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merlin COAL PTY LTD ABN 81 134 469 471

ordiv PETROLEUM PTY LTD ABN 29 111 102 697

frontier OIL & GAS PTY LTD ABN 91 103 194 136

helium AUSTRALIA PTY LTD ABN 11 078 104 006

merlin WEST PTY LTD ABN 59 114 346 968

central GREEN PTY LTD ABN 84 128 245 876

central GEOTHERMAL PTY LTD ABN 86 128 245 885

central PETROLEUM SERVICES PTY LTD ABN 57 140 628 155

ASX ANNOUNCEMENT **ASX CODE: CTP**

18 January 2011

TO: The Manager, Company Announcements ASX Limited

CONTACT: John Heugh +61 8 9474 1444

LNG Preliminary Concept Appraisal Study

Central Petroleum Limited (ASX:**CTP**) ("**Central**"), as Operator has pleasure in providing the results of a preliminary development concept appraisal report by Holt Campbell and Payton Pty Ltd, an independent engineering consultancy based in Perth, Western Australia.

The report is based upon the successful potential discovery and field development of a gas field or fields in the Amadeus Basin with similar production parameters to the existing Palm Valley field currently operated by Magellan Petroleum Corporation with co-owner Santos.

The conclusions of the report are as follows:

1. *An LNG export project based on a large gas discovery in Central Australia would have to be a 3 MTA (3 million tonnes of LNG per annum) or larger project.*
2. *Some 4 TCFG of gas EUR (expected ultimate recovery) would need to be found to supply a 3 MTA LNG export project.*
3. *Indicative costs developed in this screening study suggest that the Capital Investment required for the whole project might be of the order of A$1,700 per annual tonne.*
4. *This is marginally lower than the Capex numbers (about A$2,000 per annual tonne) that have been announced for the active Queensland LNG projects.*

"The results of the concept study mean that the Company will continue to examine, inter alia, both GTL and LNG options for potential monetisation of any large enough gas discoveries in our permits and applications" said John Heugh, the Company's Managing Director today, "and this should be of great benefit to the Company in promoting interest in our acreage exploration to potential new joint venture partners".

The study is not meant to be and should not be construed to be a financial forecast but rather an in-principle basic evaluation of the potential conceptual feasibility of the production of LNG at a Darwin based plant being fuelled by as yet undiscovered gas in CTP's and its wholly owned subsidiaries' permits in central Australia.

John Heugh
Managing Director
Central Petroleum Limited

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NOTICE: The participating interests of the relevant parties in the respective permits and permit applications which may be applicable to this announcement are:

- *EP-82 (excluding the Central subsidiary Helium Australia Pty Ltd ("HEA") and Oil & Gas Exploration Limited ("OGE") (previously He Nuclear Ltd) Magee Prospect Block) - HEA 100%*
- *Magee Prospect Block, portion of EP 82 – HEA 84.66% and OGE 15.34%.*
- *EP-93, EP-105, EP-106, EP-107, EPA-92, EPA-129, EPA-131, EPA-132, EPA-133, EPA-137, EPA-147, EPA-149, EPA-152, EPA-160, ATP-909, ATP-911, ATP-912 and PELA-77 - Central subsidiary Merlin Energy Pty Ltd 100% ("MEE").*
- *The Simpson, Bejah, Dune and Pellinor Prospect Block portions within EP-97 – MEE 80% and Rawson Resources Ltd 20%.*
- *EP-125 (excluding the Central subsidiary Ordiv Petroleum Pty Ltd ("ORP") and OGE Mt Kitty Prospect Block) and EPA-124 – ORP 100%.*
- *Mt Kitty Prospect Block, portion of EP 125 - ORP 75.41% and OGE 24.59%.*
- *EP-112, EP-115, EP-118, EPA-111 and EPA-120 - Central subsidiary Frontier Oil & Gas Pty Ltd 100%.*
- *PEPA 18/08-9, PEPA 17/08-9 and PEPA 16/08-9 - Central subsidiary Merlin West Pty Ltd 100%.*
- *EPA-130 - MEE 55% and Great Southern Gas Ltd 45%.*

Competent Persons Statement

Al Maynard & Associates
Information in this announcement or attached report or notification which may relate to Exploration Results of coal tonnages in the Pedirka Basin is based on information compiled by Mr Allen Maynard, who is a Member of the Australian Institute of Geosciences ("AIG") and a Corporate Member of the Australasian Institute of Mining & Metallurgy ("AusIMM") and an independent consultant to the Company. Mr Maynard is the principal of Al Maynard & Associates Pty Ltd and has over 30 years of exploration and mining experience in a variety of mineral deposit styles. Mr Maynard has sufficient experience which is relevant to the styles of mineralisation and types of deposit under consideration and to the activity which he is undertaking to qualify as a Competent Person as defined in the 2004 Edition of the "Australasian Code for reporting of Exploration Results, Mineral Resources and Ore Reserves". Mr Maynard consents to inclusion in this Report or announcement of the matters based on his information in the form and context in which it appears.

Mulready Consulting Services
The Mulready Consulting Services Report on UCG and CSG which may be referred to in this report or announcement or notification was prepared by their Associate Mr Roger Meaney, who holds a BSc (Hons) from Latrobe University and has over 30 years experience in the petroleum exploration and production industry with 8 years experience in the field of Coal Seam Gas.

General Disclaimer and explanation of terms:
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. Since oil via Gas to Liquids Processes (GTL) volumetrics may be derived from gas estimates the corresponding categorisation applies. Unless otherwise annotated any potential oil, gas or helium UGIIP or UOIIP figures are at "high" estimate in accordance with the guidelines of the Society of Petroleum Engineers (SPE) as preferred by the ASX Limited but the ASX Limited takes no responsibility for such quoted figures.
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 CTP in this announcement or report have not been reviewed by relevant Joint Venture partners. Therefore those resource estimates, assessments of exploration results and opinions represent the views of Central only. Exploration programmes which may be referred to in this announcement or report have not been necessarily been approved by relevant Joint Venture partners and accordingly constitute a proposal only unless and until approved. All exploration is subject to contingent factors including but not limited to weather, availability of crews and equipment, funding, access rights and joint venture relationships.

HOLT CAMPBELL PAYTON PTY LTD
Consulting Mechanical Engineers Level 10 / 5 Mill St Perth Western Australia

DEVELOPMENT CONCEPT APPRAISAL REPORT

Date	18 January 2011
Client	Central Petroleum Limited
Project	Medium Scale Central Australian LNG Development
Aspect	Preliminary review of a conceptual natural gas development involving four large (>1 TCF) gas fields in the Amadeus Basin region, each located within 200km of a central hub compressor station and with gas carried by high-pressure pipeline to LNG plant and port facilities in Darwin region
Engineer	Dave Holt [with Robert Weir]
Scale of Development	In recent years there has been a trend towards increasing train size driven by cost savings via economies of scale. Current thinking is that future LNG train design will fall within three groups with nominal capacities of 3, 5 and 8+ MTA (millions tonnes LNG shipped out per annum) . The first group will cater to limited gas supply or sales environment, the next to higher gas supply and sales and the mega trains to large complexes supported by large reservoir and serving major global markets. A three MTA single train development would thus be the smallest economical scale that could be considered for export LNG from a large gas discovery in Central Australia. This would require 176 bcf of gas to be delivered from the Central Australian gas fields each year. A production life of at least 20 years appears to be the norm from both LNG buyer commitment and project robustness aspects. This suggests that expected ultimate recoverable (EUR) would have to be in the order of 3.6 to 4 TCF.
Gas Fields	For this notional development it we have considered the gas reservoir(s) to be much the same in structure and producibility as Palm Valley, the only gas only producing field in the Amadeus Basin to date. The Palm Valley gas field is a type 2 fractured reservoir, with an interconnected fracture network that controls production in low permeability sandstone rocks (~0.1 mD); wells that do not effectively intersect the fracture network are uneconomic. Eleven gas wells have been drilled ranging in depth from 1900m to 2500m. Of these, four are being used as producers, three are retired as observation wells, two are shut in / suspended and two were abandoned. The field was produced at a plateau rate of average 8 bcf per year (22 mmscfd, or 25.0TJ/day) from 1987 through to 1997. Since then, production rate has declined gradually to about 4.5 bcf per year. Total gas production from these wells over the 20 year period 1985 to end 2005 was 140 bcf. In order to deliver over 3600 bcf of gas to a 3MTA LNG facility over 20 years, it might be concluded that a number of Palm Valley type fields or equivalent unconventional fields would have to be developed over the projected 20 year life of the conceptual project. Key features of Palm Valley wells are: ▪ Initial well rate: 6-7 mmscfd (2-2.5 bcf/year) ▪ Production rate1 bcf/year per well for first ten years then declining ▪ Expected ultimate recoverable (EUR) 20 bcf/well (with field compression) This suggests, based on comparisons with the known Palm Valley production parameters, that the notional LNG project would require approximately 80 producing wells to be in service at commencement of full LNG production and a further 100 wells and/or booster compression to be installed over the next ten years and so on.

Basis for conceptual LNG Project

1. Nominal 3MTA LNG liquefaction plant, storage and ship loading facilities at Darwin of the same type and scope as ConocoPhillips Darwin LNG Plant.
2 Trunkline of 500 mmscfd gas transmission capacity from Amadeus Basin to Darwin liquefaction plant by "fully looping" the existing 1500km NT Gas Pipeline with nominal 26" (DN 650) 15 MPa pipeline
3 Compressor stations at trunkline hub and midline, each providing approximately 26MW of gas compression via 3 Solar-Mars 100 gas turbine compressor sets at each station. The Mars100 unit (ISO rated at 11.2MW) is site rated 10MW at 38C
4 Initial development of four gas fields, each with > 1TCF EUR and located within 200 km of trunkline hub compressor station including:
   - wellhead facilities and flowlines
   - liquids separation and treatment
   - Infrastructure, utilities and access roads
   - field boost compression
5 Lateral pipelines (four of them) of 140 mmscfd gas transmission capacity from each gasfield to trunkline hub; each based on up to 200km of nominal 16" (DN 400) 10.2MPa pipeline
6. Drilling and completions for initial 80 development and production wells (assume 20 at each gasfield) needed to deliver 500 mmscfd to the main trunkline.

Note: Condensate stabilisation, onsite storage, loading and transport to port or customer are not included in this concept appraisal. This aspect is more appropriately addressed as a separate business case when reservoir GOR characteristics are known.

Estimated Capital Investment
A$ million[2010]

PROJECT ELEMENT	COST ESTIMATE BASIS	INDICATIVE COST A$ m [2010]
3MTA LNG Plant and Loading facilities	US$1100 m in 2003 (start of construction) IHS CERA DSCCI increase 175:105 =1.67 US$ 1840 m in mid-2010 AU$ 2090m in mid 2010 [3mth-X-rate 0.88]	2090
1500 km Trunkline	Looping basis A$1191m over 1252km installed.. adjusted to end 2009 dollars. AU$ 1430m Alternative- New basis; WP/Qld DRET Study A$1.306m /km TIC AU$1960m	1430
Compressor Stations 1)Inlet hub stn 150 / 55 bar 26.2MW 2) mid-line CS 150/60 26MW Both CS have 3xSolar Mars 100 Compressor Sets	A$115 million each	230
Four field delivery laterals approx 200km long 16" & 9.5MPa Operating press	New basis; WP/Qld DRET Study A$0.72m/km TIC AU$580m (all four)	580
Development and Production Wells (well drilling and completions)	A$5.5 - 7.5m per well (field ave A$6.5 m) Eighty wells initially ~A$520m Ongoing field development .10 new wells installed ea year over 20 years A$65.0m pa	520
Initial Field Development (four fields) incl. - Wellhead Facilities and Flowlines - liquids separation and treatment - Infrastructure, utilities and access roads - Field boost compression	19% of initial well cost (A$38m per field) Facilities cost data are derived from the 1997 PIRSA Report (Economics of Gas Gathering and Processing in the Cooper Basin) and escalated from 1995 to mid- 2010 using the appropriate index ratio Ongoing field development ..average A13m installed each year over 20 years	150
condensate stabilisation, loading, transportation	Not allowed for:	
	TOTAL INITIAL CAPEX	5000

Queensland CSG LNG Projects Currently Active

Queensland Curtis LNG (QGC – a BG Group business)
Estimated Production: 8.5 mtpa initially,
Estimated CAPEX : US$15 billion (development program)

Santos GLNG (Santos, Petronas, Total and Kogas)
Estimated CAPEX : US$16 billion (including upstream field development, liquefaction plant and associated infrastructure)
Estimated Production : 2 trains with combined capacity of 7.8 mtpa of LNG

	Australian Pacific LNG (Origin and ConocoPhillips) Estimated CAPEX: A$35 billion (Platts--15Dec2010) Estimated Production: Stage 1: 2 trains at 4.5mtpa each; expected production by 2014 Stage 2: 2 trains at 4.5mtpa each; expected production TBA
	Arrow Energy LNG Project (Shell and PetroChina) Estimated CAPEX: TBA Estimated Production: 16 Mtpa in phased construction of up to four trains, each with 3 to 4 Mtpa.
Conclusions	1. An LNG export project based on a large gas discovery in Central Australia would have to be 3MTA (million tonnes LNG per annum) or larger. 2. Some 4 TCF of gas EUR would need to be found to supply a 3MTA LNG export project 3 Indicative costs developed in this screening study suggest that the Capital Investment required for the whole project might be of the order of A$1700 per annual tonne. 4. This is marginally lower than the Capex numbers (about $2000 per annual tonne) that have been announced for the active Queensland LNG projects
Energy Equivalents used in this study	1 tonne LNG ~ 53.9GJ (HHV) 1 tonne LNG ~ 46500 std cu ft gas (scf) 1 scf gas (from LNG) ~ 1100 Btu (HHV) 1 tonne LNG ~ requires 62GJ gas at the LNG plant and 68GJ of gas at the well head 1 bcf gas (wellhead) ~ 1.13PJ