Response to AEMC Issues Paper

Review into the scope of economic regulation applied to covered pipelines – August 2017

Dampier Bunbury Pipeline

Australian Gas Networks

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DBP Transmission (DBP) is the owner and operator of the Dampier to Bunbury Natural Gas Pipeline (DBNGP), Western Australia's most important piece of energy infrastructure. The DBNGP is WA's key gas transmission pipeline stretching almost 1600 kilometres, linking the gas fields located in the Carnarvon Basin off the Pilbara coast with population centres and industry in the south-west of the State

Australian Gas Networks (AGN) is one of Australia's largest natural gas distribution companies and owns approximately 25,000 kilometres of natural gas distribution networks and 1,100 kilometres of natural gas pipelines, serving over 1.2 million consumers in South Australia, Victoria, Queensland, New South Wales and the Northern Territory

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1. INTRODUCTION

The Dampier Bunbury Pipeline (**DBP**) and Australian Gas Networks (**AGN**) appreciates the opportunity to respond to the Australian Energy Market Commission's (**AEMC**) Issues Paper *Review into the scope of economic regulation applied to covered pipelines* (**Issues Paper**).

We are supportive of our industry representative organisations' - APGA and ENA - submissions, which acknowledged that the economic regulatory provisions of the National Gas Rules have worked effectively in producing customer outcomes of efficient, safe, reliable provision and growth in network services. We are therefore not of the view that further significant changes are required to the framework.

The NGL and NGR framework was designed to deliver outcomes that are consistent with the National Gas Objective (**NGO**) for two distinct types of infrastructure assets with different characteristics. Gas transmission pipelines connect Australia's gas producing basins to our demand centres of capital centres, industrial zones, mining regions and export facilities. Gas transmission pipelines operate at high-pressure and are made from steel. They traverse long-distances and are, at an asset level, largely point-to-point.

The direct customers of gas transmission pipelines tend to be large corporate entities, covering gas producers, users, retailers and gas-fired power generators. Each gas transmission pipeline has a unique demand profile influenced by its major customers. Customers on gas transmission pipelines have demonstrated a clear preference to tailor a range of services that make up a bespoke package of services to take into account the specific requirements of their demand profile.

Gas distribution networks transport gas within Australia's cities and towns, providing gas connections to small and medium businesses, homes, schools and hospitals. They operate at low pressure and tend to be made from polyethylene pipe. The direct customers of gas distribution networks tend to be energy retailers, who utilise the network to provide gas to their customers. Customers on gas distribution pipelines are typically able to have their needs met through standardised services.

Further, both distribution and transmission pipelines face varying levels of competition depending on their customer base and particular circumstances.

Natural gas is a fuel of choice. This means it is in constant competition with electricity and other energy sources. This is particularly true at a distribution level, where some governments actively encourage a move away from gas to renewable sources of energy. In many regional towns, gas distribution networks also face direct competition with bottled gas.

The framework of Parts 8-12 of the National Gas Rules (**NGR**) is a fit for purpose framework that contains the flexibilities that have demonstrably supported good customer outcomes. We consider the following features are positives aspects of the current regulatory framework for gas:

- An approach to setting reference services that creates an appropriate benchmark service rather than a prescriptive menu of available services that are not sought by the majority of users;
- A lower cost light-handed regulation option recognising the existence of competitive markets and a set of diverse circumstances;
- A discretion framework that has the opportunity to increase certainty for stakeholders and reduce the cost and time involved in the access arrangement review process;
- A strong incentive framework supportive of delivering for customers

Looking forward, there are a number of modest improvements that could be made to ensure the regime supports good customer outcomes into a very different future for gas networks:

- Increasing clarity and certainty in how depreciation is dealt with under NGR 89;
- Changing the definition of natural gas so not to exclude new hydrogen and biogas projects;
- Review the time available to service providers when developing amended proposals responding to the regulators' draft decision, including allowing for stakeholder engagement and a considered response to required amendments; and
- The AEMC should actively consider the provision for a fast-tracked decision making approach to reduce the time and resources directed to access arrangement reviews where appropriate.

2. KEY ISSUES RAISED BY THE TERMS OF REFERENCE

This section of the submission responds to the particular matters referred to in the COAG Energy Council terms of reference that raised potential issues identified by the Australian Competition & Consumer Commission (**ACCC**), including:

- Reference services: the current definition of 'reference service' is that the service is sought by a 'significant part of the market'. As a result, some non-contestable services are not subject to regulated terms and conditions (including prices). The ACCC suggested that pipeline owners may be able to exercise market power on these services to the detriment of consumers and economic efficiency;
- Pipeline expansions: when a pipeline that is subject to full regulation is expanded (for example, through the addition of a compressor), the additional capacity is not necessarily included within the definition of the covered pipeline and consequently not subject to economic regulation. Again, the ACCC noted that pipeline owners may, as a result, be able to exercise market power on these services provided by the expansion to the detriment of consumers and economic efficiency; and
- Information and dispute resolution: there may be barriers that are preventing participants from using the access dispute resolution provisions in the NGR. As a result, the ACCC commented that the threat of arbitration was unlikely to be a constraint on the behaviour of pipeline service providers.

Reference Services

The ACCC in its 2015 East Coast Gas Inquiry (**Gas Inquiry**) suggested that, even if a pipeline is subject to full regulation, it may still be able to exercise market power[1]. The ACCC correctly state that the AER (or ERA) is only required to approve on an ex ante basis the price of access to the reference service(s) offered by the pipeline. Under the NGR a full access arrangement must specify as a reference service:

- At least one pipeline service that is likely to be sought by a significant part of the market; and
- Any other pipeline service that is likely to be sought by a significant part of the market and which the AER considers should be specified as a reference service.

In deciding whether to specify a pipeline service as a reference service, the regulator must take into account the revenue and pricing principles.

The ACCC contrasts the approach employed in the NGR with the electricity regime and observes that the approach used in gas has resulted in a number of non-contestable services being excluded from the AER's ex-ante review, where non-contestable services are a primary target for regulation. The ACCC suggests (at footnote 192) that where a reference service is a substitute for all of the other services provided by the pipeline operator (or there is a chain of substitutability), then it may be possible to rely on just regulating the reference services.

In our view, the ACCC has oversimplified the matter by comparing the gas framework with electricity and has not recognised the benefit the customers of transmission pipelines receive from the current approach in gas. The current framework has allowed bilateral contracting for not only reference services but also for services that are customised to better suit the particular needs of customers.

The current framework allows the regulator to determine an efficient price for the service(s) that are sought by a significant part of the market while allowing an appropriate level of customisation and innovation in service delivery afforded by the negotiate/arbitrate model implemented by the NGR. Importantly what is set by the regulator as the reference service is decided through a transparent public process as parts of the access arrangement review.

[1] *ACCC East Coast Gas Inquiry (2016) Section 7.2.2. page 134*

In DBP's experience, it has been particularly important that a transmission pipeline is able to provide a customised service to its shippers. While the DBNGP has some unique circumstances, which have led to almost all contracts to be commercially agreed with customers outside of the regulatory framework (that is not to say that the reference tariff has not been an important piece of evidence for shippers), it is routine for gas transmission business to have a proportion of bilateral contracts that are tailored and customised to customer requirements.

While the AEMC should seek the views of the customers of transmission pipelines, it is our view that a degree of flexibility has delivered efficient outcomes, facilitated investment and has demonstrably delivered for the long-term interest of consumers. The existence of negotiated services is evidence that the customers of transmission pipelines seek something akin to the reference services but require flexibility when entering into services to suit individual operations and manage their respective energy portfolios.

Transmission pipelines service a vast range of customer types from large mining operations, refineries, manufacturers, electricity generators and gas retail businesses. Each gas transmission pipeline has a unique demand profile influenced by its major customers. Some pipelines largely serve gas –fired power generators and experience high summer peaks. Others serve mining or industrial regions and have largely flat loads. Those that transport gas to colder regions tend to experience winter peaks as the demand for space heating increases.

In contrast, electricity service providers do not have this level of diversity within its pool of customers. The customers of transmission pipelines are therefore are more likely to require a higher degree to customisation to their transportation services and therefore the prescriptive one size fits all approach employed in electricity is not fit for purpose.

The consequence of adopting a more prescriptive approach that would require all services offered to be reference services, removing all flexibility would:

- Remove the service provider's ability to tailor services to suit the needs of the customer. Such a change would reduce efficiency and not be in the interest of customers; and
- Risk the regulator setting tariffs that may be efficient of a vanilla reference service but which may not be for services that have uncertain or unpredictable characteristics, based on the specific circumstances of our customers.

On the DBNGP, the ERA has for much of its history required three reference services, a forward haul, a part haul and back haul service. Shippers on the DBNGP are however contracted to negotiated services but are materially similar in nature to those approved by the regulator.

More than 85% of DBP's aggregate firm full haul contracted capacity (including the Alcoa exempt contract) have terms and conditions (including price) that are different to the reference service. The remaining contracted capacity is priced at the reference tariff but on terms (while materially similar) are not those approved by the regulator. This clearly shows a strong desire and ability for our customers to negotiate terms and conditions, including for those service that are sought by most customers.

Pipeline services other than forward, part and back haul type services on the DBNGP represent only a small fraction of overall revenue and the demand for which are highly variable. During 2011-15 (the most recent regulatory period), the 'other' service revenue averaged 1.9% of total revenue. These services included:

- As available/interruptible full and part haul services – services that are for capacity that are intermittently available or less firm than the main full, part and back haul transportation services;

- Inlet sales – which allows for shippers to flexibly receive gas from a number of inlet points on a transmission pipeline;
- Park, loan and other storage type services – a suite of services that facilitate the flexible use of gas transportation services; and
- Data services - provision of metering and other data services

It is important to note that the due to the nature of these services, demand is volatile from day to day and year to year, revenue is therefore hard to forecast and costs are also hard to ascertain. The current approach encourages efficient use of and investment in pipeline services. Where significant uncertainty exists for revenue and demand there is reduced likelihood that efficient tariffs can be set. It allows tariffs to be set based on the particular circumstances and is less likely to lead to cross-subsidisation.

We also note that the NGR already makes significant flexibility and discretion available to regulators under NGR 93. For example, the total revenue can be allocated between reference services and other services in the ratio in which costs are allocated between reference and other services. The regulator can also require a service to be a rebateable service if the service is not a reference service, substantial uncertainty exists concerning the extent of demand for the services and the market for the service is substantially different from the market for any reference service.

In our view, the long-term interests of consumers with respect to price and security of gas supply is served best by allowing regulators at the time of a review to decide whether a pipeline service sought by a significant part of the market is a reference service. The result of this approach has demonstrably allowed a level of flexibility and contract customisation for consumers of gas transmission services.

Further, the existing framework already has mechanisms deal with 'other' less sought after services were revenue may only account for a very small percentage of overall revenue where tariffs are unlikely to be set efficiently due to the lack demand related information.

Pipeline Expansions

The COAG Energy Council's terms of reference noted that when a pipeline that is subject to full regulation is expanded (for example, through the addition of a compressor), the additional capacity is not necessarily included within the definition of the covered pipeline and consequently not subject to economic regulation. The ACCC claimed that pipeline owners may, as a result, be able to exercise market power on these services provided by the expansion to the detriment of consumers and economic efficiency.

In the Gas Inquiry, the ACCC suggested the gap stems from the discretion that currently exists under the NGR to exclude expansions of a fully regulated pipeline from the definition of the covered pipeline. This has resulted in tranches of capacity on some full regulation pipelines not being subject to regulation.

We note that the decision to exclude expansions must be approved by the regulator. We agree there is little guidance in the NGR on the matters the regulator must consider when making such a decision, however, the regulator has full discretion when granting approval.

Further, the regulator's role is to approve the extensions and expansions requirements in each access arrangement prior to any expansion-taking place. It is therefore unlikely that amendment to the rules are necessary. To this end we point to the ERA's determination considering continue expansion of the uncovered pipeline capacity on the Goldfield Gas Pipeline (**GGP**) where it notes that:

"*The Authority notes that prior to the expansion, around a third of the GGP comprised uncovered capacity. The current uncovered expansion will lift that proportion significantly. The Authority notes that many of* *the customers on the GGP are large mining companies. In the event that those companies judged that coverage of the full capacity of the GGP would deliver significant net benefits for the community, and thus not be contrary to the public interest, they would be open to apply to the National Competition Council for coverage. The Authority notes that such application by a user has not occurred to date, despite the pipeline being expanded, without coverage, on a number of occasions.* "[2]

We agree with the ERA's assessment that the shippers on the GGP, mostly global scale mining houses, are significantly resourced and more than capable to pursue coverage if necessary. We do acknowledge that not all customers have the time and resources available to them however, the access arrangement review process where the regulator sets the extension and expansion policy for each regulated asset is a process that is open to all stakeholders.

While the coverage criteria are likely to provide a more rigorously tested assessment criteria (as was used in GGP's case, albeit that the ERA's assessment was made under the Code) we note that the ERA has recently required amendments to access arrangements for regulated asset in WA. In the DBNGP Access Arrangement approved in 2016[3], an expansion automatically becomes part of the covered pipeline unless the operator elects otherwise and demonstrates to the regulator's reasonable satisfaction that application of the access arrangement to such expansion is inconsistent with the National Gas Objective (**NGO**).

The regulator must make a determination that is consistent with the long-term interests of consumers. The approach taken by the ERA demonstrates that the regulator has significant discretion under the current framework and therefore it is unlikely that changes are warranted. Further customers can have input into the setting of extension and expansion policy for each asset during the access arrangement review process.

In our view, there are likely to be instances where avoiding the costs associated with regulation are in the long-term interests of consumers, i.e. where it is not in the interest of consumers that the costs of a particular expansion are shared, this situation may arise when a particular proponent requires expansion that doesn't deliver a shared benefit. The framework should retain a level of flexibility that allows for that eventuation.

In summary, there are two mechanism that already exist that deal with the ACCC concerns, the first being the transparently public process by which extension and expansion requirements are set and the regulators full discretion when approving those requirements in an access arrangement.

Information and dispute resolution

The COAG Energy Council in its terms of reference noted that there may be barriers that are preventing participants from using the access dispute resolution provisions in the NGR. As a result, the ACCC commented that the threat of arbitration was unlikely to be a constraint on the behaviour of pipeline service providers.

The fact that the arbitration framework has not been utilised does not mean there is a necessarily a problem with it. It is broadly consistent with other access regimes. The arbitration regime is a last resort and its lack of use may mean the negotiation process is working effectively, noting that commercial parties would generally prefer to reach a commercial resolution than have access terms decided by a third party.

[2] https://www.erawa.com.au/cproot/12668/2/Application%20for%20expansion%20of%20the%20Goldfields%20Gas%20Pipeline%20to%20be%20not%20regulated%20-%20Determination.pdf

[3] https://www.erawa.com.au/cproot/14394/2/Access%20Arrangement.PDF

The ACCC in the Gas Inquiry suggests that while the threat of arbitration should in principle impose a constraint on the pipeline operator's behaviour when determining the prices of these services, the Gas Inquiry said it was informed by market participants that the following factors can discourage shippers from triggering these provisions:

- the costs and resources associated with an access dispute, coupled with the uncertainty surrounding the final outcome;
- information asymmetries may also be contributing to this reluctance to trigger these provisions because shippers are unable to determine how much they are being 'overcharged'[4]

Having the AER as the arbitrator should constrain the costs of arbitration and it would be unlikely that withholding information would be advantageous to this service provider as it would not be seen favourably by the arbitrator.

There is very little information asymmetry that exist between shippers and pipeline operators of regulated assets. Substantial and detailed cost information is disclosed through the access arrangement review process for regulated pipelines. It is hard to imagine what further information could be required by prospective customers who are generally themselves large, sophisticated and hold significant countervailing power.

Further, there is little basis to the claim that customers of transmission pipeline who typically enter into multi-million dollar contract that may span 10 plus years couldn't avail themselves in an arbitration if so required. It is also unclear in what scenario a perspective shipper could not determine how much they are being 'overcharged' when it has access to:

- all building block cost information relevant to that pipeline;
- forecast demand reviewed and approved by the regulator; and
- prevailing tariffs for equivalent of near equivalent services to use as benchmarks.

We see no evidence of a regulatory processes having broken down, considering:

- The large degree of regulatory oversight applying under the NGR, including in the regulator's role in determining the reference services and in determining coverage of expansions;
- The flexibility to negotiate with our customers where appropriate, demonstrable by the successful renegotiation of 85% of firm full haul contracted capacity on the DBNGP highlighting the strong desire to negotiate outside the regulatory framework where it is to the benefit of customers;
- The incentives to negotiate given the availability of substitutes for the services offered by transmission and distribution service providers; and
- The AER is the arbitrator, which would act to constrain the cost of a potential arbitration.

The ACCC also refers to one market participant that noted that there is "little utility in being able to trigger a dispute in relation to an existing contract, because any access determination would be bound by the pre-existing contractual rights between the parties, which are protected under the NGL".

We note that the protection of pre-existing contractual rights are expressly stated in the NGL to, in our view, appropriately protect the foundation on this investments in long lived infrastructure assets like gas transmission pipelines. Without such protections the financing costs of these assets would likely be prohibitive and not in the long-term interests of consumers.

[4] *ACCC East Coast Gas Inquiry Section 7.2.2 page 135*

3. LIGHT REGUALTION IN THE CURRENT FRAMEWORK

AGN owns the Queensland Gas Distribution Network which distributes natural gas in the Brisbane Region (Brisbane CBD, Ipswich and suburbs north of the Brisbane River) and Northern Region (Rockhampton and Gladstone). The network serves nearly 100,000 residential, commercial and industrial customers and delivers approximately 2PJ per annum.

The characteristics of the market is typified by a low penetration of connections to the gas network at 15%, relative to 75% and 90% for our South Australian and Victorian networks respectively. Further, average consumption per residential connection is also low, reflecting the extremely mild climate. We consider these market characteristics explain the low number of active retailers in the market of only three – AGL, Origin Energy and Alinta Energy. It is worth noting that despite Full Retail Contestability (**FRC**) and retail price deregulation occurring ten years ago in 2007, retailer participation has not significantly developed in that time.

The network has been a covered pipeline from the commencement of the Gas Code in 1997, coverage continued with the implementation of the NGL in 2008. The network was subject to full regulation until November 2014, after which time it has been subject to light regulation. The change to light regulation was the result of the National Competition Council (**NCC**) accepting AGN's (then Envestra) application to have the form of regulation changed. The NCC determined that light regulation would be as effective as full regulation when applied to the Queensland network, but applied at a lower cost.

As identified by the NCC in its Final Determination, any market power AGN possesses in this market is offset by the ability of end users to substitute other forms of energy (such as electricity and LPG). Further, the NCC determined the application of light regulation will not serve to increase the market power of AGN within the Queensland market.

The NCC, in responding to concerns raised by some retailers in respect of information provision, also noted light regulation will still require AGN to make available on its website a range of information, such as pricing and the terms and conditions for access to the network. Light regulation would also require AGN to advise the AER annually of the outcomes of negotiations with access seekers.

AGN has now operated the Queensland network under light regulation for nearly three years. The manner by which AGN has operated the network, made investment decisions in respect of the network, marketed to potential new customers, served existing customers or engaged with access seekers of the network has not changed as a result of the shift to light regulation. In the past three years:

- We successfully renegotiated our Access Arrangement to apply from 2016/17 to 2020/21 with all three gas retailers, with no need for dispute resolution;
- the renegotiated Access Arrangements included a real cut (before inflation) to prices of 10% from 1 July 2016. The cut reflected, amongst other cost reductions, the pass back to customers of the avoided costs of full regulation – namely being avoided costs of having to prepare a full regulation Access Arrangement proposal. The price reduction also reflected an analysis of our competitive position relative to electricity and LPG;
- the terms and conditions agreed are consistent with those applied in our networks subject to full regulation (i.e. Victoria and SA);
- provided the same level of network performance consistent with that under full regulation;
- introduced monthly customer satisfaction surveys consistent with their introduction across all of AGN's gas networks; and
- made a significant investment decision to increase the security of supply to the network by determining to construct another pipeline across the Brisbane River. The new river crossing will

connect to the Roma to Brisbane pipeline, the main transmission pipeline which serves the Brisbane market, and create another supply point for the AGN network.

AGN considers its operation and activities undertaken as described above demonstrate successful application of light regulation to a covered pipeline. AGN considers the application of light regulation has been, as expected by the NCC in its final determination, at least as effective as full regulation in respect of the Queensland network at a lower cost.

Customers benefit from the operation of light regulation through avoidance of the substantial per customer cost impacts of full regulation. Light regulation also provides more flexibility and incentives for gas service providers, existing users and potential users to reach negotiated service arrangements that are responsive to customer's needs and market developments. It remains an appropriate and a proportionate regulatory option for networks facing strong competitive constraints.

In this case, it is clear that AGN is not in a position to exercise any market power in the Queensland market. This was also the decision of the NCC, who recently considered light regulation more appropriate. Under light regulation, we have delivered lower prices and improved services for customers.

Furthermore, in Queensland we were able to successfully negotiate with users revised terms and conditions without recourse to arbitration. We note that the existence of arbitration overseen by the AER strengthens the incentive to reach a successful negotiation.

Light regulation is not however appropriate for all assets. For example, AGN recently sought to consolidate the Albury network into the Victorian network rather than seek revocation or to have the network the subject of light regulation. This reflected AGN's view that the Albury gas market remains relatively strong, and that consolidation would improve the regulatory process (particularly the stakeholder engagement) and deliver a lower cost to all customers.

4. DISCRETION UNDER THE NGR

Question 4 of the Issues Paper concerns whether the three levels of regulatory discretion in approving the elements of an access arrangement are useful and assigned appropriately.

Those three levels, set out in rule 40 of the NGR are:

- No discretion (rule 40(1)) – a small number of rules, where the regulator may not withhold approval to the relevant element of the access arrangement if it meets specified conditions set out in the NGL or the NGR.
- Limited discretion (rule 40(2)) – where the regulator may not withhold approval to the access arrangement element if the regulator is satisfied that the element complies with the applicable requirements of the NGL or the NGR and is consistent with any criteria in the NGL.
- Full discretion (rule 40(3)) – when applying the majority of rules, the regulator may withhold its approval to the access arrangement element if in its opinion a more preferable alternative exists that complies with, and is consistent with applicable criteria prescribed by the NGL and NGR.

In this way, rule 40 of the NGR provides for a discretionary gradation in respect of the various rules contained in the NGR. In our submission, that regime generally provides an appropriate framework for identifying the nature and degree of discretion which a regulator may exercise in making a regulatory decision pursuant to specific rules.

The identification of certain rules as “no discretion” or “limited discretion” contributes to regulatory certainty for service providers and stakeholders and consistency of decision making, whilst not detracting from the usual obligations imposed upon service providers to ensure that proposals adhere to the relevant provisions of the NGL and the NGR. Equally, by identifying (by implication) the majority of rules within the NGR as being “*full discretion*” rules, the NGR generally recognises that the regulator is to be afforded flexibility in exercising its functions, within the bounds otherwise identified by the NGR and NGL.

Rule 89, which provides for the design of the “Depreciation criteria” is a good example of the role played by, and purpose of, the “limited discretion” criterion. If regulated businesses are to be afforded an opportunity to attract sufficient finance and investment (in line with the Revenue and Pricing Principles and to achieve the NGO) they require a degree of certainty that costs will be recognised and approved by the regulator provided that the service provider observes a clear process that meets the stated criteria prescribed by the NGR.

Depreciation represents the “building block” by which investors receive their return *of* capital within some reasonable timeframe. But in the usual way, a regulated entity ought to be afforded an opportunity to adjust the depreciation to recover capital at a different rates in to respond to demand an other market dynamics. The service provider is typically best placed to make the assessment of the market place in which it operates, and should do so in consultation with is stakeholders. The designation of this rule as a “limited discretion” rule recognises this fact – the service provider must put forward a depreciation schedule which complies with the NGL and NGR but, provided that it does so, the regulator may not withhold approval**.**

By contrast there are other rules which by their nature are less capable of clear definition or are less obviously within the service provider's control, knowledge or judgement. Other rules may import criteria which change over time in accordance with external factors and may necessitate greater flexibility. Such rules may be better assigned as "full discretion".

For these reasons, the gradation of discretionary criteria, as rule 40 NGR does, is both useful and appropriate it also reflects the inherent incentives with for gas businesses to decrease costs within the business.

5. FUTURE PROOFING THE FRAMEWORK

Decarbonisation

Australia is committed to a low-carbon future. The COP21 Paris agreement targets a 26-to-28% reduction in emissions by 2030 whilst separately, other jurisdictions have targeted net zero emissions by 2050[5]. Natural gas has played an important part in reducing Australia's emissions to date, providing 44% of household energy requirements with only one-quarter to one-sixth the greenhouse emissions of grid electricity[6], but more will need to be done to meet these future commitments.

To this extent, the decarbonisation of gas networks is critical in terms of meeting Australia's commitment to reduce emissions, whilst also balancing the other two elements of the energy trilemma; affordability of energy and security of energy supply:

- *Reliability* – gas networks are largely underground and as such are very reliable. On average customers experience only one hour off supply every forty years.[7]
- *Affordability* – the continued use of gas assets that customers have already invested in (thereby avoiding costly investments in electricity networks, which are typically constructed to transport around half of household and business energy requirements, excluding the transport sector).

Other key benefits of decarbonising our gas networks include:

- *Health* – replacing traditional transport fuels with hydrogen distributed through networks can improve air quality by removing particulates and other pollutants such as nitrogen dioxide.
- *Economic* – through the establishment of new industry and support of a future domestic and export hydrogen market.

Industry is working towards evolving the networks to meet these emission reduction targets. This includes through release of 'Gas Vision 2050' which outlines the transformational technologies (namely hydrogen, biogas and carbon capture and storage) that can facilitate decarbonisation of our networks and through implementation of Gas Vision 2050, through the development of low-carbon gas pilot projects.

Although we are at an early stage in terms of implementing Gas Vision 2050, we have identified that the definition of *natural gas* under the NGL may need to change to include gas that does not consist primarily of hydrocarbons.

The current definition of natural gas is as follows (emphasis added):
natural gas means a substance that—
(a) is in a gaseous state at standard temperature and pressure; and
(b) consists of <u>naturally occurring hydrocarbons</u>, or a naturally occurring mixture of hydrocarbons and non-hydrocarbons, the principal constituent of which is methane; and
(c) is suitable for consumption;

[5] https://www.climatechange.vic.gov.au/__data/assets/pdf_file/0019/74107/Climate-Leadership-Declaration-2017.pdf
[6] *Energy Networks Australia, Australia's Bright Gas Future – Competitive, Clean and Reliable, 2015.*
[7] *AGN, Victoria and Albury Final Plan, December 2016.*

We encourage the Commission to amend the definition of natural gas to the following:

natural gas means a substance that—
(a) is in a gaseous state at standard temperature and pressure; and
(b) has been approved by the relevant technical regulator in the relevant jurisdiction for supply to consumers.

We consider this to be an important matter as it underpins the application of the NGR, including parts 8-12 which are the subject of this review. We welcome the opportunity to work with the Commission to discuss possible alternative definitions as the review progresses.

Depreciation

There is a case for the Gas Rules to more clearly define the criteria on which the depreciation schedule should be designed. We consider NGR 89(1)(e) to be unclear. Our view is that this clause allows the depreciation schedule to be adjusted to ensure sufficient cash flows so that the credit rating of the benchmark service provider can be maintained that is assumed in setting the cost of debt (also referred to as financeability). We believe wording should be changed to make this clearer.

6. RESPONSE TIMEFRAMES

The NGR allows the regulator to require the service provider's amended access arrangement proposal, responding to a draft decision, to be re-submitted in a 15 business day period. While the regulator has the discretion to allow a longer response period, adopting the minimum been applied in the past.

These can be major decisions; individual access arrangement review processes can, in many cases, set over $1bn in revenue for a five-year regulatory period. The time allowed, to provide amended proposals to the regulator, prohibits the service provider from engaging with stakeholders in a meaningful way when considering the required amendments.

We therefore think it is appropriate for the minimum period of 30 business days to allow more time for the service provider to respond to the regulator's draft decision and that doing so would be in the in the long-term interests of consumers.

7. RESPONSE TO QUESTIONS RAISED BY THE AEMC

This section of the submission briefly responds to the specific questions raised by the AEMC in its Issues Paper.

Box 1: Question 1: Purpose of Regulatory Framework

(A) What do you think are the objectives of the current regulatory framework? Are the objectives of the framework clear? Has the framework achieved them?
(B) Are the objectives of the current regulatory framework still relevant, or should they focus on different issues such as monopoly pricing?
(C) Has the current incentive-based framework appropriately incentivised the efficient operation, use and investment in pipelines? Should a different approach to incentives be considered?
(D) Are there other third party access regimes (for example, for rail, ports or telecommunications) that would better achieve the purpose of the gas regulatory framework?

The overarching objective of the NGL and NGR is to promote efficient investment in, and efficient operation and use of, natural gas services for the long-term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas, as reflected in the NGO, which is key. The NGO is clear and appropriately focused on the long-term interests of consumers and remains relevant. Where are not of the view it needs amendment.

The NGR, while not explicitly stated within the framework, is at its core an incentives based regime. The regulator approves a level of expenditure for the forward period, the service provider is appropriately incentivised to outperform the set parameters which allows it to earn more than set for a benchmark service provider. In turn, prices are reduced at the next regulatory period based on the innovations and savings found by the service provider. Without this driving incentive, the service provider would become ambivalent to the costs it has under its control, which would not be in the long-term interests of consumers.

We are of the view that the objective and incentive based regime continues to be appropriate and works towards delivering outcomes that are in the long-term interest of consumers of natural gas. We do however, acknowledge the significant costs involved in full regulation. Undertaking an access arrangement review takes significant time and cost and involves a number of stakeholders. It is important to continue to be cognisant of those costs and only require full regulation where the societal benefits out-weigh the costs.

Box 2: Question 2: Efficiency of full regulation

(A) Do you consider that the benefits delivered by the access arrangement review process for a full regulation pipeline outweigh the costs?
(B) Is there a regulatory framework that may better achieve the desired objectives compared to the current negotiate-arbitrate framework supported by access arrangements developed under incentive-based economic regulation?
(C) Do you think that the access arrangement process should be amended to be similar to the revenue determination process for electricity service providers? Should there be greater recognition of consumer consultation, particularly for distribution pipelines?
(D) Have the NGR been effective and adaptable to the evolution of the gas industry?

The access arrangement review process has become extremely complex, time consuming and expensive. There will continue to be issues where the controversy and differences of opinion mean that a lot of detailed work and supporting expert reports will continue to be required. We therefore consider that the regulatory framework should continue to recognise that full regulation is only appropriate where the benefits to consumers outweigh the cost and burden of full regulation.

We believe that the focus of regulatory framework should be the customer and that the best way to achieve this is through fit-for-purpose stakeholder engagement, supported by appropriate incentive arrangements.

By way of example, during our recent Victorian and Albury Gas Access Arrangement (AA) (Final Plan) review process our overarching objective was to submit a plan that delivered for our customers, was underpinned by effective stakeholder engagement and was capable of being accepted by the AER. In order to achieve this, we implemented a robust and fit-for-purpose engagement program and clearly set out in our plans how we had considered this feedback.

Our Final Plan also included a proposal to introduce additional incentive arrangements, namely a Capital Expenditure Sharing Scheme (CESS) and a Network Innovation Scheme (NIS). Consistent with our view that effective, outcome-based incentive arrangements promote the long-term interest of our customers.

Our approach to developing our plans was well received by the AER, and reflected in its Draft Decision which was to largely accept our Final Plan, including strengthening the incentive mechanisms through the introduction of a CESS. This is evidenced by the following quote:

"*Let me return to the AGN exemplar of collaborative stakeholder engagement ... AGN fulfilled its objective of submitting a proposal that delivered for the consumer, was underpinned by effective engagement and on the whole has been accepted by the AER*" Paula Conboy, 2017 ENA Regulation Seminar.

In response, in August 2017, we accepted the AER's Draft Decision and turned our focus to implementing these plans. We believe that this more streamlined and collaborative approach has benefited customers through effective engagement, lower costs and a plan focused on delivered for our customers.

As illustrated by our Victorian and Albury AA process, the current regulatory framework provides sufficient opportunity for businesses to consult with stakeholders and for this consultation to be recognised by the Regulator. Indeed, listening to and focussing on the customer is something that businesses should be doing as business-as-usual activity, not because it is required under the rules. It also illustrates that the Regulator has discretion to strengthen incentive arrangements.

Consistent with this, we do not believe that any change to the current framework is required in relation to customer consultation and we support incentive-based regulation, noting that the current framework allows for strengthening of these incentives as appropriate.

Further, we are of the view that the AEMC should actively consider the provision of a fast-tracked decision making approach to reduce the time and resources directed to access arrangement reviews where deemed appropriate.

Box 3: Question 3: Efficiency of light regulation

(A) Do the form of regulation factors consider relevant structure, conduct and performance issues to enable the NCC to make an informed decision on the application of full or light regulation? (B) Do you consider that the light regulation regime has been fully utilised and appropriately enforced to produce benefits to pipeline users and achieve its objectives? If not, why not? (C) Are there other regulatory requirements that should be applied to light regulation pipelines? Are there current requirements that should not be applied? (D) Having regard to the new proposed non-scheme pipeline regulatory arrangements on information disclosure and arbitration, is the light regulation regime still relevant? Should it be retained, removed or amended?

We support the continuation for the light regulation regime. We refer to the Section 3 above.

Box 4: Question 4: Efficiency of regulatory discretion

Do you consider that the three levels of regulatory discretion in approving the elements within an access arrangement are useful and assigned appropriately?

Refer to response in Section 4.

Box 5: Question 5: Conforming capital expenditure

(A) Do you consider it beneficial that both forecast and actual capital expenditure are assessed by the regulator? (B) Does an appropriate level of regulatory scrutiny on investment occur if the regulator's discretion is limited? (C) Can the same capital expenditure criteria apply to both market carriage and contract carriage pipelines? And to both transmission and distribution pipelines?

We do not take issue with the current framework that requires the regulator to assess both forecast and actual capital expenditure.

We do however note that the assessment of capital expenditure against the assessment criteria are to be applied with limited discretion. This categorisation of discretion continues to be appropriate on the basis that is would not be appropriate to apply hindsight to the assessment and further, the incentives already built into the regulatory framework allows the regulator to have a reasonable level of comfort actual expenditure is efficiently incurred.

Box 6: Question 6: Extension and expansion requirements

(A) Should there be discretion regarding which extensions and expansions are to be included as part of a covered pipeline? On which basis do you consider that such discretion should be exercised? (B) If a pipeline is partially covered, does this impact on the application of the cost allocation and tariff setting rules? Does it impact on other aspects of an access arrangement? (C) Should the same extension and expansion requirements apply to both market carriage and contract carriage pipelines? And to both transmission and distribution pipelines?

Refer to response in Section 2.

Box 7: Question 7: Investment in excess capacity

(A) In your opinion, why has the speculative capital expenditure account rarely been used? (B) Should the regulatory framework support more or less investment of a speculative nature? If more, how could it do so most efficiently and effectively? With which party(s) should the risk of speculative investments reside? (C) If the regulatory framework permits speculative investment, should it also allow for the management of redundant assets?

The current regulatory framework discourages speculative investment simply because the rewards are not commensurate with the additional risk associated with speculation. Further, financing requirements drive owners to have new assets unpinned by contractual arrangements with foundation shippers.

NGR 84 is not well tested. It is unclear how regulators would approach the annual increase in the speculation account (which is fully within its discretion). The rules would need to allow for a commercial rate of return commensurate with market demand and regulatory risk associated with undertaking such ventures.

New non-scheme pipelines have been constructed that have the potential to capture future efficiencies through developing pipelines of a greater scale than required for the initial contracted tranche of demand. The Fortescue River Gas Pipeline (**FRGP**) is one such pipeline, which was built with future growth in mind and has available capacity beyond that currently used by the foundation shipper. While still fully underwritten by the foundation shipper, efficiencies have been achieved will be shared with the customer through the use of contractual mechanisms such as first rights to additional capacity, rebates and royalties.

Box 8: Question 8: Capacity available under an access arrangement

(A) Does the current regulatory framework offer appropriate incentives for a service provider to offer spare capacity of a covered pipeline where it is efficient to do so?
(B) Do you think that scheme pipeline service providers maintain useful spare capacity registers? Does this rule need to be amended in light of expected market reforms?
(C) Are the rules on defining a service provider interacting with ownership and operational structures in a way that impacts on disclosure of potentially available pipeline capacity?

In regards to incentives, where tariffs are set on a price cap basis which is the case of regulated gas pipelines in Australia, the service provider is highly incentivised to offer and enter into contracts for spare capacity. Where contracted capacity increases above that approved by the regulator for a regulatory period the service provider outperforms the approved total revenue, conversely, if demand reduces below that approved the service provider will not receive the total revenue approved by the regulator. In our view, this is a strong incentive for service providers to market spare capacity. A strong (short-term) incentive to market spare capacity will reduce tariffs to the benefit of consumers over time.

Regarding the obligation under NGR 111, requiring covered pipelines to maintain a spare capacity register (the spare capacity register for the DBNGP can be found here) we note that prospective shippers are currently able to use the AEMO's Gas Bulletin Boards to gain an understanding of demand and utilisation of each pipeline[8].

Further, the Access Arrangement Information document for each regulated pipeline is required to outline nameplate capacity, contracted capacity and forecast utilisation[9]. The spare capacity register obligation required under NGR 111 is likely to be superfluous to the current needs of shippers considering the availability of information via bulletin boards.

Box 9: Question 9: Extension to the pipeline

(A) Does the ability of service providers to exclude extensions from an access arrangement raise concerns for pipeline users?
(B) Would service providers and users benefit from the NGR including a negotiation framework for the connection of separately owned assets to covered pipelines?

Refer to response in Section 2.

8 *Noting that transparency will be further increased as the AEMC's fast-tracked rule change process for the improvement to natural gas bulletin board is implemented.*

9 *See Section 10 of the DBNGP AAI (https://www.erawa.com.au/cproot/14393/2/Access%20Arrangement%20Information.PDF)*

Box 10: Question 10: Performance Indicators

(A) Do the requirements to provide key performance indicators as part of an access arrangement result in useful information to users and prospective users of a pipeline? (B) Should the rules allow for the regulator to be more specific on which key performance indicators for distribution and transmission pipelines should be reported? Would this provide for better comparisons across pipelines and over time? If not, how could greater consistency be achieved?

The current access arrangement for the DBNGP includes a single key performance indicator (**KPI**) calculated by dividing operating expenditure for a regulatory year (excluding fuel gas, GEA/turbine overhauls and reactive maintenance categories) by the total energy delivered each regulatory year[10].

In our view, it provides limited value to a shipper or prospective shipper of the DBNGP and further if used, as a basis for comparison, is likely to be misleading. There may however be more scope for useful KPIs to be tracked for distribution assets, as these are less susceptible to comparison problems, due to their more homogeneous nature.

We notes that there is already a mechanism for KPIs to be captured and tracked via in Regulatory Information Notices.

Box 11: Question 11: Purpose and definition or reference service

(A) Is the purpose of a reference service as an aid to negotiation for pipeline services a relevant purpose for both transmission and distribution pipelines? Has this been a successful approach? Should access arrangements cover a broader range of services? (B) Should reference services continue to be defined in relation to market demand? Is there a more appropriate approach to defining reference services? (C) Does the access arrangement process limit the ability of the regulator and the service provider to make changes to the reference services for an access arrangement? If so, how could this be resolved? Is there merit in adopting the framework and approach process for access arrangements?

Refer to response in Section 2.

Box 12: Question 12: Light regulation and limited access arrangement

(A) Is the purpose of a reference service as an aid to negotiation for pipeline services a relevant purpose for both transmission and distribution pipelines? Has this been a successful approach? Should access arrangements cover a broader range of services? (B) Should reference services continue to be defined in relation to market demand? Is there a more appropriate approach to defining reference services? (C) Does the access arrangement process limit the ability of the regulator and the service provider to make changes to the reference services for an access arrangement? If so, how could this be resolved? Is there merit in adopting the framework and approach process for access arrangements?

Refer to response in Section 3.

[10] *See Section 12 of the DBNGP Access Arrangement - https://www.erawa.com.au/cproot/14393/2/Access%20Arrangement%20Information.PDF*

Box 13: Question 13: Providing Information

(A) Do access arrangements and access arrangement information documents contain relevant and accessible information for users and prospective users seeking access to a covered pipeline? Is consistency in the provision of information important to aid in its understanding? (B) Do the Part 11 information requirements result in the provision of information that is relevant to users and prospective users seeking access to a covered pipeline? Is there other relevant information that could be provided? How do these requirements compare to the reforms for non-scheme pipelines? (C) Could the Bulletin Board, or the scheme register, play a greater role in making available information regarding covered pipelines?

The National or WA Gas Bulletin Board (GBB) already play a significant role in providing information for covered pipelines. Where information is now provided for regulated pipelines on either GBB, the AEMC should have regard to whether it is appropriate to reduce overlap with Access Arrangement content requirements wherever possible. The most overlap is likely to exist for demand related information.

In our view, while it still maybe relevant to the regulator's determination, the information required to be included in an Access Arrangement Information under NGR 72(1)(iii)(A) & (B) is unlikely to be informative to existing or prospective shippers when considering the availability of information on the GBBs.

Box 14: Question 14: Arbitration

(A) If there is uncertainty about how the current arbitration framework operates, how could this be resolved? Should Chapter 6 of the NGL and/or Part 12 of the NGR be amended with regard to the information and/or the processes? (B) Are there aspects of the arbitration framework for non-scheme pipelines under development by GMRG that could also apply to scheme pipelines? (C) Which pipeline services should be subject to arbitration? Are there any pipeline services that should be excluded?

Refer to response in Section 2.

Box 15: Question 15: Tariffs

(A) Do you consider that the reference tariffs for transmission and/or distribution pipelines reflect the efficient costs of providing those reference services? If not, which provisions of the NGL or the NGR are contributing to that outcome? (B) Should the NGR recognise partially covered pipelines and provide specific guidance on cost allocation in this context? (C) Do the tariff setting requirements in the NGR provide the appropriate balance between discretion and guidance to achieve cost reflective tariffs? Should the discretion of the regulator be limited? (D) Why do you think that distribution pipeline service providers tend to charge the reference tariffs as the prices for the services that they provide? (E) Is the balance between prescription and discretion for the reference tariff variation mechanism appropriate? Would more guidance in the NGR or from the regulator better support the development of these mechanisms?

In regards to the discretion framework, we refer to Section 4 of this submission.

Box 16: Question 16: Non-tariff conditions

(A) Do the non-tariff requirements for access arrangements result in relevant information being provided to users and prospective users of covered pipelines? Are there other non-tariff requirements that would be relevant? (B) Should the NGR or the regulator provide more guidance on which non-tariff requirements should be included in an access arrangement? Is there a need to provide greater guidance regarding the regulator's assessment of non-tariff requirements?

Customers, rather than service providers are in a better position to answer the questions posed above.