2015 Annual Report

Central Petroleum Limited

ABN 72 083 254 308

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CORPORATE DIRECTORY

DIRECTORS

Robert Hubbard FCA, Non-executive Chairman
Andrew P Whittle BSc (Hons), Non-executive Director
Richard I Cottee BA, LLB (Hons), Managing Director and Chief Executive Officer
Wrixon F Gasteen BE (Hons), MBA (Dist), Non-executive Director
J. Thomas Wilson BSc, MSc, Non-executive Director
Peter S Moore BSc (Hons1), MBA, PhD, Non-executive Director

GROUP GENERAL COUNSEL AND JOINT COMPANY SECRETARY

Daniel C M White LLB, BCom, LLM

JOINT COMPANY SECRETARY

Joseph P Morfea FAIM, GAICD

REGISTERED OFFICE

Level 32, 400 George Street, Brisbane, Queensland 4000
Telephone: +61 7 3181 3800
Facsimile: +61 7 3181 3855
www.centralpetroleum.com.au

AUDITORS

PricewaterhouseCoopers
123 Eagle Street, Brisbane, Queensland 4000

BANKERS

ANZ Banking Group
111 Eagle Street, Brisbane, Queensland 4000

SHARE REGISTER

Computershare Investor Services Pty Limited
117 Victoria Street, West End, Queensland 4101
Telephone: +61 7 3237 2110
Fax: +61 3 9473 2085
www.computershare.com.au

STOCK EXCHANGE LISTING

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

CHAIRMAN'S LETTER

A MESSAGE FROM ROBERT HUBBARD

Dear Fellow Shareholder

This is my first letter to you as Chairman of Central Petroleum Limited and I look forward to seeing many of you at our upcoming AGM.

The Annual Report is necessarily a scorecard for the past year and our operating and financial review draws out the many activities and outcomes that your company has achieved throughout the year. In particular though, Central responded quickly to the oil price dive with the necessary cost reductions, closure of Surprise and the use of alternate funding sources rather than equity placements which would dilute our many long term loyal shareholders. We have not accessed the equity markets since this time last year in an effort to preserve the value of our existing shareholders wherever possible and in fact only once in the last 24 months. The acquisition of Mereenie should now make Central cash flow positive before elective exploration expenditure after completion of the acquisition.

However, the real achievement for the year is the continued transition of your Company from opportunistic explorer to a substantial domestic gas producer. In 2014 we acquired the Magellan assets, in 2015 we completed the development and commissioned Dingo and concluded the year with the acquisition of 50 percent of the Mereenie oil and gas field, where we are now the Operator. Our financial performance over the 2015 financial year reflects these transitional dynamics as we developed gas production and pipeline infrastructure, ramped up our contracted sales, increased equity accounted reserves and consolidated substantial operations under Central's Operatorship. We are now running on all cylinders with fixed-price gas contracts underpinning operations and financing, and significant potential upside exposure through uncontracted gas reserves.

All of this change has been achieved with an exemplary safety and environmental performance and a real commitment to the local communities within which we operate. We are passionate about making a difference for those communities and increasing the participation of traditional owners in our activities and generally at Alice Springs. Taking the employment at Palm Valley and Dingo before Central assumed operatorship, 9 percent were indigenous employees and 88 percent were employed from outside the local area. Under our operatorship, some 22.5 percent of our operating employees are indigenous and the number employed within the local area has increased to 40 percent. When NEGI occurs those employed locally should see a further increase to well over the majority.

Looking to the future, Richard Cottee and his executive team have positioned your Company to take full advantage of the North East Gas Interconnector (NEGI). Central has played a leadership role in the promotion of NEGI, a pipeline that will not only provide markets for our reserves and significant exploration potential but also a catalyst for microeconomic reform in the gas sector. We grow increasingly confident that NEGI should become a reality.

Central's achievements are a team effort and I would like to thank my colleagues on the Board, the senior executives and rest of the team at Central. In particular, we all appreciate the leadership and guidance that Andy Whittle has provided as Chairman until recently. Andy will step down from the board at the upcoming AGM and his leadership and guidance has been instrumental to the transformation of Central. We wish Andy well with his future endeavours.

Finally, my last thank you is to you, our shareholders for your ongoing support and encouragement.

Best wishes

Robert Hubbard
Chairman
Brisbane
23 September 2015

MANAGING DIRECTOR'S LETTER

Dear Fellow Shareholder

DOMESTIC GAS MARKET – THE BRIDGE OVER TROUBLED WATERS

The last 12 months has seen the industry face difficult times (not seen since the late 1980's) with Brent Crude Oil Price dropping over 50 percent in that period. This has been the prime cause of the share price drop of all oil and gas companies with the ASX Energy Index dropping around 40 percent in the last 12 months. For Central the major impact has been that the access to the equity markets have either become too expensive or difficult to access. In the last 24 months Central has only raised $6 million from the equity markets yet at the same time has acquired the gas fields at Palm Valley and Dingo and 50 percent interest in the Mereenie oil and gas field as well as constructing the Dingo gas field and the associated pipeline to Alice Springs.

Two years ago, Central embarked on a strategy to become a significant gas producer in domestic gas market. This culminated in the purchase of the Dingo and Palm Valley gas fields last year and this year in the 50 percent acquisition of the Mereenie Field together with assumption of operatorship of that field. In April last year the AFR reported that Central was agitating for the Northern Territory to be interconnected with the Eastern Seaboard gas markets. By October this concept was endorsed at the Council of Australian Governments (COAG) Meeting and in this year's Federal Budget concessional loans were provided for what is now called the North East Gas Interconnector (NEGI). The process was narrowed down to four bidders in April and two of the four bidders have publicly stated that they will build NEGI without government support. Final bids have to be lodged by the end of September with a final decision around the end of October this year. With no government funding being needed, the real question is not whether it is going to be built but whether what is built is capacity constrained or capable of being cheaply upgraded once further reserves are discovered.

Regardless of which route is selected your company will be one of the three initial company's whose gas will be transported through NEGI. Fields under Central's operatorship will contribute the majority of the gas. Any gas we sell will be sold in $A and indexed to Australian inflation fixed for up to 10 years. Whilst the oil price has halved in the last 12 months (and with some gas prices linked to oil), the domestic gas prices as reflected in the Wallumbilla Hub Spot Price has risen by over 200 percent. The opportunity for the company to secure its future on record high domestic contracts over the whole of the next resources cycle beckons. Surely a bridge over the troubled waters.

With our 200,000 square kilometres of exploration acreage predominantly gas prone having an access to market for that acreage upon exploration success must surely re-rate the value of that acreage.

Central has presently 230 PJ of gas presently discovered available for NEGI even before our $10 million Pre-NEGI programme's results are known. Central has been involved in marketing this gas and has been given indicative tariffs for the NEGI pipeline from the various proponents. Using that information the NPV of that 230 PJ is worth over three times our present market capitalisation. As NEGI approaches its first gas stage this NPV increases.

Central has existing installed capacity to deliver to the NEGI pipeline of over 20 PJ pa and so not much new built capital will be required before first gas. The capital costs of connecting into NEGI will be low and able to be accommodated within the existing financial accommodation.

In summary your company is positioned to take advantage of the historically high domestic gas prices at a time of cost-deflation occasioned by the commodity downturn. A virtuous cycle if ever there was one.

Richard Cottee
Managing Director
Brisbane
23 September 2015

DIRECTORS' REPORT
FOR THE YEAR ENDED 30 JUNE 2015

Your directors present their report on the consolidated entity, consisting of Central Petroleum Limited ("Company" 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 2015.

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.

Robert Hubbard
Andrew P Whittle
Richard I Cottee
Wrixon F Gasteen
J. Thomas Wilson
Peter S Moore
William J Dunmore *(retired, effective 26 November 2014)*
Michael R Herrington *(retired, effective 26 November 2014)*

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 (2014: $Nil). No recommendation for payment of dividends has been made.

OPERATING AND FINANCIAL REVIEW

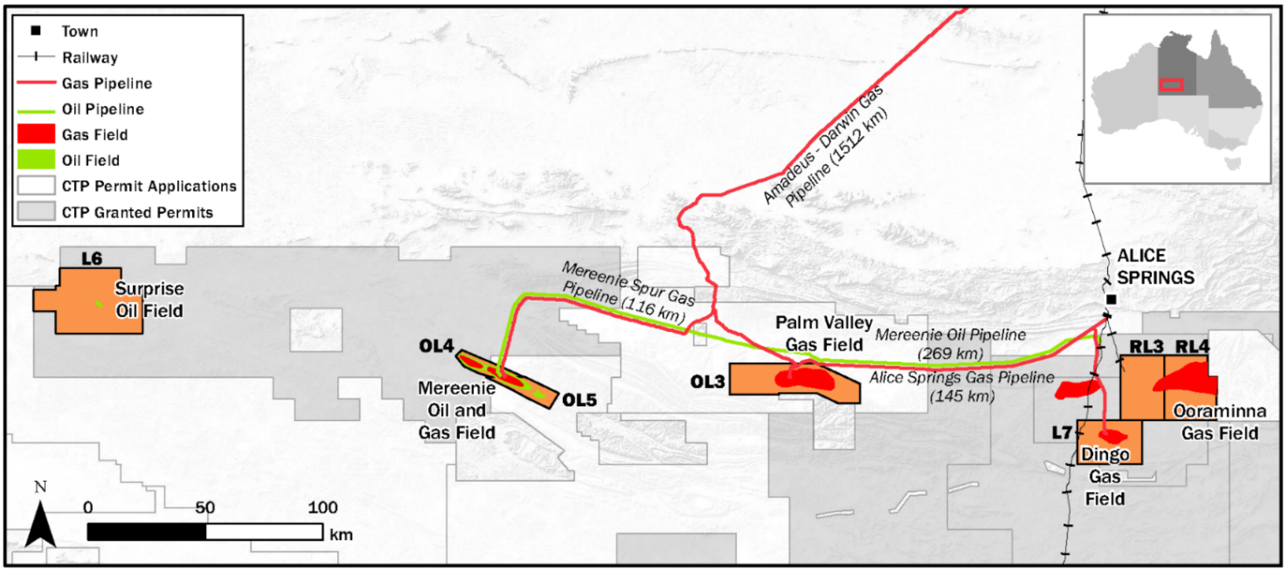
Operating Highlights

The Company's focus for the year was as follows:

- NEGI project continues to gain momentum.
- Mereenie acquisition announced with subsequent completion and Operatorship assumed.
- Dingo development project completed on time and under budget.
- Palm Valley produced 1.2 PJ of gas in the financial year. Palm Valley responded to Northern Territory wide gas interruption within hours to help offset loss of supply.
- Drilling of two Southern Georgina unconventional gas exploration wells prior to wet season.
- Inaugural reserve bookings to Central across three fields.
- Progressed evaluation of Stage 1 exploration results in the Southern Amadeus Basin, principally wireline logging of the Mt Kitty gas well, and integrating ~1,580 km 2D seismic with potential field and outcrop data. This is to locate the planned ~1,300 km 2D seismic which Santos committed to under Stage 2, and is Operator of the farm-in program.
- Identified and progressed delineation of exploration targets beneath and near to the Palm Valley field.
- Identified Dingo satellite leads and Palm Valley deep appraisal target.
- Progressed evaluation of Ooraminna gas discovery.
- Acquired and interpreted gravity data over Western Amadeus application areas and Wiso Basin, thus improving structural definition.
- Progressed negotiations on application areas in the Amadeus Basin and Wiso Basin.

Operating Result

The Consolidated Entity had an operating loss after income tax for the year ended 30 June 2015 of $27,731,000 (2014: loss of $10,858,000). This result was recorded after expensing exploration expenditure totaling $7,656,000 (2014: $4,660,000) and impairments totaling $12,092,000 ($2014: $Nil) due in part to the decrease in oil prices. Operating loss for the year before the foregoing expenditures and after income tax was $7,983,000 (2014: Loss of $6,198,000). It should also be noted that gas sales revenues for the year reflect the anticipated ramp-up in sales from the Palm Valley gas field (contract sales began May 2015) and do not include the Take-or-Pay revenue associated with the Dingo gas field ($2.2 million) which, under the terms of the Power and Water Corporation Gas Sales Agreement (PWC GSA), are payable in January 2016 (refer Note 1(e)(i)).



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

Key results for the reporting period were:

- **Sales Volumes** of 54,374 barrels of crude oil from Surprise (2014: 22,858 barrels) and 1,194 TJ of gas from Palm Valley (2014: 278 TJ). This was the first full year of production for Central from both fields. Whilst the Dingo gas field development was completed on 1 April 2014, the field is awaiting physical tie-in by the customer before physical production can commence.
- **Sales Revenue** of $10.3 million up 77 percent on the previous financial year reflecting increased production. An average oil price of A$93 was realised during the year down from A$142 in the prior corresponding period. Realised gas prices remain consistent with the prior year.
- **Research and Development** refunds totaling $7.32 million were recognised as other income (2014: $1.20 million). The refunds recorded during this period comprise $3.25 million in respect of the financial year ended 30 June 2014 and $4.07 million in respect of the financial year ended 30 June 2015 which is recognised as a receivable at year end as it was received in September 2015.
- **Underlying loss**[1] of $15.64 million. The statutory loss after tax was $27.73 million, up from a statutory loss of $10.86 million in the previous financial year. The result included non-cash impairment of the Surprise oil property amounting to $5.42 million and impairment of previously capitalised exploration properties of $6.57 million caused primarily by the fall in oil prices.
- **Exploration expenditure** of $7.66 million up from $4.66 million in the previous financial year reflecting increased drilling activities in the Southern Georgina Basin.

[1] Underlying loss after tax can be reconciled to statutory loss after tax as follows:

	2015 $ million	2014 $ million
Statutory loss after tax	(27.73)	(10.86)
Add/(less):		
Business combination transaction fees	—	1.91
Impairment of exploration assets	6.57	—
Impairment of oil producing properties	5.42	—
Impairment of real property	0.10	—
Underlying loss after tax	**(15.64)**	**(8.95)**

Financial Review

The Company continued its transformation from an exploration company to an exploration and production company during the year ended 30 June 2015. The increased underlying loss is largely reflective of increased exploration expenditure during the year associated with drilling activities in the Southern Georgina Basin in a joint venture with Total.

Key Metrics	2015	2014	Year on Year Change
Net Sales Volumes			
Oil (barrels)	53,925	17,489	211%
Natural Gas (TJ)	1,194	267	347%
Average realised oil price (A$ per barrel)	92.93	142.47	(35%)
Sales revenue ($ million)	10.31	3.72	177%
Underlying Loss[1] ($ million)	15.64	8.95	(75%)
Statutory loss (after tax)	27.73	10.86	(155%)
Cash ($ million)	3.52	10.33	(66%)

Sales Volumes

Sales volumes for both oil and gas increase substantially from 2014.

Surprise oil field: sales from the Surprise oil field increased by 211 percent from the prior year, reflecting its first full year of production. The low oil prices and the remoteness of the Company's Surprise oil field has led to the decision to temporarily shut-in oil production from this field in August 2015 to allow the Company to assess the re-charge potential of the field. Should oil prices recover significantly in $A terms, production can re-commence after assessing the pressure build-up.

Palm Valley gas field: sales under the Palm Valley GSA with Santos reflect its first full year of production (having been acquired by Central in April 2014) and the anticipated ramp-up in nominations through to May, from which point sales are anticipated to be consistent with the 1.71 PJ/year ongoing annual contract quantity. May 2015 was the first month in which sales reflected maximum daily contract quantities.

Dingo gas field: The PWC GSA (Power and Water Corporation Gas Sales Agreement) commenced on 1 April 2015, but is constrained awaiting the customer's physical tie-in to the Dingo delivery point. For the 3 month period following commencement of the GSA on 1 April 2015, a total of 150 TJ was sold from the Palm Valley gas field, with a total of 361 TJs subject to Take-or-Pay arrangements. In accordance with the PWC GSA, revenue associated with Take-or-Pay during a calendar year is payable in January of the following year. For the current period, $2.2 million in Take-or-Pay revenue will become payable in January 2016 and has therefore not been recognised in this reporting period (refer Note 1(e)(i)).

Commodity Prices

In line with the decline in world crude oil prices, and partly offset by a lower Australian dollar, the average realised price per barrel of oil declined 35 percent on the previous financial year. In financial terms this represented a reduction in revenue of approximately $2.7 million based on 2015 oil sales.

Gas prices under the Palm Valley GSA and the PWC GSA generally reflect long-term fixed gas pricing structures with CPI related escalation, and are therefore not impacted by recent weakness in global energy markets.

Other Income

Research and Development refunds totaling $7.32 million were recognised as income (2014: $1.20 million). The 2015 income included refunds in respect of the financial year ended 30 June 2014 of $3.25 million and $4.07 million in respect of the financial year ended 30 June 2015 which is recognised as a receivable at year end as it was received in September 2015.

General and Administrative Expenses

General and administrative expenses net of recoveries decreased from $2.52 million in fiscal year 2014 to $1.94 million in fiscal year 2015. The decrease was a result of cost savings implemented in response to the lower oil prices and increased recoveries from both sole and joint venture operations generated by increased activity.

Financial Review (continued)

Employee benefits and associated costs

Employee costs increased to $5.02 million from $3.1 million in the previous financial year. The increase reflects a full year of corporate, Palm Valley and Dingo manpower.

EBITDAX

The Statutory Loss after tax was $27.73 million, up from $10.86 million in the previous financial year. The statutory loss was heavily impacted by non-cash impairment charges of $12.09 million and exploration expenditure of $7.66 million. The decrease in EBITDAX was primarily due to higher research and development refunds of $6.13 million and lower business combination costs of $1.91 million. These were partly offset by lower oil prices.

Loss before interest, tax, depreciation, amortisation, impairment and exploration expense (EBITDAX[1]) decreased to $1.67 million, compared to a loss of $8.45 million in the prior year.

[1] A reconciliation of EBITDAX is shown below.

	2015 $ million	2014 $ million
Statutory loss after tax	(27.73)	(10.86)
Add/(less):		
Net interest	3.60	0.73
Income tax	—	(4.11)
Depreciation and amortisation	2.71	1.13
Impairment of assets	12.09	
EBITDA	**(9.33)**	(13.11)
Exploration expense	7.66	4.66
EBITDAX	**(1.67)**	(8.45)

The resulting EBITDAX loss of $1.67 million reflects a period of substantial transition in Central's operations. The operating and depreciation costs for Palm Valley reflect its first full year of operations, however, gas sales were in a period of anticipated ramp-up and did not achieve full contracted volumes until May 2015. In addition, Dingo operating and depreciation costs commenced from 1 April 2015 even though Take-or-Pay revenue of $2.2 million that was generated to 30 June 2015 was not recognised during the reporting period. This Take-or-Pay revenue is payable in January 2016 and will be accounted for in the financial year ending 2016 (refer Note 1(e)(i)).

Cash

At 30 June 2015 consolidated cash and cash equivalents available totaled $3,516,139 (2014: $10,330,474), including $261,827 (30 June 2014: $1,590,386) held in joint venture. Available to the Company at 30 June 2015 was $2.7 million in undrawn debt facilty.

Capital Expenditure

Capital expenditure of $20.85 million (2014: $46.1 million) relating largely to completion of the Dingo pipeline and gas processing facilities.

Financial Review (continued)

Comparative Data

The following table and discussion is a one year (and five year) comparative analysis of the Consolidated Entities' 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.

	2015 $ million	2014 $ million	2013 $ million	2012 $ million	2011 $ million
Financial Data					
Operating revenue	10.31	3.72	—	—	—
Exploration expenditure	7.66	4.66	6.98	18.72	31.34
Loss after income tax	27.73	10.86	9.28	26.36	36.64
Equity issued during year	5.56	24.97	7.56	23.60	5.90
Property, plant and equipment	58.58	46.27	1.28	1.78	0.83
Borrowings	(47.46)	(23.76)	—	—	—
Net Assets (Total Equity)	23.15	43.07	24.65	24.20	25.90
Net Working Capital	(4.41)	2.78	4.93	10.64	12.14
Operating Data					
Gas Sales (GJ)	1,194,153	267,328	—	—	—
Oil Sales (barrels)	53,925	17,489	—	—	—
No. of employees at 30 June	58	51	26	17	19

Risks

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

By its nature exploration is an extremely high risk business. Most exploration activity, in particular seismic and drilling is conducted in joint venture, thus enabling the joint venture participants to spread that risk, and reward.

The risks include, but are not limited to, land access risk, geological risk, drilling operations risk, safety and environment. In addition, as with most businesses there is also market risk, product pricing risks and foreign exchange risk. Exploration is typically funded with risk capital. Debt capital is normally only available for development activities such as facility and pipeline construction.

Over the past year, Central has substantially increased operating activities, notably in the production and sale of oil and gas. Central's operations have a significantly different risk profile compared to exploration. Central's key operating risks include changes in operating costs, changes in capital maintenance and replacement costs, plant availability and sub-surface extraction. In addition, Central is exposed to changes in $A commodity prices with respect to crude oil sales which are benchmarked against $US international markets. The majority of Central's revenues, however, are generated by gas sales which effectively mitigates $A commodity price risk through the use of long-term, $A fixed price gas sales agreements with credit worthy customers.

Business Strategy

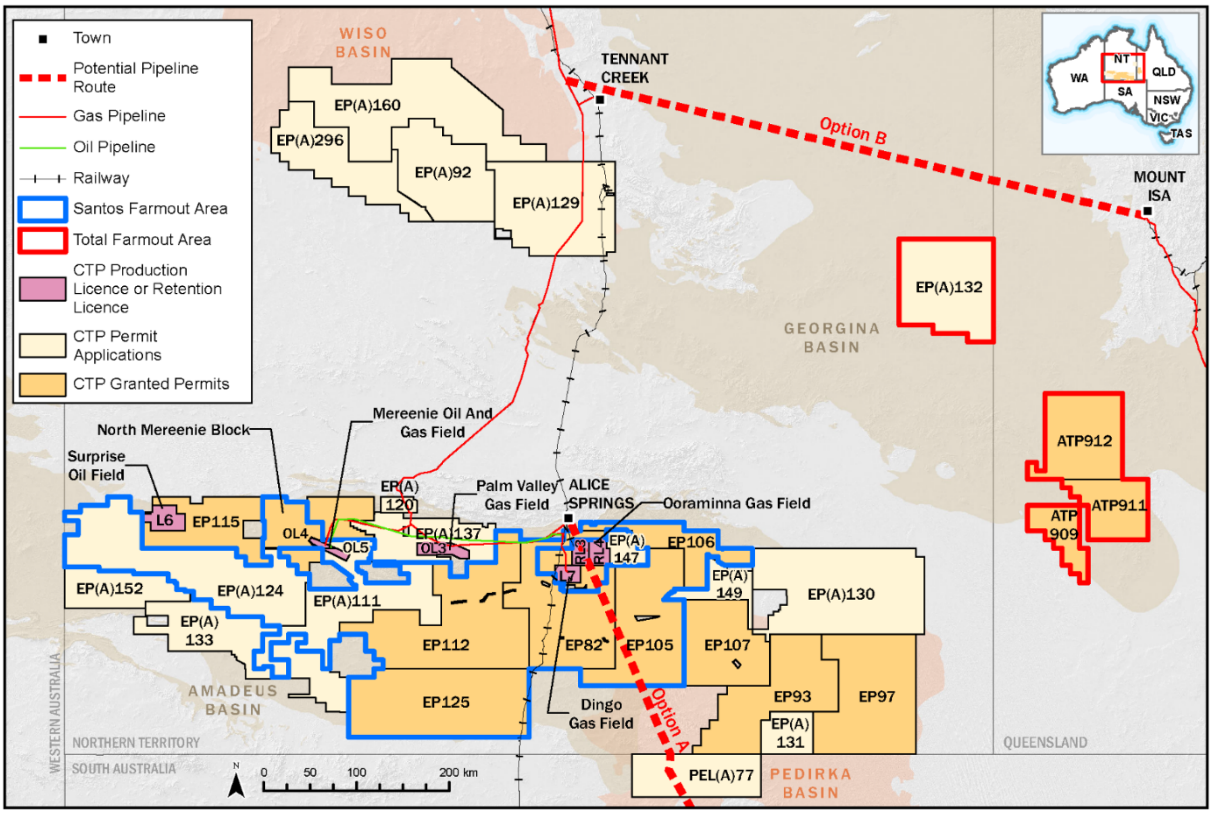
Whilst Central has historically been a pure oil and gas exploration company, over the past 2 years Central has developed and successfully pursued a strategy to gain critical mass in conventional gas production, including contracted gas sales and uncontracted gas reserves. This strategy first crystalised through the acquisition of the Palm Valley and Dingo gas fields from Magellan in April 2014, marking Central's entry into commercial gas production. Over the financial year ending 30 June 2015, Central ramped up its contracted gas sales as scheduled for the Palm Valley gas field and completed development of the Dingo gas field in 1 April 2015 on time and under budget.

Central's business strategy was bolstered significantly on 1 September 2015 when Central completed the acquisition of 50 percent of the Mereenie oil and gas field from Santos and became Operator for the Joint Venture. The past 18 months have been a period of business strategy implementation making Central a substantive domestic gas producer, with approximately 11 TJ/d contracted sales equity accounted and growing uncontracted gas reserves from proven fields.

With Mereenie, Palm Valley and Dingo fields under our common Operatorship, Central is now in a unique position to participate (and actively support) the North East Gas Interconnect (NEGI) pipeline connecting the Northern Territory to the eastern seaboard. This project is driven by clear fundamentals of a domestic gas shortfall on the East Coast and underexplored on-shore gas potential in the Northern Territory. In linking supply and demand, Central's sound business strategy of acquiring gas assets and uncontracted reserves in advance of the NEGI pipeline has positioned it to be a direct and substantive beneficiary.

Whilst the implementation of Central's Business Strategy has been relatively swift, the aggressive and sustained downturn in oil prices has served to justify our transition into gas starting 2 years ago. The acquisition of Palm Valley, Dingo and now Mereenie have all been based on existing gas contracts which are structured as long-term fixed price, CPI escalation. This provides a solid revenue stream going forward to cover Central's operating activities and debt financing arrangements secured on long term gas contracts that are not affected by oil price or currency movements and therefore largely unaffected by turmoil in international oil or LNG markets.

Creating a market for our gas should materially re-rate our significant under explored permits throughout the Amadeus, Southern Georgina, Pedirka and Wiso Basins in Central Australia. Going forward, our portfolio now allows Central to generate critical free cash flow after debt service which can be applied towards high growth and value adding activities, notably initially targeting growing high value conventional gas reserves throughout our various exploration permits.



Granted Petroleum Licences and Application Interests

Operations and Activities

Palm Valley Gas Field (OL3)

Northern Territory
(CTP — 100% Interest)

Background

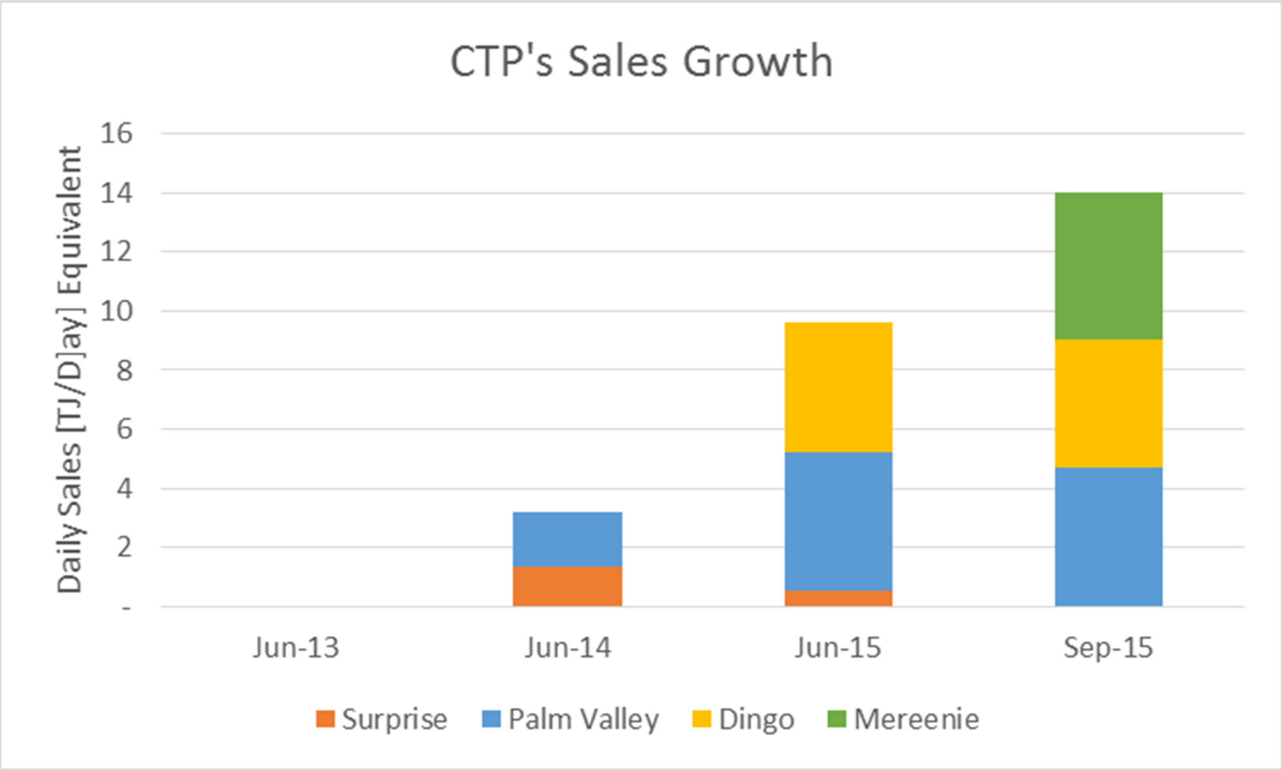
As a result of the acquisition of the Palm Valley gas field effective 1 April 2014, the Company commenced receiving revenue from gas sales. This shifted Central from an explorer to a multi-field producer on both oil and gas markets.

Performance

Gas production for the period 1 July 2014 to 30 June 2015 was 1,247,593 GJ (1.2 PJ).

Palm Valley field also pre-delivered 150 TJ of gas into the Dingo contract while purchaser worked to effect upgrades to their facilities.

Gas sales are per nominations received from the purchaser. Palm Valley currently delivers approximately 5 TJ/day into the Northern Territory domestic market.



[1] Mereenie Oil converted at 5.816 GJ/BOE
[2] Central had no ongoing production prior to April 2014

A review of the field performance was conducted, leading to an upgrade in outlook for gas production. Internationally recognised petroleum consultants Netherland, Sewell & Associates, Inc. (NSAI) estimated petroleum reserves and contingent resources as announced to the ASX on 21 July 2015.

Two exploration targets within the licence area have benefited from review of existing and acquisition of additional geological and geophysical data.

The **Palm Valley Deep prospect** has been firmed up with a drilling location selected. The objective is a test of the deeper Arumbera Sandstone which is an established gas bearing reservoir in the Dingo gas field some 100 km eastwards. The target has a similar area to the producing gas pool in the Pacoota Sandstone. The company sought regulatory permission from the Northern Territory Department of Mines and Energy (DME) and Central Land Council (CLC) clearance to drill Palm Valley-12.

The **Palm Valley West lead** has been updated with additional data collected from surface mapping. The initial results are positive, and the company intends to conduct additional surveying.

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

Northern Territory
(CTP — 100% Interest)

Background

During the June 2014 Quarter the Northern Territory Government granted the Dingo Petroleum Production Licence (L7) to Central. The production licence was converted from the retention licence (RL2).

Subsequent to 30 June 2014, the Dingo Pipeline Licence (PL30) was awarded by the Northern Territory Department of Mines and Energy.

The Dingo Gas Field Development was funded under a $30 million tranche of the loan facility agreement with Macquarie Bank and comprised construction of wellhead facilities, gathering pipelines, gas conditioning facilities, a 50 km gas pipeline to Brewer Estate in Alice Springs and custody transfer metering facilities designed to service a gas sale contract with Power and Water Corporation of the Northern Territory providing fuel to Owen Springs Power Station.

Performance

Construction of the pipeline was completed using innovative construction practices to add efficiency and reduce environmental footprint. Landowners, Traditional Owners and Environmentalists have reacted favorably to the project.

The strategic pipeline was a major milestone and signified the start of the Company being a significant player in the Northern Territory gas market. Central looks forward to playing an important role in inter-connecting Central Australia to the Eastern seaboard gas network via the North East Gas Interconnector (NEGI).

Dingo Gas processing plant during final commissioning early 2015.

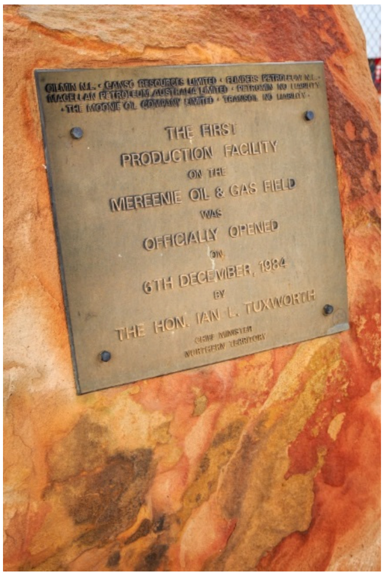
Central conducted a review of geological and engineering data, leading to a belief in upside potential of the field. Internationally recognised petroleum consultants Netherland, Sewell & Associates, Inc. (NSAI) estimated petroleum reserves and supported an increase in contingent resources as announced to the ASX on 21 July 2015.

Several structural leads were identified in the area immediately surrounding Dingo gas field, within EP 82 which is operated by Santos. These could provide interesting incremental opportunities to Central's 100 percent Dingo infrastructure. Further seismic is required to progress the targets to drillable status.

Mereenie Oil and Gas Field (OL4 and OL5)

Northern Territory
(CTP — 50% Interest, Santos — 50% Interest)

On 4 June 2015, CTP announced its acquisition of a 50 percent interest in the Mereenie oil and gas field under a farmout agreement with Santos.



Background

The Mereenie oil and gas field was discovered in 1963 by the exploration well, Mereenie-1, which was drilled on the crest of a large surface expressed anticline, with subsurface field area up to ~25,000 acres, or 100 km^2. Hydrocarbon-saturated reservoirs of variable quality within the Stairway and Pacoota formations below the regional Stokes Siltstone seal. In most gas bearing reservoirs there is a gas saturated oil rim. The gross hydrocarbon column in the field is approximately 760 metres.

Gas production and export via pipeline to Darwin commenced in 1984, with flow rates increasing to a peak of ~53 TJ/d in 2005 before declining for contractual reasons. During the seven years from 1990 a further 20 "oil" wells were drilled, adding to gas production capacity, followed by 6 dedicated gas wells during 1999–2004, and 4 oil wells since 2007. Hydraulic fracture stimulation was successfully applied during the 1990s, but only eight wells were stimulated since then.

Following expiry of the long term gas contract in 2009, the operator undertook studies and then acted in 2010 with the expansion of gas re-injection to enhance oil recovery. As of 2014 the field was producing up to 1,000 bopd (oil, condensate) from 23 wells, selling ~5 TJ/d gas (1.8 PJ pa) and reinjecting the balance into the oil reservoirs.

Gross production of 30 years to date is approximately 17 MMbbl oil, 258 PJ sales gas, and 1 MMbbl condensate.

With historical gas production of over 50 TJ/d, Mereenie can become a primary supplier of gas to the Eastern Seaboard via NEGI.

Performance

In a transformational acquisition CTP assumed Operatorship of historic Mereenie Field on 1 September 2015. CTP managed over 20 work streams to successfully accomplish the handover.

Key activities in the assumption of operatorship included:

- Job offers and acceptance by 15 current field employees.
- Contracting all services to operate the field.
- Re-structure of Central Operations team to gain efficiency across all fields; Palm Valley, Dingo and Mereenie.
- Securing of additional gas contracts.
- Development of robust computer models to support reserve and production upgrades to underpin the NEGI pipeline.

ATP909, ATP911 and ATP912

Southern Georgina Basin, Queensland
(CTP — 90% Interest, Total — 10% interest)

Farmout

During Stage 1 the Joint Venture acquired and interpreted 974 km 2D seismic, which enabled the selection of drilling locations. Two exploration wells were drilled in second half of 2014.

Should Total continue and fulfil its funding obligations for Stages 2 and 3, it will earn equity in increments to a total of 68 percent in the permits.

Central is operating the farmout areas for the first four years and after completion of Stage 3 Total will assume operatorship for 90 percent of the area. Central will retain operatorship of the upstream activities on the remaining 10 percent of the area.

Drilling

Whiteley-1 Well

Drilling commenced on 20 July 2014 at the Whiteley-1 unconventional gas exploration well in ATP 912.

Whiteley-1 was the first of a programme of unconventional gas exploration wells operated by Central and drilled using Enerdrill Rig 2. The planned depth was 1,920 metres.

The well was drilled to around 1,150 metres where severe drilling losses caused a suspension of drilling operations, pending the arrival of specialty equipment. The extent of fluids losses indicates a porous and perhaps fractured reservoir, which is yet to be fully logged for evaluation.

Gaudi-1 Well

Gaudi-1 spudded on 14 September 2014 in ATP 909, reached total depth of 2,430 metres, and the rig was released on 12 November 2015. Continuous coring operations retrieved 282 metres of core from which desorption samples were taken. A comprehensive suite of wireline logs were acquired in the well. Elevated gas readings recorded during drilling were confirmed by gas that desorbed from the core over time.

Evaluation

Data collected during Stage 1 includes laboratory analyses of core from Gaudi-1 and of core taken in offset wells, and is substantially complete. Analytical results have been integrated with interpreted logs and revised depth maps. This allows regional trend mapping using geologic attributes porosity, thermal maturity, and total organic carbon (TOC) etc. These provide insight into the unconventional LAC shale gas play, as well as new plays which have been revealed in the middle Cambrian succession.

The exploration targets in the joint venture's permits are now expanded to include:

1. Shale and tight gas reservoirs within the Lower Arthur Creek Fm, as targeted by Gaudi-1; and
2. A potential structurally controlled Hydrothermal Dolomite (HTD) play. Global analogues for this type of play are characterised by the highly localised creation of porosity in otherwise tight carbonates by the movement of hot geothermal fluids through the succession, upwards along faults. The types of mineralisation observed in the Gaudi-1 and nearby mineral well cores, the lost circulation in Whiteley-1, and anomalies observed on seismic all provide evidence for the possible presence of this play within the joint venture's permits.

The joint venture is considering various options to progress evaluation of these plays, and seeks additional play types and targets which may exist in these large permits.

Future drilling plans

Whiteley-1 well

The joint venture is encouraged by the evaluation detailed above, and believes Whiteley-1 may be ideally located, as estimated from various geologic parameters. An operational plan has been prepared to enable re-entry of Whiteley-1 so we may test the tight gas play, and several secondary targets. The primary objectives are targeted to be fully cored and sampled for gas desorption and reservoir properties, in addition to an extensive logging program.

Southern Amadeus Basin

Northern Territory
Various Permits, Retention Licences and Application Areas
(See Table on Page 89)

Santos Farmout

Under a three stage farmout agreement, Santos funded exploration in Stage 1 by investing an initial $30 million, with options to invest a further $60 million in Stage 2 and a further $60 million in Stage 3. In return Santos would earn rights to up to 70 percent of the area totaling nearly 80,000 square kilometres. Santos assumed operatorship during exploration and in the event that they are developed. Central will benefit from a free carry during the farmout period.

The Stage 1 seismic acquisition program acquired 1,587 km 2D seismic over 7 permits in the Southern Amadeus area, an additional 323 km in the North Mereenie Block (EP 115NMB), and the drilling of an exploration well, Mt Kitty-1. Stage 1 activities concluded in June 2014.

The Mt Kitty-1 well was re-entered on 23 August 2014, and a comprehensive logging program was completed which confirmed that gas flows reported did emanate from fractures in granitic basement. The well was suspended for possible later re-entry. Isotope analysis of gas samples confirmed the validity of previously announced helium contents up to 9 percent. This "fractured basement" discovery has opened up an additional play type which forms a valid objective in future wells.

Central and Santos concurred that the prospectivity of the Southern Amadeus was confirmed by the results of Mt Kitty and the 1,587 km of 2D seismic acquired during Stage 1 of the farmout. As a result, Santos elected in July 2014 to proceed to Stage 2 of an amended Southern Amadeus Joint Venture with Central, where 1,300 km 2D seismic will be acquired across areas of highest prospectivity, earning Santos a 40 percent participating interest in permits listed in the table below (the "Southern Amadeus Joint Venture").

The joint venture's exploration endeavours in this and surrounding permits will focus on maturing large sub-salt leads to drillable status by acquiring further seismic in Stage 2. The primary reservoir objective is the Heavitree Quartzite. Secondary reservoir objectives in the Neoproterozoic succession include fractured basement, the Pioneer Sst which is gas productive in the sub-commercial Ooraminna field, and the Areyonga Fm.

SOUTHERN AMADEUS AREA	TOTAL SANTOS PARTICIPATING INTEREST AFTER COMPLETION OF STAGE 1	TOTAL SANTOS PARTICIPATING INTEREST AFTER COMPLETION OF STAGE 2
EP82	25%	40% (i.e. additional 15% earned)
EP105	25%	40% (i.e. additional 15% earned)
EP106	25%	40% (i.e. additional 15% earned)
EP107	25%	40% (i.e. additional 15% earned)
EP112	25%	40% (i.e. additional 15% earned)
EP(A)147	25%	40% (i.e. additional 15% earned)

EP 125 – Northern Territory

(CTP — 30% Interest, Santos [Operator] — 70% interest)

Mt Kitty-1 Exploration Well

The Mt Kitty "fractured basement" discovery has opened up an additional play type which forms a valid objective in future wells, in addition to the large sub-salt leads present across the wider area.

Uncertainties remain as to the size of the resource discovered in the Mt Kitty-1 exploration well. Poorly constrained input parameters to resource assessment include reservoir pressure which is an indication of column height, porosity and extent or connectivity of the fracture system, as well as the source and exact gas composition. The available options to evaluate this large structure are to re-enter Mt Kitty-1 for testing, or drill an oriented sidetrack to maximise intersection with observed fracturing, or drill additional wells on the structure.

Helium detected in the gas stream sells around $100/mcf (or nearly twenty times more valuable than natural gas), so the 9 percent helium detected in the gas stream is significantly more valuable than methane. The gas-in-place estimates and potential well performance are significant in determining the potential commerciality of the resource. Central has been evaluating the prospect of Helium extraction and sales at the well head through relatively portable membrane technology. Early indications that even a relatively small field of Helium of this quality can be quite economic.

Surprise Oil Field (L6)

Northern Territory
(CTP — 100% Interest)

Background

In February 2014 Central was offered L6 for the Surprise Oil Field Development. This was the first Production Licence offered in onshore Northern Territory since the passing of the Native Titles Act 1993 and was an important milestone not only for Central but also for the Northern Territory and the Traditional Owners.

Initial production and storage facilities were installed to allow production to commence from the Surprise West well in March 2014.

The installation of additional storage tanks and ancillary equipment was completed early in the financial year.

Performance

The Surprise West well produced approximately 77,232 barrels of oil since commencing production in March 2014 to 30 June 2015 of which 54,374 barrels were produced during the period 1 July 2014 to 30 June 2015.

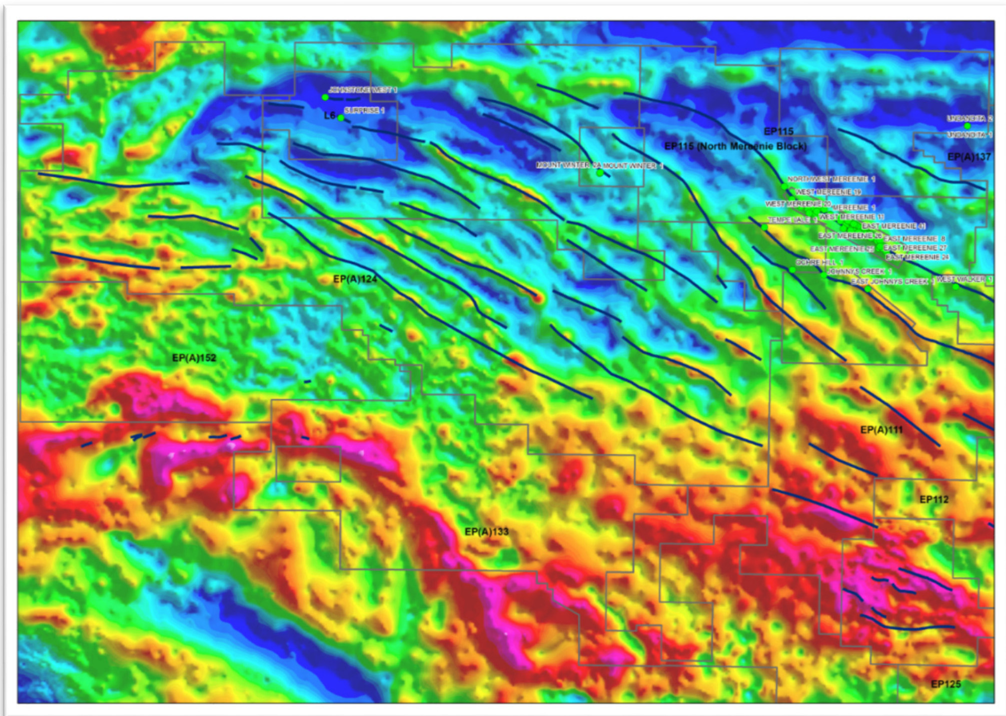
The Surprise West well was a valuable cash-flow contribution to the Company. Currently the well is shut in due to low oil prices and to obtain long term pressure data.

Exploration Application Areas, Northern Territory

Amadeus, Pedirka and Wiso Basins — Various Areas (see Table on Page 89)

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

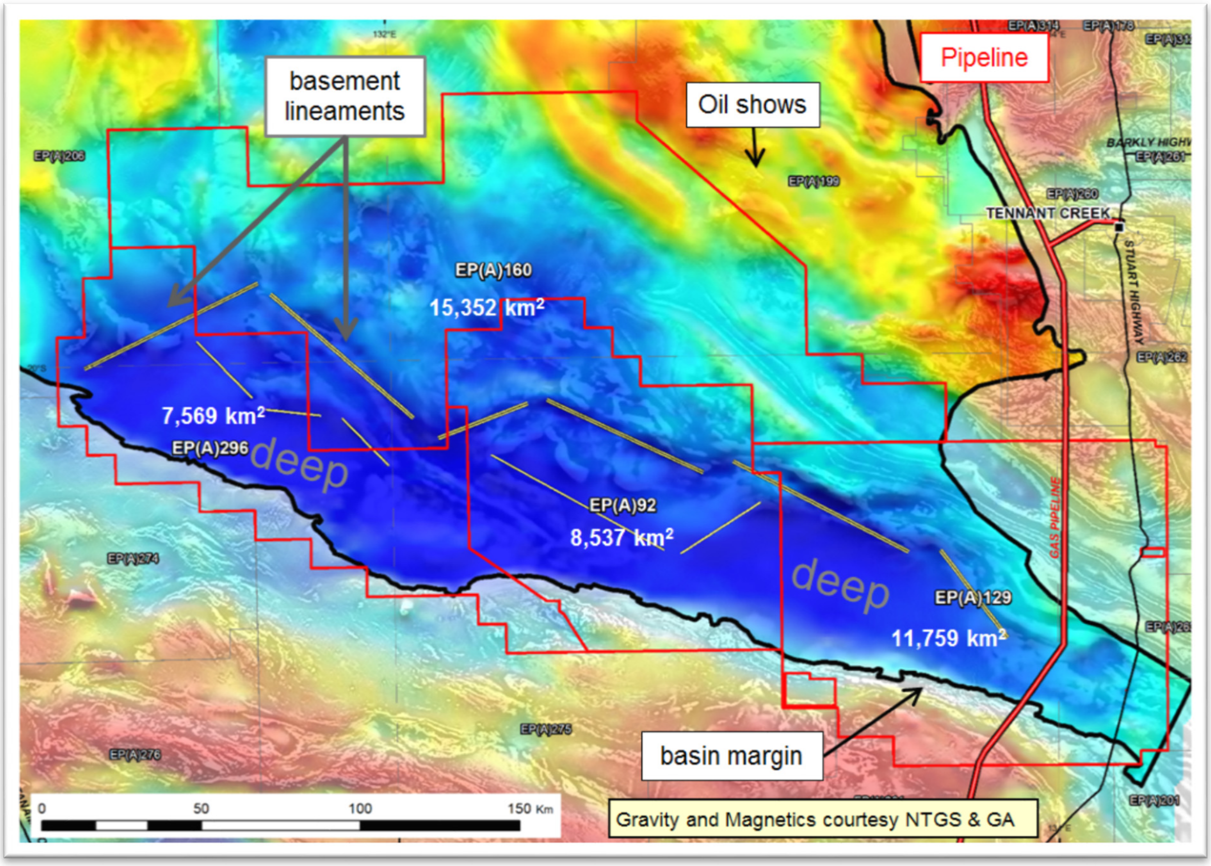
In the western Amadeus Basin a gravity survey was conducted by Geoscience Australia and Northern Territory Geologic Survey, in which Central participated and sponsored a higher level of detailed surveying. The additional data has clearly delineated structural trends which are anticipated to be prospective, and supports modeling to identify and prioritise areas of prospective sediments which are structurally high. This will greatly assist efficient layout of seismic acquisition to define drillable targets.



Western Amadeus Basin, Residual gravity, licenced and application areas.

Exploration Application Areas, Northern Territory (continued)

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 detailed of structural trends. Interpretation in conjunction with magnetics data (see image below) provides an excellent tool for planning of seismic acquisition.



Wiso Basin, Residual gravity, application areas.

Reserves Information

Reserves and Resource Volumes for Gas (Units: PJ)[1]

	1P	2P	3P	1C	2C	3C
Palm Valley[3]	18.4	24.6	—	—	—	—
Dingo[3]	10.8	34.6	—	—	—	—
Mereenie[2]	35.6	122.9	152.3	46.0	144.0	261.0
Total	**64.8**	**182.1**	**152.3**	**46.0**	**144.0**	**261.0**

[1]Reserves/Resources are 100% Gross (Field Level)

[2]Mereenie Reserves are from YE2014 Santos VOLTS Database

[3]Palm Valley & Dingo Reserves are from NSAI Report 13964 dated 30 June 2015

SIGNIFICANT CHANGES IN THE STATE OF AFFAIRS

Significant changes in the state of affairs of the group during the financial year were as follows.

Contributed equity increased by $5,562,142 (from $155,223,040 to $160,785,182) as the result of a share placement. 20,000,000 fully paid ordinary shares were issued on 2 October 2014 at an issue price of 30 cents per share. Details of the changes in contributed equity are disclosed in Note 18(a) to the Financial Statements.

EVENTS SINCE THE END OF THE FINANCIAL YEAR

Acquisition of a Fifty Percent (50%) Interest in the Mereenie Oil and Gas Field

On 1 September 2015 the consolidated entity acquired a 50 percent interest in the Mereenie oil and gas field in the Amadeus Basin, Northern Territory from the Santos group. The Company assumed operatorship of the field effective from that date. A new joint venture will be established.

The financial effects of this transaction have not been recognised at 30 June 2015 and the acquisition will be included in consolidated results from 1 September 2015.

Purchase Consideration	$
Cash paid	35,000,000
Deferred consideration	10,000,000
Free carry of Santos' share of field appraisal and development	5,000,000
Total purchase consideration	**50,000,000**

As part of the transaction the parties have agreed to a range of matters relating to other Southern Amadeus Basin exploration arrangements between the parties. The fair values of the assets and liabilities as at the date of acquisition are yet to be determined.

Contingent Consideration

Potential consideration as indicated above is payable if a final investment decision is made on the North East Gas Interconnector (NEGI) and the Mereenie Joint Venture participants (or their related parties) enter into a gas transportation agreement with the NEGI project owner within 3 years of the execution date.

The potential consideration comprises a $15 million payment and $55–75 million of sole funding work to prove up 15 PJ per annum over 10 years in excess of contracted gas for the purposes of transportation via the NEGI. A bullet payment of 50 percent of the remaining balance of the target of $65 million is payable if the required NEGI works are not completed within 3 years of the pre-conditions being satisfied.

The potential undiscounted amount of all future payments that the consolidated entity could be required to make under this arrangement is between $0 and $47,500,000.

Debt Facility

As part of the Mereenie acquisition, the Macquarie debt facility has been expanded to include a new Facility "D" of $40 million taking the total facility limit to $90 million with a final maturity date of 30 September 2020.

The existing repayment schedule has been replaced with a new repayment schedule. Commencing 31 December 2015 the principal repayment (excluding interest accruing under the facility) is a set amount of $1 million per quarter payable at the end of each calendar quarter with the balance of the facility due on the final maturity date.

Financial covenants under the revised facility:

- Current Ratio is at least 1:1
- Proved Developed Producing (PDP) Reserves Cover Ratio is greater than 1.3:1
- Trade creditors ageing over 90 days past the due date must not exceed $5 million.

Legal Matter

Central Petroleum Limited has been allegedly served with litigation filed in the District Court of Harris County Texas, located in Houston, Texas, in respect of a farm-in deal negotiated between the Perth office of Total and Central Petroleum when it was headquartered in Perth.

Central Petroleum is disputing the Court's jurisdiction. Separately, internal investigations have concluded that there is no factual basis for the alleged claim and the consolidated entity accordingly denies any liability. The action will be vigorously defended.

INFORMATION ON DIRECTORS

Robert Hubbard FCA

Independent Non-Executive Director

Mr Hubbard was a partner with PricewaterhouseCoopers for 22 years specialising in audit, deals and valuation advice specialising in the resources sector. He has highly developed financial skills and business experience including managing significant capital and growth agendas, risk management, best practice corporate governance and valuations.

Mr Hubbard is a non-executive Director of Bendigo and Adelaide Bank Limited as well as ASX and TSX listed Orocobre Limited. He is also a non-executive director of ASX listed Primary Health Care Limited. Within the last three years, he has not been a Director of any other listed public company.

Andrew P Whittle BSc (Hons)

Independent Non-Executive Chairman

Mr Whittle has around 45 years of technical and managerial experience in the petroleum exploration and production industry with a focus on South East Asia and Australia. His experience includes over 21 years with several affiliates of Exxon Corporation in Australia, Singapore, Malaysia, Canada and the US, finally in the position of geological manager of Esso Australia. Thereafter, he was exploration manager for 5 years with GFE Resources Ltd, Australia. He has over 15 years' experience through PetroVal Australasian Pty Ltd, of which he was a founding Director, in preparing independent technical reports and in evaluating exploration and production assets and providing valuations, and expert opinions for a range of clients. He was closely involved in the exploration that led to the identification and discovery of the Thylacine gas field in the Otway Basin and in promoting Pexco into Indonesian deepwater exploration. He is also a member of the American Association of Petroleum Geologists, and the Petroleum Exploration Society of Australia.

Mr Whittle stepped down as a Director of Malaysia listed Bumi Armada Sdn Bhd, a major offshore service company in June 2014, a role he held since June 2011. He also stepped down as a non-executive Director of ASX listed Bass Strait Oil Ltd during the year. Within the last three years, he has not been a Director of any other listed public company.

Richard I Cottee BA, LLB (Hons)

Managing Director and Chief Executive Officer

With a background in law and energy, Mr Cottee is a prominent figure in the Australian oil and gas industry having taken QGC from an early stage explorer to a major unconventional gas supplier sold to BG Group for $5.7 billion.

Mr Cottee has renowned international energy experience with an outstanding reputation for driving company market development. A lawyer, Mr Cottee has also served as the Director of marketing and sales for Cyprus Amax and then was named managing Director of England, Wales, Scotland, Ireland and the Scandinavian and Norway regions for NRG Energy. Previously he worked with Santos Oil and Gas. He was also chief executive officer of CS Energy Ltd, a Queensland Government owned electricity generator.

Mr Cottee was until April of this year a non-executive chairman of Austin Exploration Limited and is a principal of Freestone Energy Partners Pty Ltd (FEP). Within the last three years, he has not been a Director of any other listed public company.

Wrixon F Gasteen BE (Hons), MBA (Dist)

Independent Non-Executive Director [2]

Mr Gasteen is a Director and co-founder of Ikon Corporate (Singapore), established in 2007 to provide corporate advisory, capital raising and management consulting services. Previously Mr Gasteen was chief executive officer of Hong Leong Asia (HLA) where he presided over the transformation and rapid development of the company by both acquisition and organic growth, from a loss making South East Asian building materials company with $300 million in annual sales to $2.2 billion in annual sales. He was Director of Tasek Corporation (cement) (KLSE) and also chairman and president of China Yuchai International (diesel engines) listed on the New York Stock Exchange (NYSE).

In March 2014 Mr Gasteen joined the board of ASX listed Sino Australia Oil & Gas as a non-executive Director. Within the last three years, Mr Gasteen has not been a Director of any other listed public company.

INFORMATION ON DIRECTORS (continued)

John Thomas (Tom) Wilson BSc (Zoology), MSc (Geology)

Independent Non-Executive Director

Mr Wilson began his career as a geologist with Shell Oil Company before joining Apache Corporation, where he held various management positions and led Apache's entry into international markets. Subsequent to Apache, Mr Wilson served as president of Anderman International, which developed the Chernogoskoye Field in western Siberia. Mr Wilson joined the management team of Yamal Energy Partners, which developed the South Tambay Field, possibly the first Russian-led LNG project in the Russian Republic, which was later sold to Gazprom.

Mr Wilson was appointed a Director of US based Magellan Petroleum Corporation in 2009 and the Company's CEO in 2011. Within the last three years, he has not been a Director of any other listed public company.

Prof. Peter S Moore BSc (Hons 1), MBA, PhD

Independent Non-Executive Director

Prof. Peter S Moore has over thirty years of experience in the oil and gas business. His career includes roles with the Geological Survey of Western Australia, Delhi Petroleum Pty Ltd, the exploration operator of the Cooper Basin consortium in South Australia and Queensland at the time, Esso Australia Ltd, Exxon Exploration Company in Houston and from 1998 until his retirement in 2013, with Woodside Energy Ltd.

At Woodside, Peter held various roles including most recently as Executive Vice President Exploration. In this capacity he was a member of Woodside's Executive Committee and Opportunities Management Committee, a leader of its Crisis Management Team and Head of the Geoscience function across the company. He was also a Director of a number of Woodside's subsidiary companies.

Prof. Moore is Chair of the Curtin Graduate School of Business Advisory Board, an Executive Director of ESWA (Earth Sciences WA), a Non-Executive Director of Carnarvon Petroleum Limited, and a Member of the Elsevier's Oil & Gas Advisory Board. Within the last three years, he has not been a Director of any other listed public company.

COMPANY SECRETARIES

Daniel C M White LLB, BCom, LLM

Mr White is an experienced oil & 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.

Joseph P Morfea FAIM, GAICD

Mr Morfea has over 35 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. Prior to Magellan Mr Morfea worked for Santos Limited and Thiess Dampier Mitsui Coal Pty Ltd.

DIRECTORS' MEETINGS

The number of Directors' meetings held where the Director was eligible to attend and the number of meetings attended by each of the Directors of the Company during the financial year were:

	Full Meeting of Directors		Audit Committee		Remuneration Committee		Nominations Committee	
	Eligible	Attended	Eligible	Attended	Eligible	Attended	Eligible	Attended
Robert Hubbard	7	7	2	2	3	3	—	—
Andrew Whittle	7	7	2	2	3	3	1	1
Richard Cottee	7	7	—	—	—	—	1	1
Wrixon Gasteen	7	7	2	2	—	—	—	—
J. Thomas Wilson	7	4	—	—	—	—	—	—
Peter Moore	7	7	—	—	3	3	1	1
William Dunmore	3	2	—	—	—	—	—	—
Michael Herrington	3	3	—	—	—	—	—	—

REALISED REMUNERATION OF DIRECTORS AND KEY MANAGEMENT PERSONNEL FOR THE 2015 YEAR

The Directors consider the remuneration information contained within the tables presented in the statutory remuneration report (pages 22 to 34) may give a distorted view of the true remuneration realised by the Directors and key management personnel for the 2015 Year.

This is a voluntary disclosure and has been included to assist shareholders in forming an understanding of the cash and other benefits actually received by Directors and key management personnel.

Non-Executive Directors	Salary / fees $	Non-monetary benefits[1] $	Superannuation contributions $	Amount $	Percentage of TRP %	Value of LTI Grant that Vested $	Actual Total Remuneration Package (TRP) $
Andrew Whittle	102,667	10,799	9,753	123,219	100%	—	123,219
William Dunmore[2]	27,083	—	—	27,083	100%	—	27,083
Wrixon Gasteen	67,500	11,999	—	79,499	100%	—	79,499
Robert Hubbard	72,000	—	6,840	78,840	100%	—	78,840
J. Thomas Wilson	58,500	—	—	58,500	100%	—	58,500
Peter Moore	72,000	—	6,840	78,840	100%	—	78,840
Sub-total	399,750	22,798	23,433	445,981	100%	—	445,981

Executive Directors & Key Management Personnel	Salary / fees $	Non-monetary benefits[1] $	Superannuation contributions $	Amount $	Percentage of TRP %	Value of LTI Grant that Vested $	Actual Total Remuneration Package (TRP) $
Richard Cottee[3]	581,784	20,319	5,985	608,088	100%	—	608,088
Michael Herrington[2]	512,259	12,494	36,572	561,325	100%	—	561,325
Daniel White	411,575	1,826	30,000	443,401	100%	—	443,401
Bruce Elsholz[4]	160,171	1,694	22,556	184,421	100%	—	184,421
Leon Devaney	358,095	1,694	27,780	387,569	100%	—	387,569
Michael Bucknill	337,352	1,694	32,048	371,094	99%	2,000	373,094
Robbert Willink	340,000	—	32,300	372,300	99%	2,400	374,700
Sub-total	2,701,236	39,721	187,241	2,928,198	100%	4,400	2,932,598
Total Remuneration	**3,100,986**	**62,519**	**210,674**	**3,374,179**	**100%**	**4,400**	**3,378,579**

[1] *Fringe benefits*

[2] *Retired as Director 26 November 2014*

[3] *Mr Cottee's services were provided by Freestone Energy Partners (FEP) up to 29 June 2015 when he became a full time employee. Mr Cottee has a 50% beneficial equity interest.*

[4] *Resigned 30 November 2014*

ENVIRONMENTAL REGULATION

The Consolidated Entity is subject to significant environmental regulation with regard to its exploration activities.

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.

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.

NUMBER OF EMPLOYEES

The Company had 56 employees at 30 June 2015 (51 at 30 June 2014).

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	
	2015	2014
PwC Australian firm:	**$**	$
(i) Taxation services		
Income Tax compliance	8,500	16,311
Excise consulting	48,957	—
Other tax related services	68,354	65,955
	125,811	**82,266**
(ii) Other services		
Corporate advisory – due diligence	22,000	181,607
Remuneration benchmarking	—	10,000
Other employee related services	6,698	—
	28,698	**191,607**
Total remuneration for non-audit services	**154,509**	**273,873**

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 35.

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. Of special note are the contributions made to the Company's operations by Mr Robert Liddle and the other traditional owners who are part of the Central work force.

REMUNERATION REPORT (AUDITED)

This remuneration report for the year ended 30 June 2015 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	Remuneration Details
H	Executive Service Agreements
I	Non-Executive Director Fee Arrangements

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

Robert Hubbard	Non-Executive Chairman	
Andrew Whittle	Non –Executive Director	
Richard Cottee	Managing Director and Chief Executive Officer	
Wrixon Gasteen	Non-Executive Director	
J. Thomas Wilson	Non-Executive Director	
Peter Moore	Non-Executive Director	
Michael Herrington	Executive Director and Chief Operating Officer	Retired as Director, effective 26 November 2014
William Dunmore	Non-Executive Director	Retired, effective 26 November 2014

Other Key Management Personnel

Leon Devaney	Chief Financial Officer	Appointed, effective 31 October 2014
Michael Herrington	Chief Operating Officer	
Daniel White	Group General Counsel and Company Secretary	
Michael Bucknill	General Manager Exploration	
Robert Willink	Exploration Advisor	
Bruce Elsholz	Chief Financial Officer and Company Secretary	Resigned, effective 31 October 2014

B. Remuneration Overview

Central Petroleum'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.

B. Remuneration Overview (continued)

In the previous remuneration review cycle during 2014 the Board engaged PricewaterhouseCoopers to provide guidance on current industry practice for remunerating senior executives, and RMBN Pty Ltd to carry out a review of the proposed STIP and LTIP plans. The implementation of these Plans met key fundamentals that focused on creating strong linkages between shareholder value as measured by shareholder returns (Absolute and Relative total shareholder returns). A detail overview of the LTIP and STIP plans that were implemented for the period starting 1 July 2014 can be found at section D and E of this report.

Australia is in the midst of a significant contraction in the resource sector as commodity prices remain at multi-year lows and the outlook for most commodity markets remains clouded due to concerns over global growth. Since October 2014, the energy sector has been under increasing financial pressure, largely due to the collapse in oil prices as well as gas pricing linked to oil. This has had a profound impact on all energy sector participants. In respect of this market dynamic, the CEO positioned the Company's focus on restoring value for shareholders by reducing costs, driving operational efficiency and prudently managing capital and targeting non-oil linked gas pricing.

With the significant contraction in the resource sector specifically with the downturn in the global oil prices and corresponding loss of value in the market, Central Petroleum undertook the suspension of its 2014 pay reviews and STIP payments:

Suspended Pay	No pay rises were awarded except where appropriate on account of a change in position or other extenuating circumstance
Suspended STIP	The Company's Short Term Incentive Plan was scheduled for payment in the fourth quarter of fiscal year 2015, however, the Board with the full support of the CEO exercised its discretion to reduce and suspend its payment to the fourth quarter of calendar year 2015.
Nil LTIP VESTING	There were no awards that vested under the new Long Term Incentive Plan with it coming into its second year of implementation.

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 exploration industry. Accordingly, the Company has revamped its remuneration practices and in particular its short term and long term incentive plans with a particular focus 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). These changes are effective from 1 July 2014.

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. In this period the Remuneration Committee did not engage a remuneration consultant.

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 2015 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. Whilst some of the current non-executive Directors benefit from options issued in accordance with shareholder approval in 2012 no further issues have been made and it is not intended that non-executive Directors will participate in either the LTIP or STIP in the future.

Executives including executive Directors:

1. Annual salary and non-monetary benefits including statutory superannuation;
2. Participation in a Short Term Incentive Plan;
3. Participation in an Long Term Incentive Plan (Performance Rights scheme); and
4. There is no guaranteed base pay increases included in any executive's contract.

E. Long Term Incentive Plan (LTIP)

In its 2014 annual report CTP announced that from 1 July 2014 it would change its remuneration practices and in particular the structure of its short term incentive plan and LTIP in line with market conditions relevant to the oil and gas exploration industry.

The LTIP will be a major component of executive incentives and in developing the LTIP the board of CTP has focused on creating strong linkages between shareholder value as measured by shareholder returns and executive remuneration. Consequently vesting conditions have been divided equally between relative shareholder return and absolute shareholder return. In doing this the board have identified that it is not sufficient for CTP 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 CTP share price must increase by at least 25 percent per annum for three years, compound growth of 95 percent.

Key terms and vesting conditions

On 26 November 2014 shareholders approved the Company to implement a share based LTIP to incentivise eligible employees (Non-Executive Directors are not eligible to participate in the LTIP). The delivery instrument is performance rights, effective for years commencing 1 July 2014 onwards.

The maximum number of performance rights vested in any year is determined by measuring CTP'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 3 year cycle.

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

HURDLE	DEFINITION	HURDLE BANDING	VESTING PERCENTAGE
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	<u>Company's Absolute TSR over 3 years</u>	<u>Share Rights Vesting</u>
		Below 10% pa	0%
		10% to <15% pa	25%
		15% to <20% pa	50%
		20% to <25% pa	75%
		25% pa plus	100%
Relative TSR – E&P[2] **(50% weighting)**	Company's TSR relative to a specific group of E&P companies (determined by 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 vested to become Share Rights on the Vesting Date which may then be exercised in accordance with the ERP 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.

The personal and corporate key performance indicators and other targets for the Managing Director and other employees are reviewed at least annually to ensure they remain relevant and appropriate. These may be varied to ensure alignment of executive performance and achievement consistent with the Company's goals and objectives.

E. Long Term Incentive Plan (LTIP)

Employees must be employed by the Company at the end of the Performance Period in order for the Performance Rights to vest. The number of shares that vest 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 percent 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 the CTP strategy may receive an LTIP Percentage up to 50 percent, subject to shareholder approval.

b) EMT (Executive Management Team) Eligible Employees are those in roles which influence and drive the strategic direction of the Company's business. EMT Eligible Employees receive an LTIP Percentage up to 30 percent;

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 Executive Management Team. These Eligible Employees receive an LTIP Percentage up to 20 percent;

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 an LTIP Percentage up to 10 percent; and

e) All other Eligible Employees' are integral to the success of the Company obtaining its goals and objectives may participate in 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 the earlier of 3 years or on termination of employment; and
2. No performance conditions apply.

With the effective date of 1 July 2014 onwards, all eligible employees subscribed to the new Long Term Incentive Plan, and in doing so waived their eligibility rights to participate in the incentive Options scheme.

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 (KPI's) for all eligible employees was implemented. The Company's Board of Directors determine the maximum amount of KPI achievable in any year (normally expressed as a percentage of base salary). Achieving the maximum is contingent upon all of the KPI's in the matrix being met at the 100 percent level. The KPI's 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 percent of base salary in 2014/15.

Key terms and conditions

The 2014/2015 STIP has been holistically designed to recognise and reward individual effort through connecting Individual KPI's, Departmental KPI's and Corporate KPI's. These groups of KPI's are intrinsically linked and start by cascading from the Corporate KPI's, to the Departmental KPI's and then onto Individual KPI's. Individual KPI's drive the success of achieving Departmental KPI's which are in turn aimed at effecting the desired outcome to be reached in the Corporate KPI's.

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 KPI's after consultation with the Board. These KPI's 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.

F. Short Term Incentive Plan (STIP)

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

1. **Corporate KPI's** represent an overall 30 percent of the STIP, and Safety & Environment represents 10 percent of the STIP.
2. **Departmental KPI's** represent a spread of 40 percent for the Executive and 30 percent for all other employees.
3. **Individual KPI's** represent a spread of 20percent for the Executive and 30 percent for all other employees.

The 2014/2015 Plan Year STIP percentage allocation is a maximum of up to 10 percent of the employees Base Salary. The maximum is contingent upon all of the KPI's being met at 100 percent in the STIP. This will form the basis of the recommendation to the Board who will decide the amount. This percentage will be annually reviewed by the Board through the Remuneration Committee.

At the Board's discretion a combination of cash & Company securities, or cash or Company securities may be paid as the benefit in the 2014/2015 Plan Year STIP.

Corporate KPI's included:

OBJECTIVE	WEIGHTING	100%	75%	50%
Supply gas from Dingo through pipeline	35%	By: 01/02/2015	By: 01/04/2015	By: 11/06/2015
Complete 2014-2015 SGJV work program within JV approved AFE amounts (in the aggregate)	20%	At 90% or less of the aggregate amount	Within 100% of the aggregate amount	Under 110% of the aggregate amount
Incremental sales contracts in following year revenue	35%	$10 million	$7 million	$5 million
No Breach regarding Traditional Owner cultural heritage	5%	Zero	1 which has been remedied	Default
Training & Employment of Traditional Owners	5%	Two (2) trained Two (2) employed	Two (2) trained One (1) employed	Two (2) trained

OBJECTIVE	WEIGHTING	100%	75%	50%
Safety: No Lost Time Injuries (LTI)	5%	Zero	1 of less than 2 days	Default
Environment: No breach regarding reportable environmental incidents	5%	Zero		

The Departmental KPI's vary from one department to the next, however, all are equally important to achieve in the pursuit of achieving 100 percent of the Corporate KPI's which are re-set annually.

Individual KPI's are linked to the Departmental KPI's 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).

Incentive Option Schemes

On 9 April 2015, under the Company's 2012 Share Option Plan for Directors and Employees, there were 5,288,843 unlisted options issued to employees at various exercisable prices on or before 15 November 2017. The issue was for the performance period ending 30 June 2014.

G. Remuneration Details

Details of the remuneration of the Directors and the key management personnel of Central Petroleum Limited and the Consolidated Entity are set out in the following tables. Details of realised remuneration appear on page 20.

Table 1: Remuneration of Directors and Key Management Personnel

		SHORT-TERM		POST-EMPLOYMENT		LONG-TERM BENEFITS	SHARE-BASED PAYMENTS		
		Salary / fees $	Non-monetary benefits[1] $	Superannuation contributions $	Termination Benefits $	LSL $	(At Risk) Options & Rights[4] $	Total $	Value of Options as Proportion of Remuneration %
Non-Executive Directors									
Andrew Whittle	2015	102,667	10,799	9,753	—	—	99,124	222,343	45%
	2014	101,666	11,707	9,404	—	—	118,392	241,169	49%
William Dunmore[2]	2015	27,083	—	—	—	—	—	27,083	0%
	2014	94,476	—	—	—	—	—	94,476	0%
Wrixon Gasteen	2015	67,500	11,999	—	—	—	110,138	189,637	58%
	2014	75,000	13,008	—	—	—	131,547	219,555	60%
Robert Hubbard	2015	72,000	—	6,840	—	—	—	78,840	0%
	2014	40,265	—	3,724	—	—	—	43,989	0%
J. Thomas Wilson	2015	58,500	—	—	—	—	—	58,500	0%
	2014	16,250	—	—	—	—	—	16,250	0%
Peter Moore	2015	72,000	—	6,840	—	—	—	78,840	0%
	2014	16,042	—	1,484	—	—		17,526	0%
Sub-total	2015	399,750	22,798	23,433	—	—	209,262	655,243	32%
	2014	343,699	24,715	14,612	—	—	249,939	632,965	39%
Executive Directors and Other Key Management Personnel									
Richard Cottee[3]	2015	561,976	20,319	5,985	—	12,398	1,887,313	2,487,991	75%
	2014	580,005	—	22,945	—	7,536	1,887,313	2,497,799	76%
Michael Herrington[2]	2015	506,102	12,494	36,572	—	9,214	91,152	655,534	14%
	2014	587,995	11,707	33,068	—	6,298	118,392	757,460	16%
Daniel White	2015	397,106	1,826	30,000	—	10,972	(8,373)	431,531	0%
	2014	432,155	—	26,693	—	10,014	3,733	472,595	1%
Bruce Elsholz[5]	2015	120,520	1,694	22,556	—	2,212	(11,768)	135,214	0%
	2014	303,726	—	27,689	—	7,520	2,622	341,557	1%
Leon Devaney	2015	361,706	1,694	27,780	—	6,830	(5,165)	392,845	0%
	2014	311,241	—	29.180	—	3,837	2,576	346,834	1%
Michael Bucknill	2015	330,641	1,694	32,048	—	4,260	(5,271)	363,372	0%
	2014	321,663	—	27,651	—	2,560	2,000	353,874	1%
Robbert Willink	2015	349,810	—	32,300	—	4,553	(6,877)	379,786	0%
	2014	340,236	—	29,116	—	2,816	2,400	374,568	1%
Sub-total	2015	2,627,861	39,721	187,241	—	50,439	1,941,011	4,846,273	40%
	2014	2,877,021	11,707	196,341	—	40,581	2,019,036	5,144,687	39%
Total Remuneration	**2015**	**3,027,611**	**62,519**	**210,674**	—	**50,439**	**2,150,273**	**5,501,516**	**39%**
	2014	**3,220,720**	**36,421**	**210,954**	—	**40,581**	**2,268,975**	**5,777,652**	**39%**

1 Represents fringe benefits tax.

2 Mr Dunmore and Mr Herrington retired as a directors 26 November 2014.

3 Freestone Energy Partners Pty Ltd (FEP) have provided the services of Richard Cottee on the basis of a secondment up to 29 June 2015. As such compensation was made to FEP in line with Richard Cottee's service agreement shown on page 33. Richard Cottee has a 50% beneficial equity interest in FEP.

4 The valuation date for options issued to FEP was 19 July 2012 and to directors was 29 November 2012. Negative amounts represent revisions to estimates and/or cancelled and forfeited options.

5 Mr Elsholz resigned from employment on 30 November 2014.

The fair values of options granted during 2015 were independently valued. The values are calculated at the dates of grant using a Binomial valuation model. The values are allocated to each reporting period evenly over the period from grant date to vesting date. The fair values of deferred share rights granted during 2015 were also independently valued. The values are calculated at the date of grant using a Black Scholes valuation model with Monte Carlo simulations and a hypothetical 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.

G. Remuneration Details (continued)

The values disclosed for 2015 are the portions of the fair values applicable to and recognised in this reporting period. The following factors and assumptions were used in determining the fair value of options at grant date:

GRANT DATE	EXPIRY DATE	FAIR VALUE PER OPTION	EXERCISE PRICE	PRICE OF SHARES AT GRANT DATE	ESTIMATED VOLATILITY	RISK FREE INTEREST RATE	DIVIDEND YIELD
1 Jul 14	11 Nov 15	$0.0200	$0.400	$0.320	45% to 65%	2.54%	
9 Apr 15	15 Nov 17	$0.0033	$0.475	$0.125	55% to 75%	1.74%	
9 Apr 15	15 Nov 17	$0.0062	$0.450	$0.125	55% to 75%	1.74%	
9 Apr 15	15 Nov 17	$0.0067	$0.400	$0.125	55% to 75%	1.74%	

The values disclosed for 2014 are the portions of the fair values applicable to and recognised in this reporting period. The following factors and assumptions were used in determining the fair value of options at grant date:

GRANT DATE	EXPIRY DATE	FAIR VALUE PER OPTION	EXERCISE PRICE	PRICE OF SHARES AT GRANT DATE	ESTIMATED VOLATILITY	RISK FREE INTEREST RATE	DIVIDEND YIELD
10 Jul 13	15 Nov 15	$0.0471	$0.451	$0.631	60% to 90%	2.73%	
28 Nov 13	15 Nov 17	$0.0450	$0.475	$0.320	45% to 65%	2.69%	

Table 2: Share Based Compensation – Options Granted and Vested during the Year

		NUMBER OF OPTION GRANTED	GRANT DATE	AVERAGE FAIR VALUE AT GRANT DATE	AVERAGE EXERCISE PRICE PER OPTION	EXPIRY DATE	NUMBER OF OPTIONS VESTED	PROPORTION OF OPTIONS VESTED
Non-Executive Directors								
Andrew Whittle	2015	—	—	—	—	—	—	—
	2014	—	—	—	—	—	—	—
William Dunmore[1]	2015	—	—	—	—	—	—	—
	2014	—	—	—	—	—	—	—
Wrixon Gasteen	2015	—	—	—	—	—	—	—
	2014	—	—	—	—	—	—	—
Robert Hubbard	2015	—	—	—	—	—	—	—
	2014	—	—	—	—	—	—	—
J. Thomas Wilson	2015	—	—	—	—	—	—	—
	2014	—	—	—	—	—	—	—
Peter Moore	2015	—	—	—	—	—	—	—
	2014	—	—	—	—	—	—	—
Executive Directors and Other Key Management								
Richard Cottee	2015	—	—	—	—	—	—	—
	2014	—	—	—	—	—	—	—
Michael Herrington[1,3]	2015	—	—	—	—	—	—	—
	2014	1,800,000	28 Nov 13	$0.0820	$0.475	15 Nov 17	—	—
Daniel White	2015	450,000	9 Apr 15	$0.0062	$0.450	15 Nov 17	—	—
	2014	733,334	10 Jul 13	$0.0580	$0.450	15 Nov 15	733,334	100%
Bruce Elsholz[2]	2015	370,500	9 Apr 15	$0.0062	$0.450	15 Nov 17	—	—
	2014	570,000	10 Jul3 13	$0.0580	$0.450	15 Nov 15	570,000	100%
Leon Devaney	2015	504,000	9 Apr 15	$0.0062	$0.450	15 Nov 17	—	—
	2014	560,000	10 Jul 13	$0.0580	$0.450	15 Nov 15	560,000	100%
Michael Bucknill	2015	100,000	01 Jul 14	$0.0200	$0.400	15 Nov 15	100,000	100%
	2015	330,000	9 Apr 15	$0.0067	$0.400	15 Nov 17	—	—
	2014	—	—	—	—	—	—	—
Robbert Willink	2015	120,000	17 Jul 14	$0.0200	$0.400	15 Nov 15	120,000	100%
	2015	330,000	9 Apr 15	$0.0067	$0.400	15 Nov 17	—	—
	2014	—	—	—	—	—	—	—

1 Mr Dunmore and Mr Herrington retired as a directors 26 November 2014.

2 Mr Elsholz resigned from employment on 30 November 2014. Options were awarded in respect of prior service periods.

3. During 2015, Mr Herrington had 450,000 options cancelled out of the 1,800,000 options granted in the prior year.

G. Remuneration Details (continued)

Table 3: Options Granted as Part of Remuneration

2015	VALUE OF OPTIONS GRANTED DURING THE YEAR $	VALUE OF OPTIONS LAPSED/ CANCELLED DURING THE YEAR $	REMUNERATION CONSISTING OF OPTIONS FOR THE YEAR %
Non-Executive Directors			
Andrew Whittle	—	—	—
William Dunmore[1]	—	—	—
Wrixon Gasteen	—	—	—
Robert Hubbard	—	—	—
J. Thomas Wilson	—	—	—
Peter Moore	—	—	—
Executive Directors and Other Key Management Personnel			
Richard Cottee	—	—	—
Michael Herrington	—	(2,655)	—
Bruce Elsholz[2]	2,297	—	—
Daniel White	2,790	—	—
Leon Devaney	3,125	—	—
Michael Bucknill	4,211	—	—
Robbert Willink	4,611	—	—

2014	VALUE OF OPTIONS GRANTED DURING THE YEAR $	VALUE OF OPTIONS LAPSED DURING THE YEAR $	REMUNERATION CONSISTING OF OPTIONS FOR THE YEAR %
Non-Executive Directors			
Andrew Whittle	—	—	—
William Dunmore	—	(55,928)	—
Wrixon Gasteen	—	—	—
Robert Hubbard	—	—	—
J. Thomas Wilson	—	—	—
Peter Moore	—	—	—
Executive Directors and Other Key Management Personnel			
Richard Cottee	—	—	—
Michael Herrington	148,500	—	18
Bruce Elsholz	33,060	—	9
Daniel White	42,534	—	8
Leon Devaney	32,480	—	9
Michael Bucknill	—	—	—
Robbert Willink	—	—	—

1 Retired effective 26 November 2014

2 Resigned effective 30 November 2014

No other options were exercised during either year, and no shares were issued on exercise of compensation options.

G. Remuneration Details (continued)

Table 4: Shareholdings of Key Management Personnel

		HELD AT BEGINNING OF YEAR	HELD AT DATE OF APPOINTMENT	ON MARKET PURCHASE	RECEIVED ON EXERCISE OF OPTIONS	NET CHANGE OTHER	HELD AT DATE OF DEPARTURE	HELD AT END OF YEAR
Non-Executive Directors								
Andrew Whittle	2015	133,680	N/A	102,364	—	—		236,044
	2014	133,680	N/A	—	—	—	N/A	133,680
William Dunmore	2015	183,743	N/A		—	—	183,743	—
	2014	183,743	N/A	—	—	—	N/A	183,743
Wrixon Gasteen	2015	97,000	N/A		—	—	N/A	97,000
	2014	104,000	N/A	—	—	(7,000)	N/A	97,000
Robert Hubbard	2015	64,100	N/A	55,900	—	—	N/A	120,000
	2014	N/A	64,100	—	—	—	N/A	64,100
J. Thomas Wilson	2015	—	N/A	—	—	—	N/A	—
	2014	N/A	—	—	—	—	N/A	—
Peter Moore	2015	—	—	—	—	—	N/A	—
	2014	N/A	—	—	—	—	N/A	—
Executive Directors and Other Key Management Personnel								
Richard Cottee	2015	208,683	N/A	227,700	—	—	N/A	436,383
	2014	208,683	N/A	—	—	—	N/A	208,683
Michael Herrington	2015	200,000	N/A	50,000	—	—	N/A	250,000
	2014	200,000	N/A	—	—	—	N/A	200,000
Daniel White	2015	288,000	N/A	—	—	—	N/A	288,000
	2014	288,000	N/A	—	—	—	N/A	288,000
Bruce Elsholz[1]	2015	—	N/A	—	—	—	—	N/A
	2014	—	N/A	—	—	—	N/A	—
Leon Devaney	2015	110,000	N/A	100,000	—	—	N/A	210,000
	2014	110,000	N/A	—	—	—	N/A	110,000
Michael Bucknill	2015	31,000	N/A	25,000	—	—	N/A	56,000
	2014	—	31,000	—	—	—	N/A	31,000
Robbert Willink	2015	—	N/A	—	—	—	N/A	—
	2014	—	—	—	—	—	N/A	—

1 Resigned effective 30 November 2014

G. Remuneration Details (continued)

Table 5: Option Holdings of Key Management Personnel

		HELD AT BEGINNING OF YEAR	OPTIONS EXERCISED	GRANTED AS REMUNERATION	NET CHANGE OTHER	HELD AT DATE OF DEPARTURE	HELD AT END OF YEAR
Non-Executive Directors							
Andrew Whittle	2015	900,000	—	—	—	900,000	900,000
	2014	900,000	—	—	—	N/A	900,000
William Dunmore[1]	2015	—	—	—	—	—	N/A
	2014	280,000	—	—	(280,000)	N/A	—
Wrixon Gasteen	2015	1,000,000	—	—	—	N/A	1,000,000
	2014	1,000,000	—	—	—	N/A	1,000,000
Robert Hubbard	2015	—	—	—	—	N/A	—
	2014	N/A	—	—	—	N/A	—
J. Thomas Wilson	2015	—	—	—	—	N/A	—
	2014	N/A	—	—	—	N/A	—
Peter Moore	2015	—	—	—	—	N/A	—
	2014	N/A	—	—	—	N/A	—
Executive Directors and Other Key Management Personnel							
Richard Cottee	2015	34,584,407	—	—	—	N/A	34,584,407
	2014	34,584,407	—	—	—	N/A	34,584,407
Michael Herrington	2015	2,700,000	—	—	(450,000)	N/A	2,250,000
	2014	900,000	—	1,800,000	—	N/A	2,700,000
Daniel White	2015	1,643,334	—	450,000	(600,000)	N/A	1,493,334
	2014	929,200	—	733,334	(19,200)	N/A	1,643,334
Bruce Elsholz	2015	1,170,000	—	370,500	(400,000)	1,140,500	N/A[1]
	2014	600,000	—	570,000	—	N/A	1,170,000
Leon Devaney	2015	560,000	—	504,000	—	N/A	1,064,000
	2014	—	—	560,000	—	N/A	560,000
Michael Bucknill	2015	—	—	430,000	—	N/A	430,000
	2014	N/A	—	—	—	N/A	—
Robbert Willink	2015	—	—	450,000	—	N/A	450,000
	2014	N/A	—	—	—	N/A	—

[1] Retired, effective 26 November 2014.

The vesting profile for options held at the end of the year was as follows:

		HOLDINGS AT END OF YEAR	VESTED DURING THE YEAR	EXERCISABLE AT END OF YEAR
Non-Executive Directors				
Andrew Whittle	2015	900,000	—	300,000
	2014	900,000	—	300,000
Wrixon Gasteen	2015	1,000,000	—	333,333
	2014	1,000,000	—	333,333
Executive Directors and Other Key Management Personnel				
Richard Cottee	2015	34,584,407	—	9,683,634
	2014	34,584,407	—	9,683,634
Michael Herrington	2015	2,250,000	—	300,000
	2014	2,700,000	—	300,000
Daniel White	2015	1,183,333	—	733,333
	2014	1,643,334	—	1,643,334
Bruce Elsholz	2015	N/A	—	N/A
	2014	1,170,000	—	1,170,000
Leon Devaney	2015	1,064,000	—	560,000
	2014	560,000	—	560,000
Michael Bucknill	2015	430,000	100,000	100,000
	2014	—	—	—
Robbert Willink	2015	450,000	120,000	120,000
	2014	—	—	—

G. Remuneration Details (continued)

For each grant of options included in the tables 1 to 5 above, the percentage of the grant that was vested and the percentage that was forfeited because the person did not meet the performance or service criteria are set out below. The options vest over a range of time frames provided the vesting conditions are met. No options will vest if the conditions are not satisfied (refer page 26), hence the minimum value of the option yet to vest is nil. The maximum value of the options yet to vest has been determined as the amount of the grant date fair value of the options that is yet to be expensed.

SHARE BASED COMPENSAION BENEFITS (OPTIONS)

NAME	Year Granted	Vested %	Forfeited %	Financial Years in which Options may Vest	Maximum Value of Grant yet to Vest $
Andrew Whittle	2013	33	—	2014 to 2017	66,252
William Dunmore	2009	100	—	—	—
	2008	100	—	—	—
Wrixon Gasteen	2013	33	—	2014 to 2017	73,613
Richard Cottee	2013	28	—	2014 to 2017	3,094,211
Michael Herrington	2014	—	25	2015 to 2017	3,140
	2013	33	—	2014 to 2017	66,252
Daniel White	2015	—	—	2015 to 2017	1,175
	2014	100	—	—	—
	2013	100	—	—	—
	2010	100	—	—	—
Leon Devaney	2015	—	—	2015 to 2017	1,316
	2014	100	—	—	—
Michael Bucknill	2015	23	—	2015 to 2017	1,106
Robbert Willink	2015	27	—	2015 to 2017	1,106

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 employee 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 & 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:

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	NUMBER OF RIGHTS HELD AT END OF YEAR (UNVESTED)
Executive Directors and Other Key Management Personnel						
Richard Cottee	2015	—	—	—	—	—
	2014	—	—	—	—	—
Michael Herrington	2015	—	—	—	—	—
	2014	—	—	—	—	—
Daniel White	2015	—	330,000	—	—	330,000
	2014	—	—	—	—	—
Leon Devaney	2015	—	278,571	—	—	278,571
	2014	—	—	—	—	—
Michael Bucknill	2015	—	274,285	—	—	274,285
	2014	—	—	—	—	—
Robbert Willink	2015	—	262,286	—	—	262,286
	2014	—	—	—	—	—

H. Executive Service Agreements

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

Richard Cottee, Managing Director and Chief Executive Officer

- The term of the agreement expires 29 June 2018.
- Mr Cottee's base salary is presently $574,162 per annum. In addition, superannuation at 9.5 percent is applicable. The salary is reviewed annually.
- 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.

Mike Herrington, Executive Director and Chief Operating Officer

- The term of the current agreement expires 28 January 2016.
- Extension term of the current agreement expires 29 January 2019
- Mr Herrington's base salary is presently $465,000 per annum. In addition, superannuation at 9.5 percent is applicable. The salary is reviewed annually.
- 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.

Leon Devaney, Chief Financial Officer

- The term of the agreement expires 15 November 2015.
- Extension term of the current agreement expires 16 November 2018
- Mr Devaney's base salary is presently $391,500 per annum. In addition, superannuation at 9.5 percent is applicable. The salary is reviewed annually.
- 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.

Daniel White, Group General Counsel and Company Secretary

- The term of the agreement expires 29 November 2017.
- Mr White's base salary is presently $385,000 per annum. In addition, superannuation at 9.5 percent is applicable. The salary is reviewed annually.
- 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.

Michael Bucknill, General Manager, Exploration

- The term of the agreement expires 30 June 2017.
- Mr Bucknill's base salary is presently $320,000 per annum. In addition, superannuation at 9.5 percent is applicable. The salary is reviewed annually.
- 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.

Robbert Willink, Exploration Advisor

- The term of the agreement expires 30 June 2017.
- Mr Willink's base salary is presently $340,000 per annum. In addition, superannuation at 9.5 percent is applicable. The salary is reviewed annually.
- 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.

Bruce Elsholz, Chief Financial Officer

- The term of the agreement expires 30 August 2017.
- Mr Elsholz's base salary is presently $315,000 per annum. In addition, superannuation at 9.5 percent is applicable. The salary is reviewed annually.
- Mr Elsholz resigned his position of Company Secretary effective 25 August 2014 and resigned from Central on 30 November 2014.

I. 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 2015.

BOARD FEES (PER ANNUM)

Chairman	$95,000.00
Non-Executive Director	$65,000.00

COMMITTEE FEES (PER ANNUM)

Audit & Risk	Chair	$10,000.00
	Member	$5,000.00
Remuneration	Chair	$10,000.00
	Member	$5,000.00
Nomination	Chair	$10,000.00
	Member	$5,000.00

The Directors also receive superannuation benefits except for Messrs. Gasteen, and Wilson, who reside outside of Australia.

Signed in accordance with a resolution of the Directors:

Richard Cottee
Managing Director
Brisbane
23 September 2015

Auditor's Independence Declaration

As lead auditor for the audit of Central Petroleum Limited for the year ended 30 June 2015, 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.

Michael Shewan
Partner
PricewaterhouseCoopers

Brisbane
23 September 2015

PricewaterhouseCoopers, ABN 52 780 433 757
Riverside Centre, 123 Eagle Street, BRISBANE QLD 4000, GPO Box 150, BRISBANE QLD 4001
T: +61 7 3257 5000, F: +61 7 3257 5999, www.pwc.com.au

CORPORATE GOVERNANCE STATEMENT

Central Petroleum Limited and the 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 2015 Corporate Governance Statement is dated as at 30 June 2015 and reflects the corporate governance practices in place throughout the 2015 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/.

FINANCIAL REPORT

CONTENTS

These Financial Statements are the consolidated financial statements of the Consolidated Entity 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 32, 400 George 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 21. These pages are not part of these financial statements.

The financial statements were authorised for issue by the directors on 23 September 2015. 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 2015

	NOTE	**2015** **$**	2014 $
Operating revenue	22(a)	10,313,266	3,718,102
Cost of sales	22(b)	(10,117,038)	(3,016,494)
Gross profit	22(c)	196,228	701,608
Other income	2	7,480,298	1,530,668
Share based employment benefits	30(d)	(2,246,683)	(2,818,231)
General and administrative expenses		(1,938,425)	(2,517,230)
Business combination transaction fees		—	(1,914,004)
Depreciation & amortisation	3	(2,707,589)	(1,127,155)
Employee benefits and associated costs		(5,018,180)	(3,120,279)
Exploration expenditure		(7,655,931)	(4,659,886)
Finance costs	3 & 22(d)	(3,748,714)	(1,040,975)
Impairment expense	3	(12,092,042)	–
Loss before income tax		(27,731,038)	(14,965,484)
Income tax credit	4	–	4,107,498
Loss for the year	20	(27,731,038)	(10,857,986)
Other comprehensive loss for the year, net of tax		–	–
Total comprehensive loss for the year		(27,731,038)	(10,857,986)
Total comprehensive loss attributable to members of the parent entity		**(27,731,038)**	**(10,857,986)**
Basic and diluted loss per share (cents)	21	(7.63)	(3.42)

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

AS AT 30 JUNE 2015

	NOTE	2015 $	2014 $
ASSETS			
Current assets			
Cash and cash equivalents	6	3,516,139	10,330,474
Trade and other receivables	7	5,869,332	2,953,300
Inventories	8	2,136,673	1,940,983
Assets held for sale	9	1,755,736	1,000,000
Total current assets		13,277,880	16,224,757
Non-current assets			
Property, plant and equipment	10	58,577,415	46,266,152
Exploration assets	11	8,898,767	16,869,693
Intangible assets	12	12,052	19,521
Other financial assets	13	2,075,733	2,423,185
Goodwill	14	3,906,270	3,906,270
Total non-current assets		73,470,237	69,484,821
Total assets		**86,748,117**	**85,709,578**
LIABILITIES			
Current liabilities			
Trade and other payables	15	7,707,897	10,476,308
Interest-bearing liabilities	16	7,921,129	255,760
Provisions	17	2,060,330	2,716,068
Total Current liabilities		17,689,356	13,448,136
Non-current liabilities			
Interest-bearing liabilities	16	39,536,722	23,761,593
Provisions	17	6,375,539	5,431,136
Total non-current liabilities		45,912,261	29,192,729
Total liabilities		**63,601,617**	**42,640,865**
Net assets		**23,146,500**	**43,068,713**
EQUITY			
Contributed equity	18	160,785,182	155,223,040
Reserves	19	16,695,379	14,448,696
Accumulated losses	20	(154,334,061)	(126,603,023)
Total equity		**23,146,500**	**43,068,713**

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

FOR THE YEAR ENDED 30 JUNE 2015

	CONTRIBUTED EQUITY	RESERVES	ACCUMULATED LOSSES $	TOTAL $
Total equity at 1 July 2013	**130,258,022**	**10,132,939**	**(115,745,037)**	**24,645,924**
Total loss for the year	—	—	(10,857,986)	(10,857,986)
Other comprehensive loss	—	—	—	—
Total comprehensive loss for the year	—	—	(10,857,986)	(10,857,986)
Transactions with owners in their capacity as owners				
Share based payments	—	2,818,231	—	2,818,231
Options issued for financing	—	1,497,526	—	1,497,526
Share and option issues	25,614,373	—	—	25,614,373
Share issue costs	(649,355)	—	—	(649,355)
	24,965,018	4,315,757	—	29,280,775
Balance at 30 June 2014	**155,223,040**	**14,448,696**	**(126,603,023)**	**43,068,713**
Total loss for the year	—	—	(27,731,038)	(27,731,038)
Other comprehensive loss	—	—	—	—
Total comprehensive loss for the year	—	—	(27,731,038)	(27,731,038)
Transactions with owners in their capacity as owners				
Share based payments	—	2,246,683	—	2,246,683
Options issued for financing	—		—	—
Share and option issues	6,000,000	—	—	6,000,000
Share issue costs	(437,858)	—	—	(437,858)
	5,562,142	2,246,683	—	7,808,825
Balance at 30 June 2015	160,785,182	16,695,379	(154,334,061)	23,146,500

The accompanying notes form part of these financial statements.

CONSOLIDATED STATEMENT OF CASH FLOW

FOR THE YEAR ENDED 30 JUNE 2015

	NOTE	2015 $	2014 $
Cash flows from operating activities			
Receipts from customers		10,980,363	2,105,060
Interest received		143,396	406,273
Other income		3,420,536	7,931,000
Interest & borrowing costs		(286,761)	(375,000)
Payments to suppliers and employees (inclusive of GST)		(24,857,867)	(9,589,572)
Net cash (outflow)/inflow from operating activities	26	(10,600,333)	477,761
Cash flows from investing activities			
Payments for property, plant and equipment		(21,776,201)	(3,344,271)
Payments for exploration assets		—	—
Payments to acquire subsidiary		—	(20,595,871)
Payment of business combinations transaction fees		—	(1,914,004)
Proceeds from sale of property, plant and equipment		960,000	—
Redemption / (Acquisition) of security deposits and bonds		345,352	(566,466)
Net cash inflow/(outflow) from investing activities		(20,470,849)	(26,420,612)
Cash flows from financing activities			
Proceeds from the issue of shares and options		5,562,142	9,965,018
Proceeds from borrowings		19,000,000	25,000,000
Repayment of borrowings		(305,295)	—
Net cash inflow from financing activities		24,256,847	34,965,018
Net (decrease)/increase in cash and cash equivalents		**(6,814,335)**	**9,022,167**
Cash and cash equivalents at the beginning of the financial year		**10,330,474**	**1,308,307**
Cash and cash equivalents at the end of the financial year	**6**	**3,516,139**	**10,330,474**
Non-cash financing and investing activities	27		

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 "Consolidated Entity").

(a) Basis of Preparation

These general purpose financial statements have been prepared in accordance with Australian Accounting Standards and Interpretations of the Australian Accounting Standards Board and the Corporations Act 2001. Central Petroleum Limited is a for-profit entity for the purpose of preparing the financial statements.

(i) Going Concern

The consolidated financial statements of the Group have been prepared on a going concern basis, which contemplates continuity of business activities and realisation of assets and the settlement of liabilities in the ordinary course of business. For the year ended 30 June 2015 the Group incurred a loss before tax of $27,731,038 (2014: $14,965,484), net-cash outflow from operating activities of $10,600,333 (2014: inflow of $477,761) and as of that date, the Group's current liabilities exceeded its current assets by $4,411,476 (2014: net current assets of $2,776,621). These results are consistent with our exploration, appraisal and development activities and also reflect a ramp-up phase in the Palm Valley gas field and completion of the Dingo gas field.

As at 30 June 2015 the Group had cash assets including joint arrangement balances amounting to $3,516,139. The Group continually monitors its cash flow requirements to ensure that it has sufficient funds to meet its contractual commitments and adjusts its spending, particularly with respect to discretionary exploration activity and corporate overhead, accordingly.

Over the next 12 months, additional funds will be required as existing cash balances, combined with expected cash inflows from the Group's production operations, are not expected to be sufficient by themselves to fund the Mereenie acquisition commitments (notably $15 million comprising a free-carry work program for Santos ($5 million) and a deferred acquisition payment ($10 million) due in June 2016).

The primary focus for the Group's required funding above is via new supportable debt generated by new gas sales agreements (GSA's) connected with the North East Gas Interconnector (NEGI) pipeline. To this end, Central has entered into two non-binding letters of agreement for the sale of gas subject to the NEGI pipeline Final Investment Decision (FID), both from major gas purchasers on the east coast.

Given the significant installed capacity already invested at Mereenie, further GSA's via the NEGI indicate that sufficient debt capital could be raised beyond required project costs to fund the future Mereenie acquisition commitments whilst still maintaining very commercially acceptable debt service coverage ratios. Given the Group's existing GSA's are all long-term fixed-price CPI escalated contracts, and future NEGI related GSA's are expected to have a similar pricing construct, utilising debt capital is considered by the Group to be cost efficient (low interest rates) and appropriate in a capital structuring sense. Central's existing banker, Macquarie Bank Ltd, has provided a letter of support for expanding Central's existing $90 million debt facility to cover required development costs and up to a further $15 million to specifically cover any remaining Mereenie acquisition costs. Such increased debt funding would be subject to sufficient gas sales agreements, Macquarie's receipt of all internal approvals, and the usual and customary conditions precedent to the provision of finance to Central.

In addition to NEGI related GSA debt capital, the Group has several other alternative sources of funding it is actively considering and will select the one which is most aligned with creating shareholder value at the time. The two most notable include a sell down of a partial interest in Central's existing producing assets (Mereenie, Palm Valley and Dingo) or approaching the equity markets for a capital raising. Alternatively a combination of the above could be implemented depending on the prevailing economic and market conditions. Further to these sources of funding, if required, the Company has access to an Equity Line of Credit (ELOC) Facility of $10 million with Long State Investment Limited (LSI), the terms of which are set out in Note 18(g).

If additional funding does not materialise at the appropriate time and for the appropriate amounts then there is a material uncertainty that may cast significant doubt on whether the Group will continue as a going concern and, therefore, whether it will realise its assets and settle its liabilities and commitments in the normal course of business and at the amounts stated in the financial report.

The Directors believe that the Group will be successful in sourcing funds when required and will meet its debts and commitments as they fall due and, accordingly, have prepared the financial statements on a going concern basis. The directors, therefore, are of the opinion that no asset is likely to be realised for an amount less than the amount it is recorded in the financial report at 30 June 2015. Accordingly no adjustments have been made to the financial report relating to the recoverability and classification of the asset carrying amounts and classification of liabilities that might be necessary should the Group not continue as a going concern.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(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 2014 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.

Share-based Payments

The Group is required to use assumptions in respect of their fair value models, and the variable elements in these models, used in determining share based payments. The directors have used a model to value options, 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.

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, and temporary differences arising from the Petroleum Resource Rent Tax (Imposition – General) Act 2011, 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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(b) Principles of Consolidation

(i) Subsidiaries

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

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

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

Intercompany transactions, balances and unrealised gains on transactions between Group 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

Under AASB 11 Joint Arrangements investments in joint arrangements are classified as either joint operations or joint ventures. The classification depends on the contractual rights and obligations of each investor, rather than the legal structure of the joint arrangement.

(iii) Joint Operations

The Group recognises its direct right to the assets, liabilities, revenues and expenses of joint operations and its share of any jointly held or incurred assets, liabilities, revenues and expenses. These have been incorporated in the financial statements under the appropriate headings. Details of the joint operation are set out in Note 32.

(c) Segment Reporting

Operating segments are reported 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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(e) Revenue Recognition

Revenue is recognised and measured at the fair value of the consideration received or receivable to the extent it is probable that the economic benefits will flow to the Group and the revenue can be reliably measured. The following specific recognition criteria must also be met before revenue is recognised:

(i) Sale of Oil and Gas

Revenue is recognised when the significant risks and rewards of ownership of the product have passed to the buyer and the amount of revenue can be measured reliably. Risks and rewards are considered to have passed to the buyer at the time of delivery of the product to the customer. Revenue from take or pay contracts is recognised in earnings when the product is taken by the customer or their right to take product expires. It is recorded as unearned revenue when it has not been taken and a right to take it in future still exists.

(ii) Interest Income

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

(f) Government Grants

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.

(g) Income Tax

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 and to unused tax losses.

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.

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

Deferred tax assets 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.

Deferred tax liabilities and assets are not recognised for temporary differences between the carrying amount and tax bases of investments in foreign operations where the Group is able to control the timing of the reversal of the temporary differences and it is probable that the differences will not reverse in the foreseeable future.

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.

Central Petroleum Limited and its wholly-owned Australian controlled entities have implemented the tax consolidation legislation. As a consequence, these entities are taxed as a single entity and the deferred tax assets and liabilities of these entities are set off in the consolidated financial statements. Current and deferred tax is recognised in profit or loss, except to the extent that it relates to items recognised in other comprehensive income or directly in equity. In this case, the tax is also recognised in other comprehensive income or directly in equity, respectively.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(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 29). 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 three 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 fair value and subsequently measured at amortised cost using the effective interest method, less provision for impairment. Trade receivables are generally due for settlement within 90 days. They are presented as current assets unless collection is not expected for more than 12 months after the reporting date.

Collectability of trade receivables is reviewed on an ongoing basis. Debts which are known to be uncollectible are written off by reducing the carrying amount directly. An allowance account (provision for impairment of trade receivables) is used when there is objective evidence that the Group will not be able to collect all amounts due according to the original terms of the receivables. Significant financial difficulties of the debtor, probability that the debtor will enter bankruptcy or financial reorganisation, and default or delinquency in payments (more than 90 days overdue) are considered indicators that the trade receivable is impaired. The amount of the impairment allowance is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the original effective interest rate. Cash flows relating to short-term receivables are not discounted if the effect of discounting is immaterial.

The amount of the impairment loss is recognised in profit or loss within other expenses. When a trade receivable for which an impairment allowance had been recognised becomes uncollectible in a subsequent period, it is written off against the allowance account. Subsequent recoveries of amounts previously written off are credited against other expenses in profit or loss.

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 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 loans and receivables. 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. Loans and receivables are included in trade and other

Receivables (Note 7) and other financial assets (Note 13) 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.

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.

(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, and all development drilling and other subsurface expenditure. 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.

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 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

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 and subsurface development expenditure ("subsurface assets") 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 in the respective asset or group of assets.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

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

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

Subsequent costs are included in the asset's carrying amount or recognised as a separate asset, as appropriate, only when it is probable that future economic benefits associated with the item will flow to the Group and the cost of the item can be measured reliably. The carrying amount of any component accounted for as a separate asset is derecognised when replaced. All other repairs and maintenance 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 accumulated in respect of each separate area of interest. Acquisition costs are carried forward where right of tenure of the area of interest is current and 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. 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. Amortisation is not charged on costs carried forward in respect of areas of interest in the development phase until production commences.

(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 22).

(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) 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 interest 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.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(t) Employee benefits (continued)

(iii) Share-based Payments

Share-based compensation benefits are provided to employees (including directors) by Central Petroleum Limited.

The fair value of options or rights granted is recognised as an employee benefits expense with a corresponding increase in equity. The total amount to be expensed is determined by reference to the fair value of the 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 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 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 23, 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.

(ii) Tax Consolidation Legislation

Central Petroleum Limited and its wholly-owned Australian controlled entities have implemented the tax consolidation legislation. The head entity, Central Petroleum Limited, and the controlled entities in the tax consolidated Group account for their own current and deferred tax amounts where recognition of such is permitted under accounting standards. These tax amounts are measured as if each entity in the tax consolidated Group continues to be a standalone taxpayer in its own right.

In addition to its own current and deferred tax amounts, Central Petroleum Limited also recognises the current tax liabilities or assets and the deferred tax assets arising from unused tax losses from controlled entities, where permitted to recognise such assets under accounting standards.

(z) Business Combinations

Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at acquisition date fair value and the amount of any non-controlling interest in the acquiree. For each business combination, the Group elects whether it measures the non-controlling interest in the acquiree at fair value or at the proportionate share of the acquiree's identifiable net assets. Acquisition costs incurred are expensed and included in administrative expenses.

When the Group acquires a business, it assesses the financial assets and liabilities assumed for appropriate classification and designation in accordance with the contractual terms, economic circumstances and pertinent conditions as at the acquisition date. This includes the separation of embedded derivatives in host contracts by the acquiree.

If the business combination is achieved in stages, the acquisition date fair value of the acquirer's previously held equity interest in the acquiree is remeasured to fair value at the acquisition date through profit or loss.

Any contingent consideration to be transferred by the acquirer will be recognised at fair value at the acquisition date. Subsequent changes to the fair value of the contingent consideration that is deemed to be an asset or liability will be recognised in accordance with AASB 139 in profit or loss. If the contingent consideration is classified as equity it will not be remeasured. Subsequent settlement is accounted for within equity. In instances where the contingent consideration does not fall within the scope of AASB 139, it is measured in accordance with the appropriate AASB.

Goodwill is initially measured at cost, being the excess of the aggregate of the consideration transferred and the amount recognised for non-controlling interest over the net identifiable assets acquired and liabilities assumed. If this consideration is lower than the fair value of the net assets of the subsidiary acquired, the difference is recognised in profit or loss.

After initial recognition, goodwill is measured at cost less any accumulated impairment losses. For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Group's cash-generating units that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquirer are assigned to those units.

Where goodwill forms part of the cash generating unit and part of the operation within that unit is disposed of, the goodwill associated with the operation disposed of is included in the carrying amount of the operation when determining the gain or loss on disposal of the operation. Goodwill disposed of in this circumstance is measured based on the relative values of the operation disposed of and the portion of the cash-generating unit retained.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(aa) Standards, Amendments and Interpretations

(i) New and Amended Standards Adopted by the Group

The group has applied the following standards and amendments for first time for their annual reporting period commencing 1 July 2014:

- AASB 2013-3 Amendments to AASB 136 Recoverable Amount Disclosures for Non-Financial Assets
- AASB 2013-4 Amendments to Australian Accounting Standards – Novation of Derivatives and Continuation of Hedge Accounting.
- Interpretation 21 Accounting for Levies
- AASB 2014-1 Amendments to Australian Accounting Standards

No changes in accounting policies or adjustments to the amounts recognised in the financial statements resulted from the adoptions of these standards.

(ii) New Standards and Interpretations not yet Adopted

Certain new accounting standards and interpretations have been published that are not mandatory for 30 June 2015 reporting periods. The consolidated entity has concluded these standards and interpretations are not expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

2. OTHER INCOME

	2015 **$**	2014 $
Interest	150,003	307,274
Research and development refunds (a)	7,324,496	1,196,296
Other	5,799	27,098
Total other income	**7,480,298**	**1,530,668**

(a) The 2015 amount includes refunds received during the year in respect of the financial year ended 30 June 2014 amounting to $3,251,940. It also includes $4,072,556 accrued as receivable in respect of the financial year ended 30 June 2015. The refunds relate to exploration activities which have been expensed in the profit and loss in the current or prior year. The 2014 refund was not previously recognised as income as the amount and recoverability were uncertain at the time of preparation of the 2014 financial statements.

3. EXPENSES

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

	NOTE	2015 $	2014 $
Depreciation (i)			
Buildings		844	7,094
Producing assets		1,047,939	513,435
Restoration assets		304,162	69,146
Plant and equipment		1,301,467	502,611
Leasehold improvements		42,880	20,824
Total depreciation		2,697,292	1,113,110
Amortisation (i)			
Software		10,297	14,045
Impairment expense	3(b)	12,092,042	—
Rental expense relating to operating leases – Minimum lease payments		1,224,562	697,419
Finance costs			
Interest charge on Macquarie debt facility (ii)		2,937,287	528,067
Interest paid to other suppliers		16,829	—
Borrowing costs on Macquarie and other debt facility (ii)		285,210	375,000
Amortisation of deferred finance costs (ii)		327,827	81,956
Accretion charge		181,561	55,952
		3,748,714	1,040,975

(i) Depreciation and amortisation expense is based on a full year allocation for the Palm Valley gas field (2014: 3 months) and three months in respect of the Dingo gas pipeline and processing facilities which became ready for use on 1 April 2015. Of the amounts reported above, $492,000 relates to the Dingo gas field for which no revenue has been recognised in this financial period.

(ii) Finance Costs totaling $3.55 million relate to the Macquarie debt facility for the acquisition of the Palm Valley and Dingo gas fields and comprise borrowing costs of $613,000 and interest of $2.94 million (refer Note 31(e) for details on the facility). Of the total $3.55 million, $1.93 million relates to the Dingo gas field which although development was completed and the PWC GSA commenced on 1 April 2015 did not earn sales revenue as originally anticipated. The balance of $1.62 million relates to the Palm Valley gas field which anticipated full contract nominations during the year but did not ramp up revenues until May 2015. The Macquarie facility is secured by the Palm Valley and Dingo gas fields and is serviced by their respective cash flows.

3. EXPENSES (continued)

(b) Individually significant items

Impairment of assets

Oil Producing Assets

During the year the group fully impaired the assets relating to its Oil Producing assets in the Amadeus Basin. The impairment was based on expected future cash flows from the asset. The impairment loss included in the income statement relating to these assets was $5,420,293.

Property

Real property assets consisting of a warehouse and a residential property in Alice Springs were placed on the market for sale and were impaired to reflect their recoverable amounts. The impairment loss relating to these assets was $100,822.

Exploration Assets

During the year the following exploration permits were impaired to their recoverable amounts:

EP115 was impaired by $828,800. In light on the impairment of the oil producing assets this permit was impaired by 50 percent of its previous carrying value. Exploration and evaluation activities continue in the North Mereenie Block (operated by Santos) under a Farmout agreement with Santos.

EP97 impaired by $5,615,460. Management has impaired this asset to its likely recoverable amount under a potential divestment of the permit interests.

EP106 impaired by $126,667. Management has impaired this asset to Nil on the basis of a likely relinquishment of the permit.

4. 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.

		2015 $	2014 $
(a)	**Income tax expense**		
	Current tax	—	—
	Deferred tax	—	4,107,498
	Income tax expense	—	**4,107,498**
(b)	**Numerical reconciliation of income tax expense and prima facie tax benefit**		
	Loss before income tax expense	(27,731,038)	(14,965,484)
	Prima facie tax benefit at 30% (2014: 30%)	8,319,311	4,489,645
	Tax effect of amounts which are not deductible in calculating taxable income:		
	Non-deductible expenses	(362,625)	(439,309)
	Research and development expenditure	(2,714,864)	—
	Share based payments	(674,005)	(845,469)
	Non-assessable income	2,197,349	344,365
	Sub-total	6,765,166	3,549,232
	Under provision in prior year	—	—
	Deferred tax assets not recognised	(6,765,166)	—
	Recognition of previously unrecognised DTA		558,266
	Income tax expense	—	**4,107,498**
(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	110,871	149,335
	Deferred tax assets not recognised	(110,871)	(149,335)
	Net amounts recognised directly in equity	—	—
(d)	**Tax Losses**		
	Unutilised tax losses for which no deferred tax asset has been recognised	109,823,407	94,277,733
	Potential tax benefit at 30%	32,947,022	28,283,320

4. INCOME TAX (continued)

	2015 $	2014 $
(e) Deferred tax assets and liabilities		
Deferred tax assets		
Provisions and accruals	2,598,851	2,469,168
Blackhole expenditure	443,927	627,823
Borrowing costs	112,396	75,422
PRRT	52,254,331	40,434,838
Unutilised losses	37,756,625	36,552,974
Total deferred tax assets before set-offs	93,166,130	80,160,225
Set-off of deferred tax liabilities pursuant to set-off provisions	(6,993,154)	(8,269,654)
Net deferred tax assets not recognised	**86,172,976**	**71,890,571**
Movements		
Opening balance at 1 July	8,269,654	2,949,752
(Charged) / Credited to the income statement	(1,276,500)	5,319,902
Closing balance at 30 June	6,993,154	8,269,654
Deferred tax assets to be recovered after more than 12 months	6,970,577	8,253,466
Deferred tax assets to be recovered within 12 months	22,577	16,188
	6,993,154	8,269,654
Deferred tax liabilities		
Acquired income	1,581	2,594
Capitalised exploration	844,254	2,802,532
Property, plant and equipment	3,963,768	5,463,112
PRRT	2,183,551	—
Other	—	1,416
Total deferred tax assets before set-offs	6,993,154	8,269,654
Set-off of deferred tax liabilities pursuant to set-off provisions	(6,993,154)	(8,269,654)
Net deferred tax liabilities	—	—
Movements		
Opening balance at 1 July	8,269,654	2,949,752
Charged / (Credited) to the income statement	(1,276,500)	1,212,404
DTL arising on Business Combination	—	4,107,498
Closing balance at 30 June	6,993,154	8,269,654
Deferred tax liabilities to be recovered after more than 12 months	6,991,573	8,253,466
Deferred tax liabilities to be recovered within 12 months	1,581	16,188
	6,993,154	8,269,654

5. REMUNERATION OF AUDITORS

	2015 $	2014 $
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 financial statements	141,986	140,777
Southern Georgina joint arrangement audit	3,000	3,000
	144,986	143,777
(ii) Taxation services		
Income Tax compliance	8,500	16,311
Excise consulting services	48,957	—
Other tax related services	68,354	65,955
	125,811	82,266
(iii) Other services		
Magellan transaction due diligence	22,000	181,607
Remuneration benchmarking	—	10,000
Employee related services	6,698	—
	28,698	191,607
Total remuneration of PwC	**299,495**	**417,650**

6. CASH AND CASH EQUIVALENTS

Cash at bank and in hand	3,516,139	10,330,474
Made up as follows:		
Corporate (a)	3,254,312	8,740,088
Joint arrangements (b)	261,827	1,590,386
	3,516,139	10,330,474

(a) $1,046,123 of this balance relates to cash drawn from the Macquarie Bank Limited debt facility (2014: $2,192,082), and is restricted to use in the Palm Valley-Dingo project.

(b) $12,330 of this balance relates to the Group share of cash balances held by the Southern Georgina Joint Arrangement (2014: $807,914).

Risk exposure

The Group's exposure to interest rate risk is discussed in Note 31. The maximum exposure to credit risk at the end of the reporting period is the carrying amount of cash and cash equivalents.

7. TRADE AND OTHER RECEIVABLES

	NOTE	2015 $	2014 $
Current			
Trade receivables		244,657	868,282
Accrued income (a)		858,001	1,311,154
Accrued research and development refund		4,072,557	—
Other receivables		14,540	—
GST receivables		38,740	286,617
Prepayments		640,837	487,247
		5,869,332	**2,953,300**

(a) Accrued income relates to the revenue recognition of oil and gas volumes delivered to respective customers not yet invoiced.

The Group's exposure to credit and currency risks and impairment losses related to trade and other receivables is disclosed in Note 31.

8. INVENTORIES

Crude oil and natural gas		137,877	97,296
Spare parts and consumables		850,064	534,691
Drilling materials and supplies at cost		1,148,732	1,308,996
		2,136,673	**1,940,983**

9. ASSETS HELD FOR SALE

Land and buildings		355,736	1,000,000
Exploration assets	11	1,400,000	—
		1,755,736	**1,000,000**

During the year the consolidated entity decided to sell a residential property in Alice Springs which was previously used as employee accommodation. The property was subsequently sold in August 2015. The asset was not allocated to an operating segment in Note 22.

The consolidated entity also made the decision to divest of its interests in a number of exploration permits and is negotiating with interested parties. These assets were allocated to the Exploration segment in Note 22.

Non-recurring fair value measurements

Real property and exploration permits held for sale during the period were measured at the lower of their carrying values and their fair values less cost to sell at the time of the reclassification. Both items were valued using indicative offers being considered or being negotiated for the disposal of the assets.

As a result of this impairment losses of $67,072 were recognised in respect of the residential property still held for sale at 30 June 2015 and impairment losses of $5,615,460 were recognised in respect of the exploration permits held for sale.

10. PROPERTY, PLANT AND EQUIPMENT

	FREEHOLD LAND AND BUILDINGS $	PRODUCING ASSETS $	ASSETS IN DEVELOPMENT $	PLANT AND EQUIPMENT $	RESTORATION ASSET $	TOTAL $
Year ended 30 June 2014						
Opening net book amount	424,497	—	—	860,803	—	1,285,300
Additions	—	2,953,503	2,405,766	1,132,084	107,318	6,598,671
Additions – business combinations	—	15,859,734	16,013,524	2,953,036	4,201,265	39,027,559
Transfer from exploration	—	—	—	—	482,535	482,535
Disposals and write offs	—	—	—	(14,803)	—	(14,803)
Depreciation charge	(7,094)	(513,435)	—	(523,435)	(69,146)	(1,113,110)
Closing net book amount	**417,403**	**18,299,802**	**18,419,290**	**4,407,685**	**4,721,972**	**46,266,152**
At 30 June 2014						
Cost	430,947	18,813,237	18,419,290	6,023,358	4,791,118	48,477,950
Accumulated depreciation	(13,544)	(513,435)	—	(1,615,673)	(69,146)	(2,211,798)
Net book amount	**417,403**	**18,299,802**	**18,419,290**	**4,407,685**	**4,721,972**	**46,266,152**
Year ended 30 June 2015						
Opening net book amount	417,403	18,299,802	18,419,290	4,407,685	4,721,972	46,266,152
Additions	260,924	—	2,249,802	17,864,528	470,154	20,845,408
Assets classified as held for sale	(315,738)	—	—	—	—	(315,738)
Transfers/reclassifications	—	13,936,901	(20,669,092)	6,732,191	—	—
Disposals and write offs	—	—	—	—	—	—
Impairment	(100,821)	(381,089)	—	(4,346,903)	(692,302)	(5,521,115)
Depreciation charge	(844)	(1,047,939)	—	(1,344,347)	(304,162)	(2,697,292)
Closing net book amount	**260,924**	**30,807,675**	—	**23,313,154**	**4,195,662**	**58,577,415**
At 30 June 2015						
Cost	260,924	32,750,137	—	30,725,815	5,261,271	68,998,147
Accumulated depreciation	—	(1,942,462)	—	(7,412,661)	(1,065,609)	(10,420,732)
Net book amount	**260,924**	**30,807,675**	—	**23,313,154**	**4,195,662**	**58,577,415**

11. EXPLORATION ASSETS

	NOTE	2015 $	2014 $
Acquisition costs of right to explore		**8,898,767**	**16,869,693**
Movement for the year:			
Balance at the beginning of the year		16,869,693	16,702,228
Expenditure incurred during the year		—	—
Impairment of exploration assets		(6,570,926)	—
Additions – business combinations		—	650,000
Permits reclassified as held for sale	9	(1,400,000)	—
Restoration asset transferred to producing assets	10	—	(482,535)
Balance at the end of the year		**8,898,767**	**16,869,693**

12. INTANGIBLE ASSETS

	2015 $	2014 $
Software		
At the beginning of the year		
Cost	274,644	270,373
Accumulated amortisation	(255,123)	(241,079)
Net book value	**19,521**	**29,294**
Movements for the year		
Opening net book amount	19,521	29,294
Additions	2,828	4,271
Amortisation	(10,297)	(14,044)
Closing net book amount	**12,052**	**19,521**
At the end of the year		
Cost	262,311	274,644
Accumulated amortisation	(250,259)	(255,123)
Net book value	**12,052**	**19,521**

13. OTHER FINANCIAL ASSETS

	2015 $	2014 $
Security bonds on exploration permits & rental properties	**2,075,733**	**2,423,185**

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

	2015 $	2014 $
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 on an annual basis. The recoverable amount of a Cash Generating Unit (CGU) is determined based on value-in-use calculations which require the use of assumptions. The calculations use cash flow projections based on budgets for the next financial year as approved by management and forecasts beyond the budget based on extrapolations using estimated growth rates.

Cash flows for revenues are based on contracted gas prices with allowance for CPI increases to prices where applicable.

The following table sets out the key assumptions for the Gas Producing assets value-in-use calculations:

2015	Gas Producing Assets
Sales Volumes	Contracted
Sales Price (% annual growth rate)	2.50%
Operating costs (annual growth rate)	2.50%
Pre-tax discount rate (%)	17.42%

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

Assumption	Approach used to determining values
Sales volume	Annual minimum contracted quantities (subject to Take or Pay clauses where applicable)
Sales price	Current contracted prices escalated for CPI increases as per contracts. Some contracts contain minimum and maximum increases.
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 sale volumes. No incremental revenue or costs savings are assumed as a result of this expenditure
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
Pre-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. The equivalent pre-tax discount rates are disclosed in the table above.

15. TRADE AND OTHER PAYABLES

	2015 $	2014 $
Trade payables	2,540,490	3,893,054
Other payables	558,410	797,713
Southern Georgina joint arrangement contribution	3,676,864	4,305,514
Accruals	932,133	1,480,027
	7,707,897	**10,476,308**

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 31.

16. INTEREST BEARING LIABILITIES

	2015 $	2014 $
(a) Interest bearing liabilities (current)[1]		
Debt facilities	7,921,129	255,760
	7,921,129	**255,760**
(b) Interest bearing liabilities (non-current)[1]		
Debt facilities	39,536,722	23,761,593
	39,536,722	**23,761,593**

[1] Details regarding interest bearing liabilities are contained in Note 31(e).

17. PROVISIONS

	2015			2014		
	Current $	**Non-current $**	**Total $**	Current $	Non-current $	Total $
Employee entitlements (a)	1,761,378	228,987	1,990,365	1,105,995	167,376	1,273,371
Onerous contracts (b)	298,952	392,939	691,891	361,774	356,690	718,464
Restoration and rehabilitation (c)	—	5,753,613	5,753,613	—	4,907,070	4,907,070
Other	—	—	—	1,248,299	—	1,248,299
	2,060,330	**6,375,539**	**8,435,869**	**2,716,068**	**5,431,136**	**8,147,204**

(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. The following amounts reflect leave that is not expected to be taken or paid within the next 12 months:

	2015 $	2014 $
Current leave obligations expected to be settled after 12 months	520,916	479,696

(b) The provision for onerous contracts relates to operating lease commitments on the rental of office space at 167 Eagle Street Brisbane. The 2014 provision also included office space in Perth for which the lease has since expired.

(c) 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.

17. PROVISIONS (continued)

Movements in Provisions

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

2015	Employee entitlements $	Onerous Contracts $	Restoration and Rehabilitation $	Other $	Total $
Carrying amount at start of year	**1,273,371**	**718,464**	**4,907,070**	**1,248,299**	**8,147,204**
Additional provision charged to property, plant and equipment	—	—	470,154	—	470,154
Charged/(credited) to profit or loss					
- Additional provisions	1,291,071	311,216	194,828	—	1,797,115
- Unused amounts reversed	—	—	—	(194,485)	(194,485)
- Unwinding of discount	—	—	181,561	—	181,561
Amounts used during the year	(574,077)	(337,789)	—	(1,053,814)	(1,965,680)
Carrying amount at end of year	**1,990,365**	**691,891**	**5,753,613**	—	**8,435,869**

18. CONTRIBUTED EQUITY

	2015 $	2014 $
(a) Share Capital		
368,718,957 (2014: 348,718,957) fully paid ordinary shares	160,785,182	155,223,040

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.

(b) Movements in ordinary share capital

	2015 No. of shares	2014 No. of shares	2015 $	2014 $
Balance at start of year	348,718,957	1,440,078,845	155,223,040	130,258,022
Placement of shares to institutional investors on 26 July 2013 at 10 cents per share	—	106,000,000	—	10,600,000
Placement of shares to institutional investors on 2 October 2014 at 30 cents per share	20,000,000	—	6,000,000	—
Placement of shares to Magellan Petroleum Australia Pty Ltd on 31 March 2014 at 38 cents per share as part of business combinations	—	39,473,684	—	15,000,000
Share consolidation	—	(1,236,863,076)	—	—
Exercise of listed options at 80 cents per share	—	3,904	—	3,123
Exercise of listed options at 45 cents per share	—	25,600	—	11,250
Capital raising costs			(437,858)	(649,355)
	368,718,957	**348,718,957**	**160,785,182**	**155,223,040**

18. CONTRIBUTED EQUITY (continued)

(c) Options granted during the year

The following options over unissued ordinary shares were granted by the Company during the year:

DATE OF ISSUE	CLASS	EXPIRY DATE	EXERCISE PRICE	NUMBER OF OPTIONS
17 July 2014	Unlisted employee options	15 Nov 2015	40 cents	220,000
9 April 2015	Unlisted employee options	15 Nov 2017	Various	5,288,843

(d) Options exercised during the year

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

CLASS	EXPIRY DATE	EXERCISE PRICE	NUMBER OF OPTIONS
Listed options (CTPO)			–
Unlisted employee options			–

(e) Options lapsed or cancelled during the year

The following options over unissued ordinary shares lapsed during the year:

CLASS	EXPIRY DATE	EXERCISE PRICE	NUMBER OF OPTIONS
Unlisted employee options	31 Mar 2015	$0.625	13,000,003
Unlisted employee options	9 Apr 2015	$0.475	450,000
Unlisted employee options	31 May 2015	$0.610	1,268,000

(f) 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 options (CTPO)	30 Sep 2016	$0.500	15,000,000
Unlisted employee options	31 Oct 2015	$0.550	120,000
Unlisted employee options	15 Nov 2015	$0.400	220,000
Unlisted consulting options	15 Nov 2015	$0.450	9,683,634
Unlisted employee options	15 Nov 2015	$0.450	4,354,334
Unlisted director options	15 Nov 2015	$0.450	1,366,670
Unlisted employee options	15 Nov 2015	$0.650	207,000
Unlisted employee options	12 May 2016	$0.600	40,000
Unlisted employee options	20 Jul 2016	$0.550	669,334
Unlisted employee options	19 Aug 2016	$0.575	400,000
Unlisted employee options	30 Aug 2016	$0.575	600,000
Unlisted employee options	15 Nov 2017	$0.475	2,318,668
Unlisted employee options	15 Nov 2017	$0.475	400,000
Unlisted consulting options	15 Nov 2017	$0.450	24,900,772
Unlisted director options	15 Nov 2017	$0.450	2,733,335
Unlisted employee options	15 Nov 2017	$0.475	1,350,000
Unlisted employee options	15 Nov 2017	$0.400	782,525
Unlisted employee options	15 Nov 2017	$0.410	234,000
Unlisted employee options	15 Nov 2017	$0.450	2,429,068
Unlisted employee options	15 Nov 2017	$0.475	1,449,350
Unlisted employee options	15 Nov 2017	$0.650	393,900

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

18. CONTRIBUTED EQUITY (continued)

(g) 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.

Central has an undrawn equity line of credit facility of $10 million due to expire 24 September 2016. The facility can be drawn down in $250,000 amounts, however upon initial draw down cash fees of $200,000 and up to 5 million options would become payable.

19. RESERVES

	2015 $	2014 $
Share options reserve	**16,695,379**	**14,448,695**
Movements:		
Balance at start of year	14,448,696	10,132,939
Share based payment costs (a)	2,246,683	2,818,231
Options issued for financing (b)	–	1,497,526
Balance at end of year	**16,695,379**	**14,448,696**

(a) The reserve is primarily used to record the value of share based payments provided to employees and directors as part of their remuneration and underwriters of share placements. Refer to Note 30 for further details of share based payments.

(b) 15,000,000 options with an exercise price of $0.50 were issued to Macquarie bank in relation to the $50 million debt facility. These options were valued using a Black Scholes option pricing model.

20. ACCUMULATED LOSSES

Movements in accumulated losses were as follows:		
Balance at the start of year	(126,603,023)	(115,745,037)
Net loss for the year	(27,731,038)	(10,857,986)
Balance at end of year	**(154,334,061)**	**(126,603,023)**

21. LOSSES PER SHARE

(a) Basic loss per share (cents)	**(7.63)**	**(3.42)**
(b) Diluted loss per share (cents)	**(7.63)**	**(3.42)**
(c) Loss used in loss per share calculation		
Loss attributed to ordinary equity holders of the Company	**(27,731,038)**	**(10,857,986)**
(d) Weighted average number of ordinary shares		
Weighted average number of shares used as the denominator in calculating basic and diluted earnings per share	**363,568,272**	**317,351,393**

Options 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. Refer to Note 18 for details of options on issue.

22. 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.

Gas Producing assets
Production and sale from those fields where the major source of revenue arises from the sale of natural gas.

Oil Producing assets
Production and sale from those fields where the major source of revenue arises from the sale of crude oil.

Development assets
Fields under development in preparation for the sale of petroleum products.

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.

Financing requirements, finance income, finance costs and taxes are managed at a Group level.

The consolidated entity’s operations are wholly in one geographical location being Australia.

22. SEGMENT REPORTING (continued)

	GAS PRODUCING ASSETS 2015 $	OIL PRODUCING ASSETS 2015 $	DEVELOPMENT ASSETS 2015 $	EXPLORATION ASSETS 2015 $	UNALLOCATED ITEMS 2015 $	CONSOLIDATION 2015 $
Revenue (a)	5,301,806	5,011,460	—	—	—	10,313,266
Cost of sales (b)	(4,788,864)	(5,328,174)	—	—	—	(10,117,038)
Gross profit (c)	512,942	(316,714)	—	—	—	196,228
Other income	—	—	—	—	7,480,298	7,480,298
Share based employee benefits	—	—	—	—	(2,246,683)	(2,246,683)
General and administrative expenses	—	—	—	—	(1,938,425)	(1,938,425)
Depreciation and amortisation	(1,919,747)	(450,915)	—	(24,045)	(312,882)	(2,707,589)
Employee benefits and associated costs	—	—	—	—	(5,018,180)	(5,018,180)
Exploration expenditure	—	—	—	(7,655,931)	—	(7,655,931)
Finance costs (d)	(3,707,037)	(24,848)	—	—	(16,829)	(3,748,714)
Impairment expense	—	(5,420,293)	—	(6,570,927)	(100,822)	(12,092,042)
Loss before income tax	**(5,113,842)**	**(6,212,770)**	—	**(14,250,903)**	**(2,153,523)**	**(27,731,038)**
Taxes	—	—	—	—	—	—
Profit / (Loss) for the year	**(5,113,842)**	**(6,212,770)**	—	**(14,250,903)**	**(2,153,523)**	**(27,731,038)**
Segment assets	**63,661,928**	**1,186,421**	—	**11,641,829**	**10,257,939**	**86,748,117**
Segment liabilities	**(52,626,015)**	**(1,786,427)**	—	**(4,880,467)**	**(4,308,708)**	**(63,601,617)**
Capital expenditure						
Property, plant and equipment	331,351	2,002,241	18,442,116	8,253	61,447	20,845,408
Total capital expenditure	**331,351**	**2,002,241**	**18,442,116**	**8,253**	**61,447**	**20,845,408**

(a) Revenue from the gas producing assets for the year ended 30 June 2015 included a full year of revenues for Palm Valley (2014 only 3 months) however deliveries under the Palm Valley GSA were in ramp-up mode with full contract quantities delivered from April 2015. The Dingo pipeline and gas processing facilities were installed ready to deliver under the PWC GSA from 1 April 2015 however sales await the customer's physical tie-in to the Dingo delivery point and as such no gas was supplied under the gas sales contract during the financial year. The contract contains a "Take or Pay" arrangement however this is based on a calendar and not payable until January in the following year and therefore no revenue has been recognised to 30 June 2015 in accordance with the accounting policy for revenue recognition (Refer Note 1(e)(i)).

(b) Cost of sales for gas producing assets reflect a full year of operating costs for the Palm Valley gas field. It should be noted, however, that whilst Palm Valley was in full operational mode all year, gas sales production was in ramp-up mode under the Palm Valley GSA with full contract quantities being delivered from April 2015. In addition, although deliveries under the PWC GSA await the customer's physical tie-in to the Dingo delivery point, the field became operational from 1 April 2015 thus adding to the cost of sales reported for the year.

(c) Gross profit from gas producing assets for the period is masked by the disparity between revenues earned and cost of sales incurred as explained in (a) and (b) above and therefore does not reflect the gross profit that would otherwise be achieved from the Palm Valley and Dingo gas fields delivering full annual contract quantities.

(d) Finance Costs totaling $3.55 million relate to the Macquarie debt facility for the acquisition of the Palm Valley and Dingo gas fields and comprise borrowing costs of $613,000 and interest of $2.94 million (refer Note 31(e) for details on the facility). Of the total $3.55 million, $1.93 million relates to the Dingo gas field which although development was completed and the PWC GSA commenced on 1 April 2015 did not earn sales revenue as originally anticipated. The balance of $1.62 million relates to the Palm Valley gas field which anticipated full contract nominations during the year but did not ramp up revenues until May 2015. The Macquarie facility is secured by the Palm Valley and Dingo gas fields and is serviced by their respective cash flows.

22. SEGMENT REPORTING (continued)

	GAS PRODUCING ASSETS	OIL PRODUCING ASSETS	DEVELOPMENT ASSETS	EXPLORATION ASSETS	UNALLOCATED ITEMS	CONSOLIDATION
	2014	2014	2014	2014	2014	2014
	$	$	$	$	$	$
Revenue	**1,226,407**	**2,491,695**	—	—	—	**3,718,102**
Cost of sales	**(897,103)**	**(2,119,391)**	—	—	—	**(3,016,494)**
Gross profit	**329,304**	**372,304**	—	—	—	**701,608**
Other income	—	—	—	—	1,530,668	1,530,668
Share based employee benefits	—	—	—	—	(2,818,231)	(2,818,231)
General and administrative expenses	—	—	—	—	(2,517,230)	(2,517,230)
Business combinations transaction fees	—	—	—	—	(1,914,004)	(1,914,004)
Depreciation and amortisation	(119,569)	(393,866)	—	—	(613,720)	(1,127,155)
Employee benefits and associated costs	—	—	—	—	(3,120,279)	(3,120,279)
Exploration expenditure	—	—	—	(4,659,886)	—	(4,659,886)
Finance costs	(1,017,295)	(21,723)	—	—	(1,957)	(1,040,975)
Loss before income tax	**(807,560)**	**(43,285)**	—	**(4,659,886)**	**(9,454,753)**	**(14,965,484)**
Taxes	—	—	—	—	4,107,498	4,107,498
Profit / (Loss) for the year	**(807,560)**	**(43,285)**	—	**(4,659,886)**	**(5,347,255)**	**(10,857,986)**
Segment assets	20,767,460	3,803,319	25,989,302	21,436,107	13,713,390	**85,709,578**
Segment liabilities	(2,990,538)	(1,988,483)	(3,575,974)	(5,250,758)	(28,835,112)	**(42,640,865)**
Capital expenditure						
Exploration and evaluation assets	—	—	—	650,000	—	650,000
Property, plant and equipment	23,192,274	3,780,297	18,415,085	—	242,845	45,630,501
Total capital expenditure	**23,192,274**	**3,780,297**	**18,415,085**	**650,000**	**242,845**	**46,280,501**

In 2015 the Group changed its segment reporting to separate oil producing assets from gas producing assets. Consequently the 2014 segment reporting note has been revised to reflect the same reporting format as 2015.

	2015	2014
	$	$
Revenue from external customers by geographical location of production		
Australia	10,313,266	3,718,102
Non-current assets by geographical location		
Australia	73,470,237	69,484,821

Major Customers

Revenue from one customer represents $8,223,782 or 80 percent of the group's total oil and gas revenues (2014: $2,491,694 or 67 percent of the group's total oil and gas revenues). No other customers had revenue exceeding 10 percent of the group's total oil and gas revenue for the 2015 year.

In 2014 revenue from another customer represented $1,226,408 or 33 percent of the group's total oil and gas revenues for that year.

23. PARENT ENTITY INFORMATION

(a) Summary financial information

The individual financial summary statements for the parent entity show the following aggregate amounts:

	2015 $	2014 $
Statement of financial position		
Current assets	9,872,277	9,188,446
Non-current assets	9,065,573	11,070,840
Total assets	18,937,850	20,259,286
Current liabilities	(3,915,769)	(3,118,556)
Total liabilities	(4,308,708)	(4,806,901)
Net assets	14,629,142	15,452,385
Shareholders' equity		
Issued capital	160,785,182	155,223,040
Reserves	16,695,379	14,448,695
Accumulated losses	(162,851,419)	(154,219,350)
Total equity	14,629,142	15,452,385
Loss for the year	**(8,632,069)**	**(31,899,516)**
Total comprehensive loss	**(8,632,069)**	**(31,899,516)**

(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 Macquarie Loan Facility was entered into by Central Petroleum PVD Pty Ltd (Borrower) in February 2014, the parent and non-borrowing subsidiaries have provided guarantees to Macquarie Bank 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 Palm valley 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 Palm Valley and Dingo assets (such as Surprise) are not subject to a cash sweep or other restrictions under the Facility where no defaults exist.

(c) Contingent assets and liabilities of the parent entity

There are no contingent asset or liabilities.

(d) Commitments of the parent entity

Operating lease commitments of the parent entity are set out in Note 29(b).

24. RELATED PARTY TRANSACTION

(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 **2015** %	EQUITY HOLDING 2014 %
Merlin Energy Pty Ltd	Western Australia	Ordinary	100	100
Central Petroleum Projects Pty Ltd (formerly Merlin West 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 Green 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 (N.T) Pty Ltd	Queensland	Ordinary	100	100
Jarl Pty Ltd	Queensland	Ordinary	100	100
Central Petroleum Mereenie Pty Ltd	Queensland	Ordinary	100	—
Central Petroleum Mereenie Unit Trust	N/A	Units	100	—

(c) Key management personnel

Disclosures relating to key management personnel are set out in Note 25.

25. KEY MANAGEMENT PERSONNEL

	2015 $	2014 $
(a) Key management personnel compensation		
Short-term employee benefits	3,090,130	3,257,142
Post-employee benefits	210,674	210,954
Long-term benefits	50,439	40,581
Share based payments	2,150,273	2,268,975
	5,501,516	**5,777,652**

Detailed remuneration disclosures are provided in the remuneration report on pages 22 to 34.

(b) Equity instrument disclosures relating to key management personnel

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

Details of options provided as remuneration and shares issued on the exercise of such options, together with the terms and conditions of the options, can be found in the remuneration report on pages 22 to 34.

25. KEY MANAGEMENT PERSONNEL (continued)

(ii) Option holdings

The number of options over ordinary 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:

		BALANCE AT START OF YEAR	GRANTED AS COMPENSATION	EXERCISED	OTHER CHANGES	HELD AT DATE OF DEPARTURE	BALANCE AT END OF YEAR	VESTED EXERCISABLE	UNVESTED
Non-Executive Directors									
Andrew Whittle	2015	900,000	—	—	—	N/A	900,000	300,000	600,000
	2014	900,000	—	—	—	N/A	900,000	300,000	600,000
William Dunmore[3]	2015	—	—	—	—	—	—	—	—
	2014	280,000	—	—	(280,000)	N/A	—	—	—
Wrixon Gasteen	2015	1,000,000	—	—	—	N/A	1,000,000	333,334	666,666
	2014	1,000,000	—	—	—	N/A	1,000,000	333,334	666,666
Robert Hubbard	2015	—	—	—	—	—	—	—	—
	2014	N/A	—	—	—	N/A	—	—	—
J. Thomas Wilson	2015	—	—	—	—	—	—	—	—
	2014	N/A	—	—	—	N/A	—	—	—
Peter Moore	2015	—	—	—	—	—	—	—	—
	2014	N/A	—	—	—	N/A	—	—	—
Executive Directors and Other Key Management Personnel									
Richard Cottee[1]	2015	34,584,407	—	—	—	N/A	34,584,407	9,683,634	24,900,773
	2014	34,584,407	—	—	—	N/A	34,584,407	9,683,634	24,900,773
Michael Herrington	2015	2,700,000	—	—	(450,000)	N/A	2,250,000	300,000	1,950,000
	2014	900,000	1,800,000	—	—	N/A	2,700,000	300,000	2,400,000
Daniel White	2015	1,643,334	450,000		(600,000)	N/A	1,493,334	1,043,334	450,000
	2014	929,200	733,334	—	(19,200)	N/A	1,643,334	1,643,334	—
Bruce Elsholz[2]	2015	1,170,000	370,500	—	(400,000)	1,140,500	N/A	N/A	N/A
	2014	600,000	570,000	—	—	N/A	1,170,000	1,170,000	—
Leon Devaney	2015	560,000	504,000	—	—	N/A	1,064,000	560,000	504,000
	2014	—	560,000	—	—	N/A	560,000	560,000	—
Michael Bucknill	2015	—	430,000	—	—	N/A	430,000	100,000	330,000
	2014	—	—	—	—	N/A	—	—	—
Robbert Willink	2015	—	450,000	—	—	N/A	450,000	120,000	330,000
	2014	N/A	—	—	—	N/A	—	—	—

[1] *34,584,407 unlisted options exercisable at $0.45 on or before 15 November 2015 and 15 November 2017 were issued to FEP on 8 August 2012, a company in which Richard Cottee has a 50% beneficial interest*

[2] *Bruce Elsholz resigned effective 30 November 2014.*

[3] *William Dunmore and Michael Herrington retired as directors effective 26 November 2014. Michael Herrington remains Chief Operating Officer.*

25. KEY MANAGEMENT PERSONNEL (continued)

(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. Eligible employee 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:

		RIGHTS HELD AT START OF YEAR	MAXIMUM NUMBER GRANTED AS COMPENSATION	CANCELLED DURING THE YEAR	CONVERTED TO SHARES	RIGHTS HELD AT END OF YEAR)
Executive Directors and Other Key Management Personnel						
Richard Cottee	2015	—	—	—	—	—
	2014	—	—	—	—	—
Michael Herrington	2015	—	—	—	—	—
	2014	—	—	—	—	—
Daniel White	2015	—	330,000	—	—	330,000
	2014	—	—	—	—	—
Leon Devaney	2015	—	278,571	—	—	278,571
	2014	—	—	—	—	—
Michael Bucknill	2015	—	274,285	—	—	274,285
	2014	—	—	—	—	—
Robbert Willink	2015	—	262,286	—	—	262,286
	2014	—	—	—	—	—

25. KEY MANAGEMENT PERSONNEL (continued)

(iii) 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	ON MARKET PURCHASE	RECEIVED ON EXERCISE OF OPTIONS	NET CHANGE OTHER	HELD AT DATE OF DEPARTURE	HELD AT END OF YEAR
Non-Executive Directors								
Andrew Whittle	2015	133,680	N/A	102,364	—	—	N/A	236,044
	2014	133,680	N/A	—	—	—	N/A	133,680
William Dunmore[1]	2015	183,743	N/A	—	—	—	183,743	N/A
	2014	183,743	N/A	—	—	—	N/A	183,743
Wrixon Gasteen	2015	97,000	N/A	—	—	—	N/A	97,000
	2014	104,000	N/A	—	—	(7,000)	N/A	97,000
Robert Hubbard	2015	64,100	—	55,900	—	—	N/A	120,000
	2014	N/A	N/A	64,100	—	—	N/A	64,100
J. Thomas Wilson	2015	—	—	—	—	—	N/A	—
	2014	N/A	N/A	—	—	—	N/A	—
Peter Moore	2015	—	—	—	—	—	N/A	—
	2014	N/A	N/A	—	—	—	N/A	—
Executive Directors and Other Key Management Personnel								
Richard Cottee	2015	208,683	N/A	227,700	—	—	N/A	436,383
	2014	208,683	N/A	—	—	—	N/A	208,683
Michael Herrington[1]	2015	200,000	N/A	50,000	—	—	N/A	250,000
	2014	200,000	N/A	—	—	—	N/A	200,000
Daniel White	2015	288,000	N/A	—	—	—	N/A	288,000
	2014	288,000	N/A	—	—	—	N/A	288,000
Bruce Elsholz[2]	2015	—	N/A	—	—	—	—	N/A
	2014	—	N/A	—	—	—	N/A	—
Leon Devaney	2015	110,000	N/A	100,000	—	—	N/A	210,000
	2014	110,000	N/A	—	—	—	N/A	110,000
Michael Bucknill	2015	31,000	N/A	25,000	—	—	N/A	56,000
	2014	—	31,000	—	—	—	N/A	31,000
Robbert Willink	2015	—	N/A	—	—	—	N/A	—
	2014	—	N/A	—	—	—	N/A	—

[1] Retired, as Directors effective 26 November 2014

[2] Resigned 30 November 2014

(c) Other transactions with key management personnel

(i) During the year ended 30 June 2015 the consolidated entity paid $29,594 (2014: $24,476) to Dunmore Consulting, a business in which Mr Dunmore is the principal, for the provision of technical and corporate advisory services. This transaction was on normal commercial terms and conditions no more favourable than those available to other parties.

(ii) Prior to 26 June 2015 FEP provided the services of Richard Cottee on the basis of a secondment to the Company. As such compensation is made to FEP in line with FEP's Intercompany Services Agreement shown on page 33. Richard Cottee has a 50 percent beneficial equity interest in FEP.

During the year ended 30 June 2015 FEP has received compensation of $518,783 (2014: $516,470).

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

	2015 $	2014 $
Loss after income tax	(27,731,038)	(10,857,986)
Adjustments for:		
Depreciation and amortisation	2,707,589	1,127,155
Share-based payments	2,246,683	2,818,231
Income tax expense	—	(4,107,498)
Impairment expense	12,092,042	—
Borrowing expenses (non-cash)	3,461,743	—
Write off exploration expenditure	194,913	—
Changes in assets and liabilities relating to operating activities:		
(Increase)/Decrease in trade and other receivables	(2,920,023)	3,981,516
(Increase) in inventories	(195,691)	(965,702)
Decrease/(Increase) in exploration assets	—	(650,000)
Increase in trade and other payables	101,327	7,847,852
(Decrease)/Increase in provisions	(557,878)	1,284,193
	(10,600,333)	**477,761**

27. NON CASH INVESTING AND FINANCING ACTIVITIES

In 2014 the consolidated entity purchased 100 percent of Magellan Petroleum (NT) Pty Ltd (MPNT) from Magellan Petroleum Corporation. The consideration paid for the sale was $35,595,871 made up of $20,595,871 in cash and an issue of 39,473,684 shares in Central Petroleum Limited with a fair value of $15,000,000.

28. CONTINGENCIES

(a) Contingent liabilities

(i) The consolidated entity had contingent liabilities at 30 June 2015 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 (2014: $1,000,000) within twelve months following the commencement of any future commercial production from the permits.

(ii) 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 is obligated to pay 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 price hurdles are in excess of the current gas prices received from the Palm Valley gas field and escalate annually with CPI. The Gas Price Bonus Amount is calculated as 25 percent of the difference between the weighted average price of gas actually sold in a Contract Year and the gas price bonus hurdle applicable to that Contract Year (after adjusting for CPI), multiplied by the actual volume of gas originating and sold from the Palm Valley gas field .

The weighted average price of gas sold from the Palm Valley gas field is currently below the Gas Price Bonus hurdle price and therefore no gas price bonus is payable (or anticipated to be payable) at this time. Given 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 significantly higher priced markets eventuate, this contingent liability will be revisited. Importantly, any future payment of the Gas Price Bonus would likely only occur where sales and revenues from the Palm Valley gas field materially exceed our acquisition assumptions.

(b) Contingent assets

There were no contingent assets at 30 June 2015 (30 June 2014 - $NIL).

29. COMMITMENTS

		2015 $	2014 $
(a) Capital commitments			
The consolidated entity has the following exploration expenditure commitments:			
The following amounts are due:			
Within one year	(i)	5,516,898	32,976,497
Later than one year but not later than three years		15,500,000	15,447,000
Later than three years but not later than five years		8,000,000	24,000,000
		29,016,898	**72,423,497**

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 them altogether and, as a result, obligations may be reduced or extinguished.

(i) 2014: $21,346,497 of this commitment relates to the Dingo gas field development funded by the Macquarie debt facility.

(b) Operating lease commitments

The consolidated entity, through its parent entity Central Petroleum Limited, has non-cancellable operating leases for office premises and accommodation in Alice Springs and Brisbane. 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:

	2015 $	2014 $
Within one year	757,316	595,987
Later than one year but not later than five years	1,483,533	2,414,894
	2,240,849	**3,010,881**

30. SHARE BASED PAYMENTS

(a) Employee options

An Incentive Option Scheme operates 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.

At the discretion of the Company, performance criteria may or may not be established in respect of options that vest under the Incentive Option Scheme. Options are granted for no consideration. Options that have been granted to date to employees, excluding directors, have contained service conditions in respect of their vesting. Options have vested progressively from grant date to, in some cases, an employee's third anniversary. As of the date of this report no options issued under the Incentive Option Scheme have contained any performance criteria in respect of their vesting.

There are no rules imposing a restriction on removing the 'at risk' aspect of options granted to employees or directors. One ordinary share is issued upon exercise of one option.

Set out below are summaries of options that have been granted to directors and employees.

EXPIRY DATE	EXERCISE PRICE[1]	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.	$
2015							
31 May 2015	$0.610	1,268,000	—	—	(1,268,000)	—	—
31 Oct 2015	$0.550	120,000	—	—	—	120,000	120,000
15 Nov 2015	$0.400	—	220,000	—	—	220,000	220,000
15 Nov 2015	$0.450	9,683,634	—	—	—	9,683,634	9,683,634
15 Nov 2015	$0.450	4,354,334	—	—	—	4,354,334	4,354,334
15 Nov 2015	$0.450	1,366,670	—	—	—	1,366,670	1,366,670
15 Nov 2015	$0.650	207,000	—	—	—	207,000	207,000
12 May 2016	$0.600	40,000	—	—	—	40,000	40,000
20 Jul 2016	$0.550	669,334	—	—	—	669,334	669,334
19 Aug 2016	$0.575	400,000	—	—	—	400,000	400,000
30 Aug 2016	$0.575	600,000	—	—	—	600,000	600,000
15 Nov2016	$0.475	2,318,668	—	—	—	2,318,668	2,318,668
30 Nov 2016	$0.475	400,000	—	—	—	400,000	400,000
15 Nov 2017	$0.450	24,900,773	—	—	—	24,900,773	—
15 Nov 2017	$0.450	2,733,335	—	—	—	2,733,335	—
15 Nov 2017	$0.475	1,800,000	1,449,350	—	(450,000)	2,799,350	—
15 Nov 2017	$0.450	—	2,429,068	—	—	2,429,068	—
15 Nov 2017	$0.400	—	782,525	—	—	782,525	—
15 Nov 2017	$0.410	—	234,000	—	—	234,000	—
15 Nov 2017	$0.650	—	393,900	—	—	393,900	—
Totals		**50,861,748**	**5,508,843**	—	**(1,718,000)**	**54,652,591**	**20,379,640**
Weighted average exercise price		$0.46	$0.44		$0.57	$0.46	$0.46
Weighted average remaining contractual life (years) at the end of the year						1.71	

[1] *On 27 September 2013 shareholders approved every 5 ordinary shares held be converted into 1 ordinary share (subject to rounding).*

30. SHARE BASED PAYMENTS (continued)

(a) Employee options (continued)

EXPIRY DATE	EXERCISE PRICE[1]	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.	$
2014							
31 Mar 2014	$1.110	300,000	—	—	(300,000)	—	N/A
31 Mar 2014	$1.250	300,000	—	—	(300,000)	—	N/A
31 Mar 2014	$1.400	300,000	—	—	(300,000)	—	N/A
31 Mar 2014	$1.600	300,000	—	—	(300,000)	—	N/A
31 Mar 2014	$1.850	300,000	—	—	(300,000)	—	N/A
31 Mar 2014	$1.000	1,673,334	—	—	(1,673,334)	—	N/A
31 May 2015	$0.610	1,268,000	—	—	—	1,268,000	1,268,000
31 Oct 2015	$0.550	120,000	—	—	—	120,000	120,000
15 Nov 2015	$0.450	9,683,634	—	—	—	9,683,634	9,683,634
15 Nov 2015	$0.450	—	4,379,334	(25,000)	—	4,354,334	4,354,334
15 Nov 2015	$0.450	1,366,670	—	—	—	1,366,670	1,366,670
15 Nov 2015	$0.650	—	207,000	—	—	207,000	—
12 May 2016	$0.600	40,000	—	—	—	40,000	40,000
20 Jul 2016	$0.550	669,334	—	—	—	669,334	669,334
19 Aug 2016	$0.575	400,000	—	—	—	400,000	400,000
30 Aug 2016	$0.575	800,000	—	—	(200,000)	600,000	600,000
15 Nov2016	$0.475	2,318,668	—	—	—	2,318,668	2,318,668
30 Nov 2016	$0.475	400,000	—	—	—	400,000	400,000
15 Nov 2017	$0.450	24,900,773	—	—	—	24,900,773	—
15 Nov 2017	$0.450	2,733,335	—	—	—	2,733,335	—
15 Nov 2017	$0.475	—	1,800,000	—	—	1,800,000	—
Totals		**47,873,748**	**6,386,334**	**(25,000)**	**(3,373,334)**	**50,861,748**	**21,220,640**
Weighted average exercise price		$0.510	$0.460	$0.450	$1.210	$0.460	$0.470
Weighted average remaining contractual life (years) at the end of the year						2.60	

30. SHARE BASED PAYMENTS (continued)

(b) Employee options granted during the year

GRANT DATE	EXPIRY DATE	NUMBER OF OPTIONS	AVERAGE FAIR VALUE PER OPTION	EXERCISE PRICE	PRICE OF SHARES ON GRANT DATE	ESTIMATED VOLATILITY*	RISK FREE INTEREST RATE	DIVIDEND YIELD
2015								
17 Jul 2014	15 Nov 2015	220,000	$0.020	$0.400	$0.375	45% to 65%	2.79%	0.0%
9 Apr 2015	15 Nov 2017	1,449,350	$0.059	$0.475	$0.125	55% to 75%	1.74%	0.0%
9 Apr 2015	15 Nov 2017	2,429,068	$0.062	$0.450	$0.125	55% to 75%	1.74%	0.0%
9 Apr 2015	15 Nov 2017	782,525	$0.067	$0.400	$0.125	55% to 75%	1.74%	0.0%
9 Apr 2015	15 Nov 2017	234,000	$0.066	$0.410	$0.125	55% to 75%	1.74%	0.0%
9 Apr 2015	15 Nov 2017	393,900	$0.043	$0.650	$0.125	55% to 75%	1.74%	0.0%
2014								
10 Jul 2013	15 Nov 2015	4,379,334	$0.047	$0.450	$0.625	60% to 90%	2.73%	0.0%
28 Nov 2013	15 Nov 2017	1,800,000	$0.045	$0.475	$0.320	45% to 65%	2.69%	0.0%
10 Apr 2014	15 Nov 2015	207,000	$0.055	$0.650	$0.490	45% to 65%	2.79%	0.0%

* The estimated price volatility is based on the historical price volatility for the 12 months prior to the date of granting of the options, adjusted for any expected changes to future volatility due to publicly available information.

(c) 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. Eligible employee 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 & 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.

Invitation letters for the plan year commencing 1 July 2014 were issued to eligible employees on 17 June 2015.

	2015	2014
Maximum number of rights expected to be granted to employees	2,811,401	–
Fair value of rights (per right)	$0.074	–

(d) Expenses arising from share-based payment transactions

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

	2015	2014
	$	$
Options and rights issued to directors and employees	2,246,683	2,818,231

31. 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 doubtful debts. The consolidated entity trades only with recognised banks and large customers where the credit risk is considered minimal.

The aging of the consolidated entity's receivables at reporting date was:

	GROSS		IMPAIRMENT	
TRADE AND OTHER RECEIVABLES	**2015 $**	2014 $	**2015 $**	2014 $
Past due: 0-30 days	4,746,959	1,191,514	—	—
Past due: 31-150 days	481,536	1,274,539	—	—
Past due: 151-365 days	—	—	—	—
	5,228,495	**2,466,053**	—	—

Based on historic default rates, the consolidated entity believes that no impairment allowance is necessary in respect of receivables past due over 30 days.

The receivables at 30 June 2015 relate predominantly to the oil sales from Surprise West field and gas sales from the Palm Valley field. In addition amounts receivable exist from joint arrangement partner recharges and GST refunds due from the Australian tax office. 100 percent of trade and other receivables have been received to date.

Credit risk also arises in relation to financial guarantees given to certain parties (see Note 23(b)). Such guarantees are only provided in exceptional circumstances and are subject to specific board approval.

(b) Liquidity Risk

The following are the contractual maturities of financial assets and liabilities:

2015	≤ 6 MONTHS	6–12 MONTHS	1–5 YEARS	≥ 5 YEARS	TOTAL
Financial Assets					
Cash and cash equivalents	3,516,139	—	—	—	3,516,139
Trade and other receivables	5,228,495	—	—	—	5,228,495
Other financial assets	—	—	2,075,733	—	2,075,733
	8,744,634	—	**2,075,733**	—	**10,820,367**
Financial Liabilities					
Trade and other payables	(7,707,897)	—	—	—	(7,707,897)
Interest bearing liabilities	(1,345,761)	(6,575,368)	(39,536,722)	—	(47,457,851)
	(9,053,658)	**(6,575,368)**	**(39,536,722)**	—	**(55,165,748)**

31. FINANCIAL RISK MANAGEMENT (continued)

2014	≤ 6 MONTHS	6–12 MONTHS	1–5 YEARS	≥ 5 YEARS	TOTAL
Financial Assets					
Cash and cash equivalents	10,330,474	—	—	—	10,330,474
Trade and other receivables	2,466,053	—	—	—	2,466,053
Other financial assets	—	—	2,423,185	—	2,423,185
	12,796,527	**—**	**2,423,185**	**—**	**15,219,712**
Financial Liabilities					
Trade and other payables	(10,476,308)	—	—	—	(10,476,308)
Macquarie debt facility	—	(255,760)	(23,761,593)	—	(24,017,353)
	(10,476,308)	**(255,760)**	**(23,761,593)**	**—**	**(34,493,661)**

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 6) on the basis of 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 had access to the following undrawn borrowing facilities at the end of the reporting period:

		2015 $	2014 $
Macquarie debt facility (floating rate)	31(e)	2,692,152	24,426,000

(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-BEARING INTEREST		TOTAL	
	2015	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014
	%	%	**$**	$	**$**	$	**$**	$	**$**	$
Financial Assets:										
Cash and cash equivalents	1.2	0.9	3,516,139	10,330,474	—	—	—	—	3,516,139	10,330,474
Trade and other receivables	—	—	—	—	—	—	5,228,495	2,466,053	5,228,495	2,466,053
Other financial assets	0.7	0.6	—	—	858,391	485,828	1,217,342	1,937,357	2,075,733	2,423,185
			3,516,139	10,330,474	858,391	485,828	6,445,837	4,403,410	10,820,367	15,219,712
Financial Liabilities:										
Trade and other payables		—	—	—	—	—	(7,707,897)	(10,476,308)	(7,707,897)	(10,476,308)
Interest bearing liabilities	10.4	10.2	(47,457,851)	(24,017,353)	—	—	—	—	(47,457,851)	(24,017,353)
			(47,457,851)	(24,017,353)	—	—	(7,707,897)	(10,476,308)	(55,165,748)	(34,493,661)
Net Financial Assets / (Liabilities)	10.4	10.2	**(43,941,712)**	(13,686,879)	858,391	485,828	(1,262,060)	(6,072,898)	(44,345,381)	(19,273,949)

31. FINANCIAL RISK MANAGEMENT (continued)

Interest Rate Sensitivity

A sensitivity of 10 percent has been selected as this is considered reasonable given the current level of both short term and long term interest rates. A 10 percent 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 2014.

	PROFIT OR LOSS		EQUITY	
	10% Increase	10% Decrease	10% Increase	10% Decrease
2015				
Cash and cash equivalents	4,900	(4,900)	—	—
Interest bearing liabilities	492,186	(492,186)	—	—
2014				
Cash and cash equivalents	15,456	(15,456)	—	—
Interest bearing liabilities	255,779	(255,779)	—	—

(d) Commodity Risk

The consolidated entity is exposed to commodity price fluctuations in respect of crude oil sales. The consolidated entity does not hedge crude oil sales. Gas sales are made under long term contracts and as such do not contain any commodity risk.

(e) Financing Facilities

In February 2014, Central Petroleum PVD Pty Ltd entered into a Loan Facility Agreement (Facility) with Macquarie Bank Limited (Macquarie). The Facility consists of three tranches totaling $50 million. Tranches A and C total $20 million and were used for the acquisition of Palm Valley and Dingo gas fields and related assets from Magellan. Tranche B accounts for the balance of the Facility (up to $30 million) and is available to fund completion of the Dingo gas field, including all acquisition costs and capitalised interest expenses. Tranche C ($5 million) is structured as a 2 year, interest only bullet. Tranche A and B ($45 million in total) are structured as a 5 year partially amortising term loan. The interest costs for each loan are based on fixed spreads over the periodic Bank Bill Swap (BBSW) average bid rate. The interest rate for tranche B steps down on completion of the Dingo project provided certain production hurdles or financial ratios are achieved. 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.

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

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

The Group remains compliant with these and all other financial covenants under the Facility. Refer Note 33(ii) for post balance date events relating to the Macquarie debt facility.

(f) Currency Risk

The consolidated entity's exposure to currency risk is limited due to its ongoing operations being in Australia and all associated contracts completed in Australian dollars. A small foreign exchange risk arises 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.

(g) Fair Values

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

32. INTEREST IN JOINT ARRANGEMENTS

Details of joint arrangements in which the consolidated entity has an interest are as follows:

	PRINCIPAL ACTIVITIES	2015 %	2014 %
EP 82 (Santos)	Oil & gas exploration	60.00	75.00
EP 105 (Santos)	Oil & gas exploration	60.00	75.00
EP 106 (Santos)	Oil & gas exploration	60.00	75.00
EP 107 (Santos)	Oil & gas exploration	N/A*	75.00
EP 112 (Santos)	Oil & gas exploration	60.00	75.00
EP 125 (Santos)	Oil & gas exploration	30.00	30.00
RL 3 & RL 4 (Santos)	Oil & gas exploration	N/A*	75.00
EP 115 North Mereenie Block (Santos)	Oil & gas exploration	60.00	60.00
ATP 909 (Total)	Oil & gas exploration	90.00	90.00
ATP 911 (Total)	Oil & gas exploration	90.00	90.00
ATP 912 (Total)	Oil & gas exploration	90.00	90.00
EP(A) 147 (Santos)	Oil & gas exploration	N/A*	75.00

Total = TOTAL GLNG Australia

Santos = Santos QNT Pty Ltd

**No longer a joint arrangement. The consolidated entity now has a 100% interest in the Permit*

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' and Total's 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, otherwise may be subject to change or negotiation.

The share in the assets and liabilities of the joint arrangements where less than 100 percent 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:

	2015 $	2014 $
Current assets		
Cash and cash equivalents	12,330	807,914
Trade and other receivables	13,471	45,500
Inventory	387,625	362,958
Total current assets	413,426	1,216,372
Non-current assets		
Property, plant and equipment	161,108	176,900
Other financial assets	7,200	9,300
Total non-current assets	168,308	186,200
Current liabilities		
Trade and other payables	308,743	353,355
Joint Venture under contributions*	3,676,864	4,305,514
Accruals	109,423	38,221
Total current liabilities	4,095,030	4,697,090
Non-Current liabilities		
Restoration provision	194,829	—
Total non-current liabilities	194,829	—
Net liabilities	**3,708,125**	**3,294,518**
Joint arrangement contribution to loss before tax		
Revenue	9,986	11,112
Expenses	(6,257,000)	(2,948,314)
Profit / (Loss) before income tax	**(6,247,014)**	**(2,937,202)**

* The Group is liable for the last 20% of the Stage 1 expenditure in the Southern Georgina Joint Venture, with Total funding the first 80%.

33. EVENTS OCCURRING AFTER THE REPORTING PERIOD

Subsequent to 30 June 2015 the following events have occurred:

(i) Acquisition of Fifty Percent (50%) Interest in Mereenie Oil and Gas Field

On 1 September 2015 the consolidated entity acquired a 50 percent interest in the Mereenie oil and gas field in the Amadeus Basin, Northern Territory from the Santos group. The Company assumed operatorship of the field effective from that date. A new joint venture will be established.

The financial effects of this transaction have not been recognised at 30 June 2015 and the acquisition will be included in consolidated results from 1 September 2015.

PURCHASE CONSIDERATION	$
Cash paid	35,000,000
Deferred consideration	10,000,000
Free carry of Santos' share of field appraisal and development	5,000,000
Total purchase consideration	50,000,000

As part of the transaction the parties have agreed to a range of matters relating to other Southern Amadeus Basin exploration arrangements between the parties. The fair values of the assets and liabilities as at the date of acquisition are yet to be determined.

Contingent Consideration

Potential consideration as indicated above is payable if a final investment decision is made on the North East Gas Interconnector (NEGI) and the Mereenie Joint Venture participants (or their related parties) enter into a gas transportation agreement with the NEGI project owner within 3 years of the execution date.

The potential consideration comprises a $15 million payment and $55-75 million of sole funding work to prove up 15 PJ per annum over 10 years in excess of contracted gas for the purposes of transportation via the NEGI. A bullet payment of 50 percent of the remaining balance of the target of $65 million is payable if the required NEGI works are not completed within 3 years of the pre-conditions being satisfied.

The potential undiscounted amount of all future payments that the consolidated entity could be required to make under this arrangement is between $0 and $47,500,000.

(ii) Debt facility

As part of the Mereenie acquisition, the Macquarie debt facility has been expanded to include a new Facility "D" of $40 million taking the total facility limit to $90 million with a final maturity date of 30 September 2020.

The existing repayment schedule has been replaced with a new repayment schedule. Commencing 31 December 2015 the principal repayment (excluding interest accruing under the facility) is a set amount of $1 million per quarter payable at the end of each calendar quarter with the balance of the facility due on the final maturity date.

Financial covenants under the revised facility:

- Current Ratio is at least 1:1
- Proved Developed Producing (PDP) Reserves Cover Ratio is greater than 1.3:1
- Trade creditors ageing over 90 days past the due date must not exceed $5 million.

(iii) Legal Matter

Central Petroleum Limited has been allegedly served with litigation filed in the District Court of Harris County Texas, located in Houston, Texas, in respect of a farm-in deal negotiated between the Perth office of Total and Central Petroleum when it was headquartered in Perth. Central Petroleum is disputing the Court's jurisdiction. Separately, internal investigations have concluded that there is no factual basis for the alleged claim and the consolidated entity accordingly denies any liability. The action will be vigorously defended.

DIRECTORS' DECLARATION

In the directors' opinion:

a) the financial statements and notes set out on pages 38 to 83 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 2015 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).

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 2015.

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

Richard Cottee
Managing Director
Brisbane
23 September 2015

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

Report on the financial report

We have audited the accompanying financial report of Central Petroleum Limited (the company), which comprises the consolidated statement of financial position as at 30 June 2015, the consolidated statement of profit or loss and other comprehensive income, consolidated statement of changes in equity and consolidated statement of cash flows for the year ended on that date, a summary of significant accounting policies, other explanatory notes and the directors' declaration for Central Petroleum Limited (the consolidated entity). The consolidated entity comprises the company and the entities it controlled at year's end or from time to time during the financial year.

Directors' responsibility for the financial report

The directors of the company are responsible for the preparation of the financial report that gives a true and fair view in accordance with Australian Accounting Standards and the *Corporations Act 2001* and for such internal control as the directors determine is necessary to enable the preparation of the financial report that is free from material misstatement, whether due to fraud or error. In Note 1, the directors also state, in accordance with Accounting Standard AASB 101 *Presentation of Financial Statements*, that the financial statements comply with International Financial Reporting Standards.

Auditor's responsibility

Our responsibility is to express an opinion on the financial report based on our audit. We conducted our audit in accordance with Australian Auditing Standards. Those standards require that we comply with relevant ethical requirements relating to audit engagements and plan and perform the audit to obtain reasonable assurance whether the financial report is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial report. The procedures selected depend on the auditor's judgement, including the assessment of the risks of material misstatement of the financial report, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the consolidated entity's preparation and fair presentation of the financial report in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by the directors, as well as evaluating the overall presentation of the financial report.

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

Independence

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

PricewaterhouseCoopers, ABN 52 780 433 757
Riverside Centre, 123 Eagle Street, BRISBANE QLD 4000, GPO Box 150, BRISBANE QLD 4001
T: +61 7 3257 5000, F: +61 7 3257 5999, www.pwc.com.au

Auditor's opinion

In our opinion:

(a) the financial report of Central Petroleum Limited is in accordance with the *Corporations Act 2001,* including:

(i) giving a true and fair view of the consolidated entity's financial position as at 30 June 2015 and of its performance for the year ended on that date; and

(ii) complying with Australian Accounting Standards (including the Australian Accounting Interpretations) and the *Corporations Regulations 2001*.

(b) the financial report and notes also comply with International Financial Reporting Standards as disclosed in Note 1.

Material uncertainty regarding continuation as a going concern

Without modifying our opinion, we draw attention to Note 1 in the financial report, which indicates that, consistent with the development nature of the consolidated entity's activities it has experienced operating losses, negative cash flows and that current liabilities exceed current assets. Over the next 12 months additional funds will be required to be raised to fund future operations of the consolidated entity and the Mereenie acquisition commitments. These conditions, along with other matters set forth in Note 1, indicate the existence of a material uncertainty that may cause significant doubt about the consolidated entity's ability to continue as a going concern and therefore, the consolidated entity may be unable to realise its assets and discharge its liabilities in the normal course of business and at the amounts stated in the financial report.

Report 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 2015. The directors of the company are responsible for the preparation and presentation of the remuneration report in accordance with section 300A of the *Corporations Act 2001*. Our responsibility is to express an opinion on the remuneration report, based on our audit conducted in accordance with Australian Auditing Standards.

Auditor's opinion

In our opinion, the remuneration report of Central Petroleum Limited for the year ended 30 June 2015 complies with section 300A of the *Corporations Act 2001*.

PricewaterhouseCoopers

PricewaterhouseCoopers

Michael Shewan
Partner

Brisbane
23 September 2015

ASX ADDITIONAL INFORMATION

DETAILS OF QUOTED SECURITIES AS AT 16 SEPTEMBER 2015:

Top holders

The 20 largest registered holders of the quoted securities as at 16 September 2015 were:

	NAME	NO. OF SHARES	%
1.	Magellan Petroleum Australia Pty Ltd	32,645,554	8.85
2.	Citicorp Nominees Pty Limited	13,296,436	3.61
3.	Macquarie Bank Limited <Metals & Energy Cap Div A/C>	10,000,000	2.71
4.	Mr Gerard Pieter Tom Van Brugge	4,000,000	1.08
5.	National Nominees Limited	3,608,873	0.98
6.	Mr Mark Philip Shawcross	3,000,000	0.81
7.	J P Morgan Nominees Australia Limited	2,754,473	0.73
8.	HSBC Custody Nominees Australia Limited	2,655,496	0.72
9.	Mr James Donald Bruce Cochrane + Mrs Joan Elizabeth Cochrane		
	<Bruce and Joan Cochrane A/C>	2,500,000	0.68
10.	UBS Nominees Pty Ltd	2,438,957	0.66
11.	Franze Holdings Pty Ltd	2,046,546	0.56
12	RBJ Nominees Pty Ltd <Superannuation Fund A/C>	1,800,000	0.49
13.	John Cresswell Leigh + Dulcie Lynette Leigh <JAD Super Fund No2 A/C>	1,746,500	0.47
14.	Mr Geoffrey Rol	1,736,075	0.47
15.	Mr Stuart Francis Howes	1,400,001	0.38
16.	Edwin Holdings Pty Ltd	1,250,000	0.34
17.	Chembank Pty Limited <Philandron Account>	1,200,000	0.33
18.	Mr Seager Rex Harbour	1,178,000	0.32
19.	Garmi Holdings Pty Ltd	1,100,000	0.30
20.	Franze Holdings Pty Limited <John Franze Super Fund A/C>	1,098,546	0.30
		91,455,457	24.80

DISTRIBUTION SCHEDULE

The distribution schedule of the ordinary fully paid shares as at 16 September 2015 was:

RANGE	HOLDERS	UNITS	%
1 - 1,000	915	480,472	0.13
1,001 -5,000	2,723	7,552,913	2.05
5,001 - 10,000	1,480	11,764,061	3.19
10,001 - 100,000	3,165	111,508,405	30.24
100,001 - Over	566	237,413,106	64.39
Total	8,849	368,718,957	100.00

GEOGRAPHIC BREAKDOWN

The geographic distribution schedule of the ordinary fully paid shares as at 16 September 2015 was:

LOCATION	HOLDERS	UNITS	%
Australia	8,592	355,073,889	96.30
Overseas	257	13,645,068	3.70
Total	8,849	368,718,957	100.00

ASX ADDITIONAL INFORMATION

SUBSTANTIAL SHAREHOLDERS

NAME	NO. OF SHARES	%
Magellan Petroleum Australia Pty Ltd	32,645,554	8.85

UNMARKETABLE PARCELS

Holdings less than a marketable parcel of ordinary shares (being 1,493 shares as at 16 September 2015):

HOLDERS	UNITS
3,387	6,791,328

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.

INTERESTS IN PETROLEUM PERMITS AND PIPELINE LICENCES

Permits and Licences Granted

TENEMENT	LOCATION	OPERATOR	CTP CONSOLIDATED ENTITY Registered Interest (%)	CTP CONSOLIDATED ENTITY Beneficial Interest (%)	OTHER JV PARTICIPANTS Participant Name	OTHER JV PARTICIPANTS Beneficial Interest (%)
EP 82 (excl. EP 82 Sub-Blocks)*	Amadeus Basin NT	Santos	60	60	Santos	40
EP 82 Sub-Blocks**	Amadeus Basin NT	Central	60	100		
EP 93	Pedirka Basin NT	Central	100	100		
EP 97	Pedirka Basin NT	Central	100	100		
EP 105*	Amadeus/Pedirka Basin NT	Santos	60	60	Santos	40
EP 106*	Amadeus Basin NT	Santos	60	60	Santos	40
EP 107**	Amadeus/Pedirka Basin NT	Santos	60	100		
EP 112*	Amadeus Basin NT	Santos	60	60	Santos	40
EP 115 (excl. EP 115NMB)	Amadeus Basin NT	Central	100	100		
EP 115NMB (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	0***	50	Santos	50
OL 5 (Mereenie)**	Amadeus Basin NT	Central	0***	50	Santos	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	90	90	Total	10
ATP 911*	Georgina Basin QLD	Central	90	90	Total	10
ATP 912*	Georgina Basin QLD	Central	90	90	Total	10

Permits and Licences under Application

TENEMENT	LOCATION	OPERATOR	CTP CONSOLIDATED ENTITY Registered Interest (%)	CTP CONSOLIDATED ENTITY Beneficial Interest (%)	OTHER JV PARTICIPANTS Participant Name	OTHER JV PARTICIPANTS Beneficial Interest (%)
EPA 92	Wiso Basin NT	Central	100	100		
EPA 111**	Amadeus Basin NT	Central	100	100		
EPA 120	Amadeus Basin NT	Central	100	100		
EPA 124**	Amadeus Basin NT	Central	100	100		
EPA 129	Wiso Basin NT	Central	100	100		
EPA 130	Pedirka Basin NT	Central	100	100		
EPA 131	Pedirka Basin NT	Central	100	100		
EPA 132	Georgina Basin NT	Central	100	100		
EPA 133	Amadeus Basin NT	Central	100	100		
EPA 137	Amadeus Basin NT	Central	100	100		
EPA 147**	Amadeus Basin NT	Central	100	100		
EPA 149	Amadeus Basin NT	Central	100	100		
EPA 152	Amadeus Basin NT	Central	100	100		
EPA 160	Wiso Basin NT	Central	100	100		
EPA 296	Wiso Basin NT	Central	100	100		
PELA 77	Pedirka Basin SA	Central	100	100		

Pipeline Licences

PIPELINE LICENCE	LOCATION	OPERATOR	CTP CONSOLIDATED ENTITY Registered Interest (%)	CTP CONSOLIDATED ENTITY Beneficial Interest (%)	OTHER JV PARTICIPANTS Participant Name	OTHER JV PARTICIPANTS Beneficial Interest (%)
PL 2	Amadeus Basin NT	Central	0***	50	Santos	50
PL 30	Amadeus Basin NT	Central	100	100		

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

*** In line with the Company's announcement of 4 June 2015, Central has entered into an agreement to purchase 50% of OL 4 / OL 5 (Mereenie oil and gas field) and PL 2 (Mereenie Alice Springs Pipeline) and have granted Santos the right to acquire a 50% interest in EPA 111 and EPA 124, which was completed 1 September 2015. 100% of EP 82 Sub-Blocks, EP 107 and EPA 147 were returned to Central on execution of this agreement on 3 June 2015.*

**** 50% on registration.*