INTERIM REPORT

31 December 2014

Central Petroleum Limited

ABN 72 083 254 308

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31 December 2014

DIRECTORS' REPORT

31 December 2014

The Directors present their report on the consolidated entity consisting of Central Petroleum Limited and the entities it controlled at the end of, or during, the half-year ended 31 December 2014.

Directors

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

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

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

Principal Activity

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

Highlights for the half-year reporting period and up to the date of this Report

- Southern Georgina Joint Venture begins two well unconventional exploration drilling programme with Whiteley 1 and Gaudi-1;
- Central awarded Pipeline Licence for Dingo gas field;
- Approximately 40km of high pressure composite pipeline from the Dingo Gas Field to Brewer Estate installed as part of the Dingo Development Project;
- Santos commits to Stage 2 of Southern Amadeus Joint Venture.
- COAG endorses Northern Territory Gas Interconnect Process (NEGI) and 14 companies express interest;
- Central Petroleum enters into Framework Agreement with Incitec Pivot to supply up to 15PJ per annum from 2017 subject to certain conditions centered around NEGI and includes a provision for funding support;
- Company focus on increasing gas reserves through Gas Acceleration Project (GAP) aimed at supplying a domestic gas shortfall;
- Dingo Development on time, under budget and fully funded by debt;
- Surprise Oil Field averaged 173 BOPD for the six month period with approximately 98% uptime (i.e. produced every day); and
- Gaudi #1 unconventional gas well results encouraging and being evaluated.

DIRECTORS' REPORT

31 December 2014

Principal Activity *(continued)*

Commentary and Outlook

The last half year has been an exciting period for Central Petroleum in which the strategy of becoming a major domestic gas producer quarantined from oil price fluctuation made substantive progress. This strategy recognises that the key to achieving actual value for the 88% of its acreage (23,703,376.1 acres) that is gas prone is to create a pathway to the gas market.

The strategy uses as its precedence the enormous value accretion to the Queensland CSG acreage holders that occur as and when the access to market became apparent to its shareholders. In 2002, Queensland was not connected to the Southern market, the Queensland market apparently was to be supplied by the PNG Gas Pipeline and the total domestic consumption of gas in Queensland was substantially less than 100 PJ pa. With each step in creating the market for Queensland's own gas however, the value of the CSG assets multiplied. These steps included building of power stations, foundation contracts for CSG, the demise of the PNG Pipeline, the connection of Queensland to Moomba via Ballera and finally the advent of the LNG industry.

Central is potentially at the beginning of an analogous journey to a destination unknown. The Dingo contract to sell gas for power generation in Alice Springs and the Palm Valley contract are the present foundation contracts. We have recently announced Early Gas Sales arrangements under the Dingo contract and the completion of the hydro testing phase of the Dingo Project. When the electricals and instrumentation position reaches completion, regulatory approvals to operate will be sought. Pleasingly, the Dingo Project is not only on time but also nearly 10% below the Debt Financing Limits for the Project. This has released around $2.5 million of the undrawn facility towards the Gas Acceleration Project (GAP) further enhancing the value of the Palm Valley and Dingo fields.

The main goal of the gas strategy is to facilitate the connection of our Northern Territory Gas Fields to the eastern seaboard gas markets. Most analysts see prices for domestic gas strengthening to record highs around 2017-18 regardless of the actual price for oil.

The Northern Territory Eastern Gas Interconnect ("NEGI") achieved major milestones in the half-year to 31 December 2014. The Council of Australian Governments ("COAG") endorsed NEGI and appointed the NT Government as the co-ordinator for the project. The NSW & NT governments signed a MOU in respect of NEGI and Stage 1 of the process saw exceptional interest in NEGI from potential participants. Towards the end of March we expect the announcement of the 3 short-listed candidates.

Notwithstanding such progress in the domestic gas markets the December Quarter saw a savage re-action to the oil price drop being delivered in equal measure to both oil-exposed companies and gas exposed companies. No recognition was afforded to the fact that consistently, and inexorably, Central Petroleum had become a domestic-gas-focussed company. For example, the initial announcements of the Santos and Total Farm-ins were gas focussed and Santos had subsequently moved to Stage 2 of its farm-in on the gas-prone acreage. Central had entered into a Framework Agreement with Incitec Pivot Ltd for a potential sales of up to 15 PJ pa. The acquisition of the Magellan assets meant that on the completion of the Dingo Project, Central's main source of revenue would be from gas with its pricing indexed to inflation. In the panic occasioned by the oil price collapse all of the above counted for naught. It is pleasing to note the eventual market correction that began in February.

The company has been able to enter the 2015 year in a sound financial condition. As referred to in Note 1 of the Financial Statements the accounts have been prepared on a "going concern" basis validating the actions taken by the company in early December of a 40% reduction in headcount. This means that any fundraising in the next 12 months will only occur if there is an overwhelming value proposition for such funds. The last 3 years of tight fiscal discipline has paid off.

DIRECTORS' REPORT

31 December 2014

Review of Operations and other Joint Venture Activities

Dingo Gas Field (L7) and Dingo Pipeline (PL30) – Northern Territory
(CTP - 100% Interest)

During the period, approximately 40km of high pressure composite (HDPE and glass reinforced epoxy) pipeline was installed from the Dingo Field to Brewer Estate. Subsequent to the authority to clear and grade earthworks on both the pipeline and facility sites are well advanced.

During the Quarter, agreements were negotiated for crossing roads and railways.

The Dingo Gas Field Development, which is being funded under a $30 million tranche of the loan facility agreement with Macquarie Bank, comprises construction of wellhead facilities, gathering pipelines, gas conditioning facilities, a 50km (40km composite; 10km steel) gas pipeline to Brewer Estate in Alice Springs, compression and custody transfer metering facilities, and is designed to service a gas sale contract with Power and Water Corporation of the Northern Territory.

The progressing of the site works for this strategic pipeline is a major milestone and signifies the start of the Company being a significant player in the Northern Territory gas market. Over time Central looks forward to playing an important role in inter-connecting Central Australia to the eastern seaboard gas network, possibly through Moomba.

The gas sales agreement with Power and Water Corporation will commence on 15 May 2015.

Palm Valley Gas Field (OL3) – Northern Territory
(CTP - 100% Interest)

The sales nominations received since May 2014 have continued at the acquisition economics levels of around 100,000GJ per month. With a successful transition of operatorship having been completed, Central has conducted field reviews with a view to increase reliability and for any efficiency gains that can be garnered from operations. Numerous improvements have been implemented in dehydration, compression and instrumentation.

The Company has also identified a range of optimisation and market strategies that could materially enhance the profitability of the Palm Valley and Dingo fields.

Surprise Production Licence (L6) – Northern Territory
(CTP - 100% Interest)

The Surprise West well averaged 173 bopd during the period. Central is actively pursuing efficiencies in its operating and transportation costs to combat the low priced oil market.

The drilling of Surprise East has been deferred until oil prices recover.

ATP909, ATP911 and ATP912, Southern Georgina Basin – Queensland
(Joint Venture between CTP - 80% interest [Operator] and Total – 20% interest [earning])

Drilling commenced in ATP912P on 20 July 2014 with the spudding of the exploration well Whiteley-1 targeting the unconventional gas potential of the Lower Arthur Creek Formation.

Drilling was suspended at a depth of 1141mRT due to operational difficulties on 2 September 2014 for later re-entry and drilling to target the intended depth of 1609mRT.

The joint venture has developed plans to recover core from this well during the next drilling campaign.

Drilling commenced in ATP909P on 14 September 2014 with the spudding of Gaudi-1 likewise targeting the unconventional gas potential of the Lower Arthur Creek Formation. The well reached a total depth of 2,430 metres KB before wireline logging and formation integrity tests were successfully conducted prior to suspension of the well.

A total of 290 metres of core was recovered from the Lower Arthur Creek formation and underlying Thorntonia Limestone and is currently undergoing laboratory testing. Initial results show the core to contain hydrocarbon gas.

DIRECTORS' REPORT

31 December 2014

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

Selected segments of the core were placed in sealed canisters for gas desorption analysis to determine gas content. Further laboratory analyses are in progress to determine various rock properties including but not limited to porosity, permeability, total organic carbon content, level of thermal maturity and rock strength. Selected gas samples are being analysed for gas composition.

The results of all analytical data when integrated with wireline logs will determine the way forward in Gaudi 1.

In the channel country region where these wells are located, operations are curtailed in December to March by regulatory "wet season".

The Company is reviewing the results from the earlier exploration phase and before embarking on further activities is assessing whether and to what extent the work to date together with future works meet the objectives of Stage 1; namely assessing the potential of the southern acreage being a major new source of gas and satisfying the minimum permit commitments of the three Authorities to Prospect. As part of this review, the Company will factor in the impact (if any) of the recent Queensland election.

Santos Stage 2 Farmout – Southern Amadeus Basin, Northern Territory

On 31 July 2014, Santos elected:

- to proceed to Stage 2 of an amended Southern Amadeus Joint Venture. As a result Central will be free carried through a 1300km 2D seismic program over permits within the Southern Amadeus Joint Venture area;
- not to proceed to Stage 2 in relation to the EP115 Farmin area but retains its 40% working interest and operatorship;
- not to take up the option of acquiring a working interest in RL3 and RL4 over Ooraminna. The structure was drilled by Ooraminna-2 in 2010 which flowed gas at sub-commercial rates from the Pioneer Sandstone on test 2010; and
- not to proceed as a joint venture in the Pedirka Basin EP93 and EP97.

Santos commenced Stage 2 activities, completing cultural heritage clearances in preparation for the acquisition of 1300 km 2D seismic in the Southern Amadeus farm in area. Multiple large structural leads have been identified on the existing gravity and sparse seismic data across EP's 125, 112, 82 and 105, and will be delineated in the Stage 2 seismic activities. Pre-stack depth migration processing trials for the 2013 Stage 1 2D Seismic are scheduled for 2015 to improve seismic imaging and confidence in the structural interpretation.

Southern Amadeus Area	Total Santos Participating Interest after completion of Stage 1	Total Santos Participating Interest after completion of Stage 2
EP82	25%	40% (ie additional 15% earned)
EP105	25%	40% (ie additional 15% earned)
EP106	25%	40% (ie additional 15% earned)
EP107	25%	40% (ie additional 15% earned)
EP112	25%	40% (ie additional 15% earned)
EP(A)147	25%	40% (ie additional 15% earned)

EP 125 – Southern Amadeus Basin, Northern Territory
(CTP-30% interest, Santos [Operator]-70%interest [earning])

Mt Kitty Exploration Well
(Central is free carried for this well under the Santos farm-in arrangements)

The exploration well Mt Kitty-1 was re-entered on 23 August 2014, and a comprehensive logging program was completed which confirmed that the Heavitree Sandstone was absent in the well, and that gas flows in the well reported earlier emanated from fractures in granitic basement.

DIRECTORS' REPORT
31 December 2014

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

Evaluation of the Mt Kitty-1 samples and log data continued during the second quarter, to enhance understanding of the petroleum system and enable estimation of raw gas in-place. Gas isotope and geochemical analyses will be undertaken by experts in Australia and USA, to investigate the origin of various inert constituents such as helium and nitrogen and modelling of basinal gas compositions.

EP 115 and North West Mereenie Block (NMB), Northern Territory

Gravity data acquired over the western part of the permit were received during the period and processing and interpretation commenced. Delineation of structural trends will guide the placement of future seismic acquisition.

Palm Valley Exploration (OL3), Northern Territory

A preliminary field survey was conducted in October to collect structural information over the Palm Valley West lead at surface which will assist in planning for additional surveying in April 2015.

Synthesis of existing geological and geophysical data has high graded the Palm Valley Deep prospect. The opportunity is to test a large closure at Arumbera Sst level beneath the existing gas pool in the Pacoota Sst. The Arumbera Sst is an established gas bearing reservoir in the nearby Dingo gas field.

Ooraminna Exploration (RL3 and RL4), Northern Territory

A brief field survey was conducted in October 2014 to collect structural information over the Ooraminna structure. Following up on aerial photo interpretation, the suggestion of more fractured locations updip and west of Ooraminna 1 and 2 is sufficiently encouraging to warrant additional field work in the April 2015 mapping season.

Exploration Review

No significant developments occurred in the Company's Wiso Basin and Pedirka Basin areas during the reporting period.

Operating and Financial Review

Risks

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

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.

Crude oil prices are benchmarked against a series of global pricing points, such as WTI, Brent and Tapis. Until recently crude oil, unlike most other commodities, has enjoyed low volatility in the market price. However since June 2014 crude oil has experienced a downward turn.

Business Strategy

Gas producers in Australia currently do not have a comparable spot market mechanism for their gas. Gas is generally sold under fixed price long term contracts. However, Central is of the view that there is an emerging push by Federal, State and Territorial governments for the near term (3 to 5 years) construction of additional gas pipelines to link the Northern Territory with pipeline infrastructure in the East Coast in order to expand Australia's

DIRECTORS' REPORT
31 December 2014

Operating and Financial Review (*continued*)

national pipeline grid. This will provide large and new markets for the estranged gas fields, present and future, in the Northern Territory and elsewhere. As a gas producer, the Company is planning to be a part of this exciting "game changer".

Key financial and operating data (segment reporting)

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

Central continues to explore for hydrocarbons and develop the Dingo gas field which are managed and reported in the exploration and development segments respectively.

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

	Segment Revenues		Segment Results	
Financial Data	31 Dec 14	31 Dec 13	31 Dec 14	31 Dec 13
	$	$	$	$
Gas Producing Assets	2,991,993	-	(254,548)	-
Oil Producing Assets	3,340,979	-	(5,369,537)	-
Development Assets	-	-	-	-
Exploration Assets	-	-	(7,065,609)	(2,855,666)
Unallocated Items	-	-	(5,700,692)	(3,587,848)
Total Segment	6,332,972	-	(18,390,386)	(6,443,514)

Operating Data	31 Dec 14	31 Dec 13
Surprise Oil Field (bbls)	32,569	-
Palm Valley Gas Field (gjs)	642,801	-

Key financial and operating data *(continued)*

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

Significant factors that have affected the group's operations and results during the six months to 31 December 2014 are described below:

- Oil production commenced at the Surprise Field in the second half of the prior year and continued throughout the reporting period.
- As a result of purchasing the producing Palm Valley Gas Field effective 31 March 2014 with an associated gas contract, the Company is also generating gas revenues.

The Company recorded $6.3 million of operating revenue for the half-year ended December 2014. The currently undeveloped Dingo Gas Field is scheduled to provide gas into a new contract around the time the Dingo pipeline is completed, expected mid-2015. The Company will also actively seek out new gas sales opportunities.

Exploration expenditure fluctuates year over year depending on activity levels, particularly with seismic and drilling costs. The fluctuations are even more pronounced for the smaller pure explorers like Central as their funding comes from the equity markets which over the last 2 to 3 years have essentially dried up for resource stocks. With onshore wells in central Australia costing between $10 million to $15 million per well, securing joint venture partners is critical to an active, meaningful exploration program.

Loss before income tax for the half-year ended 31 December 2014 for Central is largely driven by the level of exploration expenditure and the impairment expense following the substantial fall in oil price. Central's accounting policy has consistently been to expense its exploration costs on an annual basis. Many other companies, particularly the smaller explorers, adopt the more conservative accounting policy of carrying forward those exploration costs on their balance sheets and then expensing at defined future points in time.

DIRECTORS' REPORT

31 December 2014

Operating and Financial Review (*continued*)

The significant change in the Company's Balance Sheet between 31 December 2014 and 31 December 2013 reflects the major acquisition transaction which saw Central acquire the onshore Australian assets of Magellan Petroleum ("Magellan") through debt funding with Macquarie; being the Palm Valley Gas Field and the undeveloped Dingo Gas Field including the impact of impairment following the substantial fall in the oil price. At 31 December 2014 Central had drawn down $39.2 million of the facility, which is recorded on the balance sheet as Borrowings.

Equity issued during the 31 December 2014 half-year raised $6 million, comprising 20 million of shares issued at 30 cents per share in October 2014.

Net working capital is the excess of current assets over current liabilities. For an explorer cash is usually the major component of current assets.

Auditor's Independence Declaration

A copy of the auditor's independence declaration as required under section 307C of the Corporations Act 2001 is set out on page 8.

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

Richard Cottee
Managing Director

10 March 2015

Competent Persons Statement

General Legal Disclaimer

Potential volumetrics of gas or oil may be categorised as Undiscovered Gas or Oil Initially In Place (UGIIP or UOIIP) or Prospective Recoverable Oil or Gas in accordance with AAPG/SPE guidelines.

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

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

Auditor's Independence Declaration

As lead auditor for the review of Central Petroleum Limited for the half-year ended 31 December 2014, I declare that to the best of my knowledge and belief, there have been:

a) no contraventions of the auditor independence requirements of the *Corporations Act 2001* in relation to the review; and

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

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

Michael Shewan
Partner
PricewaterhouseCoopers

Brisbane
10 March 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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

for the half-year ended 31 December 2014

	Notes	**2014** **$**	2013 $
Operating revenue		6,332,972	-
Cost of sales		(5,855,254)	-
Gross profit		477,718	-
Other income	5	119,862	1,398,455
Share based employment benefits		(1,306,821)	(1,545,025)
General and administrative expenses		(279,141)	(1,713,865)
Depreciation & amortisation		(1,344,711)	(168,903)
Employee benefits and associated costs		(2,445,165)	(1,545,692)
Exploration expenditure		(6,236,809)	(2,855,666)
Finance costs		(1,589,287)	(12,818)
Impairment expense	4	(5,786,032)	-
Loss before income tax		(18,390,386)	(6,443,514)
Income tax credit		-	-
Loss for the half-year		(18,390,386)	(6,443,514)
Other comprehensive loss for the half-year, net of tax		-	-
Total comprehensive loss for the half-year		(18,390,386)	(6,443,514)
Total comprehensive loss attributable to members of the parent entity		(18,390,386)	(6,443,514)
<u>Earnings per share</u>			
Basic and diluted loss per share (cents)		(5.13)	(2.11)

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

CONSOLIDATED BALANCE SHEET

as at 31 December 2014

	Notes	31 December 2014 $	30 June 2014 $
ASSETS			
Current assets			
Cash and cash equivalents		5,469,852	10,330,474
Trade and other receivables		2,325,752	2,953,300
Inventories		2,083,275	1,940,983
Assets held for sale	6	960,000	1,000,000
Total current assets		10,838,879	16,224,757
Non-current assets			
Property, plant and equipment	7	54,209,381	46,266,152
Exploration assets		16,040,893	16,869,693
Intangible assets		15,676	19,521
Other financial assets		2,470,866	2,423,185
Goodwill		3,906,270	3,906,270
Total non-current assets		76,643,086	69,484,821
Total assets		**87,481,965**	**85,709,578**
LIABILITIES			
Current liabilities			
Trade and other payables		9,934,160	10,476,308
Interest-bearing liabilities	8	1,810,608	255,760
Provisions	9	1,662,380	2,236,372
Total current liabilities		13,407,148	12,968,440
Non-current liabilities			
Interest-bearing liabilities	8	36,264,704	23,761,593
Provisions	10	6,262,823	5,910,832
Total non-current liabilities		42,527,527	29,672,425
Total liabilities		55,934,675	42,640,865
Net assets		**31,547,290**	**43,068,713**
EQUITY			
Contributed equity	11	160,785,182	155,223,040
Reserves	11	15,755,517	14,448,696
Accumulated losses		(144,993,409)	(126,603,023)
Total equity		**31,547,290**	**43,068,713**

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

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CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

for the half-year ended 31 December 2014

	Notes	Attributable to owners of Central Petroleum Limited			
		Contributed Equity	**Option Reserve**	**Accumulated Losses**	**Total**
		$	**$**	**$**	**$**
Balance at 1 July 2013		**130,258,022**	**10,132,939**	**(115,745,037)**	**24,645,924**
Loss for the half-year		-	-	(6,443,514)	(6,443,514)
Other comprehensive income		-	-	-	-
Total comprehensive loss for the half-year		-	-	(6,443,514)	(6,443,514)
Transactions with owners in their capacity as owners					
Contributions of equity, net of transaction costs					
Share based payments		-	1,545,025	-	1,545,025
Share and option issue		10,602,483	-	-	10,602,483
Share issue costs		(649,355)	-	-	(649,355)
		9,953,128	1,545,025	-	11,498,153
Balance at 31 December 2013		**140,211,150**	**11,677,964**	**(122,188,551)**	**29,700,563**
Balance at 1 July 2014		**155,223,040**	**14,448,696**	**(126,603,023)**	**43,068,713**
Loss for the half-year		-	-	(18,390,386)	(18,390,386)
Other comprehensive income		-	-	-	-
Total comprehensive loss for the half-year		-	-	(18,390,386)	(18,390,386)
Transactions with owners in their capacity as owners					
Contributions of equity, net of transaction costs		-	-	-	-
Share based payments		-	1,306,821	-	1,306,821
Share and option issue		6,000,000	-	-	6,000,000
Share issue costs		(437,858)	-	-	(437,858)
		5,562,142	1,306,821	-	6,868,963
Balance at 31 December 2014		**160,785,182**	**15,755,517**	**(144,993,409)**	**31,547,290**

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

CONSOLIDATED STATEMENT OF CASH FLOWS

for the half-year ended 31 December 2014

	2014 $	2013 $
Cash flows from operating activities		
Receipts from customers	6,803,211	-
Interest received	106,636	162,480
Other income received	134,406	-
Interest & borrowing costs	(180,000)	-
Proceeds from research & development refund	-	5,887,231
Payments to suppliers and employees (inclusive of GST)	(14,108,627)	(4,133,833)
Settlement of legal case	(598,298)	-
Net cash (outflow)/inflow from operating activities	(7,842,672)	1,915,878
Cash flows from investing activities		
Payments for property, plant and equipment	(14,482,371)	(572,506)
Payment for interest bearing security bonds	(47,439)	(140,000)
Net cash outflow from investing activities	(14,529,810)	(712,506)
Cash flow from financing activities		
Proceeds from contributed equity	5,562,142	10,002,483
Proceeds from borrowings	12,000,000	-
Repayment of borrowings	(50,282)	-
Payments for capital raising costs	-	(49,354)
Net cash inflow from financing activities	17,511,860	9,953,129
Net increase/(decrease) in cash and cash equivalents	**(4,860,622)**	**11,156,501**
Cash and cash equivalents at the beginning of the half-year	**10,330,474**	**1,308,307**
Cash and cash equivalents at the end of the half-year	**5,469,852**	**12,464,808**

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

for the half-year ended 31 December 2014

1. Basis of Preparation of Half-Year Report

This condensed consolidated interim financial report for the half-year reporting period ended 31 December 2014 has been prepared in accordance with Accounting Standard AASB 134 Interim Financial Reporting and the Corporations Act 2001.

This condensed consolidated interim financial report does not include all the notes of the type normally included in an annual financial report. Accordingly, this report is to be read in conjunction with the annual report for the year ended 30 June 2014 and any public announcements made by Central Petroleum Limited during the interim reporting period in accordance with the continuous disclosure requirements of the Corporations Act 2001.

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

(a) Going Concern

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

During the period ended 31 December 2014, Central Petroleum Limited (Central) incurred a loss of $18,390,386 and had a cash outflow from operating activities of $7,842,672. These results are consistent with the initial exploration, appraisal, development and production phase of the business.

At 31 December 2014 the Group held cash of $5,469,852 and has net assets of $31,547,290 and a working capital deficit of $2,568,269 which includes $5,859,575 of accrued liabilities in respect of the Southern Georgina Joint Venture. During the period ended 31 December 2014, the Group has been able to continue to meet working capital requirements principally as a result of a $6 million capital raising that took place in October 2014.

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. The Directors have also, during the period, undertaken a strategic review of the Group's operations and portfolio. The result of the strategic review led to a restructure which provides for a significant reduction in the Group's overheads, deferral of exploration commitments and a number of other initiatives to streamline the Group's business. The Directors have also assessed that they have the ability to defer the timing of Joint Venture related accrued liabilities until such a point that sufficient capital is available.

Without further new capital, the Group expects that current cash on hand combined with future Research and Development (R&D) refunds and access to the remaining debt facility funding available for general use as a consequence of amended terms of the Macquarie Facility (refer to note 8) will be sufficient to meet its debts and commitments as they fall due. If required, the Directors believe that the Group will be successful in sourcing alternative sources of funds.

In addition, Central has in place an Equity Line of Credit (ELOC) facility with Long State Investment Limited (LSI) which was executed in June 2013. The term of the ELOC is 2 years (June 2015), with an option for Central to extend it for a further 6 months. Under the facility, Central may place ordinary shares with LSI at the prevailing 5-day VWAP subject to a maximum of $250,000 for each 5 ASX trading days and a total aggregate funding under the ELOC of $10 million.

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 31 December 2014. 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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

for the half-year ended 31 December 2014

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

(b) New and Amended Standards Adopted by the Group

In the current period, the Group has adopted all new and revised Standards and Interpretations issued by the Australian Accounting Standards Board that are relevant to its operations and effective for reporting periods beginning on or after 1 July 2014. The adoption of these new and revised Standards and Interpretations has not resulted in any changes to the Group's accounting policies.

(c) Impact of standards issued but not yet applied by the entity

AASB 9 Financial Instruments addresses the classification, measurement and derecognition of financial assets and financial liabilities. The standard is not applicable until 1 January 2017 but is available for early adoption.

There will be no impact on the group's accounting for financial liabilities, as the new requirements only affect the accounting for financial liabilities that are designated at fair value through profit or loss and the group does not have any such liabilities. The derecognition rules have been transferred from AASB 139 Financial Instruments: Recognition and Measurement and have not been changed.

(d) 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.

(ii) Interest Income

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

(iii) 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.

(e) 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.

(f) 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.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

for the half-year ended 31 December 2014

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

(g) 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.

These costs are subject to depreciation and depletion in accordance with note 1(f).

(h) 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.

(i) 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.

2. Significant changes in the current reporting period

The financial position and performance of the group was particularly affected by the following events and transactions during the six months to 31 December 2014:

- a significant increase in revenue from the sale of oil from the Surprise field that came into production in the previous financial year
- a significant increase in revenue from sale of gas from the Palm Valley field as a result of business combinations that occurred in the previous financial year (see note 11)
- Impairment of the carrying value of Surprise assets and oil related exploration assets
- increase in group debt to fund Dingo development
- increase in the capitalised value of properties under development related to the Dingo gas field
- issue of 20 million shares for $6 million.

For a detailed discussion about the group's performance and financial position please refer to our review of operations on pages 3 to 5.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

for the half-year ended 31 December 2014

3. Segment Reporting

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

Gas and Oil Producing assets

Production and sale of natural gas and crude oil

Development assets

Development of oil and gas fields

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.

	Gas Producing Assets 31 Dec 2014 $	Oil Producing Assets 31 Dec 2014 $	Development Assets 31 Dec 2014 $	Exploration Assets 31 Dec 2014 $	Unallocated Items 31 Dec2014 $	Consolidated 31 Dec 2014 $
Revenue	2,991,993	3,340,979	-	-	-	6,332,972
Cost of sales	(2,512,885)	(3,342,369)	-	-	-	(5,855,254)
Gross profit	**479,108**	**(1,390)**	**-**	**-**	**-**	**477,718**
Other income	-	-	-	-	119,862	119,862
Share based employment benefits	-	-	-	-	(1,306,821)	(1,306,821)
General and administrative expenses	-	-	-	-	(279,141)	(279,141)
Depreciation & amortisation	(733,656)	(450,915)	-	-	(160,140)	(1,344,711)
Employee benefits and associated costs	-	-	-	-	(2,445,165)	(2,445,165)
Exploration expenditure	-	-	-	(6,236,809)	-	(6,236,809)
Finance costs	-	-	-	-	(1,589,287)	(1,589,287)
Impairment expense	-	(4,917,232)	-	(828,800)	(40,000)	(5,786,032)
Loss before income tax	**(254,548)**	**(5,369,537)**	**-**	**(7,065,609)**	**(5,700,692)**	**(18,390,386)**
Taxes	-	-	-	-	-	-
Profit / (Loss) for the period	**(254,548)**	**(5,369,537)**	**-**	**(7,065,609)**	**(5,700,692)**	**(18,390,386)**

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
for the half-year ended 31 December 2014

3. Segment Reporting *(continued)*

Performance monitoring and evaluation *(continued)*

	Gas Producing Assets 2013 $	Oil Producing Assets 2013 $	Development Assets 2013 $	Exploration Assets 2013 $	Unallocated Items 2013 $	Consolidated 2013 $
Revenue	**-**	**-**	**-**	**-**	**-**	**-**
Cost of sales	**-**	**-**	**-**	**-**	**-**	**-**
Gross profit	**-**	**-**	**-**	**-**	**-**	**-**
Other income	-	-	-	-	1,398,455	1,398,455
Share based employment benefits	-	-	-	-	(1,545,025)	(1,545,025)
General and administrative expenses	-	-	-	-	(1,713,865)	(1,713,865)
Depreciation & amortisation	-	-	-	-	(168,903)	(168,903)
Employee benefits and associated costs	-	-	-	-	(1,545,692)	(1,545,692)
Exploration expenditure	-	-	-	(2,855,666)	-	(2,855,666)
Finance costs	-	-	-	-	(12,818)	(12,818)
Loss before income tax	**-**	**-**	**-**	**(2,855,666)**	**(3,587,848)**	**(6,443,514)**
Taxes	-	-	-	-	-	-
Loss for the year	**-**	**-**	**-**	**(2,855,666)**	**(3,587,848)**	**(6,443,514)**
Total Segment Assets						
31 December 2014	17,970,766	978,494	32,894,575	19,063,920	16,574,210	87,481,965
30 June 2014	20,767,460	3,803,319	25,989,302	21,436,107	13,713,390	85,709,578
Total Segment Liabilities						
31 December 2014	(3,283,779)	(1,894,211)	(2,073,585)	(6,602,344)	(42,080,756)	(55,934,675)
30 June 2014	(2,990,538)	(1,988,483)	(3,575,974)	(5,250,758)	(28,835,112)	(42,640,865)

In 2014 the Group changed its segment reporting from one operating segment to four separately identifiable operating segments. Consequently the 31 December 2013 half-year segment reporting note has been revised to reflect the same reporting format as 31 December 2014 half-year, refer to table above.

Revenue from external customers by geographical location of production:

	31 Dec 2014 $	31 Dec 2013 $
Australia	**6,332,972**	**-**

Non-current assets by geographical location:

	31 Dec 2014 $	30 Jun 2014 $
Australia	**76,643,086**	**69,484,821**

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

for the half-year ended 31 December 2014

3. Segment Reporting *(continued)*

Major Customers

There are two customers with revenue exceeding 10% of the group's total oil and gas sales revenue.

Revenue from one customer represents $5,217,085 or 82% of the group's total oil and gas revenues (2013: $nil). Revenue from one customer represents $675,212 or 11% of the group's total oil and gas revenues (2013: $nil).

4. Profit and loss information

(a) Significant items

Profit for the half-year includes the following items that are unusual because of their nature, size or incidence:

	31 Dec 2014 $	31 Dec 2013 $
Gains		
Research and development refund from ATO	-	1,196,296
Expenses		
Impairment of Surprise assets and oil related exploration assets(i)	5,746,032	-
Other assets(ii)	40,000	-
	5,786,032	**-**

(i) At 31 December 2014 the Group reassessed the carrying amount of its oil and gas assets for indicators of impairment such as changes in future prices, future costs and reservoir performance. As a result, the recoverable amounts related to the Surprise oil field were formally reassessed, resulting in an impairment loss of $4,917,232. In addition an impairment loss of $828,800 was booked in respect of oil exploration assets. Estimates of recoverable amounts of oil and gas assets are based on either fair value less costs to sell or value in use, determined by discounting each asset's estimated future cash flows at asset-specific discount rates.

(ii) Refer to Note 6.

5. Other Income

	31 Dec 2014 $	31 Dec 2013 $
Interest revenue	111,824	198,475
Research and development refunds	-	1,196,296
Other	8,038	3,684
	119,862	**1,398,455**

6. Assets held for sale

	31 Dec 2014 $	30 Jun 2014 $
Land and buildings	960,000	1,000,000
	960,000	**1,000,000**

As part of the Magellan acquisition, an office and yard was acquired in Alice Springs. An independent valuation was obtained providing a fair value of $1,000,000 as at 30 June 2014. Subsequently a conditional contract for sale was entered into for $960,000 with funds to be used to retire debt on the Macquarie finance facility. Settlement of the sale occurred in February 2015. An impairment of $40,000 has been recognised as an expense during the current half-year.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

for the half-year ended 31 December 2014

7. Property, Plant and Equipment

	Freehold Land & Buildings $	Producing Assets $	Assets in Development $	Plant and equipment $	Restoration asset $	Total $
30 June 2014						
Cost	430,947	18,813,237	18,419,290	6,146,745	4,791,118	48,601,337
Accumulated depreciation	(13,544)	(513,435)	-	(1,739,060)	(69,146)	(2,335,185)
Net book amount	**417,403**	**18,299,802**	**18,419,290**	**4,407,685**	**4,721,972**	**46,266,152**
31 December 2014						
Opening net book amount	417,403	18,299,802	18,419,290	4,407,685	4,721,972	46,266,152
Additions	-	26,681	12,315,111	1,525,877	332,449	14,200,118
Additions – business combs[1].	-	-	-	-	-	-
Transfers	-	(2,130,148)	-	2,130,148	-	-
Disposals and write offs	-	-	-	-	-	-
Impairment		(354,245)		(4,173,849)	(389,138)	(4,917,232)
Depreciation charge	(423)	(623,145)	-	(466,334)	(249,755)	(1,339,657)
Closing net book amount	**416,980**	**15,218,945**	**30,734,401**	**3,423,527**	**4,415,528**	**54,209,381**
31 December 2014						
Cost	430,947	16,709,770	30,734,401	9,802,770	5,123,567	62,801,455
Accumulated depreciation	(13,967)	(1,136,580)	-	(2,205,394)	(318,901)	(3,674,842)
Provision for Impairment	-	(354,245)	-	(4,173,849)	(389,138)	(4,917,232)
Net book amount	**416,980**	**15,218,945**	**30,734,401**	**3,423,527**	**4,415,528**	**54,209,381**

[1] Details regarding business combinations are contained in note 11

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

for the half-year ended 31 December 2014

8. Interest bearing liabilities

		31 Dec 2014 $	30 Jun 2014 $
(a)	Interest bearing liabilities (current) [1]		
	Insurance premium funding	241,526	-
	Debt facilities	1,569,082	255,760
		1,810,608	**255,760**
(b)	Interest bearing liabilities (non-current) [1]		
	Debt facilities	36,264,704	23,761,593
		36,264,704	**23,761,593**

In February 2014, Central Petroleum PVD Pty Ltd entered into a Loan Facility Agreement ("Facility") with Macquarie Bank Limited (Macquarie). The Facility consists of 3 tranches totalling $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. Subsequent to period end the facility was amended allowing the Group to have access to the remaining debt facility funding for general use. The Group does not have any interest rate hedging arrangements in place. Central Petroleum Ltd can repay the Facility in part or in whole at any time without a pre-payment penalty.

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

1. The Group Current Ratio is at least 1:1, excluding amounts payable under the Maquarie 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.
3. Financial indebtedness to creditors.

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

for the half-year ended 31 December 2014

9. Provisions – current liabilities

	Consolidated 31 Dec 2014 $	Consolidated 30 Jun 2014 $
Employee entitlements (a)	739,875	626,299
Onerous contracts (b)	260,662	361,774
Redundancy costs	158,847	-
Other	502,996	1,248,299
Total	**1,662,380**	**2,236,372**

	Consolidated				
	Employee Entitlements [(a)] $	**Onerous Contracts[(b)] $**	**Redundancy $**	**Other $**	**Total $**
Carrying amount at 1 July 2014	626,299	361,774	-	1,248,299	2,236,372
Transfer from non-current provision	-	65,675	-	-	65,675
Charged/(credited) to profit or loss	542,068	-	158,847	(116,489)	584,426
Amounts used during the half year	(428,492)	(166,787)	-	(628,814)	(1,224,093)
Carrying amount at 31 December 2014	**739,875**	**260,662**	**158,847**	**502,996**	**1,662,380**

(a) The current provision for employee entitlements includes accrued annual leave and long service leave. For long service leave it covers all unconditional entitlements where employees have completed the required period of service. The amount is 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 consolidated entity does not expect all employees to take the full amount of accrued leave or require payment within the next 12 months. The following amounts reflect leave that is not expected to be taken within the next 12 months.

	31 Dec 2014	30 Jun 2014
Leave obligations expected to be settled after 12 months	445,505	479,696

(b) A provision for onerous contracts was recognised during the previous years in respect of operating lease commitments on both167 Eagle Street, Brisbane and Suite 3, Level 4 South Shore Centre, Perth.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

for the half-year ended 31 December 2014

10. Provisions – non-current liabilities

	Consolidated	
	31 Dec 2014	30 Jun 2014
	$	$
Employee entitlements	652,444	647,072
Onerous contracts	291,015	356,690
Restoration and rehabilitation (a)	5,319,364	4,907,070
Other	-	-
Total	**6,262,823**	**5,910,832**

	Employee Entitlements	Onerous Contracts	Restoration & Rehabilitation[(a)]	Total
	$	$	$	$
Carrying amount at 1 July 2014	647,072	356,690	4,907,070	5,910,832
Additional provisions created	-	-	324,871	324,871
Charged/(credited) to profit or loss	5,372	-	-	5,372
Unwinding of discount	-		87,423	87,423
Transfer to current	-	(65,675)	-	(65,675)
Carrying amount at 31 December 2014	**652,444**	**291,015**	**5,319,364**	**6,262,823**

(a) *Provisions for future removal and restoration costs are recognised where there is a present obligation as a result of exploration, extended production testing, transportation or storage activities having been undertaken, 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.*

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

for the half-year ended 31 December 2014

11. Contributed Equity and Reserves

	31 Dec 2014 $	30 Jun 2014 $
Share Capital		
368,718,957 ordinary shares [1] (30 June 2014: 348,718,957 ordinary shares)	160,785,182	155,223,040
Share Options Reserve		
79,081,750 share options [1] (30 June 2014: 78,861,750 Share options)	15,755,517	

	Half-Year ended 31 December 2014	2013
Movements in Share Capital:		
Balance at start of year	155,223,040	130,258,022
Issues of ordinary shares	6,000,000	10,600,000
Exercise of share options	-	2,483
Transaction costs	(437,858)	(649,355)
Balance at the end of the half year	**160,785,182**	**140,211,150**

Movements in Share Options Reserve:	Half-Year ended 31 December 2014	2013
Balance at start of year	14,448,696	10,132,939
Share based payments costs	1,306,821	1,545,025
Balance at the end of the half year	**15,755,517**	**11,677,964**

Movements in Ordinary Shares on Issue during the half-year:	2014 No. of securities	2013 No. of securities
Balance at the beginning of the half-year	348,718,957	1,440,078,845
Issue of ordinary shares	20,000,000	106,000,000
Exercise of share options	-	3,104
Share consolidation[1]	-	(1,236,862,476)
Balance at the end of the half-year	**368,718,957**	**309,219,473**

Movements in Share Options on Issue during the half-year:	2014 No. of securities	2013 No. of securities
Balance at the beginning of the half-year	**78,861,750**	**607,242,075**
15/11/2015 options exercisable at $0.40	220,000	
15/11/2015 options exercisable at $0.45	-	4,379,338
Exercise of options at $0.80	-	(3,104)
Cancellation of options exercisable at $0.575	-	(200,000)
15/11/2017 options exercisable at $0.48	-	-
Share consolidation[1]	-	(485,793,497)
Balance at the end of the half-year	**79,081,750**	**125,624,812**

[1] *On 27 September2013 shareholders approved every 5 ordinary shares held be converted into 1 ordinary share (subject to rounding).*

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

for the half-year ended 31 December 2014

12. Business Combination

On 31 March 2014 the Group purchased 100% of Magellan Petroleum (NT) Pty Ltd ("MPNT") from Magellan Petroleum Corporation, a NASDAQ Stock Exchange-listed oil and gas exploration and production company.

The Group identified the purchase of MPNT as a strategic acquisition for the CTP Group in line with delivering strong growth from exploration and production across Central Australia. The acquisition provides Central with infrastructure and production revenues.

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. Transaction fees of $1,914,004 were incurred.

The provisional fair value allocation to the identifiable assets and liabilities is detailed below. To the extent that the purchase consideration exceeds the aggregate of the fair value of the identifiable assets and liabilities of MPNT, then goodwill has been recognised and recorded on acquisition.

	Provisional fair value recognised on acquisition $
Assets	
Exploration assets	650,000
Property, plant & equipment	39,027,558
Trade and other receivables	63,973
Inventory	534,689
Assets held for sale	1,000,000
	41,276,220
Liabilities	
Provisions for liabilities and charges	5,479,121
Provision for deferred tax	4,107,498
	9,586,619
Net assets at fair value	31,689,601
Goodwill arising on acquisition	3,906,270
	35,595,871
Purchase consideration transferred	
Cash	20,595,871
Issued share capital	15,000,000
	35,595,871

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

for the half-year ended 31 December 2014

12. Business Combination *(continued)*

Contingent Consideration

Under the Share Sale and Purchase Deed entered into with Magellan Petroleum Australia Pty Ltd ("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% 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 NT 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 consideration. Should access to significantly higher priced markets eventuate, this contingent consideration 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.

13. Contingencies and Commitments

(a) Exploration Contingencies and Commitments

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

	Consolidated	
	31 Dec 2014	**30 Jun 2014**
	$	**$**
Within 1 year	15,592,436	32,976,497
Later than one year but not later than three years	31,147,000	15,447,000
Later than three years but not later than five years	12,300,000	24,000,000
Total	**59,039,436**	**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 and, as a result, obligations may be reduced or extinguished.

(b) Operating Lease Commitments

The Group has non-cancellable operating leases for office premises in Brisbane expiring on 30 September 2018 and in Alice Springs expiring January 2016.

	Consolidated	
	31 Dec 2014	**30 Jun 2014**
	$	**$**
Due not later than 1 year	753,966	595,987
Due later than 1 year but less than 5 years	2,063,260	2,414,894
Total	**2,817,226**	**3,010,881**

(c) Contingent Liabilities

The Group had contingent liabilities at 31 December 2014 in respect of certain joint venture 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 (2013: $1,000,000) within twelve months following the commencement of any future commercial production from the permits.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

for the half-year ended 31 December 2014

13. Contingencies and Commitments *(continued)*

(d) Contingent Assets

There were no contingent assets at 31 December 2014 (30 June 2014 - $nil).

14. Post Balance Sheet Events

There were no events that occurred subsequent to 31 December 2014 other than noted elsewhere in these accounts.

15. Related Party Transactions

i. During the half-year ended 31 December 2014, the consolidated entity paid $22,202 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. Freestone Energy Partners Pty Ltd (FEP) has 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 which expires on 29 June 2015. Richard Cottee has a 50% beneficial equity interest in FEP. Payments to FEP during the half year ended 31 December 2014 amounted to $332,886

DIRECTORS' DECLARATION

31 December 2014

In the directors' opinion:

The financial statements and notes set out on pages 9 to 26 are in accordance with the Corporations Act 2001, including:

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

(b) giving a true and fair view of the consolidated entity's financial position as at 31 December 2014 and of its performance for the half-year ended on that date, and

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

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

Richard I Cottee – Managing Director
Brisbane, Queensland
10 March 2015

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

Report on the Half-Year Financial Report

We have reviewed the accompanying half-year financial report of Central Petroleum Limited (the Company), which comprises the consolidated balance sheet as at 31 December 2014, the consolidated statement of comprehensive income, consolidated statement of changes in equity and consolidated statement of cash flows for the half-year ended on that date, selected explanatory notes and the directors' declaration for Central Petroleum Limited (the consolidated entity). The consolidated entity comprises the company and the entities it controlled during that half-year.

Directors' responsibility for the half-year financial report

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

Auditor's responsibility

Our responsibility is to express a conclusion on the half-year financial report based on our review. We conducted our review in accordance with Australian Auditing Standard on Review Engagements ASRE 2410 *Review of a Financial Report Performed by the Independent Auditor of the Entity*, in order to state whether, on the basis of the procedures described, we have become aware of any matter that makes us believe that the financial report is not in accordance with the *Corporations Act 2001* including: giving a true and fair view of the consolidated entity's financial position as at 31 December 2014 and its performance for the half-year ended on that date; and complying with Accounting Standard AASB 134 *Interim Financial Reporting* and the *Corporations Regulations 2001*. As the auditor of Central Petroleum Limited, ASRE 2410 requires that we comply with the ethical requirements relevant to the audit of the annual financial report.

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

Independence

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

PricewaterhouseCoopers, ABN 52 780 433 757
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

Conclusion

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

a) giving a true and fair view of the consolidated entity's financial position as at 31 December 2014 and of its performance for the half-year ended on that date;

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

Matters relating to the electronic presentation of the reviewed financial report

This review report relates to the financial report of the company for the half-year ended 31 December 2014 included on Central Petroleum Limited's web site. The company's directors are responsible for the integrity of the Central Petroleum Limited web site. We have not been engaged to report on the integrity of this web site. The review report refers only to the statements named above. It does not provide an opinion on any other information which may have been hyperlinked to/from these statements. If users of this report are concerned with the inherent risks arising from electronic data communications they are advised to refer to the hard copy of the reviewed financial report to confirm the information included in the reviewed financial report presented on this web site.

PricewaterhouseCoopers

Michael Shewan
Partner

Brisbane
10 March 2015

CORPORATE DIRECTORY

31 December 2014

Directors

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

Company Secretaries

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

Registered Office

Level 32, 400 George Street
Brisbane, QLD 4000
Telephone: +61(0)7 3181 3800
Facsimile: +61(0)7 3181 3855
www.centralpetroleum.com.au

Auditors

PricewaterhouseCoopers
125 Georges Terrace
Perth, WA 6000
www.pwc.com.au

Share Registrar

Computershare Investor Services Pty Limited
117 Victoria Street
West End, QLD 4101
Telephone: +61(0)7 3237 2100
Facsimile: +61(0)7 9473 2085
www.computershare.com