02 December 2021

Submission: Review into extending the regulatory frameworks to hydrogen and renewable gases Consultation paper

The Australian Pipelines and Gas Association (APGA) represents the owners, operators, designers, constructors and service providers of Australia's pipeline infrastructure, with a focus on high-pressure gas transmission. APGA's members build, own and operate the gas transmission infrastructure connecting the disparate gas supply basins and demand centres of Australia, offering a wide range of services to gas producers, retailers and users.

APGA welcomes the opportunity to contribute to the Review into extending the regulatory frameworks to hydrogen and renewable gases consultation (the **Consultation**) and supports the overall objective of the combined consultations to extend the National Gas Regulatory Framework (NGRF) to cover hydrogen and other renewable gases. APGA notes that the Consultation is occurring simultaneously with consultation on the Extending the national gas regulatory framework to hydrogen blends & renewable gases: Changes to the NGL, NERL and Regulations Consultation Paper (the **Officials Paper**)

APGA supports a net zero emission future for Australia by 2050[1]. Renewable gases represent a real, technically viable approach to lowest-cost energy decarbonisation in Australia. As set out in Gas Vision 2050[2], APGA sees renewable gases such as hydrogen and biomethane playing a critical role in decarbonising gas use for both wholesale and retail customers. APGA is the largest industry contributor to the Future Fuels CRC[3], which has over 80 research projects dedicated to leveraging the value of Australia's gas infrastructure to deliver decarbonised energy.

The proposed extension of the National Gas Law (NGL) and broader NGRF to Natural Gas Equivalents (NGEs) is a critical step to enabling a future renewable gas industry and has APGA's full support. The approach proposed in the combined consultation papers is a well-considered method for removing any regulatory barriers impeding blending of renewable gases into the domestic gas market. The definitions of NGE, Other Gas Product (OGP) and

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[1] APGA Climate Statement
https://www.apga.org.au/apga-climate-statement
[2] Gas Vision 2050, APGA
https://www.apga.org.au/sites/default/files/uploaded-content/website-content/gasinnovation_04.pdf
[3] Future Fuels CRC Website
https://www.futurefuelscrc.com/

Constituent Gas (CG) effectively address the need for more versatile definitions without tying definitions to specific types of gas.

APGA is concerned however with the way in which the NGL and broader NGRF is proposed to apply to CG and OGP infrastructure.

Renewable gas markets of the future will be very different to existing gas markets. Renewable gas is a manufactured product and the location of production facilities and transmission infrastructure to transport them to market is highly flexible. This contrasts with the limited flexibility of natural gas markets, given natural gas is a resource that is extracted from specific locations. This key difference will manifest in markets in many ways. From a gas transmission infrastructure perspective, it means gas transmission infrastructure services offerings must be highly competitive or renewable gas producers will locate facilities closer to markets to avoid transmission costs.

If there is a circumstance where a renewable gas producer must be placed distant to a market and will require access to existing transmission infrastructure, the renewable gas producer will be competing with renewable gas producers closer to market, limiting any market power a transmission infrastructure service provider could hold.

As the competitive hydrogen and renewable gas markets grow, it is apparent to APGA that the forms of regulation for Scheme and Non-Scheme pipelines may not necessarily be appropriate in the context of the level of competition that will exist in these new markets. Where the NGRF extension consultations propose immediate application of economic regulation, other international jurisdictions are taking more of a wait and see approach[4]. It is appropriate that flexibility built into the framework of the NGL and NGR to ensure suitable treatment of renewable gases, renewable gas infrastructure and services in the presence of effective competition.

In the short-term, the renewable gas industry needs significant investment and development. Service providers are developing the first CG and OGP infrastructure assets as fundamental parts of existing gas distribution networks subject to the economic regulatory framework in the NGL. The hydrogen and other renewable gases industries are in their infancy and the development of these industries is considered by many to be directly relevant to the longevity of today's gas distribution networks. The development of these first assets, essential to demonstrate the viability of the future renewable gas industry, should be able to be considered as part of the regulated gas networks they supply rather than individual pipeline assets.

Regarding OGPs specifically, APGA considers it important that an OGP inclusive NGL be clear about the boundaries within which a jurisdiction can define an OGP. This will be critical for investor certainty in what is or is not open to being brought into regulation as an OGP asset. The Officials Paper hints towards this, noting that an OGP *may in future be supplied to consumers for use in appropriate appliances*. Ensuring that only the compositional aspects of

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[4] When and How to Regulate Hydrogen Networks?, EU ACER 2021
https://documents.acer.europa.eu/Official_documents/Position_Papers/Position%20papers/ACER_CEER_WhitePaper_on_the_regulation_of_hydrogen_networks_2020-02-09_FINAL.pdf

the NGL definition of natural gas are differed from when creating the new NGL OGP definition will be key reflecting the policy intent set out in the Energy Ministers Objectives.

There are clearly significant matters and complex issues to consider in expanding economic regulatory frameworks found in the NGL to CG and OGP infrastructure, especially in seeking to achieve the Energy Minister objectives. In lieu of either industry or governments knowing what the future will hold, the most no-regrets option becomes optionality itself. There are reasonable grounds to consider implementing a level of flexibility in the NGL and broader NGRF to ensure that economic regulation is appropriately adaptable to a range of possible futures.

APGA can envisage a range of simultaneous market conditions arising across the coming decades. From the current natural gas market to highly diverse hydrogen markets with absolute competition, moderately diverse biogas markets reflecting waste management markets as much as energy markets, and the unknown unknowns which we cannot account for right now. The only certainty amongst all this change is that a one size fits all economic regulatory regime is unlikely to result in the most efficient outcomes for consumers in all circumstances over the long-term.

There are a range of options available to policy makers to work flexibility into the existing NGL and broader NGRF to ensure that economic regulation is not applied in the presence of effective competition, and to ensure that where it makes sense, CG and OGP infrastructure can be considered part of otherwise regulated assets. APGA comments on a few possible flexibility options in Section 3 below, and commits to continuing to engage with DISER, the AEMC, AEMO and Energy Ministers to work constructively towards achieving these appropriately flexible ends.

APGA's feedback on other aspects of the combined NGRF extension consultations includes:

- APGA supports the introduction of the new definitions NGE, CG and OGP alongside the definition of Natural Gas (NG) and consider these to represent an effective approach to achieving the goals of the combined NGRF extension consultations.
- Expanding all aspects applied to NG within the NGRF to NGEs represents a reasonable expansion of regulatory scope as there is a direct parallel between NGE and NG for all intents and purposes under the NGRF.
- Market designs which enable the trade of all gases on a per gigajoule basis within a single market best achieve the Energy Ministers objectives. For example, trading gigajoules of NGE in the DWGM would be preferable over trading gigajoules of natural gas and CG separately alongside NGE in the DWGM or STTM; and
- Where the combined consultations pose questions of asset operational assurance (including composition assurance), the operator of an asset is in the best possible position to efficiently provide such operational assurance, as occurs now.

Further detail on this and all above feedback can be found in the Detailed Feedback section below.

To discuss any of the above feedback further, please contact APGA National Policy Manager Jordan McCollum on +61 422 057 856 or jmccollum@apga.org.au.

Yours Sincerely,

STEVE DAVIES
Chief Executive Officer
Australian Pipelines and Gas Association

Detailed Feedback

1. Constituent Gas Transmission Infrastructure services will be highly competitive

CG transmission infrastructure service markets, including blending facilities and CG transmission pipelines, will be highly competitive. Unlike locationally constrained natural gas production, hydrogen (and other renewable gas) production is a manufactured product that can be located almost anywhere, including bypassing existing infrastructure altogether by being located directly at its demand market. Blending facilities are not constrained to a particular location either and are relatively low-cost. As such, any existing CG transmission infrastructure will be in constant competition with new CG infrastructure pathways, as well as non-infrastructure pathways to market (ie tube trailer) and vehicle refuelling.

The difference between natural gas infrastructure and CG infrastructure is described in Figure 1 below which considers new natural gas production and new CG production connecting to an existing NGE transmission pipeline. The existing NGE transmission pipeline (solid purple line) connects an existing natural gas supply (left most purple dot) to an existing customer (yellow dot). The new natural gas production location is constrained to within the purple hashed box, with some room to move but ultimately constrained to a specific area. The new CG production location can exist anywhere, being able to move both up and down the existing transmission pipeline, as well as closer to or further from the existing pipeline as it sees fit.

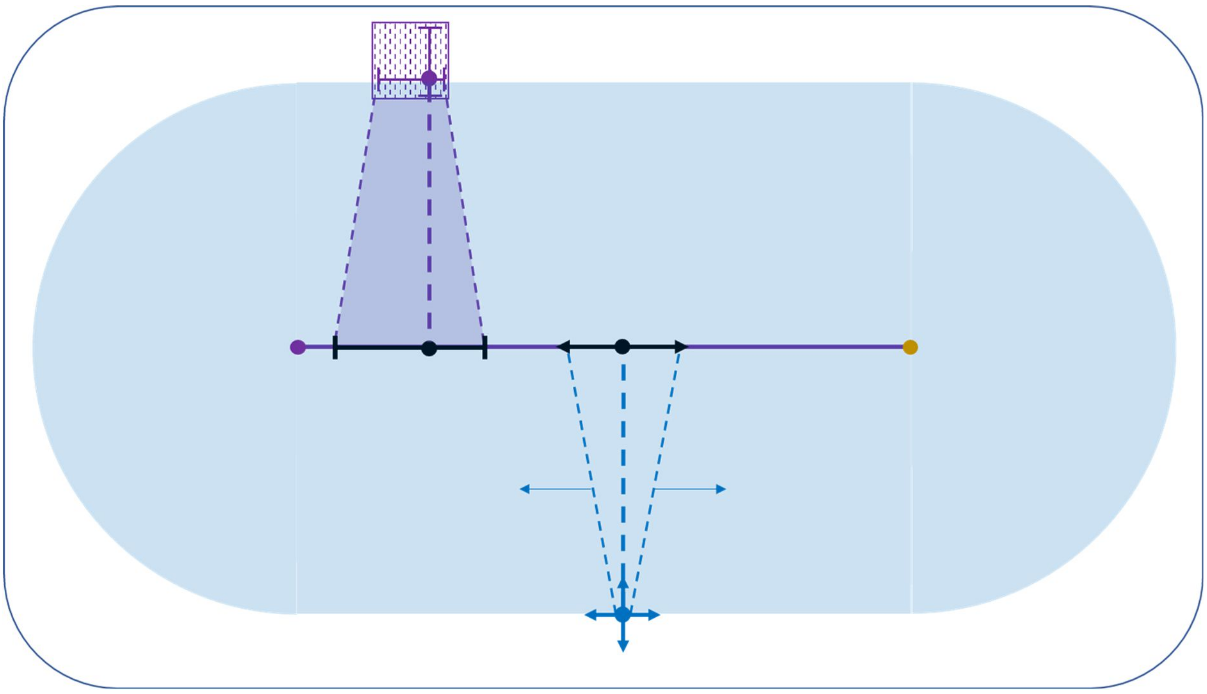

Figure 1: Range of potential competitive pathways for natural gas and CG pipelines

The dashed purple and blue lines represent the possible range of cost-effective lateral pipeline pathways from the proposed production locations; however, the solid purple and blue areas represent the full range of potential lateral pipeline pathways available to each production option. The range available to the CG lateral pipeline is immensely larger than the range available to the natural gas lateral pipeline and could even be considered infinite. Not only do the initial options available to each lateral differ significantly, but the circumstances which follow their development also differ significantly.

New CG production can be located anywhere and is not necessarily incentivised or required to collocate with existing production. There are many CG production location and resultant infrastructure options, all of which compete with the existing CG infrastructure. Some options will bypass wholesalers and infrastructure services altogether. By way of example, there are already containerised electrolysers available to the market producing 15 to 150kg of hydrogen per day, allowing small users to bypass wholesalers and infrastructure altogether if they choose.

This broader threat of competition will limit any market power possessed by an existing CG transmission infrastructure service provider. If it fails to deliver a competitive offer, the CG producer can simply shift the location of its project.

This contrasts with natural gas production, which must be located where the resource is and where there are likely to be a more limited number of paths to market available.

These issues are explored in more detail at Appendix 1.

If market power of CG transmission infrastructure is effectively constrained by competition, there is limited basis to apply economic regulation. The possibility of effective competition suppressing market power is contemplated in a recent Australian Energy Regulator (AER) information paper which notes that *the basis for economic regulation of infrastructure is when there are conditions in the market which severely limit effective competition*[5]. The AER goes on to identify that *effective competition in a market exists when there is an opportunity for sufficient influences to constrain the market power of suppliers (eg. rivalry amongst existing suppliers, the threat of substitute goods and services, the threat of new entrants, or the buying power of consumers)*.

Innovative asset developers investing in CG and OGP transmission infrastructure should be able to operate in commercial, competitive markets without regulatory intervention where effective competition exists. Maximising innovation and risk taking within developing markets will be key to the future growth of the Australia hydrogen and renewable gases industries. Issues of effective competition have also been considered in the preceding Pipeline Regulation Decision RIS process. Competitive processes and the ability of infrastructure service providers to deliver outcomes consistent with those expected in a workably competitive market are being considered as a basis to regulatory exemptions for greenfield infrastructure.

APGA notes that the above principles also apply to OGPs and OGP infrastructure. The current round of NGRF extension consultation papers does not contemplate the *immediate*

[5] Regulating gas pipelines under uncertainty – Information paper, AER 2021 https://www.aer.gov.au/networks-pipelines/performance-reporting/regulating-gas-pipelines-under-uncertainty-information-paper

application of the economic regulatory frameworks found within the NGL to OGP pipelines, proposing to require jurisdictions to opt-in to defining an OGP. In defining an OGP, Jurisdictions will need to consider the possibility that doing so risks the application of economic regulation in the presence of effective competition, which in turn increases regulatory based revenue uncertainty and reduces commercial flexibility for investments in OGP infrastructure.

APGA accepts that it is possible to envisage a specific scenario where market power does exist for a CG or OGP transmission infrastructure asset. However, APGA considers that there are many more scenarios where effective competition will exist. As such, the regulatory framework should be developed in a manner that does not apply economic regulation in all circumstances to this new infrastructure.

2. Supporting development of the renewable gas industry through the regulatory framework.

There is a need in the immediate term to support service providers to develop early CG and OGP infrastructure as part of assets subject to economic regulatory frameworks found within the NGL. The hydrogen and other renewable gases industries are in their infancy with no existing basis for investment revenue security. These first early foundations of a future renewable gas industry need to be able to access the revenue certainty of regulated incomes as part of a broader, already regulated asset base.

CG supply chains will generally include three components – CG production, CG transmission infrastructure downstream of CG production, and NGE infrastructure downstream of CG transmission infrastructure. This section to this point considers the full spectrum of potential CG infrastructure service provider configurations, including CG infrastructure service providers which are:

- Extensions of CG producers;
- Entirely separate from the service providers for the downstream NGE infrastructure; and
- Service providers which are also the service providers for the downstream NGE infrastructure.

There are major differences between these types of service providers and at different stages of the development of the renewable gas industry it is apparent they should be treated differently. As highlighted in Section 1, CG transmission infrastructure service providers will be operating in a highly competitive renewable gas market once it is established.

In cases where early CG infrastructure service providers are also the service providers for the downstream NGE infrastructure, it would be a major boost to the development of the renewable gas industry if they were provided the ability to obtain an exemption to the ringfencing provisions in the NGL. With such an exemption, the investments necessary to develop the industry and decarbonise gas networks could be included as a part of existing natural gas networks. Under these circumstances, Service providers should effectively be able to choose between ringfencing the CG infrastructure business separately from NGE infrastructure or considering CG Infrastructure as an extension of NGE infrastructure (hence extending economic regulation to the CG Infrastructure).

There is precedent for facilities which would otherwise not be subject to the economic regulatory frameworks found within the NGL being considered part of an asset base which is covered by these economic regulatory frameworks[6]. This is achieved without the economic regulatory frameworks found within the NGL being extended to all assets of the same type. This correlates with the purpose of economic regulation where a) a broader asset base combining many components may experience market conditions which severely limit effective competition; but while b) acknowledging that each component type may not

[6] An example of this precedent is the circumstance of measurement facilities, which may or may not be subject to economic regulation dependant on whether they are considered part of a pipeline or part of a supply or demand facility.

experience market conditions which severely limit effective competition when they are not part of a broader asset base.

3. The need for flexibility in the framework

There are clearly significant matters and complex issues to consider in expanding economic regulatory frameworks found in the NGL to CG and OGP infrastructure, especially in seeking to achieve the Energy Minister objectives. Foundation asset development needs to be supported by the ability to include adjoining CG and OGP infrastructure within an existing regulated asset, while the innovative investors that follow are more likely to be impeded by economic regulation in a highly competitive market.

The gas market of tomorrow will not uniformly reflect the gas market of today. Coming decades will see broad reaching competition growing across a number of unique gas markets alongside continuation of the gas market of today. While a one size fits all regulatory regime has been determined as necessary for the gas market of today, it cannot be seen as a reasonable fit to the diverse gas market of tomorrow.

At this early stage, it is not possible to know what the best regulatory options are for the future market. The most we can hope to achieve at this stage is to deliver no-regrets outcomes which do not impede the development of hydrogen or other renewable gas markets in the process. Locking in a set of economic regulations designed for existing natural gas markets early on in industry development risks suppression of early industry growth. APGA is concerned that simply expanding like for like economic regulation to CG and OGP infrastructure at this stage poses exactly this risk, especially where it is already apparent that these industries will experience different competitive dynamics.

In not knowing what the best regulatory option is for each and every circumstance, APGA proposes that a level of flexibility be considered when developing economic regulation for CG and OGP infrastructure. In order to deliver on the Energy Ministers Objectives, regulation must be fit for purpose, hence the ability to determine which purpose to target with which regulatory approach should be built into the regulatory framework. Creating flexibility in regulation would need to be done with care as to avoid uncertainty, however this can be achieved through the implementation of well-defined rules to determine the outcomes of flexible regulatory aspects.

While APGA is comfortable in stating that it does not have all of the answers yet, in contemplating possible flexibility options, two areas have arisen as possible areas for flexibility:

- <u>Criteria to determine application of economic regulation in the presence of effective competition</u>
  Development of criteria for CG and OGP infrastructure such that economic regulation only applies in the absence of effective competition.; and
- <u>Exemption from ring fencing provisions to allow service providers to include CG and OGP infrastructure as part of an existing regulated asset</u>
  Service Providers of an existing gas asset which is subject to the economic regulatory frameworks found within the NGL should be able to choose to incorporate directly connected CG and OGP infrastructure as part of the asset.

APGA is still developing its views on how to structure the above exemptions to best achieve the Energy Ministers objectives. Some of the options which APGA note may be reasonable around the above core exemptions include:

- <u>Differences in exemption application to distribution pipelines and transmission pipelines</u>
  It is possible for there to be differences in the way which effective competitive interacts within distribution pipeline and transmission pipeline contexts. If effective competition arises in future CG and OGP transmission infrastructure but not in future CG and OGP distribution infrastructure, it may be reasonable to provide different exemption frameworks for transmission pipeline markets relative to distribution pipeline markets.
- <u>Automatic Exemptions</u>
  Where the basis for an exemption becomes prevalent, it may be reasonable to apply exemptions on an automatic basis. This would require the Relevant Regulator to identify that the basis for exemption does not exist in order to terminate the exemption. This would be preferable in the presence of prevalent effective competition in the future CG and OGP infrastructure industries in order to avoid the application of economic regulation where effective competition is prevalent.
- <u>Opt-In Exemptions</u>
  Where the basis for an exemption is uncommon, it may be reasonable to apply exemptions on an opt-in basis. This would require the Relevant Regulator to identify that the basis for exemption does exist in order to grant the exemption. This would be preferable where a service provider wishes to extend their primary asset to include CG or OGP infrastructure for the purposes of demonstrating the future viability of the primary asset.

APGA welcomes further discussion on possible options for create flexibility within the NGL and broader NGRF.

Appendix 1: Fundamental Concepts

Differences in the market dynamics and therefore in the likelihood that market power might be held by hydrogen and other renewable gas infrastructure are founded upon four concepts:

- The locationally constrained nature of natural gas production;
- Distributed nature of hydrogen and other renewable gas production;
- Minimum barrier to entry for new hydrogen and other renewable gas production; and
- Minimum barrier to entry for new blending facilities.

These points are combined to form a basis for the influence of distributed CG production on transmission infrastructure market power

Locationally Constrained Nature of Natural Gas Production

Natural gas cannot be produced just anywhere in Australia. Even following the identification of large conventional and unconventional natural gas reservoirs beneath significant expanses of Australian territory, natural gas is only able to be produced from wells in extremely precise locations. Identifying the specific location of viable natural gas production is feat of science and engineering, with natural gas exploration combining the technical capabilities of exploration reservoir engineers with the scientific expertise of geoscientists from the likes of CSIRO's Exploration Geosciences & Reservoir Dynamics department[7].

The risks of getting the science wrong are high as demonstrate in the 2018 failure of ExxonMobil's $120M "Dory" exploration drilling program[8]. The failure of this program and programs like it demonstrates that natural gas isn't even guaranteed in regions containing extensively explored reservoirs.

Locational constraints are regularly seen in unconventional gas reservoirs as well. Both Coal Seam Gas (CSG) and Shale Gas reservoirs are highly susceptible to reservoir disruption by fissures, leading to the potential for well failing to produce only hundreds of meters from successfully producing wells. Not only this, but the propensity for CSG reservoirs to intersect with coal mining leases presents additional locational challenges.

Whether conventional or unconventional, natural gas production is locationally constrained for the most part to within units of kilometres. Once a viable production location has been identified, the expense of transporting raw gas relative to transporting consumption quality gas incentivises natural gas processing plants to be located within tens of kilometres of raw gas production. Preparing natural gas for transport, including compression and alteration of raw natural gas composition to comply with the requirements of consumer appliances is a reasonably costly task. Doing so however makes natural gas easier to transport and

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[7] CSIRO Exploration Geoscience & Reservoir Dynamics Webpage, CSIRO 2021 https://research.csiro.au/oilandgas/conventional-resources/exploration/

[8] Exxon's $120m Bass Strait bet fails to deliver gas, Chambers 2018 https://www.theaustralian.com.au/business/mining-energy/exxons-120m-bass-strait-bet-fails-to-deliver-gas/news-story/72d9abadea92b2c2f350b5e79a860f74

tradeable as an interchangeable natural gas commodity, further incentivising processing to occur early in the supply chain.

Distributed Nature of Hydrogen and Other Renewable Gas Production

The production of hydrogen and other renewable gases can occur anywhere in Australia. In particular, green hydrogen can be produced anywhere a source of renewable electricity can be accessed. The areas in which either solar PV or wind power generation is possible covers all Australian territory[9]. Areas of potential access to water also cover the entire country, making is a competitive factor defined by the price of access to water at any given location.

Another key category of renewable gas is renewable sources of methane. The best-known source of renewable methane is biogas, which is also able to be produced virtually anywhere in Australia. Only requiring a viable source of biomass, biogas is able to be produced either anywhere that agricultural activity is occurring, or anywhere where an energy crop can be produced. Renewable synthetic methane can also be produced via the methanation of green hydrogen and atmospherically sourced carbon dioxide. Green hydrogen and atmospheric carbon dioxide can both be sourced anywhere in Australia, providing a second distributed renewable methane production option if biological sources of methane are unavailable.

Whether renewable hydrogen or renewable methane, the distributed nature of the production of these gases means that competition between producers is not bounded to specific locations. This allows investors to optimise the choice of location for their investments alongside all other factors, reducing their susceptibility to the application of market power for infrastructure services based on locational constraint.

This ability to optimise choice of location effectively neutralises the market power of infrastructure service providers. Not only can an individual project locate itself to avoid accessing infrastructure, but the producers who are closest to market will be setting the most competitive prices for renewable gas products. Infrastructure service providers must offer highly competitive prices to any customers to ensure that customers can compete in renewable gas markets.

There are also forms of renewable and decarbonised hydrogen and methane production which are locationally constrained. One such example would be blue hydrogen produced from specific gas or coal resources. These will be similarly locationally constrained as natural gas production. However, due to some (or even a majority of) potential producers being distributed, the restrictions experienced between these specific renewable or decarbonised hydrogen or methane producers is simply part of the robust competition within a diverse market, rather than the experience of the entire market. The competitive pressures from those producers that are not constrained may limit the market power of infrastructure service providers.

[9] National Solar and Wind resource maps as available via databases accessible via National Map https://nationalmap.gov.au/

New Hydrogen and Other Renewable Gas Production do not need to collocate

The potential market power of infrastructure service providers is further limited as renewable gas production does not tend to derive efficiency from collocation with other production.

For hydrogen, the economic advantages of collocation are considered minimal. Considering hydrogen production from behind the meter solar PV, both solar PV and hydrogen electrolysers are modular at a scale many times smaller than the size of wholesale natural gas production, with electrolysers being the larger of the two. As such, each linear step up in electrolyser capacity required an equally linear increase in solar PV capacity, with the economies of scale of the rest of the facility being minimal.

Similarly, biogas experiences linear production uplift through the increase in anerobic digester capacity, with some economies of scale in processing to upgrade to biomethane. Renewable synthetic methane would similarly experience some economies of scale in increased methanation capacity, however the cost of methanation is predicted to be an order of magnitude lower than the cost of hydrogen production[10].

With these linear relationships for the key capital costs of hydrogen and renewable gas production, there is very little reason for the next production facility to be developed alongside an existing production facility. This allows investors in new hydrogen and renewable gas production to consider a wide range of factors other than collocation with existing production in determining the location of the next production facility, including the competitiveness of infrastructure options.

Minimum Barrier to Entry for New Blending Facilities

Blending of gases occurs at every supply and interconnection point on every pipeline today. When this occurs at a location where custody of gas is being transferred, both sides of the transfer monitor and operate their infrastructure to ensure the blending of gases does not result in an off-specification mixture, generally in line with contractual obligations which are guided by jurisdictional safety requirements. Currently, this mostly comprises composition monitoring and associated shutdown equipment, or a commitment to undertake such arrangements well upstream of a specific custody transfer point.

In today's market, new wholesale connections to natural gas infrastructure are not economically regulated. Relative to the infrastructure both upstream and downstream of a connection point, the cost of a connection point is economically trivial, often costing orders of magnitude less than associated infrastructure or the annual value of product passing through the point. Recently proposed changes to the economic regulatory frameworks found within the NGL have secured the right for any request to connect to a pipeline to be

[10] Renewable Methane Economics, Oakley Greenwood November 2021 http://oakleygreenwood.com.au/wp-content/uploads/2021/11/OGW-Renewable_Gas_Economics_23November2021.pdf

reasonably considered, ensuring there is no way for a natural gas pipeline service provider to apply market power to a potential connection.

Similar to existing pipeline connections, blending facility connections between CG pipelines and NGE pipelines are expected to be similarly economically trivial.

While more expensive than a typical connection, the cost of blending facilities is still expected to be orders of magnitude lower cost than associated infrastructure or the annual value of product passing through the point. Additionally, the distributed nature of CG production means that blending facilities will be linearly distributed. That is to say that, while they will need to be connected to existing NGE infrastructure, they will be able to be located anywhere across the entire length of NGE infrastructure, only to be constrained by their relative proximity to distributed CG production and the ability for the NGE pipeline to have additional CG blended into it – an aspect which will be regulated under proposed NGE infrastructure regulation.

Influence of distributed CG production on transmission infrastructure market power

The natural gas supply chains of today are fundamentally different to the CG (hydrogen or other renewable gas) supply chains of tomorrow. This is predominantly due to the distributed nature of CG production and the minimal advantages in collocating production. These factors lead to many possible CG production locations, which in turn lead to many possible pathways to market. Each of these potential CG supply chains compete with each other, as well as with existing CG supply chains.

In APGAs view, this competition between CG supply chains is sufficient to address the potential for application of market power by any particular CG infrastructure asset or service provider.

The impact of distributed CG production is in stark contrast to the impact of locationally fixed natural gas production and processing. In addition to very high up-front capital costs for producers, natural gas is characterised by minimal flexibility in the successful placement of gas wells and is incentivised to collocate processing with production. Natural gas producers cannot choose to simply set up shop elsewhere like CG producers, with an effective range of potential natural gas supply locations constrained to within tens of kilometres. With gas customers generally being locationally constrained as well, the range of potential least cost pathways to market for natural gas are constrained to a narrow corridor between supply and demand.

This constrained nature of economically viable natural gas transport corridors has the potential to lead to conditions in the natural gas pipeline market which limit effective competition from new natural gas pipeline alternatives. Distributed CG production does not experience these same infrastructure constraints as natural gas. Able to be located anywhere in Australia, each of the infinite potential production locations creates its own competitive CG infrastructure options between its location and potential markets. These directly compete with any existing CG infrastructure.

This difference in potential competitive pathways to market for natural gas and CGs increases further when considering greenfield lateral pipelines connections to existing pipelines. The connection point of a natural gas lateral pipeline is constrained by the location consistent with the least cost lateral pipeline from the constrained production location. Distributed CG production can connect to linearly distributed CG blending facilities through infinite possible lateral pipeline pathways, with both production and connection points being able to move to optimise for the least cost lateral pipeline pathway.

Based on the above, it is apparent that the market power of natural gas pipelines does not extend to CG Pipelines and their associated blending facility infrastructure. The distributed nature of hydrogen and other renewable gas production erodes the basis of the market power claim upon CG infrastructure. As such, automatic application of the economic regulatory frameworks found within the NGL to CG transmission infrastructure should be considered carefully.

Attachment 1: Consultation Feedback Form

Review into extending the regulatory fameworks to hydrogen and renewable gases

STAKEHOLDER FEEDBACK TEMPLATE

The template below has been developed to enable stakeholders to provide their feedback on the questions posed in the consultation paper and any other issues that they would like to provide feedback on. The AEMC encourages stakeholders to use this template to assist it to consider the views expressed by stakeholders on each issue. Stakeholders should not feel obliged to answer each question, but rather address those issues of particular interest or concern. Further context for the questions can be found in the consultation paper.

SUBMITTER DETAILS

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PROJECT DETAILS

NAME OF RULE CHANGE:	**Review into extending the regulatory frameworks to hydrogen and renewable gases**
PROJECT CODE:	EMO0042
PROPONENT:	Energy Ministers
SUBMISSION DUE DATE:	2 December 2021

QUESTION 1 – CHAPTER 1 – INTRODUCTION

1. Do you agree with the Commission's preliminary position on the scope of this review?	Yes
2. Are there additional areas in the NGR or NERR that should be excluded or included in the current review? If so, why?	The future injection of NGEs in transmission pipelines should be considered as part of the review to ensure any potential issues are identified.

QUESTION 2 – CHAPTER 2 – ASSESSMENT FRAMEWORK

3. Do you agree with the Commission's proposed assessment framework for this review?	Yes
4. Are there any criteria the Commission should or should not consider as a part of its assessment framework??	No

QUESTION 3 – CHAPTER 3 – SUPPLIER ACCESS TO PIPELINES

5. Do you think that any additional guidance is required in the NGR to deal with connections by suppliers of natural gas equivalents or constituent gases, or are the new draft interconnection rules sufficient? If you think additional guidance is required, please set out what guidance you think is required.	The new draft interconnection rules sufficient. APGA consider that the new draft interconnection rules are sufficient to ensure that sufficient information be made available to any new interconnecting supplier to enable it to assess the likely availability of capacity from the interconnection point. Part (b) of the proposed amendments under section 4.2 of the Improving gas pipeline regulation Proposed legal package to give effect to the Decision Regulation Impact Statement Consultation Paper states: *b) The service provider to make sufficient information available to the interconnecting party to enable it to assess the likely availability of capacity to or from the interconnection point.* As the AEMC notes, connections of this form are likely to be somewhat infrequent, and bilateral discussions have been effective in ensuring acceptable gas compositions be delivered to customers since the industry's foundation.
6. Do you think service providers should be required to publish information on where connections by suppliers of natural gas equivalents or constituent gases would be technically feasible, or should this just be left to negotiations?	This should be left to negotiations. Not only is this unnecessary as discussed in Question 5, but the publication of this data to any degree of accuracy is unworkable. An acceptable location for blending of gases is a multi-part equation, with each part containing a large and often changing set of variables. One key part to this equation is the composition of the new supply being considered. Without this information, any description of the technical feasibility of NGE or CG injection would not be accurate.

	There is no single, simple, yes or no answer to the question of whether a connection can occur at a particular location in either the NGE or CG context. The unworkability of publishing this data also means that the publication of this data has the potential to be misleading. Further, even if inaccurate information was required to be published, the same bilateral discussions that would occur without this information would still need to occur to determine the true technical feasibility of connection.
7. Do you think that any specific rules are required in the NGR to deal with the risk that service providers may favour their own natural gas equivalents or constituent gas facilities by curtailing other facilities ahead of their own, or do you think this should be dealt with through ring-fencing arrangements?	To date, order of curtailment has been managed effectively via commercial gas contracts. APGA have found no evidence of any concerns of existing curtailment arrangements despite the existence of the ACCC Gas Inquiry and broad scrutiny of the gas transport sector across the past decade. Order of curtailment is generally an aspect addressed within commercial gas contracts and as such is already subject to transparency requirements under the draft NGL, and the negotiation/dispute resolution frameworks for both scheme and non-scheme pipelines which are currently in the process of being overhauled/strengthened. Pipeline service providers are not generally able to breach contractual obligations to their own customers, however any instances of curtailment occurring outside of contracted provisions would be highly visible if they were to occur. This should give comfort both in both the past performance of service providers and the ability to identify improper behaviour into the future. It is also worth noting the complexity in developing a single approach to curtailment across all gas assets. Being a contractually assigned right, there will be as many curtailment methods as there are pipelines. Developing a single method which achieves the desired outcomes across the multitude of different contracting styles will not only undoubtedly change some rights hence leave some customers worse off, but also must be considered in line with the Energy Ministers Objective principle that *competition and market signals will generally lead to better outcomes than regulation*.

QUESTION 4 – CHAPTER 3 – RING-FENCING ARRANGEMENTS

8. Do you think the ring-fencing exemptions in the NGR should be amended to accommodate trials by service providers? Why?	Yes, the NGR should be amended to accommodate trials by service providers. To date, pipeline service providers have led the development of the renewable gas industries through development of trial facilities. As noted in the Cover Letter to this submission: In the short-term, the renewable gas industry needs significant investment and development. Service providers are developing the first CG and OGP infrastructure assets as fundamental parts of existing gas distribution networks subject to the economic regulatory framework in the NGL. The hydrogen and other renewable gases industries are in their infancy and the development of these industries is considered by many to be directly relevant to the longevity of today's gas distribution networks. The development of these first assets, essential to demonstrate the viability of the future renewable gas industry, should be able to be considered as part of the regulated gas networks they supply rather than individual pipeline assets.

9. If so, do you think there should be any limit on the volume service providers should be able to producer, purchase or sell (e.g. up to the unaccounted for gas level)?	No, APGA does not think there should be any limit on the volume service providers should be able to produce, purchase or sell, within the bounds of the safe operation of gas infrastructure and customer appliances as protected by jurisdictional safety regulation and pipeline connection agreement provisions. APGA cannot see how limits would be conducive to achieving Energy Minsters Objective of not posing barriers to investment, especially where it is not clear why a limit would need to be imposed.
10. Do you think any other changes need to be made to the ring-fencing provisions in the NGL or NGR to accommodate natural gas equivalents or constituent gases?	Ringfencing of CG and OGP infrastructure should not be limited to only trial facilities. In particular, the ability to consider a blending facility or CG pipeline as part of a larger economically regulated asset base is reasonably analogous to the ability to consider gate stations and high-pressure natural gas pipelines as part of existing economically regulated assets today. This does not mean that all blending facilities should be economically regulated, rather, that an asset which is otherwise not economically regulated asset may considered part of a larger asset which is economically regulated.

QUESTION 5 – CHAPTER 3 – RULES FOR SCHEME PIPELINES

11. Do you think Part 9 of the NGR should be amended to provide the regulator with additional guidance on how to assess service provider proposals to transition to natural gas equivalents in those cases where a jurisdiction does not mandate the transition? If so, please explain what changes you think need to be made and why.	Yes, the expenditure criteria need to be amended to consider the broader range of activities required to enable the transition from natural gas to natural gas equivalents. Where there is not a blending target in a state, activities to enable NGEs have the potential to be seen as unnecessarily costly. Consequently, these may be considered against prudential requirements for conforming expenditure criteria under the NGR. This could impede uptake of NGE in regions where NGEs are not jurisdictionally mandated. Allowing for demonstrated customer support for such activities as an optional basis for conforming CAPEX could address these circumstances. This approach has already demonstrated promising outcomes in the above circumstances, with an example of this approach seen in the AGIG South Australian Access Arrangement. The AER approved expenditure which allowed AGIG to offset 20% of their UAFG requirements with renewable gas. This renewable gas may be more expensive than natural gas, therefore might not have otherwise met prudency requirement. This was approved by the AER based on evidence of customer support for the more costly activity and have mentioned this in their recent paper on the future of gas[1]. The option to allow such activity on the basis of demonstrated customer support is currently at the AER's (or ERA's) absolute discretion. Having the customer support limb enshrined in Rules would help sure up investment in the transition to renewable gas uptake in the form of NGEs. It would be envisaged that such an allowance would be applied more broadly than only considering the offsetting of UAFG.

[1] Regulating gas pipelines under uncertainty – Information paper, AER 2021 https://www.aer.gov.au/networks-pipelines/performance-reporting/regulating-gas-pipelines-under-uncertainty-information-paper

12. Do you think Part 9 of the NGR should be amended to clarify how government grants or funding are to be treated for regulatory purposes?	Yes
13. Do you think any of the other rules that will apply to scheme pipelines under the new regulatory framework need to be amended to accommodate pipelines hauling natural gas equivalents or constituent gases?	Yes, rules applying to scheme pipelines under the new regulatory framework need to be amended to accommodate pipelines hauling NGEs. However, consistent with our response to the Energy Ministers' consultation paper, we do not consider that rules should necessarily apply to constituent gases without proper consideration of issues such as the presence or absence of effective competition. Please see the APGA cover letter to this consultation for more details on this concept.

QUESTION 6 – CHAPTER 3 – RULES FOR NON-SCHEME PIPELINES

14. Do you think the arbitration principles applying to non-scheme pipelines should be amended to: a) require the arbitrator to take into account any regulatory obligation that a pipeline may be subject to? b) provide the arbitrator with greater guidance on how to assess proposals by a service provider to transition to transporting a natural gas equivalent where the transition is not mandated? c) clarify how government grants are to be treated?	a) Yes b) Yes c) Yes
15. Do you think any of the other rules that will apply to non-scheme pipelines under the new regulatory framework need to be amended to accommodate pipelines hauling natural gas equivalents or constituent gases?	Yes, rules applying to non-scheme pipelines need to be amended to accommodate pipelines hauling NGEs. However, consistent with our response to the Energy Ministers' consultation paper, we do not consider that rules should necessarily apply to constituent gases without proper consideration of issues such as the presence or absence of effective competition. Please see the APGA cover letter to this consultation for more details on this concept.

QUESTION 7 – CHAPTER 3 – PIPELINE GAS INFORMATION

16. Do you think service providers should be required to publish information on: a) the type of gas they are licensed to transport in their user access guides and, in the case of scheme pipelines, the access arrangement and access arrangement information? Why? b) any firm plans to conduct either a trial or to transition the pipeline (or part of the pipeline) to a natural gas equivalent or other gas product? Why?	a) Yes b) Yes
17. Do you think this information should also be reported on the AEMC's Pipeline Register?	Yes

QUESTION 8 – CHAPTER 4 – EXTENSION OF THE TRANSPARENCY MECHANISMS TO NATURAL GAS EQUIVALENTS

18. Except for blending facilities are there any other facilities or activities involved in the supply or use of natural gas equivalents that are not already captured by: c) the BB facilities listed in rule 141 of Part 18 of the NGR? d) the DWGM registration categories in rule 135A of Part 15A of the NGR?	No
19. If the information to be reported by facilities involved in the production, transportation, storage, compression and or use of natural gas equivalents is to be based on the information reported by their natural gas counterparts, are any amendments required to reflect differences in the physical characteristics of these facilities compared to natural gas facilities for: a) the Bulletin Board reporting obligations in Part 18 of the NGR? b) the GSOO content in rule 135KB of Part 15D of the NGR? c) rules 323-324 in Part 19 of the NGR? d) the compression and storage reporting obligations in Part 18A of the NGR? e) the price information to be published by the AER in proposed rule 140B in Part 17 of the NGR?	No
20. Should blending facilities be treated as production facilities for the purposes of the Bulletin Board, GSOO and VGPR, or should specific reporting obligations be developed for these facilities? Why? If you think specific reporting obligations are required, what should these be?	This depends on the decisions made around what gases are being traded in markets. If it is gigajoules of the NGE that is added to the pipeline stream that is being traded, then yes; if it is gigajoules of the CG produced upstream of the CF pipeline that is being traded, then no. In each case, it is one location or the other that should be treated as the production facility, not both. Alongside this consideration, it will be important to maintain an appropriate threshold for these facilities to report daily BB data as to avoid unnecessary compliance burden upon very small facilities. This burden could be so great that it discourages investment in small CG or NGE producers.
21. Are there any other gaps in the NGR that have not been identified that would need to be addressed if the five transparency mechanisms were to be extended to natural gas equivalents? Why? If you think there are other issues, what are they and what amendments are needed?	

QUESTION 9 - CHAPTER 4 – EXTENSION OF THE TRANSPARENCY MECHANISMS TO CONSTITUENT GASES

22. Do you think the following transparency mechanisms should be extended to the facilities and activities involved in the supply of constituent gases as part of the initial rules package or should the application of one or more be deferred until a later process? Why? A) The Bulletin Board B) The GSOO C) The VGPR D) The compression and storage terms and prices E) The AER's gas reporting functions.	APGA notes that it is uncertain how the range of potential market options develop from here on in. In order to implement no-regrets rules and maintain maximum flexibility during early stages of market development, APGA proposes deferring all of these until a later process. This will allow the AEMC to wait and see how or what market(s) develop first before implementing these transparency mechanisms, with benefits to both AEMC and new market participant efficiency. Additionally, consistent with our response to the Energy Ministers' consultation paper, we do not consider that rules should necessarily apply to constituent gases without proper consideration of issues such as the presence or absence of effective competition. Please see the APGA cover letter to this consultation for more details on this concept.
23. If you think the transparency mechanisms should be extended as part of the initial rules package: a) What facilities do you think need to be captured? b) Do you think the facilities and activities involved in the supply of constituent gases should be subject to equivalent reporting obligations as their natural gas counterparts, or are some modifications required to reflect differences in the physical characteristics of these facilities?	
24. Are there any other gaps in the NGR that have not been identified that would need to be addressed if the transparency mechanisms were to be extended to constituent gases? Why? If you think there are other issues, what are they and what amendments are needed?	

QUESTION 10 - CHAPTER 5 – TRADING NATURAL GAS EQUIVALENTS IN THE FACILITATED GAS MARKETS

25. Do you think natural gas equivalents should be traded through the facilitated markets, or outside of the facilitated markets?	APGA considers that natural gas equivalents should be traded both through the facilitated markets and outside of the facilitated markets. That is to say that where a facilitated market exists, natural gas equivalents should be traded through the facilitated markets, while trading outside of facilitated markets should also be allowed to occur.
26. What do you consider are the implications of these two options, in terms of required regulatory changes, costs of implementation and potential market inefficiencies?	Ensuring that NGEs are able to be traded in exactly the same way as natural gas is today will be key to enabling renewable gas development and fits well within the intent of the Energy Ministers' Objectives.

QUESTION 11- CHAPTER 5 – FACILITATED MARKETS REGISTRATION CATEGORIES

27. If natural gas equivalents are to be integrated into the facilitated markets, are new registration categories required to accommodate facilities and participants involved in the creation of these products, including through the injection of blends into the distribution system?	Once a distribution system is considered to transport NGE instead of natural gas, the injection of a blend into a distribution system is the same as the injection of natural gas. As such, this does not appear immediately necessary to specifically identify between types of injection point.
28. If flows associated with distribution-connected blending facilities are not scheduled in facilitated markets, are new registration categories required for blending facilities and associated participants or can they be exempted from registration?	With the exception of small distribution-connected facilities, APGA consider the inclusion of all other distribution-connected blending facilities in scheduling processes for facilitated markets would be conducive to achieving Energy Minister Objectives. APGA would anticipate that a blending facility be scheduled on the basis of the NGE it withdraws and injects to facilitate CG blending. In the case of small distribution-connected facilities, it may be reasonable for small distribution-connected facilities to be exempt from scheduling (or trading) in facilitated markets based on some form of materiality test. This is reflected in the NEM with small generation facilities and facilities which are unable to be scheduled (ie Variable Renewable Generation).

QUESTION 12- CHAPTER 5 – UNACCOUNTED FOR GAS IN THE FACILITATED MAKRETS

29. Do you think initial trials involving the injection of natural gas equivalents into the distribution system should be accommodated by amending jurisdictional arrangements for UAFG?	In the event that a jurisdiction specifies obligations for renewable gas uptake, APGA support this approach.
30. If so, how will this impact the operation of the matched allocation mechanism (as used by the distributor in the Sydney STTM hub)?	
31. What changes would be required to UAFG arrangements in the DWGM?	

QUESTION 13 - CHAPTER 5 – SETTLEMENT ISSUES IN THE FACILITATED MARKETS

32. If distribution connected blending facilities are not integrated into the facilitated markets, what settlement issues may arise?	With the exception of small distribution-connected facilities, APGA consider the inclusion of all other distribution-connected blending facilities in scheduling processes for facilitated markets would be conducive to achieving Energy Minister Objectives. Facilitated markets must balance, hence must integrate all supply and demand locations, noting that integration of very small suppliers could be achieved relative to a materiality threshold.

33. If distribution injections and corresponding end use consumption need to be excluded from settlement, how should excluded consumption be treated? What factors might affect this?	Please refer to the answer for Question 32.
34. If distribution connected blending facilities are integrated into the facilitated markets, are settlement issues in the STTM likely to be relatively straightforward to resolve? Why?	Yes, settlement issues in the STTM which arise from distribution connected blending facilities being integrated into the facilitated markets are likely to be relatively straightforward to resolve. Issues are only likely to occur if blending facilities aren't treated like the combined demand + injection location that they are. The STTM does not have issues with existing demand locations or injection locations, hence issues will only arise if blending facilities are treated as somehow special, resulting in improper treatment.
35. How should facilities exempted from registration, or that fall below a materiality threshold, be treated under settlement arrangements in the facilitated markets?	Injection or demand facilities should not be exempt from market participation with the exception of small distribution-connected facilities. Small distribution-connected facilities which fall below a materiality threshold should be subject to some form of less frequent reporting which can be taken into account when balancing facilitated markets.

QUESTION 14 - CHAPTER 5 – METERING AND HEATING VALUES IN THE FACILITATED MARKETS

36. Does the NGR restrict distributors' ability to calculate heating values in different parts of the distribution system to accommodate the different uses of natural gas equivalent gases in the facilitated markets?	
37. Are amendments required to the NGR to facilitate the determination of more granular heating values and any other matters relating to the metering provisions for the DWGM?	APGA do not believe that any barriers currently exist to moving to a zonal heating value model in the DWGM, hence no amendments are necessary.

QUESTION 15 - CHAPTER 5 – GAS SPECIFICATION IN THE FACILIATED MARKETS

38. In relation to the STTM, do you think Part 20 of the rules should be amended to clarify that AS 4564 – 2005 can be augmented or replaced to accommodate blending in certain parts of STTM distribution systems? Are any other changes required, including to accommodate impacts on connected transmission pipelines?	Yes. Noting that the NGR is not the place for safety regulation, APGA suggests that the NGR only allow for replacement of augmentation of gas composition boundaries to occur in line with the guidance of the relevant jurisdictional safety regulator. Where possible, consistency in composition between states and between interconnected networks should be sought to the extent that jurisdictional safety regulatory requirements allow.
39. In relation to the DWGM, do you think Part 19 of the rules should be amended to give AEMO (or another party) the	APGA do not support this option.

ability to directly determine the gas specification on distribution systems?	

QUESTION 16 - CHAPTER 5 – BLENDING CONSTRAINTS IN THE FACILITATED MARKETS

40. Who should be responsible for the creation of natural gas equivalent blends and ensuring that these remain consistent with a revised gas specification?	From a composition limit boundary setting perspective, the relevant jurisdiction or jurisdictional safety regulator should maintain this responsibility. From a facility operation perspective, the operator of the facility should be responsible for the creation of natural gas equivalent blends and ensuring that these remain consistent with a revised gas specification as part of their activities as a reasonable and prudent operator. This is consistent with the broad activities undertaken by all gas production and interconnect facility operators today who ensure that composition limits don’t breach the boundaries of existing composition limits.
41. In the DWGM, should AEMO be given operational control over the distribution system to manage blending constraints? If so, what changes to the rules would be required?	APGA do not support this option.

QUESTION 17 - CHAPTER 5 – OTHER IDENTIFIED ISSUES IN THE FACILITATED GAS MARKETS

42. Do the identified issues in the NGR and changes required cover all necessary changes to facilitate the trade of natural gas equivalents in the DWGM and STTM?	
43. Are there any other issues the Commission should be aware of?	
44. Are all of these changes required now for natural gas equivalents? Could some of these changes be made at a later date, or when other gas products are taken into consideration?	
45. Are there any transitional issues?	

QUESTION 18 – CHAPTER 6 – INITIAL IDENTIFIED ISSUES IN THE REGULATED RETAIL MARKETS

46. Are changes to the retail market registration provisions required to accommodate natural gas equivalents?	
47. Are there any other changes required to the retail market provisions in the NGR to accommodate natural gas equivalents?	

QUESTION 19 – CHAPTER 6 – OTHER POTENTIAL ISSUES IN THE REGULATED RETAIL MARKETS

48. Are there any issues the AEMC should consider in relation to the recovery of the cost of the renewable component of the natural gas equivalent from retail customers, for a natural gas equivalent?	No. Any form of additional consideration for supply of renewable gas via a facilitated market should occur as either a derivative product or a wholly separate product. Introduction of additional aspects within existing markets risks disassociating the renewable gas and natural gas markets.
49. Are there any issues the AEMC should consider in relation to retail competition and consumer choice as a consequence of the introduction of natural gas equivalents?	
50. How are these issues impacted by jurisdictional policies in relation to mandated renewable gas targets or mandated green value in a gas stream? Are any changes to the NGR and NERR needed, either now or in the near future, to address any concerns about competition, consumer choice and cost pass through of renewables in the retail market.	

QUESTION 20 - CHAPTER 7 – CONSUMER PROTECTION FRAMEWORK

51. Do you consider that changes are required to the consumer protection framework to reflect the physical properties of natural gas equivalents compared to natural gas? Specifically: a) Should retailers be required to notify existing customers prior to the transition from the supply of natural gas to a natural gas equivalent that the customer is now being supplied with the natural gas equivalent and the changes the customer may see in relation to the quantity of gas metered at their premises following the transition? b) Should the model terms and conditions for standard retail contracts and the minimum requirements for market retail contracts be amended to make clear if the supply of gas under that contract is a supply of natural gas or a natural gas equivalent? c) Should retailers who receive requests for historical billing data from a customer be required to state in the billing information provided if there was a transition from natural gas to a natural gas equivalent during the billing history period for which information is requested, and the date at which the transition occurred? d) If the natural gas equivalent to be supplied has a different heating value from natural gas, should there be a requirement for retailers to issue a bill based on an actual meter read for customers with accumulation (non-interval) meters before supply is transitioned to a natural gas equivalent?	
52. Are there any other gaps in the consumer protection framework that arise because of the difference in the physical properties of natural gas and natural gas equivalents?	
53. Do you consider that customers should be informed if price variations occur because of the transition to natural gas equivalents?	
54. How should the risks of 'off spec' natural gas equivalents be allocated under the NERL and NERR? Is the existing allocation of risk for the quality of natural gas appropriate if distributors have responsibility for creating the natural gas equivalent (for example, through the operation of blending facilities)? What is the appropriate mechanism for managing loss suffered by customers as a result of 'off spec' natural gas equivalents?	

QUESTION 21 - CHAPTER 8 – REGULATORY SANDBOX ARRANGEMENTS

55. Is it practicable for a retail customer to opt out of a change of product trial? If not: a) should the definition of explicit informed consent be required to provide information that the customer is unable to opt out of the trial for the period of the trial? b) should the AER have power to extend a change of fuel trial if retail customers cannot practicably opt out of the trial?	APGA supports these aspects at a high level.
56. Are any changes to the consultation requirements regarding proposed trial waivers for change of product trials needed? For example, on the AER public consultation requirements for change of product trials.	APGA supports these aspects at a high level.
57. Should amendments be made to specify certain pre-conditions to the granting of a trial waiver for a change of product trial involving the sale and supply of an 'other gas product'? If so: a) should the applicant be required to provide this approval as part of its application for a trial waiver? b) should the rule change proponent for a trial rule be required to provide this approval as part of its request for the rule?	APGA supports these aspects at a high level.
58. Are there any other gaps that would arise in the proposed regulatory sandbox framework if it is extended to natural gas equivalents, other gas products and constituent gases?	