Central Petroleum

Central Petroleum Limited

15 April 2016

Dear Shareholder

I am writing to you to keep you abreast with the positive developments which have occurred validating our gas strategy.

Since the beginning of 2014, Central Petroleum Limited (**ASX:CTP**) (“**the Company**” or “**Central**”) has embarked on a strategy to capitalise on the rising domestic gas price in the eastern seaboard as a safe harbour from the then anticipated fall in crude price. An essential part of that strategy was to do everything possible to ensure that our Northern Territory gas fields were physically connected to the markets where the shortage was predicted. The basis of this strategy was recently endorsed in a speech (transcript attached) by Mr Rod Sims, the Chairman of the ACCC, where on 9 March this year he said, “There is an urgent need for both new and importantly more diverse sources of gas supply into the domestic market”.

As part of our efforts Central offered between 20–25 PJ p.a. into the NEGI data room as gas available for the pipeline from Mereenie, Palm Valley and Dingo. At the time Central had assumed that the Northern Gas Pipeline’s (“**NGP**”) construction would depend on those volumes being contractually committed, thus creating a sense of urgency on gas customers and pipeline owners to commit in the early part of this year. It turned out that the winning tender had made the decision to go ahead with the construction of the NGP regardless of our commitment with the only risk mitigation being the option to downsize the interconnect to 12 inches, which they have done. After subtracting the gas committed into the interconnect by Power and Water Corporation, there remains roughly 22 PJ p.a. capacity, before upgrade (e.g. compression), available to contract.

Recent political debate about a moratorium being imposed on CSG and shale gas exploration in the NT makes it unlikely that alternative gas suppliers will emerge to fill this uncontracted capacity by the time the interconnect is commissioned in late 2018.

This turn of events have given the Company the advantage of time to ensure the value of its current uncontracted reserves are optimised. In addition, the Company takes the view that domestic gas prices will only tighten further as the remaining LNG trains are commissioned and the Brent Crude Index (a prime driver of LNG pricing) has risen 50% since 20 January 2016. Whilst Central aims to enter into a Gas Sales Agreement this fiscal year if justified by the economics (including transportation costs), it may consider delaying the sale of a portion of its gas to a later date (but not the delivery) to take further advantage of a tightening market. We have already split the reserve upgrade programme into three stages with the more capital intensive Stage 3 being able to be spent closer to the date of delivery. This is made possible by the fact that the Mereenie field’s existing field development has close to 15 PJ of spare capacity requiring minimal capital spend for de-mothballing and maintenance aimed at increasing reliability.

The commitment of the NGP developers enables us to confirm the timing of our cash flows and also delay the capital spending for delivery. These recent development mean Central remains well positioned to maximise existing fields' shareholder value whilst providing what ACCC Chairman Rod Sims called "new and importantly more diverse sources of gas supply into the domestic market". It is important to understand that there has been no change to the timing of our cash flows from the NGP, just a delay in the expenditure of capital.

Without even touching on our vast appraisal and exploration potential (the development of which can be timed to respond to a critical shortage in the domestic gas market), the future for Central looks bright.

Yours faithfully

Richard Cottee
Managing Director and Chief Executive Officer

Keynote address: Observations on the east Australian gas market

Speakers:
Mr Rod Sims, Chairman

Conference:
Australian Domestic Gas Outlook Conference, Sydney

9 March 2016

At the Australian Domestic Gas Outlook Conference in Sydney, ACCC Chairman Rod Sims provides three observations on the operations, intricacies and efficiency of the east Australian gas market.

Transcript:

Check against delivery

Introduction

It is a pleasure to be here. As most of you know, the ACCC's report on the East Coast Gas Inquiry is due to the Minister for Small Business and the Assistant Treasurer, the Hon Kelly O'Dwyer MP, by 13 April 2016.

As part of the formal inquiry, we have held more than 30 private and public hearings with gas producers, retailers and customers. We have consulted with over 50 interested parties and received around 73,000 company documents, reports, contracts and papers.

Based on this raft of information, today I will provide just three main observations on the operations, intricacies and efficiency of the eastern Australian gas market.

- First, eastern Australia's gas market is experiencing a triple whammy that has important ramifications for all Australians.
- Second, without new gas supply from a range of basins and producers there will be significant implications for gas prices and possibly gas availability.
- Third, particularly given these price implications, it is important that the regulation of gas transmission pipelines, or the threat of regulation, is effective but that does not seem to be the case.

Changing landscape for the gas market

The triple-whammy that is fundamentally upending the gas market in eastern Australia is driven by a combination of local and international factors.

- First, the introduction of LNG, and in particular the demand and supply fundamentals for the projects, has come under question.
- Second, oil prices have fallen faster and further than nearly anyone thought possible, with important implications for gas exploration and supply.
- Third, regulatory uncertainty and exploration moratoria are making life very difficult for the upstream sector.

As I have stated on previous occasions, in this environment commercial and industrial (C&I) gas users have had a particularly difficult time.

As everyone knows, the ACCC's East Coast Gas Inquiry arose out of a desire by the Government to understand the truth behind conflicting statements from producers and consumers over gas availability.

I have said before that during the 2012-14 period, C&I users were getting few if any real offers for gas, and those that they did get were at sharply higher prices and on strict "take it or leave it" terms.

Receiving and finalising gas supply offers became increasingly difficult for C&I customers as producers and retailers watched domestic gas prices rise in anticipation of linking to high international prices, and uncertainty grew as to how much gas the LNG projects could require.

As LNG production schedules firmed and international prices started to fall, gas did become available for domestic users, especially for the crunch years of 2016-2018 when many gas contracts rolled off.

Turning to the second element of the triple whammy, gas price uncertainty, this of course, is illustrated by the oil price changes of the last five years.

When the three LNG projects took their final investment decisions from October 2010 to January 2012, the oil price averaged around US$108 per barrel.

When we started our inquiry in April 2015, it was around US$55 per barrel. It is now jumping around US$30 to $40 per barrel.

While this is a low price, and comes as a shock for many in the industry, it is much closer to the 30 or even the 40 year inflation-adjusted price for oil of around US$55 per barrel than the US$100 per barrel that many industry pundits believed would be the new normal floor price for oil back in 2011-12.

Does this mean we should see the $65 billion investment in Queensland LNG projects as poor decisions where capital is lost, or that the projects and their parent companies are doomed to penury?

Of course not. These are long-term projects, which will suffer the ups and downs of commodity price cycles during their 20 or 30-year life spans.

While we can question some of the decisions around establishing three stand-alone LNG projects based on a relatively untried resource base, these are now permanent investments which will benefit Australia over the years to come.

There may, of course, have been an element of hubris which flowed from the rhetoric of an unending resource super-cycle.

There seemed little questioning of the prevailing orthodoxy that CSG would meet the LNG requirements and that there would be ample supply for the domestic market.

There was also an acceptance that existing market structures would cope with the very different dynamics of LNG supply and demand, and insufficient focus on how industries would be affected.

This includes the unsuitability of an opaque, long-term, bilateral contract market to new realities of rising prices at a time of increasing supply and demand uncertainty.

"Uncertainty" should be a watchword for governments where policy options like exploration moratoria are put in place which further reduce new supply options.

The cost or benefits that these policy decisions impose on the wider community and industry need to be fully explored on a case by case basis.

All of the above risks and uncertainties were largely foisted on industrial and commercial customers operating in a market structure that offered few tools or opportunities to manage those risks and uncertainties.

Risk and uncertainty has a price in the market, and we have seen domestic gas prices rising, sometimes significantly, during this period.

In this environment, we should be seeing a supply response, but this is not happening to the degree that we would expect.

Gas supply

The east coast gas market is in a ‘clash of cycles’ where falling international oil prices have coincided with historically high domestic gas prices.

Indeed, Australian domestic gas prices are now relatively high by world standards, and our gas prices have risen while they have fallen in many other countries.

A domestic market with historically high prices and supply uncertainty should be seeing a supply response with increasing investment, exploration and development activity.

However, the fall in oil prices has downgraded the profits of a number of companies largely reliant on oil revenues to finance gas exploration and development.

Negative sentiment in financial institutions about the sector is also curtailing finance available to other pure gas explorers and developers in the east coast market.

Any new gas production will be complicated by relatively high barriers to entry, with geological risk overlain with large upfront capital costs and long development timeframes.

As I have just mentioned, further complicating this picture for new entrants and existing players is the spectre of regulatory uncertainty and state and territory-based moratoria which are making new exploration increasingly risky or stopping development.

If the basic exploration and appraisal activity required to bring new gas to the market is significantly reduced for a significant amount of time at some point the market is going to face declining production from mature fields, which will not be replaced in time to meet demand.

In turn, this will make other market reforms more difficult.

There is an urgent need for both new and importantly more diverse sources of gas supply into the domestic market.

New sources of supply will assist in ameliorating the supply uncertainty for downstream gas users and put downward pressure on prices in the market.

There are some encouraging signs of smaller explorers and developers either seeking to develop gas previously deemed too difficult to develop or teaming up with customers to develop new gas sources.

However, reforms to increase liquidity in trading markets require more gas and importantly, increasingly diverse sources of gas from basins located close to markets in the south where much of the domestic demand is.

The best-designed trading markets will falter without gas to trade.

The critical importance of new gas supplies, and new suppliers, for the level of gas prices is shown by is what may be termed the “buyer / seller alternative prices”.

The key point is that the effect of the level of LNG netback prices on domestic gas prices depends more than is realised on the level of supply competition in the market.

Let me explain.

Traditionally, the Cooper Basin and basins offshore Victoria have supplied the southern states, in direct competition with one another.

Cooper Basin production has been declining since 2001, but more importantly most Cooper production is now largely going east to LNG rather than south to Sydney and Adelaide.

Offshore Victoria has therefore become increasingly important for the southern markets.

As the Otway and Bass Basin reserves decline during the next decade, gas from the Gippsland Basin, and the Gippsland Basin Joint Venture in particular, will be increasingly important in meeting southern market demand.

As this situation inexorably develops, new and diverse gas supply into the southern market will be important for providing price competition for the Gippsland Basin producers.

This is where a key contrast comes into play.

In a competitive gas market, with many supply alternatives in the southern states, buyers can effectively negotiate with producers where the price of gas is its production cost and a profit margin dictated by the level of competition.

In this world, the alternative price southern producers may expect is the LNG netback price at Wallumbilla **less** the cost of transport that they would need to pay to get their gas north.

This is the so-called “seller’s alternative price”.

However, if new supply is not forthcoming and gas users have very few supply alternatives, then the price that southern producers could charge is effectively the LNG netback price at Wallumbilla **plus** the transport cost to ship it to the southern gas users.

That is, the users option is to buy gas from the southern producer or get it from Queensland, with an added transport cost.

That is the so-called “buyer’s alternative price”.

To re-emphasise this point, whether gas users in the southern states pay the lower more competitive price for gas or the higher near monopoly price for gas depends on the diversity of supply that is brought into the market over the next few years.

New producers supplying relatively close to demand centres in the south increases competition which will put downward pressure on gas prices.

Pipeline regulation

While gas supply is crucial for the market, an efficient gas market also depends on an efficient transportation sector with competitive prices.

Indeed, there is an amplified effect of gas transport costs on gas prices through the differing “buyer and seller alternatives” I have just mentioned.

Unfortunately the dispersed geography of the market, with distinct demand centres in the capital cities and supply becoming increasingly concentrated in a small number of basins, has created a market where some pipelines are increasingly unrestrained by effective competition.

Changes in gas demand brought on by the LNG industry has also changed flow directions on gas pipelines, such as the Moomba to Sydney Pipeline (MSP) and the Moomba to Adelaide Pipeline System (MAPS).

Pipelines that have traditionally been competitors for the supply of gas to markets in Sydney or Adelaide are now in effect part of a complementary network transporting gas to Queensland.

In addition, three pipeline owner/operators dominate transportation in the gas market, with APA having an interest in almost 50 per cent of the sector.

This is a market where market power can be exercised and where the potential impact of monopoly pricing can be significant.

Less than 20 per cent of pipelines in the east coast are subject to any form of economic regulation.

The transmission pipeline sector of the gas markets is subject to access regulation under the *National Gas Law*. The test for regulation largely mirrors the test used in Part IIIA of the *Competition and Consumer Act 2010*.

The focus of this test is on the promotion of a material increase in competition in upstream or downstream markets to the pipeline, where the lack or restriction of access to infrastructure services provided by pipelines that cannot be economically duplicated would otherwise limit competition in those markets.

It is becoming increasingly apparent that the threat of regulation under the *National Gas Law* is not acting as an effective deterrent to monopoly pricing and other exercises of market power.

For example, pipeline owners, with one or two minor exceptions, are not vertically integrated, so it is difficult to demonstrate they have an incentive to deny access or set prices in a way that adversely affects competition in another market.

The fact that there may be no competition and so market power in the pipeline market itself is not taken into account.

This is an area of particular concern to the ACCC because monopoly pricing on gas transmission pipelines can lead to inefficient downstream investment decisions and can limit investment in upstream exploration.

The debate on pipeline regulation has played out between regulators, governments and the industry periodically over the years.

However, if some form of price regulation to mitigate the potential for monopoly pricing and increase economic efficiency is a desired public policy outcome, an alternative test to that set out in the *National Gas Law* would seem to be required.

The argument is sometimes made that regulation to address monopolistic pricing is unnecessary, because monopolistic pricing is the simple transfer of economic rents between parties in a supply chain.

However, in Australia, the upstream gas sector requires massive capital investment to bring on new and more costly gas supplies.

Downstream, gas users are competing in a global market place where every input needs to be provided at peak efficiency.

Excessive pipeline charges can affect investment in new gas supply, and in its downstream use.

I would note that the regulation of natural monopolies like transmission pipelines is accepted in other areas of the economy and in many other countries; even in the most free market supportive ones like the United States.

I think there would be very few policy makers in Australia who would push for the deregulation of the poles and wires pricing in the electricity transmission sector in Australia.

Just as Part IIIA is not today relied on to regulate the electricity sector, nor should it necessarily be relied on to regulate the transmission pipeline sector. Part IIIA was largely envisaged as a regime providing for access to vertically integrated monopolies and in some circumstances provides a useful deterrent to discriminatory conduct.

However, there are some circumstances within the Australian economy where it simply does not work or where its deterrent potential is ineffective.

In these cases, and I think the transmission pipeline sector is one such instance, we may need to seek alternative forms of regulation to address monopolistic pricing and rent transfers which contribute to inefficient economic outcomes.

Closing remarks

It has become a truism that the eastern Australian gas market is in transition phase as the LNG projects come on-line.

I have touched on a number of areas where the east coast gas inquiry can highlight inefficiencies which should be addressed and where perhaps new policy or better informed policy decisions may be needed.

Thank you for your time this morning. We look forward to finalising and delivering our report.

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Media Enquiries
Martin Debelle at Citadel-MAGNUS
T: +61 (0)2 8234 0100
M: +61 (0)409 911 189

Central Petroleum Limited
ABN 72 083 254 308
Level 32, 400 George Street, Brisbane, QLD 4000, Australia
PO Box 12214, George Street, QLD 4003, Australia

T: +61 (0)7 3181 3800
F: +61 (0)7 3181 3855
info@centralpetroleum.com.au
www.centralpetroleum.com.au