessment of the changes and concluded that there is no material 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 requires recognition of an allowance for ECLs for all debt instruments not held at fair value through profit or loss and contract assets recognised under AASB 15. As the Group's trade receivables are short term and relate to credit worthy customers and Joint Venture partners, the change to a forward looking ECL approach did not have a material impact on the amounts recognised in the financial statements.

(ii) New Standards and Interpretations not yet adopted

(a) AASB 16 Leases

AASB 16 was issued in February 2016. It will result in almost all leases being recognised on the balance sheet by lessees, 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.

Impact

Management has reviewed all of the group's leasing arrangements over the last year in light of the new lease accounting rules in AASB 16. The standard will affect the accounting for the group's operating leases. As at the reporting date, the group has non-cancellable operating lease commitments of $1,898,431, see Note 31(c). Of these commitments, approximately $30,295 relate to short-term leases which will be recognised on a straight-line basis as expense in profit or loss.

For the remaining lease commitments, the group expects to recognise right-of-use assets of approximately $1,475,000 on 1 July 2019, and lease liabilities of $1,615,000 (after adjustments for prepayments and accrued lease payments recognised as at 30 June 2019). Unrecognised deferred tax assets will amount to $42,000. Overall net assets will be approximately $140,000 lower, and net current assets will be $532,000 lower due to the presentation of a portion of the liability as a current liability.

The group expects that net profit after tax will increase by approximately $19,000 for 2020 as a result of adopting the new rules. EBITDA/EBITDAX used to measure segment results is expected to increase by approximately $628,000, as the operating lease payments were included in EBITDA, but the amortisation of the right-of-use assets and interest on the lease liability are excluded from this measure.

Operating cash flows will increase, and financing cash flows decrease by approximately $532,000 as repayment of the principal portion of the lease liabilities will be classified as cash flows from financing activities.

The group does not act as a lessor.

Mandatory application date

The group will apply the standard from its mandatory adoption date of 1 July 2019. The group intends to apply the simplified transition approach and will not restate comparative amounts for the year prior to first adoption. Right-of-use assets will be measured on transition as if the new rules had always been applied.

2. REVENUE FROM CONTRACTS WITH CUSTOMERS

(a) Revenue from contracts with customers

	2019 $	2018 $
Sale of hydrocarbon products - point in time		
Natural gas	49,657,736	25,458,550
Crude oil and condensate	9,700,022	9,480,644
Total revenue from contracts with customers	**59,357,758**	**34,939,194**

Revenue relating to contracts with Major Customers is disclosed in Note 23 – Segment Reporting

(b) Contract Liabilities

	2019 $	2018 $
Current		
Deferred Revenue – take or pay contracts[1]	2,714,334	2,714,334
Deferred Revenue – other gas sales contracts[2]	4,038,234	4,568,734
Total current contract Liabilities	**6,752,568**	**7,283,068**
Non-current		
Deferred Revenue – take or pay contracts[1]	15,559,186	10,381,732
Deferred Revenue – other gas sales contracts[2]	—	3,297,248
Total non-current contract liabilities	**15,559,186**	**13,678,980**
Deferred Revenue		
Revenue recognised that was included in the deferred revenue balances at the beginning of the period	**3,827,748**	—
Revenue recognised during the year for gas forfeited under take or pay contracts not in deferred revenue balances at the beginning of the period	**46,807**	**90,950**

1 *Take or Pay proceeds 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*

2 *In June 2018 Macquarie Bank novated its rights and obligations under the First Contract Year of the MBL Gas Sale and Prepayment Agreement (refer Note 18), to Incitec Pivot Limited ("IPL") through a new Gas Sale Agreement. There was no cash settlement option under the novation. This resulted in $7,865,982 being transferred from Other Financial Liabilities to Deferred Revenue. Revenue is recognised as gas is delivered to IPL.*

3. OTHER INCOME

	2019 $	2018 $
Interest	360,058	525,109
Sale of exploration permits	—	280,000
Profit on disposal of inventory and other assets	—	224,415
Other income	24,670	25,660
Total other income	**384,728**	**1,055,184**

4. EXPENSES

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

	NOTE	2019 $	2018 $
Depreciation			
Buildings		350,203	350,202
Producing assets		7,851,021	3,657,662
Plant and equipment		4,394,912	3,950,098
Leasehold improvements		39,602	33,414
Total depreciation		12,635,738	7,991,376
Amortisation			
Software		59,500	41,716
Rental expense relating to operating leases – Minimum lease payments		735,845	609.396
Finance costs			
Interest charge on debt facilities		6,466,119	6,003,851
Interest on other financial liabilities		649,787	938,119
Revaluation of financial liabilities	4(b)	(163,786)	414,431
Amortisation of deferred finance costs		1,132,952	393,147
Accretion charge		489,759	513,760
		8,574,831	8,263,308

(b) Individually significant items

Revaluation of financial liabilities

In 2016 the Group entered into a Gas Sale and Prepayment Agreement ("GSPA") with Macquarie Bank Limited ("MBL"), to commence following completion of the Northern Gas Pipeline. Under the agreement Macquarie may elect to receive a financial settlement in lieu of taking physical delivery of gas. The financial settlement amount, if so elected, is dependent on the ex-field price received by the Group under any new gas sales agreements from the designated production area. In June 2018 MBL novated its rights under the first year of the GSPA to Incitec Pivot Limited (refer also Note 18). As a result, the first year obligations will be satisfied by physical delivery of gas. For subsequent years it will be satisfied by either the physical delivery of gas or paid out of the proceeds of the sale of gas contracted under the GSA's for which no asset has been recognised in the accounts.

The value of the financial liability is adjusted to reflect the latest pricing and quantity assumptions of the underlying agreements, which impact either the timing or amount of any potential financial settlement.

5. INCOME TAX

This note provides an analysis of the Group's income tax expense, shows what amounts are recognised directly in equity and how the tax credit is affected by non-assessable and non-deductible items. It also explains significant estimates made in relation to the Group's tax position.

	2019 $	2018 $
(a) Income tax expense		
Current tax	–	–
Deferred tax	–	–
Income tax expense	–	–
(b) Numerical reconciliation of income tax expense and prima facie tax benefit		
Loss before income tax expense	(14,526,414)	(14,076,129)
Prima facie tax benefit at 30% (2018: 30%)	4,357,924	4,222,839
Tax effect of amounts which are not deductible in calculating taxable income:		
Non-deductible expenses	(341,648)	(309,262)
Share based payments	(180,569)	(486,699)
Other items	(1,666)	1,181
Sub-total	3,834,041	3,428,059
Deferred tax assets not recognised	(3,834,041)	(3,428,059)
Income tax expense	–	–
(c) Amounts recognised directly in equity		
Aggregate deferred tax arising in the reporting period and not recognised in net profit or loss or other comprehensive income but directly debited or credited to equity:		
Net deferred tax – debited directly to equity	–	532,514
Deferred tax assets not recognised	–	(532,514)
Net amounts recognised directly in equity	–	–
(d) Tax Losses		
Unutilised tax losses for which no deferred tax asset has been recognised	127,224,588	131,114,647
Potential tax benefit at 30%	38,167,376	39,334,394

Unutilised tax losses are available for use in Australia and are available to offset future taxable profits of the income tax consolidated group, subject to the relevant tax loss recoupment requirements being met.

5. INCOME TAX (CONTINUED)

(e) Deferred tax assets and liabilities

	2019 $	2018 $
Deferred tax assets		
Provisions and accruals	14,643,493	8,875,664
Financial liabilities	2,384,250	2,238,662
Deferred revenue	609,642	1,187,294
Blackhole expenditure	569,299	848,653
Borrowing costs	38,251	51,121
PRRT[1]	—	244,162,165
Unutilised losses	52,621,107	49,740,525
Total deferred tax assets before set-offs	70,866,042	307,104,084
Set-off of deferred tax liabilities pursuant to set-off provisions	(14,453,731)	(13,916,012)
Net deferred tax assets not recognised	**56,412,311**	**293,188,072**
Movements in deferred tax assets		
Opening balance at 1 July	13,916,012	12,050,541
(Charged) / Credited to the income statement	537,719	1,865,471
Closing balance at 30 June	14,453,731	13,916,012
Deferred tax assets to be recovered after more than 12-months	11,555,623	12,060,386
Deferred tax assets to be recovered within 12-months	2,898,108	1,855,626
	14,453,731	13,916,012
Deferred tax liabilities		
Accrued income	11,274	12,061
Capitalised exploration	476,254	463,254
Property, plant and equipment	13,966,203	9,930,815
PRRT[1]	—	3,509,882
Total deferred tax liabilities before set-offs	14,453,731	13,916,012
Set-off of deferred tax assets pursuant to set-off provisions	(14,453,731)	(13,916,012)
Net deferred tax liabilities	**—**	**—**
Movements in deferred tax liabilities		
Opening balance at 1 July	13,916,012	12,050,541
Charged / (Credited) to the income statement	537,719	1,865,471
Closing balance at 30 June	14,453,731	13,916,012
Deferred tax liabilities to be recovered after more than 12-months	14,442,457	13,903,950
Deferred tax liabilities to be recovered within 12-months	11,274	12,062
	14,453,731	13,916,012

1 *In April 2019 The Treasury Laws Amendment (2019 Petroleum Resource Rent Tax Reforms No. 1) Bill 2019 received Royal Assent, removing onshore petroleum projects from the scope of Petroleum Resource Rent Tax (PRRT) from 1 July 2019. The Group does not have any offshore Petroleum Projects subject to PRRT.*

5. INCOME TAX (CONTINUED)

(f) Other tax related matters

In July 2018 the Consolidated Entity submitted objections in respect of its income tax assessments for the income years ended 30 June 2013 to 30 June 2016 inclusive. The objections relate to Research & Development Tax offsets and the treatment of Farmout Arrangements in respect of those years of income. At 30 June 2019 the objections were still under review by the Australian Taxation Office and the Consolidated Entity has not recognised any potential tax benefits from the objections lodged.

6. REMUNERATION OF AUDITORS

	2019 $	2018 $
The following fees were paid or payable for services provided by PwC Australia, the auditor of the Company, its related practices and non-related audit firms:		
(i) Audit and other assurance services		
Audit and review of group financial statements	199,681	173,401
Audit of separate subsidiary financial statements	43,430	—
	243,111	173,401
(ii) Taxation services		
Income Tax compliance	8,670	8,160
R&D Services	35,350	—
Other tax related services	44,752	26,259
	88,772	34,419
(iii) Other services		
Consulting services	8,865	—
	8,865	—
Total remuneration of PwC	**340,748**	**207,820**

7. CASH AND CASH EQUIVALENTS

Cash at bank and in hand	17,805,869	27,222,845
Made up as follows:		
Corporate (a)	17,296,319	26,706,273
Joint arrangements (b)	509,550	516,572
	17,805,869	27,222,845

(a) $3,084,832 of this balance relates to cash held with Macquarie Bank Limited to be used for allowable purposes under the Facility Agreement (2018: $1,782,026), including, but not limited to operating costs for the Palm Valley, Dingo and Mereenie fields, taxes, and debt servicing.

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

Risk exposure

The Group's exposure to interest rate risk is discussed in Note 33. The maximum exposure to credit risk at the end of the reporting period is the carrying amount of cash and cash equivalents.

8. TRADE AND OTHER RECEIVABLES

	2019 $	2018 $
Current		
Trade receivables	372,371	1,556,150
Accrued income (a)	7,427,028	4,121,642
Other receivables	30,595	57,541
Prepayments	1,230,161	896,309
	9,060,155	**6,631,642**

(a) Accrued income relates to the revenue recognition of hydrocarbon volumes delivered to respective customers but not yet invoiced.

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

9. INVENTORIES

	2019 $	2018 $
Crude oil and natural gas	107,920	337,534
Spare parts and consumables	1,870,295	1,877,937
Drilling materials and supplies at cost	741,311	1,360,009
	2,719,526	**3,575,480**

10. PROPERTY, PLANT AND EQUIPMENT

	FREEHOLD LAND AND BUILDINGS $	PRODUCING ASSETS $	PLANT AND EQUIPMENT $	TOTAL $
Year ended 30 June 2018				
Opening net book amount	3,229,217	76,109,148	27,477,994	106,816,359
Additions	—	—	4,668,165	4,668,165
Changes to rehabilitation estimates	—	379,448	611	380,059
Disposals and write offs	—	—	(19,838)	(19,838)
Depreciation charge	(350,202)	(3,657,662)	(3,983,512)	(7,991,376)
Closing net book amount	**2,879,015**	**72,830,934**	**28,143,420**	**103,853,369**
At 30 June 2018				
Cost	3,868,743	84,823,014	49,442,072	138,133,829
Accumulated depreciation	(989,728)	(11,992,080)	(21,298,652)	(34,280,460)
Net book amount	**2,879,015**	**72,830,934**	**28,143,420**	**103,853,369**
Year ended 30 June 2019				
Opening net book amount	2,879,015	72,830,934	28,143,420	103,853,369
Additions	—	—	16,187,514	16,187,514
Changes to rehabilitation estimates	—	16,066,651	5,424	16,072,075
Disposals and write offs	—	—	(1,807)	(1,807)
Depreciation charge	(350,203)	(7,851,021)	(4,434,514)	(12,635,738)
Closing net book amount	**2,528,812**	**81,046,564**	**39,900,037**	**123,475,413**
At 30 June 2019				
Cost	3,868,743	100,889,665	65,546,087	170,304,495
Accumulated depreciation	(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**

11. EXPLORATION ASSETS

	2019 $	2018 $
Acquisition costs of right to explore	**8,898,767**	**8,898,767**
Movement for the year:		
Balance at the beginning of the year	8,898,767	8,898,767
Balance at the end of the year	**8,898,767**	**8,898,767**

12. INTANGIBLE ASSETS

	2019 $	2018 $
SOFTWARE		
At the beginning of the year		
Cost	495,191	379,615
Accumulated amortisation	(339,174)	(297,458)
Net book value	**156,017**	**82,157**
Movements for the year		
Opening net book amount	156,017	82,157
Additions	16,848	115,576
Disposals and write offs	—	—
Amortisation	(59,500)	(41,716)
Closing net book amount	**113,365**	**156,017**
At the end of the year		
Cost	512,039	495,191
Accumulated amortisation	(398,674)	(339,174)
Net book value	**113,365**	**156,017**

13. OTHER FINANCIAL ASSETS

Current		
Security deposits paid for drilling operations	—	**2,333,333**
Non-Current		
Security bonds on exploration permits and rental properties	**2,770,782**	**2,535,915**

Security bonds are provided to State or Territory governments in respect of certain performance obligations arising from awarded petroleum and mineral tenements. The bonds are typically provided as cash or as bank guarantees in favour of the State or Territory government secured by term deposits with the financial institution providing the bank guarantee.

14. GOODWILL

Goodwill arising from business combinations	**3,906,270**	**3,906,270**

Impairment tests for goodwill

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

In determining impairment indicators, an assessment of the fair value less cost of disposal is made by estimating future cash flows from 2P reserves, including estimated capital expenditure to enhance production. The future cash flows are discounted to their present value using a post-tax discount rate, which includes an assessment of asset specific risks and the time value of money. The calculations require significant management judgement and are subject to risk and uncertainty, and broader economic conditions.

14. GOODWILL (CONTINUED)

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

2019	Producing Assets
Sales volumes	2P Reserves
Sales price (% annual growth rate)	2.5%
Operating costs (% annual growth rate)	2.5%
Post-tax discount rate (%)	11.75%

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

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

15. TRADE AND OTHER PAYABLES

	2019 $	2018 $
Current		
Trade payables	2,079,473	2,287,469
Other payables	39,658	1,311
Tax related payables	634,167	634,167
Deposits held	150,000	150,000
Accruals	3,103,234	5,040,720
	6,006,532	**8,113,667**

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

16. INTEREST BEARING LIABILITIES

		2019 $	2018 $
(a)	Interest bearing liabilities (current)[1]		
	Debt facilities	10,956,896	3,727,338
		10,956,896	**3,727,338**
(b)	Interest bearing liabilities (non-current)[1]		
	Debt facilities	70,773,157	74,599,221
		70,773,157	**74,599,221**

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

17. PROVISIONS

	2019			2018		
	Current $	**Non-current $**	**Total $**	Current $	Non-current $	Total $
Employee entitlements (a)	**3,529,565**	**763,299**	**4,292,864**	2,883,557	660,179	3,543,736
Restoration and rehabilitation (b)	**529,681**	**38,322,469**	**38,852,150**	522,958	21,639,197	22,162,155
Other:						
Joint Venture production over-lift (c)	**—**	**4,008,462**	**4,008,462**	—	3,541,059	3,541,059
Other provisions (d)	**1,316,553**	**—**	**1,316,553**	—	—	—
	5,375,799	**43,094,230**	**48,470,029**	**3,406,515**	**25,840,435**	**29,246,950**

(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 Consolidated Entity does not have an unconditional right to defer settlement for these obligations. However, based on past experience, the Group does not expect all employees to take the full amount of accrued leave or require payment in the next 12-months. Current leave obligations that are not expected to be taken or paid within the next 12-months amount to $738,952 (2018: $778,897).

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

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

(d) Other Provisions comprises provisions for liquidated damages under gas sales agreements and settlement of legal matters.

17. PROVISIONS (CONTINUED)

Movements in Provisions

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

2019	Employee Entitlements $	Restoration & Rehabilitation $	Joint Venture Production Over-lift $	Other $	Total $
Carrying amount at start of year	3,543,736	22,162,155	3,541,059	—	29,246,950
Change in provision charged to property, plant and equipment	—	16,072,075	—	—	16,072,075
Additional provisions charged to profit or loss	2,354,446	128,161	467,403	1,316,553	4,266,563
Unwinding of discount	—	489,759	—	—	489,759
Amounts used during the year	(1,605,318)	—	—	—	(1,605,318)
Carrying amount at end of year	**4,292,864**	**38,852,150**	**4,008,462**	**1,316,553**	**48,470,029**

18. OTHER FINANCIAL LIABILITIES

	2019 $	2018 $
Current		
Lease incentive liabilities	38,600	38,600
Liabilities associated with forward gas sales agreements containing a cash settlement option (a)	1,986,414	—
	2,025,014	**38,600**
Non-Current		
Lease incentive liabilities	45,033	83,633
Liabilities associated with forward gas sales agreements containing a cash settlement option (a)	13,778,460	15,278,873
	13,823,493	**15,362,506**

In June 2018 Macquarie Bank Limited novated its rights and obligations under the First Contract Year of the MBL Gas Sale and Prepayment Agreement, to Incitec Pivot Limited ("IPL"). This resulted in an amount of $7,865,982 being reclassified from Other Financial Liabilities to Deferred Revenue. The balance at 30 June 2019 and 30 June 2018 represents the remaining liabilities under the Second and Third Contract Year where Macquarie Bank Limited has an option to receive a financial settlement in lieu of physical gas delivery.

19. CONTRIBUTED EQUITY

(a) Share capital

	2019 $	2018 $
713,355,716 fully paid ordinary shares (2018: 707,115,793)	197,776,487	197,776,487

Ordinary shares have no par value and the Company does not have a limited amount of authorised capital.

On a show of hands, every holder of ordinary shares present at a meeting in person or by proxy, is entitled to one vote, and upon a poll each share is entitled to one vote.

19. CONTRIBUTED EQUITY (CONTINUED)

(b) Movements in ordinary share capital

	2019 No. of shares	2018 No. of shares	2019 $	2018 $
Balance at start of year	707,115,793	433,197,647	197,776,487	172,301,532
Placement of shares to institutional investors on 17 August 2017 at 10 cents per share	—	92,000,980	—	9,200,098
Shares issued pursuant to the 5 for 12 Entitlement Offer on 08 September 2017 at 10 cents per share	—	180,499,020	—	18,049,902
Capital raising costs	—	—	—	(1,775,045)
Shares issued under Employee Long Term Incentive Plans	6,239,923	1,418,146	—	—
Balance at end of year	**713,355,716**	**707,115,793**	**197,776,487**	**197,776,487**

(c) Movements in Share Options

No options were exercised, and no options lapsed during the year.

The following options over unissued ordinary shares were issued during the year:

CLASS	EXPIRY DATE	EXERCISE PRICE	NUMBER OF OPTIONS
Unlisted financing options	31 Dec 2019	$0.140	22,500,000

(d) Unissued shares under option

At year end, options over unissued ordinary shares of the Company are as follows:

CLASS	EXPIRY DATE	EXERCISE PRICE	NUMBER OF OPTIONS
Unlisted financing options	01 Sep 2019	$0.194	30,000,000
Unlisted financing options	31 Dec 2019	$0.140	22,500,000

None of the options entitle holders to participate in any share issue of the Company or any other entity.

(e) Deferred share rights under the Long Term Incentive Plan

Under the Group's Employee Rights Plan, eligible employees may receive rights to deferred shares of Central Petroleum Limited. The rights are granted in respect of a plan year which commences 1 July each year. The share rights remain unvested until the end of the performance period, which is three years commencing from the start of each plan year. Except in a limited number of circumstances, eligible employees must still be in the employment of Central Petroleum Limited as at the vesting date for the rights to vest.

Final vesting percentages are determined by a combination of performance hurdles in respect of a combination of absolute total shareholder return and relative total shareholder return compared to a specific group of exploration and production companies as determined by the Board.

The number of rights to be granted to eligible employees is determined based on the maximum long term incentive amount applicable for each employee, being either a fixed dollar amount or a percentage of the employee's base salary, divided by the volume weighted average share price ("VWAP") at the start of the plan year. The table below sets out the maximum number of deferred share entitlements outstanding at year end, subject to performance hurdles.

19. CONTRIBUTED EQUITY (CONTINUED)

CLASS	EXPIRY DATE	PLAN YEAR COMMENCING	NUMBER OF RIGHTS
Employee LTIP rights	05 Jan 2021	1 Jul 2015	7,305
Employee LTIP rights	08 Dec 2022	1 Jul 2016	9,577,506
Employee LTIP rights	09 Feb 2022	1 Jul 2016	25,324
Employee LTIP rights	03 Oct 2022	1 Jul 2016	70,000
Employee LTIP rights	03 Oct 2022	1 Jul 2017	5,431,222
Employee LTIP rights	23 May 2023	1 Jul 2017	16,868
Employee LTIP rights	28 Jun 2023	1 Jul 2017	135,920
Employee LTIP rights	22 May 2024	1 Jul 2018	7,000,371
Total Deferred Share Rights on issue			**22,264,516**

6,239,923 rights were converted to shares during the year (2018: 1,418,146) and 11,088,670 rights were cancelled (2018:1,523,870). The rights do not entitle the holders to participate in any share issue of the Company or any other entity.

(f) Capital risk management

The Group's objective when managing capital is to safeguard the ability to continue as a going concern to ultimately add value for shareholders through the exploitation and production of hydrocarbon resources. This is monitored through the use of cash flow forecasts. In order to maintain the capital structure, the Group may issue new shares or other equity instruments.

On 27 September 2018, the Company executed a $10 million Equity Line of Credit ("ELOC") facility with Long State Investment Limited ("LSI"). Under the terms of the facility, the Company may, at its discretion, issue shares to LSI at any time over 24 months from execution, up to a total of $10 million. The Company may draw down up to $250,000 in any period of 5 trading days.

Any shares issued to LSI will be priced at the lowest daily weighted average price ("VWAP") of the Company shares traded on each of the 5 trading days which follow an advance notice by the Company. A commission of 5% will be payable by the Company at the time of issue.

LSI may receive up to five million unlisted options through four separate tranches, subject to ELOC utilisation. An initial tranche of 1.25 million options with an exercise price of 35 cents will be granted on activation of the ELOC. Further tranches of 1.25 million options, with an exercise price of 200% of the 20-day VWAP immediately preceding the date on which the Company is required to grant the options, will be granted when the aggregate advances first exceeds $2.5 million, $5 million, and $7.5 million. The options have an exercise period of five years from the date of issue.

To date, the Company has not utilised the ELOC facility and no options have been granted to LSI.

20. RESERVES

	2019 $	2018 $
Share options reserve	**25,310,162**	**23,463,784**
Movements:		
Balance at start of year	23,463,784	21,841,455
Share based payment costs (a)	601,897	1,622,329
Options issued for financing	1,244,481	—
Balance at end of year	**25,310,162**	**23,463,784**

(a) Share based payments are provided to employees as part of the Long Term Incentive Plan. Refer to Note 32 for further details of share based payments.

21. ACCUMULATED LOSSES

	2019 $	2018 $
Movements in accumulated losses were as follows:		
Balance at the start of year	(214,176,963)	(200,100,834)
Net loss for the year	(14,526,414)	(14,076,129)
Balance at end of year	**(228,703,377)**	**(214,176,963)**

22. LOSSES PER SHARE

(a)	**Basic loss per share (cents)**	**(2.05)**	**(2.13)**
(b)	**Diluted loss per share (cents)**	**(2.05)**	**(2.13)**
(c)	**Loss used in loss per share calculation**		
	Loss attributed to ordinary equity holders of the Company	**(14,526,414)**	**(14,076,129)**
(d)	**Weighted average number of ordinary shares**		
	Weighted average number of shares used as the denominator in calculating basic and diluted earnings per share	**709,669,029**	**660,637,923**

Options and Rights on issue are considered to be potential ordinary shares and have not been included in the calculation of basic earnings per share. Additionally, any exercise of the options would be antidilutive as their exercise to ordinary shares would decrease the loss per share. In accordance with AASB 133, they are also excluded from the diluted loss per share calculation.

23. SEGMENT REPORTING

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

Producing assets

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

Development assets

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

Exploration assets

Exploration and evaluation of permit areas.

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.

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.

23. SEGMENT REPORTING (CONTINUED)

2019	PRODUCING ASSETS 2019 $	EXPLORATION ASSETS 2019 $	CORPORATE ITEMS 2019 $	CONSOLIDATION 2019 $
Revenue from contracts with customers				
Natural gas	49,657,736	—	—	49,657,736
Crude oil and condensate	9,700,022	—	—	9,700,022
Total revenue from contracts with customers	**59,357,758**	**—**	**—**	**59,357,758**
Cost of sales	(30,369,092)	—	—	(30,369,092)
Gross profit	28,988,666	—	—	28,988,666
Other income	122,544	515	261,669	384,728
Share based employee benefits	—	—	(601,897)	(601,897)
General and administrative expenses	—	—	(1,031,636)	(1,031,636)
Employee benefits and associated costs	—	—	(5,194,131)	(5,194,131)
EBITDAX	**29,111,210**	**515**	**(6,565,995)**	22,545,730
Depreciation and amortisation	(12,378,327)	—	(316,911)	(12,695,238)
Exploration expenditure	(14,802,879)	(999,196)	—	(15,802,075)
Finance costs	(7,932,034)	(40,055)	(602,742)	(8,574,831)
Loss before income tax	**(6,002,030)**	**(1,038,736)**	**(7,485,648)**	(14,526,414)
Taxes	—	—	—	—
Loss for the year	**(6,002,030)**	**(1,038,736)**	**(7,485,648)**	(14,526,414)
Segment assets	**143,022,770**	**11,067,874**	**14,659,503**	168,750,147
Segment liabilities	**(158,284,408)**	**(2,991,402)**	**(13,091,065)**	(174,366,875)
Capital expenditure				
Property, plant and equipment	16,077,944	—	109,570	16,187,514
Total capital expenditure	**16,077,944**	**—**	**109,570**	**16,187,514**

23. SEGMENT REPORTING (CONTINUED)

2018	PRODUCING ASSETS 2018 $	EXPLORATION ASSETS 2018 $	CORPORATE ITEMS 2018 $	CONSOLIDATION 2018 $
Revenue from contracts with customers				
Natural gas	25,458,550	—	—	25,458,550
Crude oil and condensate	9,480,644	—	—	9,480,644
Total revenue from contracts with customers	**34,939,194**	**—**	**—**	**34,939,194**
Cost of sales	(18,704,042)	—	—	(18,704,042)
Gross profit	16,235,152	—	—	16,235,152
Other income	—	504,415	550,769	1,055,184
Share based employee benefits	—	—	(1,622,329)	(1,622,329)
General and administrative expenses	—	—	(595,925)	(595,925)
Employee benefits and associated costs	—	—	(4,061,759)	(4,061,759)
Other operating expenses	—	—	—	—
EBITDAX	**16,235,152**	**504,415**	**(5,729,244)**	**11,010,323**
Depreciation and amortisation	(7,745,236)	—	(287,856)	(8,033,092)
Exploration expenditure	(6,027,109)	(2,762,943)	—	(8,790,052)
Finance costs	(7,741,281)	(28,223)	(493,804)	(8,263,308)
Loss before income tax	**(5,278,474)**	**(2,286,751)**	**(6,510,904)**	**(14,076,129)**
Taxes	—	—	—	—
Loss for the year	**(5,278,474)**	**(2,286,751)**	**(6,510,904)**	**(14,076,129)**
Segment assets	**121,601,949**	**12,625,994**	**24,885,695**	**159,113,638**
Segment liabilities	**(136,584,039)**	**(2,828,327)**	**(12,637,964)**	**(152,050,330)**
Capital expenditure				
Property, plant and equipment	**4,433,420**	—	234,745	4,668,165
Total capital expenditure	**4,433,420**	**—**	**234,745**	**4,668,165**

	2019 $	2018 $
Revenue from external customers by geographical location of production:		
Australia	**59,357,758**	**34,939,194**
Non-current assets by geographical location:		
Australia	**139,164,597**	**119,350,338**

Major Customers

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

	2019 $	% of Sales Revenue	2018 $	% of Sales Revenue
Largest customer	22,706,279	38%	8,665,876	25%
Second largest customer	8,829,598	15%	6,948,934	20%
Third largest customer	7,153,839	12%	6,314,195	18%
Fourth largest customer	6,362,703	11%	5,250,226	15%
Fifth largest customer	5,695,139	10%	4,008,261	11%

24. PARENT ENTITY INFORMATION

(a) Summary financial information

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

	2019 $	2018 $
Statement of financial position		
Current assets	16,127,970	28,495,981
Non-current assets	23,291,275	19,431,083
Total assets	39,419,245	47,927,064
Current liabilities	(28,344,300)	(25,645,024)
Non-current liabilities	(1,032,212)	(958,070)
Total liabilities	(29,376,512)	(26,603,094)
Net assets	**10,042,733**	**21,323,970**
Shareholders' equity		
Issued capital	197,776,487	197,776,487
Reserves	25,310,162	23,463,784
Accumulated losses	(213,043,916)	(199,916,301)
Total equity	**10,042,733**	**21,323,970**
Loss for the year	**(13,127,615)**	**(21,216,129)**
Total comprehensive loss	**(13,127,615)**	**(21,216,129)**

Comparative balances for the 2018 year have been amended to reflect the impact of UIG 1052 in accounting for tax balances by individual entities part of the tax consolidated group.

(b) Guarantees entered into by the Parent Entity

Guarantees have been provided by the Parent Entity to subsidiaries arising out of the course of ordinary operations.

A loan facility exists under which the parent and non-borrowing subsidiaries have provided guarantees to a financier in relation to the repayment of monies owing and other performance related obligations of the Borrower typical for a borrowing of this nature. Monies received through the operation of the Palm Valley, Dingo and Mereenie fields are subject to a proceeds account and can be distributed to the parent as available when no default exists. Revenues resulting from operations outside of these assets (such as the Surprise field) are not subject to a cash sweep or other restrictions under the Facility where no defaults exist.

(c) Commitments of the Parent Entity

Operating lease commitments of the Parent Entity are set out in Note 31(c).

25. RELATED PARTY TRANSACTIONS

(a) Parent Entity

The parent entity is Central Petroleum Limited.

(b) Subsidiaries

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

NAME OF ENTITY	PLACE OF INCORPORATION	CLASS OF SHARES	EQUITY HOLDING 2019 %	EQUITY HOLDING 2018 %
Merlin Energy Pty Ltd	Western Australia	Ordinary	100	100
Central Petroleum Projects Pty Ltd	Western Australia	Ordinary	100	100
Helium Australia Pty Ltd	Victoria	Ordinary	100	100
Ordiv Petroleum Pty Ltd	Western Australia	Ordinary	100	100
Frontier Oil & Gas Pty Ltd	Western Australia	Ordinary	100	100
Central Petroleum Eastern Pty Ltd	Western Australia	Ordinary	100	100
Central Geothermal Pty Ltd	Western Australia	Ordinary	100	100
Central Petroleum Services Pty Ltd	Western Australia	Ordinary	100	100
Central Petroleum PVD Pty Ltd	Queensland	Ordinary	100	100
Central Petroleum (NT) Pty Ltd	Queensland	Ordinary	100	100
Jarl Pty Ltd	Queensland	Ordinary	100	100
Central Petroleum Mereenie Pty Ltd	Queensland	Ordinary	100	100
Central Petroleum Mereenie Unit Trust	N/A	Units	100	100
Central Petroleum WS (NO 1) Pty Ltd	Queensland	Ordinary	100	100
Central Petroleum WS (NO 2) Pty Ltd	Queensland	Ordinary	100	100

(c) Key management personnel

Disclosures relating to key management personnel are set out in Note 27.

26. DEED OF CROSS GUARANTEE

On 24 June 2019 Central Petroleum Limited and its wholly owned subsidiary companies entered into a deed of cross guarantee under which each company guarantees the debts of the others. By entering into the deed, the wholly-owned entities have been relieved from the requirement to prepare a financial report and directors' report under *ASIC Corporations (Wholly-owned Companies) Instrument 2016/785*.

The parties to the deed of cross guarantee are:

- Central Petroleum Limited
- Central Petroleum Projects Pty Ltd
- Ordiv Petroleum Pty Ltd
- Central Petroleum Eastern Pty Ltd
- Central Petroleum Services Pty Ltd
- Central Petroleum (NT) Pty Ltd
- Central Petroleum Mereenie Pty Ltd
- Central Petroleum WS (NO 2) Pty Ltd
- Merlin Energy Pty Ltd
- Helium Australia Pty Ltd
- Frontier Oil & Gas Pty Ltd
- Central Geothermal Pty Ltd
- Central Petroleum PVD Pty Ltd
- Jarl Pty Ltd
- Central Petroleum WS (NO 1) Pty Ltd

(a) Consolidated statement of profit or loss, statement of comprehensive income and summary of movements in consolidated retained earnings

The above companies represent a 'closed group' for the purposes of the instrument, and as there are no other parties to the deed of cross guarantee that are controlled by Central Petroleum Limited, they also represent the 'extended closed group'.

Set out below is a consolidated statement of profit or loss, a consolidated statement of comprehensive income and a summary of movements in consolidated retained earnings of the closed group for the year ended 30 June 2019.

	2019 $
Revenue from the sale of goods	18,046,341
Cost of sales	(14,436,725)
Gross profit	3,609,616
Other income	354,138
Share based employment benefits	(601,897)
General and administrative expenses	(299,967)
Depreciation and amortisation	(4,308,910)
Employee benefits and associated costs	(5,194,131)
Exploration expenditure	(15,482,380)
Finance costs	(5,252,743)
Loss before income tax	(27,176,274)
Income tax credit	6,540,518
Loss for the year	(20,635,756)
Other comprehensive loss for the year, net of tax	—
Total comprehensive loss for the year	**(20,635,756)**
Retained earnings at the beginning of the financial year	**(194,251,967)**
Loss for the period	(20,635,756)
Retained earnings/(Accumulated losses) at the end of the financial year	**(214,887,723)**

26. DEED OF CROSS GUARANTEE (CONTINUED)

(b) Consolidated balance sheet

Set out below is a consolidated balance sheet of the closed group as at 30 June 2019.

	2019 $
ASSETS	
Current assets	
Cash and cash equivalents	17,296,309
Trade and other receivables	3,397,921
Inventories	1,394,118
Total current assets	**22,088,348**
Non-current assets	
Property, plant and equipment	65,996,497
Exploration assets	8,898,767
Intangible assets	72,863
Investments	10
Other financial assets	2,254,751
Deferred Tax Assets	5,636,241
Goodwill	3,906,270
Total non-current assets	**86,765,399**
Total assets	**108,853,747**
LIABILITIES	
Current liabilities	
Trade and other payables	13,698,128
Deferred revenue	1,983,456
Interest-bearing liabilities	6,675,343
Other financial liabilities	38,600
Provisions	4,380,079
Total current liabilities	**26,775,606**
Non-current liabilities	
Deferred revenue	15,119,689
Interest-bearing liabilities	39,223,704
Other financial liabilities	45,033
Provisions	19,490,789
Total non-current liabilities	**73,879,215**
Total liabilities	**100,654,821**
Net assets	**8,198,926**
EQUITY	
Contributed equity	197,776,487
Reserves	25,310,162
Accumulated losses	(214,887,723)
Total equity	**8,198,926**

27. KEY MANAGEMENT PERSONNEL

(a) Key management personnel compensation

	2019 $	2018 $
Short-term employee benefits	3,120,547	2,561,475
Post-employment benefits	179,537	139,774
Termination benefits	80,908	—
Long-term benefits	(81,319)	59,756
Share based payments	(21,388)	1,097,869
	3,278,285	**3,858,874**

Detailed remuneration disclosures are provided in the remuneration report on pages 28 to 41.

(b) Equity instrument disclosures relating to key management personnel

(i) Options provided as remuneration and shares issued on exercise of such options

No options were provided as remuneration and no shares were issued on the exercise of options during the current or prior financial year.

(ii) Share rights issued under the short term incentive plan

During the year zero cost share rights were issued under the short term incentive plan ("STIP"), in lieu of cash, for certain employees. The following Share Rights were issued to key management personnel during the year:

	STIP RIGHTS HELD AT START OF YEAR	RIGHTS RECEIVED UNDER 2017/18 STIP	CONVERTED TO SHARES	STIP RIGHTS HELD AT END OF YEAR
2019				
Daniel White	—	83,464	(83,464)	Nil

(iii) Deferred shares – long term incentive plan

Under the Group's Employee Rights Plan, eligible employees may receive rights to deferred shares of Central Petroleum Limited. The rights are granted in respect of a plan year which commences 1 July each year. The share rights remain unvested until the end of the performance period, which is three years commencing from the start of each plan year. Except in limited circumstances, eligible employees must still be in the employment of Central Petroleum Limited as at the vesting date for the rights to vest.

Final vesting percentages are determined by a combination of performance hurdles in respect of a combination of absolute total shareholder return and relative total shareholder return compared to a specific group of exploration and production companies as determined by the Board.

The number of rights to be granted to eligible employees is determined based on the maximum long term incentive amount applicable for each employee, being either a fixed dollar amount or a percentage of the employee's base salary, divided by the volume weighted average share price ("VWAP") at the start of the plan year.

The maximum number of rights to ordinary shares in the Company under the long term incentive plan held during the financial year by other key management personnel of the Consolidated Entity, including their personally related parties, are set out below:

27. KEY MANAGEMENT PERSONNEL (CONTINUED)

(iii) Deferred shares – long term incentive plan (Continued)

		RIGHTS HELD AT START OF YEAR	MAXIMUM NO. GRANTED AS COMPENSATION	CANCELLED DURING THE YEAR	CONVERTED TO SHARES	RETAINED FOLLOWING DEPARTURE	RIGHTS HELD AT END OF YEAR
Executive Directors and Other Key Management Personnel							
Richard Cottee[1]	2019	6,952,766	183,540	(6,098,087)	—	1,038,219[1]	N/A
	2018	5,307,887	1,854,229	(104,675)	(104,675)	N/A	6,952,766
Leon Devaney	2019	2,985,158	75,089	(433,335)	(424,754)	N/A	2,202,158
	2018	2,373,104	917,339	(152,643)	(152,642)	N/A	2,985,158
Ross Evans[2]	2019	—	778,854	—	—	N/A	778,854
	2018	N/A	—	—	—	N/A	—
Michael Herrington[3]	2019	3,380,501	980,600	(1,870,478)	(504,497)	1,986,126	N/A
	2018	2,886,237	931,057	(218,397)	(218,396)	N/A	3,380,501
Duncan Lockhart[4]	2019	N/A	—	—	—	N/A	—
	2018	N/A	N/A	N/A	N/A	N/A	N/A
Robin Polson[5]	2019	—	603,491	—	—	N/A	603,491
	2018	N/A	—	—	—	N/A	—
Daniel White	2019	2,795,985	878,827	(426,141)	(417,702)	N/A	2,830,969
	2018	2,389,666	767,966	(180,824)	(180,823)	N/A	2,795,985

1. *Richard Cottee resigned as CEO 31 January 2019 and as a Director on 5 February 2019. 1,038,000 Rights vested and were exercised after resignation. All remaining rights were cancelled.*
2. *Ross Evans commended 1 June 2018*
3. *Michael Herrington ceased employment effective 29 January 2019. The number of Rights retained following departure represents the maximum number that may vest in the future subject to vesting and other conditions.*
4. *Duncan Lockhart commenced 8 April 2019*
5. *Robin Polson commenced 1 May 2018*

27. KEY MANAGEMENT PERSONNEL (CONTINUED)

(iv) Share holdings

The number of shares in the Company held during the financial year by each Director of Central Petroleum Limited and other key management personnel of the Consolidated Entity, including their personally related parties, are set out below. There were no shares granted as compensation during the year.

		HELD AT BEGINNING OF YEAR	HELD AT DATE OF APPOINTMENT	SPP & ON MARKET PURCHASE	RECEIVED ON EXERCISE OF RIGHTS	NET CHANGE OTHER	HELD AT DATE OF DEPARTURE	HELD AT END OF YEAR
Non-Executive Directors								
Stuart Baker[1]	2019	N/A	—	—	—	—	N/A	—
	2018	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Wrixon Gasteen	2019	293,337	N/A	—	—	—	N/A	293,337
	2018	136,473	N/A	156,864	—	—	N/A	293,337
Katherine Hirschfeld[1]	2019	N/A	200,000	—	—	—	N/A	200,000
	2018	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Robert Hubbard[2]	2019	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	2018	298,947	N/A	365,667	—	—	664,614	N/A
Martin Kriewaldt[3]	2019	1,100,000	N/A	—	—	—	N/A	1,100,000
	2018	N/A	200,000	900,000	—	—	N/A	1,100,000
Peter Moore[4]	2019	265,000	—	50,000	—	—	315,000	N/A
	2018	—	N/A	265,000	—	—	N/A	265,000
Sarah Ryan[3,4]	2019	105,000	N/A	100,000	—	—	205,000	N/A
	2018	N/A	—	105,000	—	—	N/A	105,000
Timothy Woodall[5]	2019	1,500,000	N/A	250,000	—	—	1,750,000	N/A
	2018	N/A	1,000,000	500,000	—	—	N/A	1,500,000
Executive Directors and Other Key Management Personnel								
Richard Cottee[6]	2019	889,933	N/A	—	—	(47,700)	842,233	N/A
	2018	571,829	N/A	216,929	104,675	(3,500)	N/A	889,933
Leon Devaney	2019	629,022	N/A	—	424,754	—	N/A	1,053,776
	2018	210,000	N/A	266,380	152,642	—	N/A	629,022
Ross Evans[7]	2019	—	N/A	—	—	—	N/A	—
	2018	N/A	—	—	—	—	N/A	—
Michael Herrington[8]	2019	572,564	N/A		504,497	—	1,077,061	N/A
	2018	250,000	N/A	104,168	218,396	—	N/A	572,564
Duncan Lockhart[9]	2019	N/A	—	—	—	—	N/A	—
	2018	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Robin Polson[10]	2019	—	—	—	—	—	N/A	—
	2018	N/A	—	—	—	—	N/A	—
Daniel White	2019	628,823	N/A	—	501,166	—	N/A	1,129,989
	2018	288,000	N/A	160,000	180,823	—	N/A	628,823

1 *Stuart Baker and Katherine Hirschfeld AM were appointed Directors 7 December 2018*

2 *Robert Hubbard retired 14 May 2018*

3 *Martin Kriewaldt and Sarah Ryan were appointed Directors 23 October 2017*

4 *Sarah Ryan and Peter Moore resigned 13 November 2018*

5 *Timothy Woodall was appointed Director 20 December 2017 and resigned 29 September 2018*

6 *Richard Cottee ceased employment effective 31 January 2019*

7 *Ross Evans commenced 1 June 2018*

8 *Michael Herrington ceased employment effective 29 January 2019*

9 *Duncan Lockhart commenced 8 April 2019*

10 *Robin Polson commenced 1 May 2018*

(c) Other transactions with key management personnel

There were no other transactions with Key Management Personnel

28. RECONCILIATION OF LOSS AFTER INCOME TAX TO NET CASH OUTFLOW FROM OPERATING ACTIVITIES

	2019 $	2018 $
Loss after income tax	(14,526,414)	(14,076,129)
Adjustments for:		
Depreciation and amortisation	12,695,238	8,033,092
Loss/(Profit) on disposal of assets	1,807	(13,799)
Profit on disposal of exploration permits	—	(280,000)
Share-based payments	601,897	1,622,329
Financing costs and interest (non-cash)	1,632,975	1,762,250
Changes in assets and liabilities relating to operating activities:		
Increase in trade and other receivables	(2,429,134)	(1,634,805)
Decrease/(increase) in inventories	855,954	(302,466)
(Decrease)/increase in trade and other payables	(829,072)	2,687,060
Increase in deferred revenue	1,349,706	5,097,991
Decrease in financial liabilities	(38,600)	(38,600)
Increase in provisions	3,151,005	2,316,307
Net cash inflow from operations	**2,465,362**	**5,173,230**

29. CASH FLOW INFORMATION

(a) Non-cash investing and financing activities

Non-cash interest relating to Other Financial Liabilities amounted to $649,787 (2018: $938,119). Additionally, non-cash revaluation credits amounted to $163,786 (2018 expense of $414,431). Refer Note 4(a).

Due to a novation of rights and obligations under the MBL Gas Sale and Prepayment Agreement from MBL to IPL in respect of the First Contract Year, an amount of $nil (2018: $7,865,982) was transferred to Deferred Revenue, reflecting the removal of the cash settlement option for the First contract year (Refer Note 18 for further details).

(b) Net debt reconciliation

This section provides an analysis of those liabilities for which cash flows have been or will be classified as financing activities in the statement of cash flows. Cash balances included as current assets on the Statement of Financial Position are included as the Group considers these to form part of its net debt.

29. CASH FLOW INFORMATION (CONTINUED)

(b) Net debt reconciliation (continued)

Net debt

	2019 $	2018 $
Cash and cash equivalents	17,805,869	27,222,845
Borrowings – repayable within one year	(10,956,896)	(3,727,338)
Borrowings – repayable after one year	(70,773,157)	(74,599,221)
Net debt	**(63,924,184)**	**(51,103,714)**

Cash	17,805,869	27,222,845
Gross debt – variable interest rates	(81,730,053)	(78,326,559)
Net debt	**(63,924,184)**	**(51,103,714)**

Movement in Net Debt

	Other Assets	Liabilities from financing activities		
	Cash $	Borrowings due within 1 year $	Borrowings due after 1 year $	Total $
Net debt 1 July 2017	**5,478,140**	**(3,606,853)**	**(78,310,007)**	**(76,438,720)**
Cash flows	21,744,705	4,000,000	—	25,744,705
Reclassification of category	—	(3,710,786)	3,710,786	—
Other non-cash movements	—	(409,699)	—	(409,699)
Net debt 30 June 2018	**27,222,845**	**(3,727,338)**	**(74,599,221)**	**(51,103,714)**
Cash flows	(9,416,976)	(3,501,000)	—	(12,917,976)
Reclassification of category	—	(3,826,064)	3,826,064	—
Other non-cash movements	—	97,506	—	97,506
Net debt 30 June 2019	**17,805,869**	**(10,956,896)**	**(70,773,157)**	**(63,924,184)**

30. CONTINGENCIES

(a) Contingent liabilities

(i) Exploration Permits

The Consolidated Entity had contingent liabilities at 30 June 2019 in respect of certain joint arrangement payments. As partial consideration under the terms of the purchase agreement for EPs 105, 106 and 107, there is a requirement to pay the vendor the sum of $1,000,000 (2018: $1,000,000) within 12-months following the commencement of any future commercial production from the permits. No commercial production is currently forecast from these permits.

(ii) Palm Valley Gas Field Gas Price Bonus

Under the Share Sale and Purchase Deed entered into with Magellan Petroleum Australia Pty Limited ("Magellan") in February 2014 for the purchase of Palm Valley and Dingo gas fields and related assets, Central Petroleum Limited is obligated to pay to Magellan a Gas Price Bonus where the weighted average price of gas sold from the Palm Valley gas field during a Contract Year exceeds certain price hurdles during a period of 15-years following Completion of the Agreement. The Gas Price Bonus Amount is calculated as 25% of the difference between the weighted average price of gas actually sold (excluding GST and other costs) in a Contract Year and the gas price bonus hurdle applicable to that Contract Year (after adjusting for CPI), multiplied by the actual volume of gas originating and sold from the Palm Valley gas field.

30. CONTINGENCIES (CONTINUED)

(a) Contingent liabilities (continued)

(ii) Palm Valley Gas Field Gas Price Bonus (continued)

The weighted average price of gas sold from the Palm Valley gas field is currently below the Gas Price Bonus hurdle price and therefore no gas price bonus is payable at this time. Based on current reserves and production profiles for the Palm Valley Gas Field, and current Northern Territory gas market conditions, we do not anticipate paying a gas price bonus over the relevant term and have therefore ascribed a $nil value to this contingent liability. Should access to additional reserves and significantly higher priced markets eventuate, this contingent liability will be revisited. Importantly, any future payment of the Gas Price Bonus would only occur where sales and revenues from the Palm Valley gas field materially exceed our acquisition assumptions.

31. COMMITMENTS

(a) Capital commitments

The Consolidated Entity has the following capital expenditure commitments:

	2019 $	2018 $
The following amounts are due:		
Within one year	608,787	1,675,020
Later than one year but not later than three years	—	—
Later than three years but not later than five years	—	—
	608,787	**1,675,020**

(b) Exploration commitments

The Consolidated Entity has the following minimum exploration expenditure commitments:

	2019 $	2018 $
The following amounts are due:		
Within one year	12,175,000	14,155,000
Later than one year but not later than three years	46,105,000	13,325,000
Later than three years but not later than five years	4,450,000	11,050,000
Later than five years	6,000,000	—
	68,730,000	38,530,000

These commitments may be varied in the future as a result of renegotiations of the terms of exploration permits. In the petroleum industry it is common practice for entities to farm-out, transfer or sell a portion of their rights to third parties or relinquish (whole or part of the permit) and, as a result, obligations may be reduced or extinguished.

(c) Operating lease commitments

The Consolidated Entity has non-cancellable operating leases. The leases have varying terms, escalation clauses and renewal rights.

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

	2019 $	2018 $
Within one year	658,188	560,413
Later than one year but not later than five years	1,059,047	1,221,665
Later than five years	181,196	—
	1,898,431	**1,782,078**

32. SHARE BASED PAYMENTS

(a) Employee options

An Incentive Option Scheme previously operated to provide incentives for employees. Participation in the plan is at the Board's discretion; however, the plan is open to all employees and Directors of the Company.

All remaining options expired or were forfeited during the 2018 year as shown below.

EXPIRY DATE	EXERCISE PRICE	BALANCE AT START OF THE YEAR	GRANTED DURING THE YEAR	EXERCISED DURING THE YEAR	EXPIRED OR FORFEITED DURING THE YEAR	BALANCE AT END OF THE YEAR	VESTED AND EXERCISABLE AT THE END OF THE YEAR
		No.	No.	No.	No.	No.	$
2018							
15 Nov 2017	$0.450	24,900,773	—	—	(24,900,773)	—	—
15 Nov 2017	$0.450	1,466,667	—	—	(1,466,667)	—	—
15 Nov 2017	$0.450	1,800,595	—	—	(1,800,595)	—	—
15 Nov 2017	$0.400	365,100	—	—	(365,100)	—	—
15 Nov 2017	$0.650	27,300	—	—	(27,300)	—	—
Totals		**28,560,435**	**—**	**—**	**(28,560,435)**	**—**	**—**
Weighted average exercise price		$0.45	—	—	$0.45	—	—

(b) Rights to shares — Short Term Incentive Plan

Under the Group's short term incentive plan, the Board may issue share rights in lieu of cash payments. The following Rights were issued during the year:

GRANT DATE	PLAN YEAR END	BALANCE AT START OF YEAR	NUMBER OF RIGHTS GRANTED	AVERAGE FAIR VALUE PER RIGHT	EXERCISED DURING THE YEAR	CANCELLED OR FORFEITED	BALANCE AT END OF YEAR
2019							
22 Mar 2019	30 June 2018	—	1,634,631	$0.130	(1,634,631)	—	—

32. SHARE BASED PAYMENTS (CONTINUED)

(c) Rights to Deferred shares — Long Term Incentive Plan

Under the Group's Employee Rights Plan, eligible employees may receive rights to deferred shares of Central Petroleum Limited. The rights are granted in respect of a plan year which commences 1 July each year. The share rights remain unvested until the end of the performance period which is three years commencing from the start of each plan year. Except in limited circumstances, eligible employees must still be in the employment of Central Petroleum Limited as at the vesting date for the rights to vest.

Final vesting percentages are determined by a combination of performance hurdles in respect of a combination of absolute total shareholder return and relative total shareholder return compared to a specific group of exploration and production companies as determined by the Board.

The number of rights to be granted to eligible employees is determined based on the maximum long term incentive amount applicable for each employee, being either a fixed dollar amount or a percentage of the employee's base salary, divided by the volume weighted average share price ("VWAP") at the start of the plan year. Share based payment expense for the year includes amounts expensed in respect of the following number of rights either granted or expected to be granted:

GRANT DATE	PLAN YEAR END	BALANCE AT START OF YEAR	GRANTED DURING THE YEAR	AVERAGE FAIR VALUE PER RIGHT	EXERCISED DURING THE YEAR	CANCELLED OR FORFEITED DURING THE YEAR	BALANCE AT END OF YEAR
2019							
09 May 2019	30 June 2019	—	791,808	$0.101	—	—	791,808
17 Apr 2019	30 June 2019	—	49,321	$0.111	—	—	49,321
17 Apr 2019	30 June 2019	—	7,816	$0.150	—	—	7,816
24 Sep 2019	30 June 2019	—	5,784,715	$0.087	—	—	5,784,715
24 Sep 2019	30 June 2019	—	366,711	$0.120	—	—	366,711
02 Oct 2018	30 June 2016	—	781,438	$0.067	(395,964)	(384,835)	639
27 Jun 2018	30 June 2018	135,920	—	$0.102	—	—	135,920
16 May 2018	30 June 2018	6,562	—	$0.126	—	—	6,562
16 May 2018	30 June 2018	10,306	—	$0.175	—	—	10,306
29 Nov 2017	30 June 2018	1,835,910	—	$0.055	—	(1,835,910)	—
29 Sep 2017	30 June 2015	7,041	—	$0.097	(7,041)	—	—
01 Sep 2017	30 June 2018	6,124,904	—	$0.081	—	(926,672)	5,198,232
01 Sep 2017	30 June 2018	262,500	—	$0.115	—	(29,510)	232,990
01 Sep 2017	30 June 2017	70,000	—	$0.082	—	—	70,000
01 Sep 2017	30 June 2016	327,000	—	$0.056	(161,865)	(165,135)	—
24 Jan 2017	30 June 2017	25,324	—	$0.190	—	—	25,324
16 Nov 2016	30 June 2017	6,050,315	—	$0.151	—	(3,419,207)	2,631,108
20 Oct 2016	30 June 2017	7,053,384	—	$0.106	—	(445,428)	6,607,956
20 Oct 2016	30 June 2017	372,385	—	$0.135	—	(33,943)	338,442
20 Oct 2016	30 June 2016	18,517	—	$0.135	(18,517)	—	—
20 Oct 2016	30 June 2016	106,666	—	$0.087	(52,800)	(53,866)	—
22 Dec 2015	30 June 2016	1,913,873	—	$0.123	(1,038,000)	(875,873)	—
03 Dec 2015	30 June 2016	6,063	—	$0.165	(6,063)	—	—
09 Nov 2015	30 June 2016	515,083	—	$0.184	(285,881)	(222,536)	6,666
14 Oct 2015	30 June 2016	5,261,487	—	$0.147	(2,565,732)	(2,695,755)	—
17 Jun 2015	30 June 2015	73,429	—	$0.074	(73,429)	—	—
Totals		**30,176,669**	**7,781,809**		**(4,605,292)**	**(11,088,670)**	**22,264,516**

32. SHARE BASED PAYMENTS (CONTINUED)

(c) Rights to Deferred shares — Long Term Incentive Plan (continued)

	PLAN YEAR END	BALANCE AT START OF YEAR	GRANTED DURING THE YEAR	AVERAGE FAIR VALUE PER RIGHT	EXERCISED DURING THE YEAR	CANCELLED OR FORFEITED DURING THE YEAR	BALANCE AT END OF YEAR
2018							
27 Jun 2018	30 June 2018	—	135,920	$0.102	—	—	135,920
16 May 2018	30 June 2018	—	6,562	$0.126	—	—	6,562
16 May 2018	30 June 2018	—	10,306	$0.175	—	—	10,306
29 Nov 2017	30 June 2018	—	1,835,910	$0.055	—	—	1,835,910
29 Nov 2017	30 June 2015	—	18,319	$0.084	(9,159)	(9,160)	—
29 Sep 2017	30 June 2015	—	239,556	$0.097	(109,776)	(122,739)	7,041
01 Sep 2017	30 June 2018	—	6,124,904	$0.081	—	—	6,124,904
01 Sep 2017	30 June 2018	—	281,250	$0.115	—	(18,750)	262,500
01 Sep 2017	30 June 2017	—	70,000	$0.082	—	—	70,000
01 Sep 2017	30 June 2016	—	327,000	$0.056	—	—	327,000
24 Jan 2017	30 June 2017	31,655	—	$0.190	—	(6,331)	25,324
16 Nov 2016	30 June 2017	6,050,315	—	$0.151	—	—	6,050,315
20 Oct 2016	30 June 2017	7,053,384	—	$0.106	—	—	7,053,384
20 Oct 2016	30 June 2017	405,718	—	$0.135	—	(33,333)	372,385
20 Oct 2016	30 June 2016	28,761	—	$0.135	—	(10,244)	18,517
20 Oct 2016	30 June 2016	106,666	—	$0.087	—	—	106,666
22 Dec 2015	30 June 2016	1,913,873	—	$0.123	—	—	1,913,873
03 Dec 2015	30 June 2016	6,063	—	$0.165	—	—	6,063
09 Nov 2015	30 June 2016	521,749	—	$0.184	—	(6,666)	515,083
14 Oct 2015	30 June 2016	5,261,487	—	$0.147	—	—	5,261,487
22 Dec 2015	30 June 2015	191,031	—	$0.085	(95,516)	(95,515)	—
17 Jun 2015	30 June 2015	2,498,256	—	$0.074	(1,203,695)	(1,221,132)	73,429
Totals		**24,068,958**	**9,049,727**		**(1,418,146)**	**(1,523,870)**	**30,176,669**

(d) Expenses arising from share-based payment transactions

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

	2019 $	2018 $
Share Rights issued to employees	601,897	1,622,329

33. FINANCIAL RISK MANAGEMENT

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

(a) Credit Risk

The credit risk on financial assets of the Consolidated Entity which have been recognised in the statement of financial position is generally the carrying amount, net of any provision for expected credit losses. The Group applies the simplified approach to providing for expected credit losses prescribed by AASB 9, which permits the use of the lifetime expected loss provision for all trade receivables. Under this method, determination of the loss allowance provision and expected loss rate incorporates past experience and forward-looking information, including the outlook for market demand and forward-looking interest rates. As the expected loss rate at 30 June 2019 is nil (2018: nil), no loss allowance provision has been recorded at 30 June 2019 (2018: nil).

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

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

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

TRADE AND OTHER RECEIVABLES	GROSS		EXPECTED CREDIT LOSS PROVISION	
	2019	2018	**2019**	2018
	$	$	**$**	$
Current: 0-30 days	7,829,994	5,735,333	—	—
Past due: 31-150 days	—	—	—	—
Past due: 151-365 days	—	—	—	—
	7,829,994	**5,735,333**	**—**	**—**

Based on historic default rates, the Consolidated Entity believes that no impairment allowance is necessary.

The receivables at 30 June 2019 relate predominantly to oil and gas sales which have all been received subsequent to year end.

Credit risk also arises in relation to financial guarantees given by the Parent Entity and other non-borrowing Group entities to certain parties in respect of borrowings by other Group entities (refer Note 24(b)). Such guarantees are only provided in exceptional circumstances and are subject to specific Board approval.

33. FINANCIAL RISK MANAGEMENT (CONTINUED)

(b) Liquidity Risk

Prudent liquidity risk management implies maintaining sufficient cash and marketable securities and the availability of funding. Management monitors rolling forecasts of the Group's liquidity reserve (comprising the undrawn borrowing facilities below) and cash and cash equivalents (Note 7) based on expected cash flows. This is carried out at the Group level in accordance with practice and limits set by the Board of Directors. In addition, the Group's liquidity management policy involves projecting cash flows, monitoring balance sheet liquidity ratios against internal and external regulatory requirements and maintaining debt financing plans.

The Group manages its exposure to key financial risks primarily through supervision by the Audit and Risk Committees. The primary function of these Committees is to assist the Board to fulfil its responsibility to ensure that the Group's internal control framework is effective and efficient.

The following are the contractual maturities of financial liabilities:

2019	≤ 6 MONTHS	6–12 MONTHS	1–5 YEARS	≥ 5 YEARS	CONTRACTUAL CASH FLOW	CARRYING AMOUNT
Financial Assets						
Cash and cash equivalents	17,805,869	—	—	—	17,805,869	17,805,869
Trade and other receivables	7,829,994	—	—	—	7,829,994	7,829,994
Other financial assets	—	—	2,770,782	—	2,770,782	2,770,782
	25,635,863	**—**	**2,770,782**	**—**	**28,406,645**	**28,406,645**
Financial Liabilities						
Trade and other payables	(6,006,532)	—	—	—	(6,006,532)	(6,006,532)
Interest bearing liabilities	(12,232,892)	(4,462,885)	(72,039,417)	—	(88,735,194)	(81,730,053)
Other financial liabilities	—	(2,056,730)	(14,878,886)	—	(16,935,616)	(15,848,507)
	(18,239,424)	**(6,519,615)**	**(86,918,303)**	**—**	**(111,677,342)**	**(103,585,092)**

2018	≤ 6 MONTHS	6–12 MONTHS	1–5 YEARS	≥ 5 YEARS	CONTRACTUAL CASH FLOW	CARRYING AMOUNT
Financial Assets						
Cash and cash equivalents	27,222,845	—	—	—	27,222,845	27,222,845
Trade and other receivables	5,735,333	—	—	—	5,735,333	5,735,333
Other financial assets	2,333,333	—	2,535,915	—	4,869,248	4,869,248
	35,291,511	**—**	**2,535,915**	**—**	**37,827,426**	**37,827,426**
Financial Liabilities						
Trade and other payables	(8,113,667)	—	—	—	(8,113,667)	(8,113,667)
Interest bearing liabilities	(4,982,834)	(4,827,280)	(81,029,340)	—	(90,839,454)	(78,326,559)
Other financial liabilities	—	—	(17,050,028)	—	(17,050,028)	(15,401,106)
	(13,096,501)	**(4,827,280)**	**(98,002,471)**	**—**	**(116,003,149)**	**(101,841,332)**

33. FINANCIAL RISK MANAGEMENT (CONTINUED)

(c) Interest Rate Risk

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

	WEIGHTED AVERAGE EFFECTIVE INTEREST RATE		FLOATING INTEREST RATE		FIXED INTEREST		NON-INTEREST-BEARING		TOTAL	
	2019	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
	%	%	**$**	$	**$**	$	**$**	$	**$**	$
Financial Assets:										
Cash and cash equivalents	1.3	1.7	17,805,869	27,222,845	—	—	—	—	17,805,869	27,222,845
Trade and other receivables	—	—	—	—	—	—	7,829,994	5,735,333	7,829,994	5,735,333
Other financial assets	0.9	1.2	—	—	1,162,597	3,495,930	1,608,185	1,373,318	2,770,782	4,869,248
			17,805,869	**27,222,845**	**1,162,597**	**3,495,930**	**9,438,179**	**7,108,651**	**28,406,645**	**37,827,426**
Financial Liabilities:										
Trade and other payables	—	—	—	—	—	—	(6,006,532)	(8,113,667)	(6,006,532)	(8,113,667)
Interest bearing liabilities	6.8	7.7	(81,730,053)	(78,326,559)	—	—	—	—	(81,730,053)	(78,326,559)
Other financial liabilities	—	—	—	—	—	—	(15,848,507)	(15,401,106)	(15,848,507)	(15,401,106)
			(81,730,053)	**(78,326,559)**	**—**	**—**	**(21,855,039)**	**(23,514,773)**	**(103,585,092)**	**(101,841,332)**
Net Financial Assets / (Liabilities)			**(63,924,184)**	**(51,103,714)**	**1,162,597**	**3,495,930**	**(12,416,860)**	**(16,406,122)**	**(75,178,447)**	**(64,013,906)**

Interest Rate Sensitivity

A sensitivity of 10% has been selected as this is considered reasonable given the current level of both short term and long term interest rates. A 10% movement in interest rates at the reporting date would have increased (decreased) equity and profit and loss by the amounts shown below based on the average amount of interest bearing financial instruments held. This analysis assumes that all other variables remain constant.

The analysis is performed only on those financial assets and liabilities with floating interest rates and is prepared on the same basis as for 2018.

	PROFIT OR LOSS		EQUITY	
	10% Increase	10% Decrease	10% Increase	10% Decrease
2019				
Cash and cash equivalents	22,596	(22,596)	—	—
Interest bearing liabilities	(558,012)	558,012	—	—
2018				
Cash and cash equivalents	46,419	(46,419)	—	—
Interest bearing liabilities	(604,182)	604,182	—	—

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

33. FINANCIAL RISK MANAGEMENT (CONTINUED)

(d) Commodity Risk

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

Under a Gas Sale & Prepayment Agreement entered into in 2016, the customer may elect for a financial settlement in lieu of taking physical delivery of gas. The delivery period commences one year after commissioning of the Northern Gas Pipeline. The financial settlement amount is either a base price per the agreement, or the weighted average price of gas delivered under any new Gas Sales Agreements ("GSA") entered into by the Consolidated Entity and supplied from the production area, or a combination of both. The first new GSA commenced June 2017.

Volume Sensitivity

The financial liability is valued based on achieving take or pay volumes under new GSA's in existence. A sensitivity of 10% has been selected on the deliverable volumes under the new GSA's to show the impact on the carrying value:

	PROFIT OR LOSS		EQUITY	
	10% Increase	10% Decrease	10% Increase	10% Decrease
2019				
Other financial liabilities	—	919,064	—	—
2018				
Other financial liabilities	—	1,040,756	—	—

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

Price Sensitivity

A sensitivity of 1% of the weighted average gas price under new GSA's has been to show the impact on the carrying value of the financial liability:

	PROFIT OR LOSS		EQUITY	
	1% Increase	1% Decrease	1% Increase	1% Decrease
2019				
Other financial liabilities	(157,649)	157,649	—	—
2018				
Other financial liabilities	(152,789)	152,789	—	—

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

(e) Financing Facilities

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

Interest costs are based on fixed spreads over the periodic Bank Bill Swap ("BBSW") average bid rate. The Facility is structured as a five year partially amortising term loan and has a maturity date of 30 September 2020. Repayments commenced December 2015 and comprise fixed quarterly principal repayments of $1,000,000 along with accrued interest (excluding the Second Facility D and Facility E repayments - refer below). The Group does not have any interest rate hedging arrangements in place. Central Petroleum Limited can repay the Facility in part or in whole at any time without a pre-payment penalty.

In April 2018 Macquarie agreed to an increase in the Facility D Commitment by $5,000,000 ("Second Facility D"). This facility was drawn down in September 2018 and is repayable in quarterly instalments over calendar year 2019. The outstanding balance of this facility was $2,500,000 as at 30 June 2019.

33. FINANCIAL RISK MANAGEMENT (CONTINUED)

(e) Financing Facilities (continued)

In September 2018 Macquarie agreed to increase the facility by a further $7,500,000 (“Facility E”). The facility was drawn down in January 2019 and is repayable over nine monthly instalments which commenced in April 2019. $5,001,000 of this facility remains outstanding as at 30 June 2019.

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

1. The Group Current Ratio is at least 1:1, excluding amounts payable under the Macquarie debt facility
2. The Net Present Value with a 10% discount rate (“NPV10”) of forecasted net cash flow from the Palm Valley, Dingo and Mereenie gas fields limited by the sales of only Proved Developed Producing reserves, divided by the outstanding loan amount must be greater than 1.3:1.

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

(f) Currency Risk

The Consolidated Entity’s exposure to currency risk is limited due to its ongoing operations being in Australia and most associated contracts completed in Australian dollars. A foreign exchange risk arises from oil sales denominated in US dollars and from liabilities denominated in a currency other than Australian dollars. The Group generally does not undertake any hedging or forward contract transactions as the exposure is considered immaterial, however, individual transactions are reviewed for any potential currency risk exposure.

At reporting date, the Group had the following exposure to foreign currency risk for balances denominated in US dollars from its continuing operations, which are disclosed in Australian dollars:

	2019 $	2018 $
Trade and other receivables	1,922,863	2,129,035
Trade and other payables	(138,289)	—

The following table details the Group’s sensitivity to a 10% increase or decrease in the Australian dollar against the US dollar, with all other variables held constant. The sensitivity analysis is based on the foreign currency risk exposure at the reporting date.

	2019 $	2018 $
Australian dollar/ US dollar + 10%	(162,234)	(193,549)
Australian dollar/ US dollar -10%	198,286	212,904

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

(g) Fair Values

The carrying amounts of cash, cash equivalents, financial assets and financial liabilities, approximate their fair values.

34. INTERESTS IN JOINT ARRANGEMENTS

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

	PRINCIPAL ACTIVITIES	2019 %	2018 %
OL4, OL5 and PL2 (Mereenie) (Macquarie[1])	Oil & gas exploration	50.00	50.00
EP 82 (Santos[2])	Oil & gas exploration	60.00	60.00
EP 105 (Santos[2])	Oil & gas exploration	60.00	60.00
EP 106 (Santos[2])	Oil & gas exploration	60.00	60.00
EP 112 (Santos[2])	Oil & gas exploration	30.00	60.00
EP 125 (Santos[2])	Oil & gas exploration	30.00	30.00
EP 115 North Mereenie Block (Santos[2])	Oil & gas exploration	60.00	60.00
EPA 111 (Santos[2])	Oil & gas exploration – application	50.00	50.00
EPA 124 (Santos[2])	Oil & gas exploration – application	50.00	50.00
ATP 2031 (IPL[3])	Oil & gas exploration	50.00	—

1 Macquarie = Macquarie Mereenie Pty Ltd

2 Santos = Santos Group companies

3 IPL = Incitec Pivot Limited

The Joint Arrangements are accounted for based on contributions made to the Joint Operated Arrangements on an accruals basis. The principal place of business is Australia.

Santos' right to earn and retain participating interests in each permit is subject to satisfying various obligations in their respective farmout agreement. The participating interests as stated assume such obligations have been met, or otherwise may be subject to change or negotiation.

In June 2018 an agreement was reached with Incitec Pivot Limited ("IPL") to form a 50:50 Joint Venture in respect of ATP 2031 effective on and from the Grant Date. The Queensland government formally awarded the permit to Central in August 2018. Under the agreement IPL will fund $10 million of the Group's joint venture obligations ($20 million in total) for appraisal drilling costs during the initial exploration period.

34. INTERESTS IN JOINT ARRANGEMENTS (CONTINUED)

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

	2019 $	2018 $
Current assets		
Cash and cash equivalents	509,550	516,573
Trade and other receivables	6,224,124	3,546,014
Inventory	1,325,408	1,522,351
Other financial assets	—	416,667
Total current assets	8,059,082	6,001,605
Non-current assets		
Property, plant and equipment	57,519,417	50,050,670
Other financial assets	301,031	393,360
Total non-current assets	57,820,448	50,444,030
Current liabilities		
Trade and other payables	541,019	1,083,012
Accruals	1,275,441	3,273,550
Deferred revenue	730,878	730,878
Total current liabilities	2,547,338	5,087,440
Non-current liabilities		
Deferred revenue	439,497	439,497
Provision for production over-lift	4,008,462	3,541,059
Restoration provision	19,594,978	12,352,212
Total non-current liabilities	24,042,937	16,332,768
Net assets / (liabilities)	39,289,255	35,025,427
Joint arrangement contribution to loss before tax		
Revenue	42,991,825	25,680,706
Other income	22,283	29,662
Expenses	(25,908,972)	(21,646,937)
Profit / (Loss) before income tax	17,105,136	4,063,431

35. EVENTS OCCURRING AFTER THE REPORTING PERIOD

The Queensland and Texas court proceedings with Geoscience Resource Recovery, LLC ("GRR") have settled. The parties filed the relevant paperwork with the Queensland and Texas courts to finalise ending the legal proceedings. The Group has included a provision for the settlement of this matter in the financial statements.

The Dukas exploration well in EP112 (100% free carry by Santos) was suspended after encountering much higher than predicted formation pressures. A forward plan is to be developed over the coming months.

The four well exploration programme in ATP 2031 concluded with encouraging results. Netherland, Sewell & associates (NSAI) has independently certified 2C contingent resources of 270PJs (100% JV) of Walloons coal seam gas.

No other matter or circumstance has arisen that will affect the Group's operations, results or state of affairs, or may do so in future years.

DIRECTORS' DECLARATION

1. In the Directors' opinion:

    a) the financial statements and notes set out on pages 44 to 94 of the Consolidated Entity are in accordance with the *Corporations Act 2001* (Cth), including:

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

        (ii) giving a true and fair view of the Consolidated Entity's financial position as at 30 June 2019 and of its performance for the financial year ended on that date;

    b) there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable; and

    c) the financial statements comply with the International Financial Reporting Standards as issued by the International Accounting Standards Board as disclosed in Note 1(a).

2. This declaration has been made after receiving the declarations required to be made to the Directors in accordance with section 295A of the *Corporations Act 2001* (Cth) for the financial year ended 30 June 2019.

3. As at the date of this declaration, there are reasonable grounds to believe that the members of the Closed Group identified in note 26 will be able to meet any obligations or liabilities to which they are or may become subject by virtue of the Deed of Cross Guarantee between the Company and those members of the Closed Group pursuant to ASIC Corporations (Wholly owned Companies) Instrument 2016/785.

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

Wrixon Gasteen
Director
Brisbane

25 September 2019

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Independent auditor's report

To the members of Central Petroleum Limited

Report on the audit of the financial report

Our opinion

In our opinion:

The accompanying financial report of Central Petroleum Limited (the Group) and its controlled entities (together the Group) is in accordance with the *Corporations Act 2001*, including:

(a) giving a true and fair view of the Group's financial position as at 30 June 2019 and of its financial performance for the year then ended

(b) complying with Australian Accounting Standards and the *Corporations Regulations 2001*.

What we have audited

The Group financial report comprises:

- the consolidated statement of financial position as at 30 June 2019
- the consolidated statement of changes in equity for the year then ended
- the consolidated statement of cash flows for the year then ended
- the consolidated statement of profit or loss and other comprehensive income for the year then ended
- the notes to the consolidated financial statements, which include a summary of significant accounting policies
- the declaration of the directors.

Basis for opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial report* section of our report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Independence

We are independent of the Group in accordance with the auditor independence requirements of the *Corporations Act 2001* and the ethical requirements of the Accounting Professional and Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants (including Independence Standards)* (the Code) that are relevant to our audit of the financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

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Our audit approach

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

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

Materiality	*Audit scope*	*Key audit matters*
• For the purpose of our audit we used overall Group materiality of $1.6 million, which represents approximately 1% of the Group's total assets. • We applied this threshold, together with qualitative considerations, to determine the scope of our audit and the nature, timing and extent of our audit procedures and to evaluate the effect of misstatements on the financial report as a whole. • We chose Group's total assets because it is a generally accepted benchmark in the oil and gas industry for entities of a similar size and stage of development. • We utilised a 1% threshold based on our professional judgement, noting it is within the range of commonly acceptable thresholds.	• Our audit focused on where the Group made subjective judgements; for example, significant accounting estimates involving assumptions and inherently uncertain future events. • The accounting processes are structured around the Group finance function located in Brisbane.	• Amongst other relevant topics, we communicated the following key audit matters to the Audit and Risk Committee: – Basis of preparation of the financial report – Accounting for asset retirement obligations • These are further described in the *Key audit matters* section of our report.

Key audit matters

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

Key audit matter	*How our audit addressed the key audit matter*
Basis of preparation of the financial report *Refer to note 1(a)(i) of the financial report* As described in Note 1 to the financial report, the financial statements have been prepared by the Group on a going concern basis, which contemplates that the Group will continue to meet its commitments, realise its assets and settle its liabilities in the normal course of business. Assessing the appropriateness of the Group's basis of preparation for the financial report was a key audit matter due to its importance to the financial report and the level of judgement involved in assessing future funding and operational status, in particular with respect to the Group forecasting future cash flows for a period of at least 12 months from the date of the financial report (cash flow forecasts).	The Group have prepared a going concern position paper and a cash flow forecast model (the model) which concludes that the Group is a going concern for a period of at least 12 months from the date of signing the financial report. We considered this paper and model, focussing specifically on: • Evaluated the appropriateness of the Group's assessment as to their ability to continue as a going concern, including; whether the level of analysis is appropriate given the nature of the Group; checking that the period covered is at least 12 months from the date of the auditor's report; and that relevant information of which the auditor is aware as a result of the audit has been considered; • Enquired of management and the board of directors as to its knowledge of events or conditions that may cast doubt on the Group's ability to continue as a going concern; • Assessed the cash flow forecast by evaluating the reliability of selected underlying data and considered selected evidence around key assumptions in the Group's cash flow forecasts; • Performed a sensitivity analysis by varying key assumptions, including revenue and expenditure, in the cash flow forecasts, to assess the impact on financing facilities utilised in the event that actual performance varies from that assumed in the Group's forecasts; • Obtained an understanding from management and the Board of Directors regarding their plans for future action and the feasibility of these plans, including the availability of alternative sources of funds, if required;

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Key audit matter	*How our audit addressed the key audit matter*
	• Read the terms associated with the existing debt facility agreement and draft terms from potential financiers and assessed the amount and terms, including maturity date, of the facility available; In relation to the financial statement disclosures, we considered the going concern basis of preparation disclosures in note 1 (a) (i) and their consistency with the Group's going concern position paper and model.
Accounting for asset retirement obligations *Refer to note 17 of the financial report* The Group has legal, environmental or constructive obligations to rehabilitate sites, either during or at the end of their operations. The Group have recorded a provision of $38.8 million for this rehabilitation obligation at 30 June 2019. We considered this a key audit matter given that the estimation of rehabilitation provisions involves significant judgment by the Group on the required rehabilitation activities, cost of rehabilitation activities, timing of rehabilitation, inflation and discount factors, amongst other matters. Further, the carrying amount of the provision is material for the Group.	Our audit procedures included assessing the appropriateness of the key assumptions underlying the rehabilitation provision calculation through: • developing an understanding of the extent of field development and production activity through enquiries with operations management and consideration of site restoration plans prepared by environmental experts (the experts); • assessment of the provision calculations to check that they incorporate the restoration activities required as advised by the experts and that the experts' estimated costs of conducting those activities are included in the calculation; • assessment of the competence and objectivity of the experts; • assessment of the cash flows and production profiles, and reserve estimation for timing of rehabilitation; • tested the consistency of the application of principles and assumptions to other areas of the audit, such as reserve estimation and impairment testing, • corroborating a sample of estimates in the rehabilitation provision calculations to third party evidence; • tested the mathematical accuracy of the Group's present value calculations and considered the appropriateness of the discount rate applied in the calculation; and • agreed the calculations to the financial statements.

Other information

The directors are responsible for the other information. The other information comprises the information included in the annual report for the year ended 30 June 2019, but does not include the financial report and our auditor's report thereon.

Our opinion on the financial report does not cover the other information and accordingly we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial report, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial report or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

If, based on the work we have performed on the other information that we obtained prior to the date of this auditor's report, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of the directors for the financial report

The directors of the Group are responsible for the preparation of the financial report that gives a true and fair view in accordance with Australian Accounting Standards and the *Corporations Act 2001* and for such internal control as the directors determine is necessary to enable the preparation of the financial report that gives a true and fair view and is free from material misstatement, whether due to fraud or error.

In preparing the financial report, the directors are responsible for assessing the ability of the Group to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the Group or to cease operations, or have no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial report

Our objectives are to obtain reasonable assurance about whether the financial report as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with the Australian Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial report.

A further description of our responsibilities for the audit of the financial report is located at the Auditing and Assurance Standards Board website at: http://www.auasb.gov.au/auditors_responsibilities/ar1.pdf. This description forms part of our auditor's report.

Report on the remuneration report

Our opinion on the remuneration report

We have audited the remuneration report included in pages 26 to 38 of the directors' report for the year ended 30 June 2019.

In our opinion, the remuneration report of Central Petroleum Limited for the year ended 30 June 2019 complies with section 300A of the *Corporations Act 2001*.

Responsibilities

The directors of the Group are responsible for the preparation and presentation of the remuneration report in accordance with section 300A of *the Corporations Act 2001*. Our responsibility is to express an opinion on the remuneration report, based on our audit conducted in accordance with Australian Auditing Standards.

PricewaterhouseCoopers

PricewaterhouseCoopers

Tim Allman
Partner

Brisbane
25 September 2019

ASX ADDITIONAL INFORMATION

DETAILS OF QUOTED SECURITIES AS AT 19 SEPTEMBER 2019

Top holders

The 20 largest registered holders of the quoted securities as at 19 September 2019 were:

	NAME	NO. OF SHARES	%
1.	UBS Nominees Pty Ltd	31,873,994	4.41
2.	Citicorp Nominees Limited	19,218,035	2.66
3.	Mr. Christopher Ian Wallin + Ms Fiona Kay McLoughlin + Mrs Sylvia Fay Bhatia <Chris Wallin Super Fund A/C>	17,571,648	2.43
4.	Fanchel Pty Ltd	17,000,000	2.35
5.	Norfolk Enchants Pty Ltd <Trojan Retirement Fund A/c>	16,260,000	2.25
6.	Rocket Science Pty Ltd <The Trojan Capital Fund A/C>	15,800,000	2.19
7.	Macquarie Bank Limited <Metals Mining and AG A/C>	14,166,667	1.96
8.	J P Morgan Nominees Australia Limited	11,349,717	1.57
9.	HSBC Custody Nominees (Australia) Limited – A/C 2	8,617,285	1.19
10.	Kensington Capital Partners Pty Ltd	7,400,000	1.02
11.	JH Nominees Australia Pty Ltd <Harry Family Super Fund A/C>	6,700,000	0.93
12.	CS Fourth Nominees Pty Limited <HSBC CUST NOM AU LTD 11 A/C>	6,494,837	0.90
13.	Brazil Farming Pty Ltd	5,300,000	0.73
14.	Morgan Stanley Australia Securities (Nominee) Pty Limited <NO 1 Account>	5,095,143	0.71
15.	Mr James Donald Bruce Cochrane + Mrs Joan Elizabeth Cochrane <Bruce & Joan Cochrane A/C>	5,000,001	0.69
16.	Chembank Pty Limited <R T Unit A/C>	5,000,000	0.69
16.	Dynasty Peak Pty Ltd <The Avoca Super Fund A/C>	5,000,000	0.69
18.	Edwin Holdings Pty Ltd	4,604,167	0.64
19.	Justwright Investments Pty Ltd <Justwright Super Fund A/C>	4,500,000	0.62
20.	Mr Philip Gasteen <Thrushton Investment A/C>	4,462,840	0.62
		211,414,334	29.27

DISTRIBUTION SCHEDULE

A distribution schedule of the number of holders in each class of equity securities as at 19 September 2019 was:

	NUMBER OF HOLDERS		
SIZE OF HOLDING	LISTED FULLY PAID SHARES	UNLISTED SHARE RIGHTS	UNLISTED OPTIONS
1 - 1,000	769	—	—
1,001 -5,000	2,000	2	—
5,001 - 10,000	1,066	10	—
10,001 - 100,000	2,853	54	—
100,001 - Over	1,000	38	5
Total	7,688	104	5

SUBSTANTIAL SHAREHOLDERS

Substantial shareholders as disclosed by notices received by the Company as at 19 September 2019 with holdings of 5% or more of the total votes attached to the voting shares or interests in the Entity:

HOLDER	UNITS
Troy Harry	46,160,000

ASX ADDITIONAL INFORMATION

UNMARKETABLE PARCELS

Holdings less than a marketable parcel of ordinary shares (being 2,500 shares as at 19 September 2019):

HOLDERS	UNITS
1,790	2,132,120

VOTING RIGHTS

Subject to any rights or restrictions for the time being attached to any class or classes of shares, at meetings of shareholders or classes of shareholders:

- each shareholder entitled to vote may vote in person or by proxy, attorney or representative of a shareholder;
- on a show of hands, every person present who is a shareholder or a proxy, attorney or representative of a shareholder has one vote; and
- on a poll, every person present who is a shareholder shall, in respect of each fully paid share held by him, or in respect of which he is appointed a proxy, attorney or representative, have one vote for their share, but in respect of partly paid shares, shall have such number of votes being equivalent to the proportion which the amount paid (not credited) is of the total amounts paid and payable in respect of those shares (excluding amounts credited).

ON-MARKET BUY BACK

There is no current on-market buy-back.

CORPORATE GOVERNANCE STATEMENT

Central Petroleum Limited and its Board are committed to achieving and demonstrating high standards of corporate governance. The Company has reviewed its corporate governance practices against the Corporate Governance Principles and Recommendations (3rd edition) published by the ASX Corporate Governance Council.

The 2019 Corporate Governance Statement is dated as at 30 June 2019 and reflects the corporate governance practices in place throughout the 2019 financial year. The Company's Corporate Governance Statement undergoes periodic review by the Board. A description of the Group's current corporate governance practices is set out in the Group's Corporate Governance Statement which can be viewed at www.centralpetroleum.com.au/about/corporate-governance/.

INTERESTS IN PETROLEUM PERMITS AND PIPELINE LICENCES AT THE DATE OF THIS REPORT

PERMITS AND LICENCES GRANTED

TENEMENT	LOCATION	OPERATOR	CTP CONSOLIDATED ENTITY		OTHER JV PARTICIPANTS	
			Registered Interest (%)	Beneficial Interest (%)	Participant Name	Beneficial Interest (%)
EP 82 (excl. EP 82 Sub-Blocks) [1]	Amadeus Basin NT	Santos	60	60	Santos QNT Pty Ltd ("Santos")	40
EP 82 Sub-Blocks	Amadeus Basin NT	Central	100	100		
EP 93 [4]	Pedirka Basin NT	Central	100	0		
EP 97 [4]	Pedirka Basin NT	Central	100	0		
EP 105 [1]	Amadeus/Pedirka Basin NT	Santos	60	60	Santos	40
EP 106 [3]	Amadeus Basin NT	Santos	60	60	Santos	40
EP 107 [4]	Amadeus/Pedirka Basin NT	Central	100	0		
EP 112 [1]	Amadeus Basin NT	Santos	30	30	Santos	70
EP 115 (excl. EP 115 North Mereenie Block)	Amadeus Basin NT	Central	100	100		
EP 115 North Mereenie Block	Amadeus Basin NT	Santos	60	60	Santos	40
EP 125	Amadeus Basin NT	Santos	30	30	Santos	70
OL 3 (Palm Valley)	Amadeus Basin NT	Central	100	100		
OL 4 (Mereenie)	Amadeus Basin NT	Central	50	50	Macquarie Mereenie Pty Ltd ("Macquarie Mereenie")	50
OL 5 (Mereenie)	Amadeus Basin NT	Central	50	50	Macquarie Mereenie	50
L 6 (Surprise)	Amadeus Basin NT	Central	100	100		
L 7 (Dingo)	Amadeus Basin NT	Central	100	100		
RL 3 (Ooraminna)	Amadeus Basin NT	Central	100	100		
RL 4 (Ooraminna)	Amadeus Basin NT	Central	100	100		
ATP 909	Georgina Basin QLD	Central	100	100		
ATP 911	Georgina Basin QLD	Central	100	100		
ATP 912	Georgina Basin QLD	Central	100	100		
ATP 2031 [6]	Surat Basin QLD	Central	50	50	Incitec Pivot Queensland Gas Pty Ltd	50

PERMITS AND LICENCES UNDER APPLICATION

TENEMENT	LOCATION	OPERATOR	CTP CONSOLIDATED ENTITY		OTHER JV PARTICIPANTS	
			Registered Interest (%)	Beneficial Interest (%)	Participant Name	Beneficial Interest (%)
EPA 92	Lander Trough NT	Central	100	100		
EPA 111 [2]	Amadeus Basin NT	Santos	100	50	Santos	50
EPA 120	Amadeus Basin NT	Central	100	100		
EPA 124 [2 & 5]	Amadeus Basin NT	Santos	100	50	Santos	50
EPA 129	Lander Trough NT	Central	100	100		
EPA 130	Pedirka Basin NT	Central	100	100		
EPA 131 [4]	Pedirka Basin NT	Central	100	100		
EPA 132	Georgina Basin NT	Central	100	100		
EPA 133	Amadeus Basin NT	Central	100	100		
EPA 137	Amadeus Basin NT	Central	100	100		
EPA 147	Amadeus Basin NT	Central	100	100		
EPA 149	Amadeus Basin NT	Central	100	100		
EPA 152 [5]	Amadeus Basin NT	Central	100	100		
EPA 160	Lander Trough NT	Central	100	100		
EPA 296	Lander Trough NT	Central	100	100		

INTERESTS IN PETROLEUM PERMITS AND PIPELINE LICENCES AT THE DATE OF THIS REPORT

PIPELINE LICENCES

PIPELINE LICENCE	LOCATION	OPERATOR	CTP CONSOLIDATED ENTITY		OTHER JV PARTICIPANTS	
			Registered Interest (%)	Beneficial Interest (%)	Participant Name	Beneficial Interest (%)
PL 2	Amadeus Basin NT	Central	50	50	Macquarie Mereenie	50
PL 30	Amadeus Basin NT	Central	100	100		

Notes:

1 *Santos' right to earn and retain participating interests in the permit is subject to satisfying various obligations in their farmout agreement with Central. The participating interests as stated assume such obligations have been met, otherwise may be subject to change.*

2 *Effective 1 May 2017, Santos exercised its option to acquire a 50% participating interest in and be appointed operator of EPA 111 and EPA 124, which was granted as part of Central's acquisition of a 50% interest in the Mereenie oil & gas field.*

3 *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.*

4 *These exploration permits and exploration permit applications and have been disposed, with transfers for the granted exploration permits undergoing the process of registration with the NT Department of Primary Industry and Resources.*

5 *On 22 March 2018 (in respect EPA 124) and on 23 March 2018 (in respect of EPA 152) Central received notice from the NT Department of Primary Industry and Resources that EPA 124 and EPA 152, as applicable, had been placed in moratorium for a period of 5 years from 6 December 2017 until 6 December 2022.*

6 *As per Central's announcement dated 29 August 2018, Central was granted ATP 2031. As per Central's announcement dated 25 June 2018 ATP 2031 is subject to a 50:50 joint venture with Incitec Pivot.*

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