- the Carpentaria Gas Pipeline (the "CGP") and the Amadeus Gas Pipeline (the "AGP"). As noted[2], "There is evidence that a large number of existing pipelines have been engaging in monopoly pricing". A good example of this is the transportation of gas through the scheme pipelines from the Mereenie or Palm Valley gas fields to Ballera.

Despite for both the CGP or AGP:

1) having been built more than 15 years ago; and
2) the carriage is essentially "back haul".

The combined quoted tariffs are nearly 50% greater than the tariff quoted for the NGP presently under construction whilst they require no new investment. This clearly inhibits the promotion of efficiency in both the upstream and downstream markets – a major objective of the NGO.

The prime reason for this is the present asset valuation techniques and the present pricing principles (which are now inconsistent with and anomalous to Rule 569 of the National Gas Rules ("NGR")) do not adequately take account the return of capital recovered since the commissioning of the pipeline.

2 The advent and consequences of international gas pricing

As the ACCC IECGM noted [3] "All the participants in the east coast gas market are now exposed to international LNG & oil prices" and later on " The International LNG prices through the LNG netback prices, which are calculated by subtracting the costs of shipping, liquefaction and transmission from the spot or contract LNG prices".

The 6 LNG trains at Gladstone have been reported as being contracted up to an average 80% of design but each are capable of running consistently at 110% of design. In effect, nearly 1/3 of their respective design capacity is available for spot cargo which over 6 trains is nearly 2 trains worth of gas which can be diverted either to the international spot market or the domestic gas market. Using the said ACCC definition of LNG netback pricing, the essential determinant of whether that gas goes to the domestic market or the international spot market, is whether "the costs of shipping liquefaction & transmission" from the pricing point is less than or greater than "the cost of delivery gas from the pricing point to the prime domestic demand centres.

As noted earlier, there are scheme pipelines leading into 3 of the 4 prime domestic demand centres, namely the Roma & Brisbane Pipeline ("RBP"), the Marsden to Wilton pipeline and the Victorian Transmission System ("VTS").

It is critically important to the National Gas Objective ("NGO") that not only is there a consistency in pricing principles but also in the long term interests of consumers of natural gas that the gas transportation tariffs for the transmission to the city gate from the pricing point (presently Wallumbilla) is ideally less than the cost of supply liquefaction and transmission for export.

3 The Brave New World of Multi-lateral Gas Markets

The Australian domestic gas market and its infrastructure have historically been developed by bi-lateral arrangements primarily through Gas Sales Agreements ("GSAs") with Take or Pay provisions and Gas Transportation agreements ("GTAs") with Take or Pay provisions. This has worked well but with the advent of international LNG netback pricing & in particular the opening an arbitrage between spot LNG pricing and domestic pricing the market will be more fluid. If there is no such arbitrage then the gas will be exported.

The net result is that if the pipeline system is efficient, cost-effective, with spare capacity able to be utilised and storage viable, then security of supply will be obtained through the pricing signal. Essentially there will be approximately 2 LNG trains of gas that will no longer be dedicated to bi-lateral

[2] ACCC IECGM page 8
[3] ACCC IECGM page 31

long term contracts. In this brave new world, price certainty essential to manufacturers and small gas producers will need to be obtained through futures contracts and the system will need to reflect this.

As the LNG market increasingly transitions towards a spot market, it will be the Gulf of Mexico and Gladstone that will become the LNG price makers. The spot LNG market will move away from being oil-linked to oscillating between Henry Hub pricing and the Australian domestic spot market (provided it becomes more deep and liquid).

If this were to be the case, a major new financial market in the form of the LNG Futures may well be centred in an Eastern seaboard capital city with all the obvious benefits which would flow from that.

The reform of the pipeline system to international standards must be empathetic to this future. These scheme pipelines must become another brick in the wall following the recent reforms to the non-scheme pipelines.

4 Asset Valuation & Impact on the NGO

As noted in our submission to the GMRG dated 20 July 2017, the most important contribution to the pricing disadvantage Australian domestic gas suppliers and gas consumers face is the mismatch between the actual residual asset value for existing mature pipelines, which are typically fully repaid over 15 years (consistent with the existing greenfield exemption period) and asset value for pipeline regulation, which is derived through accounting depreciation that is spread over extremely long life assets. Appendix 2 shows a simplified impact of this mismatch which essentially provides a 50% uplift to pipeline owners whom are able to charge customers as if they are rebuilding the entire east coast pipeline network every 15 years without having to actually spend any material capital expenditure.

Conclusion

The reforms to parts 8 to 12 of NGR must be part of and synergistic to the reforms considered by the GMRG so that the total system can react to the permanent change in the gas market occasioned by the advent of the LNG export facilities in Gladstone[4]. Australian manufacturers and chemical users must not be exposed to greater price and supply uncertainties merely to continue a regime that has allowed the total return on the pipeline business to be double that of the regulated electricity network operator[5]. The scheme pipelines are fundamental to the opening of the NT and Mt Isa gas provinces as new supplies become available. Regulated pipelines should not be guaranteed higher returns than unregulated. Central has legal advice that the arbitration provisions presently in the NGR are likely to be too costly and difficult for our lawyers to be able to recommend commencing arbitration (a copy of this advice is available on a confidential basis).

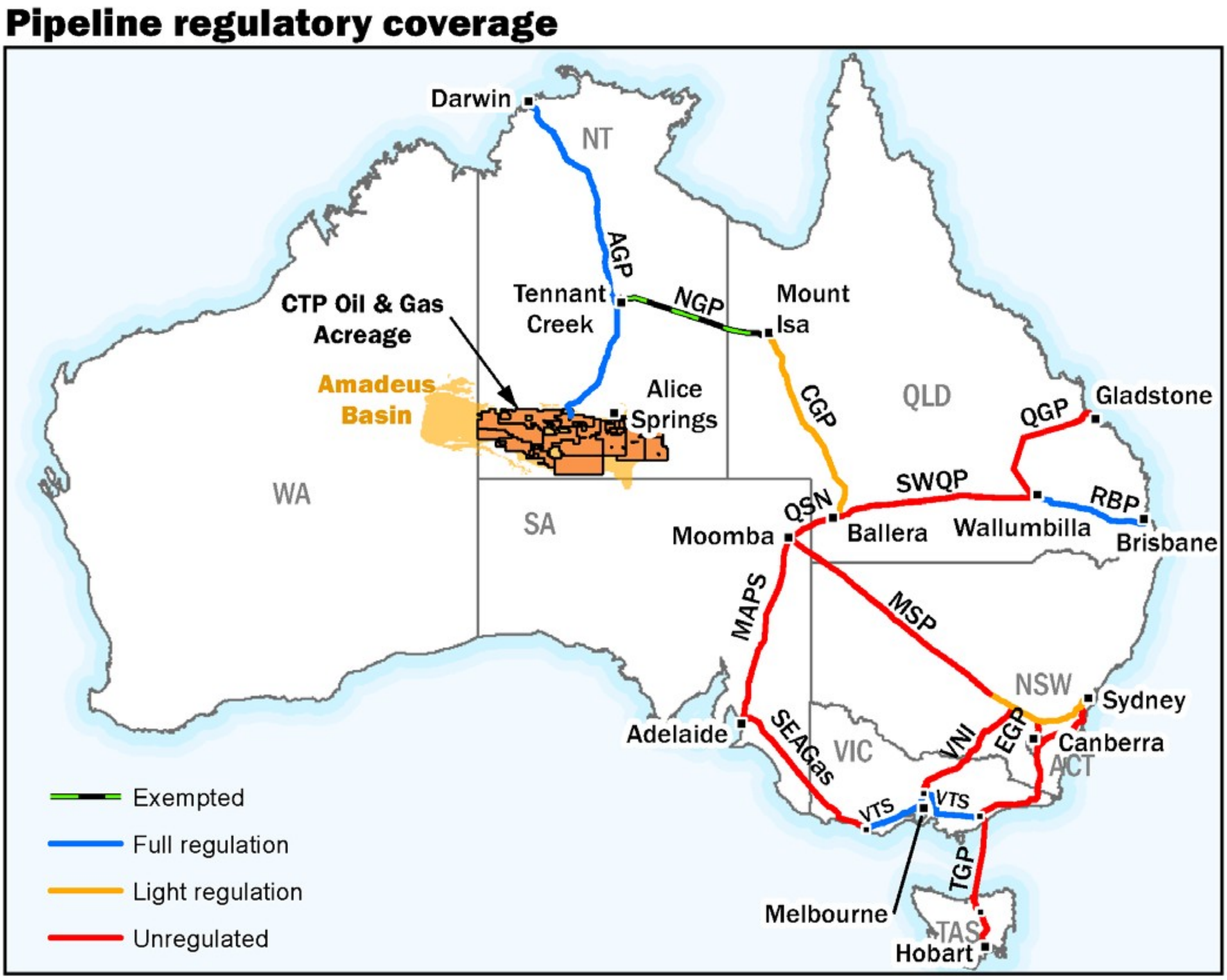
We urge the AEMC to consider reforms to Part 8 – 12 of the NGR to enable Australia to adapt to the natural gas market now exposed to international market forces.

Yours faithfully
CENTRAL PETROLEUM LIMITED

Richard Cottee
Managing Director and CEO

[4] As such, this submission should be read in conjunction with Central's submissions to the Vertgan examination dated 18 October 2016, the initial response to the GMRG reform group dated 13 April 2017 and final submission to the GMRG dated 20 July 2017.
[5] Vertigan Examination page 10

Appendix 1 – Pipeline Regulation Coverage



Appendix 2 - Impact of Excessive Tariff Rates

Assumptions		
Asset Life	Yrs	80
Capital Recovery Period	Yrs	15
Initial Capital Investment	$	100
Inflation Rate	%	2.5%
Risk Adjusted Market Rate of Return	%	8.0%
Monopoly Pricing Premium	%	7.0%
Annual Rate of Return for Pipeline Assets (No Economic Regulation)	%	15.0%

Fair Market Value Scenario (Economic Regulation)		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
		With Economic Regulation															
Capital Related Tariff Charges																	
Return on Investment (Reasonable Market Rate of Return of 8%)	$	-	8.0	7.8	7.6	7.4	7.1	6.8	6.4	6.0	5.5	4.9	4.3	3.6	2.9	2.0	1.1
Return of Initial Pipeline Capital Investment (15-Year Payback)	$	(100.0)	2.1	2.5	3.0	3.5	4.1	4.7	5.3	6.1	6.8	7.7	8.6	9.6	10.7	11.9	13.2
Total Capital Related Tariff Charges	**$**	**-**	**10.1**	**10.4**	**10.6**	**10.9**	**11.2**	**11.5**	**11.7**	**12.0**	**12.3**	**12.6**	**13.0**	**13.3**	**13.6**	**14.0**	**14.3**

With Economic Regulation (15-Years)

Fair Market Value with Economic Regulation* **100**

Unregulated Pricing Scenario (Monopolistic Pricing Power)		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21-80
		No Economic Regulation																					
Capital Related Tariff Charges																							
Return on Investment (Reasonable Market Rate of Return of 8%)	$	-	8.0	7.8	7.6	7.4	7.1	6.8	6.4	6.0	5.5	4.9	4.3	3.6	2.9	2.0	1.1	-	-	-	-	-	-
Return on Investment (Monopoly Pricing Premium of 7%)	$	-	7.0	7.1	7.2	7.3	7.4	7.3	7.2	7.1	6.8	6.4	5.9	5.2	4.3	3.2	1.7	22.0	22.6	23.1	23.7	24.3	3,388.6
Return of Initial Pipeline Capital Investment (15-Year Payback)	$	(100.0)	0.2	0.6	1.1	1.7	2.3	3.1	4.0	5.0	6.2	7.6	9.2	11.1	13.3	15.8	18.7	-	-	-	-	-	
Total Capital Related Tariff Charges	**$**	**-**	**15.2**	**15.6**	**16.0**	**16.4**	**16.8**	**17.2**	**17.6**	**18.1**	**18.5**	**19.0**	**19.5**	**20.0**	**20.5**	**21.0**	**21.5**	**22.0**	**22.6**	**23.1**	**23.7**	**24.3**	**3,388.6**

No Economic Regulation (80-Years)

Asset Value to Pipeline Owner with No Economic Regulation* **272**

* NPV8 of Capital related tariff charge cash flows