2 December 2021

Ms Anna Collyer
Chair
Australian Energy Market Commission
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Sent by email

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Dear Ms Collyer

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

Jemena welcomes the opportunity to assist the Australian Energy Market Commission (**AEMC**) develop a set of rules to incorporate natural gas equivalents (**NGEs**) into the National Gas Rules (**NGR**) and National Energy Retail Rules (**NERR**).

Jemena delivers gas to over 1.4 million residential, business and industrial customers in Sydney, Newcastle, the Central Coast, Wollongong and more than 20 regional centres. We also own a number of gas transmission pipelines serving customers throughout Queensland, NSW, Victoria and the Northern Territory.

We welcome the Energy Ministers' decision to bring renewable gases into the scope of the national gas regulatory framework. The introduction of renewable gases is an important element of the wider transformation of Australia's energy system. This transformation gives rise to the fundamental problem of how to ensure that a market and supply chain for green gases develops fast enough to satisfy the needs of gas customers who want a decarbonised source of energy. It is important that the regulatory framework does not impede, and in fact facilitates, development of this market and supply chain.

Accordingly, incorporating renewable gases into the NGR and NERR requires the regulatory framework as a whole to have sufficient flexibility to recognise that the energy system of the future will not operate as it does today.

In respect of NGEs, once changes to the National Gas Law (**NGL**) are made, we consider that minimal changes are required to both the NGR and NERR. This is primarily because by definition NGEs can be delivered to, and used by customers, using the same equipment and facilities that currently deliver and consume natural gas. No technical or operational changes are needed to our pipelines or customer appliances. As a result, all of the mechanisms which are in place for natural gas can generally be applied to NGEs.

While we welcome the comprehensive review of the NGR and NERR, we note that many of the measures floated would introduce prescription and additional regulatory barriers which could delay or prevent the development of the market for renewable gas. Instead we suggest building on existing mechanisms and processes which work well, are fit-for-purpose and provide sufficient flexibility.

Please find attached:

- Attachment A – Our submission to the Energy Senior Officials Extending the national gas regulatory framework to hydrogen blends & renewable gases consultation paper. This submission provides further context and background as well as a list of the kinds of activities and functions that we are considering or anticipate that we will need to undertake in the future.

- Attachment B – Answers to the specific questions posed.

- Attachment C – Jemena Gas Networks (NSW) Ltd (JGN) submission on the gas pipeline reforms draft legal package.

We are keen to continue engaging with the AEMC and other policy makers in the development and implementation of these reforms. Should you have any questions please do not hesitate to contact James Turnley, Gas Networks Regulation Manager, on (02) 9867 8659.

Yours sincerely,

Ana Dijanosic

General Manager Regulation

Attachment B. Responses to questions

Chapter 3 Economic regulation of pipelines

Question 3: Supplier access to pipelines

Questions	Feedback
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.	We broadly agree that the interconnection principles' requirement around it being 'technically feasible and consistent with the safe and reliable operation of the pipeline' should allow a service provider the ability to constrain/reject a proposed connection for a NGE or constituent gas (CG), including where this would breach blending limits. However, the existing provisions in the NGL and NGR with respect to negotiating access and applying for a connection are designed to ensure that all access seekers should be entitled to connection with limited discretion to pipeline service providers to refuse a connection. This regime is based on a well-established framework for natural gas and a presumption that access will be granted. Connections involving NGEs or constituent gases are still evolving and the technical and regulatory landscape in which these connections will operate is not certain. We consider pipeline service providers should be given greater flexibility on being able to refuse a connection for safety, technical, legal, economic or other operational reasons during the transition while the parameters for the connections framework continue to evolve. Without such discretion, there may be unintended consequences to the safety, security and reliability of the pipeline and pipeline services without any additional benefits to third party access.
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?	We agree that information on the technical feasibility of connections by suppliers of NGEs or CGs could be valuable, particularly in a future of decentralised injections. However, the existing connection processes ensure that interested parties have access to such information. It also does not follow that a new requirement mandating identification and publication of possible interconnection locations is appropriate and will provide, on balance, added value to the development of NGE and CG industries. In particular: • The technical feasibility of a potential interconnection is not black and white and will require consideration of multiple factors including the design and operating requirements of the pipeline in that geographic location, hourly, daily and annual gas injections and

	withdrawals, and an assessment of the specific NGE/constituent gas facility which intends to connect. • Given the pace of technology change what is technically feasible can change quickly. • Pipelines have a strong incentive to encourage injections, in particular green gas injections to ensure ongoing viability. • There are other more flexible, fit-for-purpose regulatory solutions than prescriptive rules. <u>Scheme pipelines</u> Consistent with Jemena Gas Networks (NSW) Ltd (**JGN**) submission on the pipeline reforms (Attachment C) we consider that pipelines should be able to engage with their users on what information would be useful to be disclosed as part of the established and well tested access arrangement process. This approach will enable service providers, with user submissions and AER approval to: • develop a set of terms and conditions, including relevant information disclosures and information to be required by the interconnecting party which reflects individual pipeline circumstances. This can include how information on interconnection services will be provided, including standing terms and conditions; and • take into account the existing robust information disclosure requirements to avoid duplication. Importantly, this will provide the flexibility to apply a proportionate and targeted approach that meets user needs and recognises the very different nature of pipelines. <u>Non-scheme pipelines</u> From a transmission pipeline perspective, our engagement with customers suggests that connections are likely to be infrequent. We consider that these matters are best left to bilateral negotiations between service providers and connection proponents, accompanied by the existing safeguards the NGL and NGR provide for proponents negotiating with scheme and non-scheme pipelines.
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?	While we understand the theoretical risk that a service provider might have an incentive to favour its own facilities, we consider that when this issue is considered in context there is no issue, for several reasons:

	• Pipelines have an incentive to encourage the injection of renewable gases – and unnecessarily or unfairly curtailing facilities (if it were possible) would stifle investment. • Pipelines have a history of seeking to avoid curtailment except where necessary. For instance, we have accepted out of spec gas where we are confident that as a result of commingling with other gas in the pipeline it will not have any downstream impacts on our users. • There are already existing regulatory, contractual, procedural and practical mechanisms in place to manage curtailment issues when they arise – which mean that pipelines do not have the discretion to curtail services/shippers[1] to obtain some kind of market advantage. Further detail on how curtailment works for scheme distribution pipelines and non-scheme pipelines is provided below. <u>Scheme distribution pipelines</u> JGN's Access Arrangement (and similarly for many other pipelines) addresses the curtailment of deliveries where this is required. In relation to curtailment arrangements for injection of NGEs or CGs, including where the pipeline offers some sort of blending service, the Access Arrangement review process is the most appropriate forum in which these issues should be addressed (including who has firm injection rights and whether these should be priced in some way). This will enable a mechanism to be approved by the AER which reflects the circumstances of the individual pipeline and the requirements of producers of NGEs which inject gas into that pipeline. <u>Non-scheme pipelines</u> Similarly, for non-scheme pipelines, curtailment schemes are set through gas transportation agreements, with those shippers able to use an access dispute resolution process (currently being strengthened through the Pipeline RIS process) when negotiating their agreement. Importantly, even in a scenario where a pipeline service provider shipped gas injected by its own facility, it would only contractually be possible for a service provider to provide itself a higher curtailment priority than others if those existing shippers agreed to accommodate this—noting that third parties are unlikely to have any incentive to agree to the pipeline service provider having higher priority.

[1] Curtailment applies to services/shippers, not necessarily to injection facilities.

Question 4: Ring-fencing arrangements

Questions	Feedback
Do you think the ring-fencing exemptions in the NGR should be amended to accommodate trials by service providers? Why?	As outlined in our submission to the Energy Senior Officials (see attachment A) we consider that the national regulatory framework needs to be amended to take into account the fundamental transformation the sector is undertaking. In particular, we note that many fundamental assumptions underpinning the regulatory framework no longer hold and that pipelines will need to play a greater role in enabling a renewable gas future by providing more ancillary services (see Appendix B to our Energy Senior Officials submission). We consider that amending the NGL will largely address the barriers which may prevent us from providing these essentially ancillary services. However, we also support an enhanced exemption framework to ensure additional flexibility in the regulatory framework.
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)?	
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?	

Question 5: Rules for scheme pipelines

Questions	Feedback
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.	Our scheme distribution pipelines can already deliver natural gas and NGEs without a physical and operational transition. As Part 9 of NGR applies price and revenue regulation of pipeline services, the definition of pipeline services is key. Incorporating NGEs and other gases into the NGL will ensure that the pipeline services considered by Part 9 can encompass NGE and other gases. For instance, it will allow the reference service to apply to natural gas and/or NGEs. In turn this will mean that expenditure incurred to provide this service will meet the requirements such as the new conforming capex criteria in Rule 79 and criteria governing operating expenditure in Rule 91. Given the fundamental problem we face (how to ensure that a market and supply chain for green gases develops fast enough to satisfy the needs of gas customers who want a decarbonised source of energy) a prudent service provider acting efficiently in accordance with accepted good industry practice would seek to undertake projects which increase the probability that a renewable gas future can be achieved. As a result, we consider that expenditure of this nature would meet the new conforming capex criteria and criteria governing operating expenditure. However, to reduce regulatory uncertainty and encourage efficiency investment we consider that greater guidance in the rules would be beneficial.

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?	It is established regulatory practice to net off these components of any spend. For instance, only net capex is rolled into the capital base of scheme pipelies.
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?	At this stage, we have not identified any other rules that will need to be amended to accommodate NGEs or constituent gases.

Question 6: Rules for non-scheme pipelines

Questions	Feedback
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. It would be expected that the arbitrator would take into account all relevant regulatory obligations as these would be inextricably linked to the ability of the pipeline operator to provide the requested service. However, we consider expressly requiring the arbitrator to consider regulatory obligations will provide better clarity. b. Refer to our response to Question 5 – we consider that any such guidance should be consistent for scheme and non-scheme pipelines. c. Government grants take different forms and serve different purposes. They could be in the form of a loan or as a lump sum contribution towards a particular project. Like any other third party source of funds, it underpins the commercial terms and should not be treated any different to other commercial arrangements on which the arbitration principles are applied. To the extent that a government grant is accompanied by regulatory obligations, this should be addressed by paragraph (a) above.
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?	At this stage, we have not identified any other rules that will need to be amended to accommodate NGEs or constituent gases.

Question 7: Pipeline gas information

Questions	Feedback
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?	a. We consider that publication of information on the licenced type of gas for a pipeline in the user access guide is likely to be a low cost, fit-for-purpose solution for market participants. b. We agree that it may be helpful for customers and other market participants to be provided with information about trials and transition plans, but this should not be an obligation

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?	prescribed in the NGR. Instead for scheme pipelines, the Access Arrangement should set out the information which is to be provided, consistent with our proposed alternative approach to information disclosure proposed in our submission to the Energy Senior Officials on the pipeline legal consultation package, consistent with the reasoning provided in response to question 3. This will avoid the potential costs and inefficiencies of a "cookie-cutter" approach which assumes that the same sort of information will be relevant to every scheme pipeline and its customers.
Do you think this information should also be reported on the AEMC's Pipeline Register?	We are comfortable with reporting this information on the AEMC's Pipeline Register.

Chapter 4 Market transparency mechanisms

Question 8 Extension of the transparency mechanisms to natural gas equivalents

Questions	Feedback
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: a. the BB facilities listed in rule 141 of Part 18 of the NGR? b. the DWGM registration categories in rule 135A of Part 15A of the NGR?	It is not possible at this time to identify the sorts of facilities or activities that may be involved in the emerging renewable gas market. If new facilities are to be captured by the NGR, it is important to ensure that an appropriate level of materiality is included (as is currently the case with BB facilities) to avoid unnecessary cost to customers and potential barriers to entry.
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?	
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?	In answering this question is it important to consider the context in which blending could occur. Whether blending is undertaken by a pipeline operator or a third party will depend on a number of matters, including the configuration of the connection assets which connect the constituent gas equipment to the pipeline. Like any other connection, the process is largely at the discretion of the connection applicant with the pipeline operator specifying requirements in relation to the technical envelope for the connection. This is reflected in the current market where receipt points on transmission or distribution pipelines are sometimes owned by the pipeline.

	Different pipeline operators and producers may have different preferences for development of blending facilities where a facility is required to create a NGE blend (either a new receipt point or a blending facility). Pipelines could provide a blending function if a connection applicant requests a single receipt point is built on the network. The pipeline operator would then construct the assets to allow hydrogen to be injected through direct injection[2] or in-stream blending.[3] Alternatively if the connection application requests both a delivery and receipt point it could withdraw natural gas from then network, blend in the hydrogen then reinject the gas as a NGE, in this case, the upstream facilities and blending will not form part of the pipeline service. Lastly, an NGE could be created upstream of a pipeline. In our view, 'blending' is something distinct from other mid-stream activities such as compression and processing. It does not neatly fall within the current definitions of either production or a pipeline service. Where blending is undertaken by a pipeline it should be treated no differently to any other injection into a pipeline (and the pipeline blending function is not considered to be a production facility). Lastly, we note that reporting requirements around a production facility's 'size of reserves' may not be applicable to facilities where energy is manufactured rather than extracted out of the ground (blending facilities and some other production facilities, such as biogas). For instance, we note that the 'reserves and resources estimate' reporting requirements to be introduced as a result of the Transparency RIS are framed around natural gas reserves.
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?	We have not identified any gaps at this stage.

[2] Direct injection is where the composition and flow of the upstream natural gas is known and hydrogen is metered, hydrogen can be blended in the network through commingling. This approach only requires a single physical connection to an existing gas main. The heating value of the resultant gas blend can then be adjusted based on the composition and flow rate data.

[3] In-stream blending is where the composition and flow of the hydrogen is measured for the purposes of controlling and metering the composition. This involves diverting the path of natural gas to an above ground facility, where the hydrogen is blended with natural gas. To install on an existing gas main it would typically require two physical connections.

Question 9: Extension of the transparency mechanisms to constituent gases

Questions	Feedback
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.	We consider that the transparency measures shouldn't be extended as part of the initial rules package. Deferring these measures will provide time for the market to develop and will allow any Rules to be targeted and fit-for-purpose. Creating rules now risks creating regulatory obligations which don't work or create unnecessary administration and regulatory costs and risk, and may preclude or deter small and new entrants.
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?	
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?	

Chapter 5 Facilitated gas markets

Question 10: Trading natural gas equivalents in the facilitated gas markets

Questions	Feedback
Do you think natural gas equivalents should be traded through the facilitated markets, or outside of the facilitated markets?	As natural gas and NGEs are interchangeable we consider that NGEs should be able to be traded in facilitated markets, just as natural gas is. The primary consideration is that producers of NGEs should be able to access the same markets as natural gas shippers. Whether additional compensation is received by these producers for producing renewable gas (likely through the sale of renewable gas certificates) is irrelevant. We have not identified any value in creating a parallel market process, with additional complexity and cost, when the current market is fit-for-purpose.
What do you consider are the implications of these two options, in terms of required regulatory changes, costs of implementation and potential market inefficiencies?	

Question 11: Facilitated markets registration categories

Questions	Feedback
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?	As natural gas and NGEs are interchangeable we generally do not consider that any change to the registration categories is required due to the nature of the gas. However, given the infancy of the markets, production facilities are likely to be smaller and more decentralised than conventional gas production facilities. We suggest that consideration is given to exempting small facilities (including blending and distributed production facilities) and the parties purchasing gas from these facilities from the STTM. We also consider that the introduction of a small producer registration category with less onerous requirements could be worthwhile. This would recognise the small impact these facilities are likely to have in the near future, while avoiding unnecessary cost which could deter new entrants from establishing production facilities in the STTM. Consideration should also be given to options such as allowing aggregated registration and reporting for multiple small facilities under common ownership, or the introduction of a facility size threshold (potentially aligned with the 10TJ/d BB reporting threshold) which allows for smaller facilities to face streamlined registration and ongoing reporting requirements for facilitated markets.
If flows associated with distribution-connected blending facilities are not scheduled in facilitated markets, are new registration categories required for	Given that the market has not yet developed, we do not have a clear view. We consider that these changes should be deferred where possible to allow the market to develop, and that there may be lessons from the electricity market where small scale solar is injected directly into the distribution

blending facilities and associated participants or can they be exempted from registration?	network without scheduling and registration requirements, which avoids unnecessary regulatory barriers to investment.

Question 12: Unaccounted for gas in the facilitated markets

Questions	Feedback
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?	The jurisdictional arrangements within NSW/ACT for UAFG do not require amendment to accommodate injections of NGEs.
If so, how will this impact the operation of the matched allocation mechanism (as used by the distributor in the Sydney STTM hub)?	We note that the matched allocation mechanism does not always apply to UAFG purchases. It is only in place where the shippers, the connecting transmission pipeline and the distribution network agree. Under the matched allocation mechanism, the UAFG supplier can elect to have some, none or all of the gas supplied to JGN excluded from the operation of the STTM. This mechanism was included in the NGR to avoid the potential impact on the cost of UAFG, where customers would ultimately bear the STTM-related risk premium applied by the UAFG supplier. The drafting of the relevant rules reflects the market structure at the time – where gas was delivered into the network through transmission pipelines, not from connected production facilities. Particularly in this transition period, network purchases of UAFG are likely to play a role in underpinning development of facilities for production of renewable gas. We would support the broadening of the rules relating to matched allocation quantities to also apply to UAFG purchases from distribution-connected production facilities. We also note that not all distribution networks are part of a hub – for example, JGN's regional gas networks are not part of the STTM and JGN is responsible for replacing UAFG in these networks as well as in the STTM network section. It is important that any changes in relation to UAG do not have unintended consequence for these non-STTM networks.
What changes would be required to UAFG arrangements in the DWGM?	We do not have a view on the DWGM.

Question 13: Settlement issues in the facilitated markets

Questions	Feedback
If distribution connected blending facilities are not integrated into the facilitated markets, what settlement issues may arise?	The STTM currently accommodates multiple injection and withdrawal points – fundamentally the market settles on the basis of total volumes of gas injected into the network and withdrawn. The fact that there has been a blending activity will not change this.
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?	As long as the injections and the corresponding withdrawals are matched there is no issue.
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?	We do not see any issues to resolve.
How should facilities exempted from registration, or that fall below a materiality threshold, be treated under settlement arrangements in the facilitated markets?	In the case that a facility is exempted or falls below a materiality threshold we consider that they should be excluded from the settlement arrangements in the facilitated markets. Similarly, if a facility is not exempted from the facilitated market it should be included in the settlement arrangements.

Question 14: Metering and heating values in the facilitated markets

Questions	Feedback
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?	No. Rule 303 allows different heating values in different parts of the distribution system. The Sydney STTM and our regional networks currently have multiple heating values zones to reflect that there are several sources of gas supplied into our network. We do not believe any changes are required to accommodate NGE in the markets.
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?	We do not have a view on the DWGM.

Question 15: Gas specification in the facilitated markets

Questions	Feedback
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	Part 20 refers to AS 4564 – 2005 "as amended or replaced from time to time". Together with the interpretation rules in Schedule 2 of the NGL, the legislative framework already accommodates

accommodate blending in certain parts of STTM distribution systems? Are any other changes required, including to accommodate impacts on connected transmission pipelines?	changes to AS4564 – such as the current version published in 2020. Part 20 also allows for additional gas quality specifications to be stated in a distributor's Access Arrangement. This is broad enough to accommodate the changes currently foreseen.
In relation to the DWGM, do you think Part 19 of the rules should be amended to give AEMO (or another party) the ability to directly determine the gas specification on distribution systems?	We do not have a view on the DWGM.

Question 16: Blending constraints in the facilitated markets

Questions	Feedback
Who should be responsible for the creation of natural gas equivalent blends and ensuring that these remain consistent with a revised gas specification?	We do not consider that the NGL or NGR should impose obligations in relation to the creation of NGE blends. This is unnecessary and would duplicate existing regulatory frameworks which already establish responsibility for ensuring gas meets the relevant quality specification. For example, in NSW, the *Gas Supply (Safety and Network Management) Regulation 2013* imposes obligations in relation to responsibility for ensuring gas specifications are met. We do not believe changes are required to this current regime.
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?	We do not have a view on the DWGM.

Question 17: Other identified issues in the facilitated gas markets

Questions	Feedback
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?	We have not identified any further changes or issues to be considered for the introduction of NGEs.
Are there any other issues the Commission should be aware of?	
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?	
Are there any transitional issues?	

Chapter 6 Regulated retail markets

Question 18: Initial identified issues in the regulated retail markets

Questions	Feedback
Are changes to the retail market registration provisions required to accommodate natural gas equivalents?	Consideration of changes to the retail market registration presumes that the injection, transportation and sale of NGEs is something different to the current arrangements for natural gas. For 'on spec' natural gas (which includes natural gas and NGEs), the existing framework is fit for purpose (on the presumption that the NGEs are recognised). From a retail market perspective, the activities of additional facilities and services involved in creating NGEs (such as blending) do not require registration recognition. These are technical input services and facilities to the retail market functions.
Are there any other changes required to the retail market provisions in the NGR to accommodate natural gas equivalents?	

Question 19: Other potential issues in the regulated retail markets

Questions	Feedback
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?	We do not consider that there are any issues to consider. We anticipate that the future gas market will work akin to how the electricity market currently operates. Customers and retailers will soon have the option to purchase a renewable energy certificate for a proportion of their energy usage. This market will be separate but connected to the market for energy. Like the renewable electricity certificates, there are existing safeguards in place under the NECF as well as the Australian Consumer Law to address this emerging market.
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?	
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.	

Chapter 7 Consumer protections

Question 20: Consumer protection framework

Questions	Feedback
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?	The extension of the existing NERL consumer protection framework to NGEs will not change the underlying purpose of the framework – ensuring appropriate consumer protections are in place in relation to the sale and supply of energy to end use customers. As the NGEs will be supplied to customers on the same terms and for the same purposes (i.e. substitutable product and service and will not require a change to a customer's appliances) no amendments are required to the framework. The existing protections are fit for purpose. In particular: • the Retail Market Procedures which underpin the measurement of gas metered at the premises, are designed to measure the quantity of gas and already take into account different heating values. These arrangements do not impact the substantive protections under the NERL and NERR and for this reason, we cannot identify any required changes; • The only change required to model terms and conditions for customer retail contracts and customer connection contracts is to ensure it captures both natural gas and NGEs. The extension of the framework to NGEs relates to the changes to the physical supply of gas (i.e. the composition of the gas) and does not affect the retail contract or arrangements with retailers. • The billing requirements under the NERL (and those that are supported in the NGL) are sufficiently flexible to address different heating values and associated meter reads to the extent that the Retail Market Procedures addresses those issues (if any). To the extent that a customer requires historical billing information and that period covers the formal transition from natural gas to NGEs such that there were different heating values to the changes in gas composition, this could be addressed within the existing historical billing rules and procedures. It is important to note that natural gas and NGEs are interchangeable. Depending on flows in the network consumption and injections, a customer could receive natural gas one day and a NGE the next. As a result, there is no clear line between when a customer would be supplied natural gas or an NGE.

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?	For the purposes of end use customers, any difference in the composition between natural gas and NGEs does not change how the consumer protection framework applies to those customers as it will be the same service or product.
Do you consider that customers should be informed if price variations occur because of the transition to natural gas equivalents?	We note that the basis of this question is the statement that: *A retailer may wish to increase the prices it charges to customers connected to a distribution system that has transitioned to supply a natural gas equivalent because the constituent gas has a higher cost gas than natural gas.* No transition is required as Natural Gas and NGEs are interchangeable. Retailers will be able to continue to source Natural Gas or procure NGEs for their customers. As a result, there will be no price variation directly due to a transition to natural gas equivalents. Of course, there may be price variations as retailers purchase energy from different sources. However, this is no different to electricity – where retailers' prices will depend on their wholesale electricity procurement strategy.
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?	There are already mechanisms in place to manage the risk of 'off spec' gas. Distributors control and monitor the composition of natural gas injected into its network to ensure it meets the technical specification, and have statutory and/or contractual obligations to ensure that gas delivered to customers meets the relevant specification. These are managed through the existing access arrangement provisions (including reference service agreements) with users. There is no reason to consider that there is a greater risk of distributors not adequately managing 'off spec' gas under a NGE model as it is the same service provided. If there are any issues relating to the quality of service as a result of the inclusion of NGEs there is an existing jurisdictional mechanism for managing the level of distributor service.

Chapter 8 Regulatory sandbox framework

Question 21: Regulatory sandbox arrangements

Questions	Feedback
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?	We note that: • 'Change of product' trials will not be required for NGEs as natural gas and NGEs are interchangeable. • Change of product trials will not necessarily require the regulatory sandbox to provide regulatory relief. • It is more likely that regulatory sandboxing could be applied to trial lighter touch registration or reporting obligations. • Introducing additional requirements, hurdles or even limiting AER discretion to extend a trial (which it can only do if it is satisfied the eligibility requirements are still met) will stifle innovation and investment. To achieve a renewable gas future more, rather than less, flexibility is required.
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.	No, the AER is already required to undertake consultation unless the trial waiver and trial project: (1) is unlikely to have an impact on other registered participants / regulated entities; and (2) is unlikely to have a direct impact on retail customers other than those who provide explicit informed consent to participate in the trial project.
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?	Introducing additional requirements to obtain approval from relevant jurisdictional technical regulators simply to be able to *apply* for a trial waiver or trial rule adds unnecessary red-tape stifling innovation and investment. We note that: • All trial projects will need to comply with all relevant laws and regulations, including jurisdictional technical requirements (so there is no need for approval to be supplied in an application or rule change proposal). • Requiring relevant jurisdictional technical regulators in a trial waiver or trial rule application will require a sequential approach preventing applicants from working through several

	matters simultaneously. This is contrary to the very policy intent of the regulatory sandbox: to avoid unnecessary delays.
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?	We have not identified any specific gaps.

26 November 2021

Mr Sean Sullivan
Chair
Energy Senior Officials
Department of Industry, Science, Energy and Resources
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Dear Mr Sullivan

Consultation paper: extending the national gas regulatory framework to hydrogen blends & renewable gases

Jemena welcomes the opportunity to provide a submission on extending the regulatory framework to renewable gases. Our NSW distribution network delivers gas to over 1.4 million residential, business and industrial customers in Sydney, Newcastle, the Central Coast, Wollongong and more than 20 regional centres. We also own a number of gas transmission pipelines serving customers throughout Queensland, NSW, Victoria and the Northern Territory.

We welcome the Energy Ministers' decision to bring renewable gases (including biomethane, hydrogen and hydrogen blends) into the scope of the national gas regulatory framework. We support the approach of expediting changes in respect of renewables gases that are suitable for consumption in existing appliances. We also support the approach to accommodate the evolving future of renewable gas and avoiding changes that could have unintended consequences.

These changes are not simple. The introduction of renewable gases is just one element of the wider transformation of Australia's energy systems. Accordingly, regulatory change to bring renewable gases in scope needs to also provide flexibility to recognise that the energy system of the future will not operate as it does today.

Just as the reforms recognise that pipelines will transport gases other than natural gas, other fundamental assumptions which underpin the regulatory framework are breaking down or will soon no longer hold. For instance, up- and down-stream markets for renewable gas either don't exist or are in their infancy, and pipelines are looking to provide services which currently don't exist (requiring a departure from the current mature business model). Perhaps most challenging of all, we can no longer assume that gas networks will be able to provide services into perpetuity.

Understanding this context is essential to ensuring that economic regulation is targeted at the right issues and problems. Economic regulation in and of itself cannot resolve the technical and economic challenges for gas pipelines. However, it can ensure that the regulatory compact between pipelines and customers adjusts to reflect the different environment in which consumers, pipelines and upstream providers must operate and invest in. Indeed, the very point of economic regulation is to provide a price and access governance mechanism that provides all parties with sufficient incentives to continue investing while taking into account changing circumstances.

With this context in mind, the successful integration of Natural Gas Equivalents (**NGEs**) and Other Gases (**OGs**) into the National Gas Law framework rests on the application of the key definitions (or lack thereof). We consider that several definitions need to be adjusted and new ones need to be created so that pipeline operators can operate with sufficient flexibility to enable and deliver a renewable gas future.

Lastly, we consider that the regulatory framework should have some form of optionality to determine whether specific pipeline assets and services should be covered by the regulatory framework. While in many cases it makes sense for assets to be regulated under the National Gas Law (**NGL**), economic intervention may not always be justified or may otherwise inhibit the development of new gas markets and industries. For instance, while it may make sense for a hydrogen pipeline built as part of our NSW distribution network to be captured, it may not make sense for other pipelines or blending facilities where other mechanisms could produce better outcomes for consumers.

Please find attached further elaboration on the issues outlined:

- Attachment A provides further context on the wicked problem gas distribution networks and the wider community face, the role of economic regulation and what changes to the NGL are required.

- Attachment B provides a practical list of the kind of activities and functions that we are considering or anticipate that we will need to undertake in the future.

- Attachment C provides a summary of what pipeline blending practically entails.

- Attachment D provides answers to the specific questions posed.

Given the significance of these changes, their complexity and the ramifications for Australia's future energy system, ongoing transparent and comprehensive consultation will be crucial. We are keen to continue engaging in this and consequent processes.

Should you have any questions please do not hesitate to contact James Turnley, Gas Networks Regulation Manager, on (02) 9867 8659.

Yours sincerely,

Ana Dijanosic

General Manager Regulation

Attachment A. The wicked problem gas networks and the wider community faces, the role of economic regulation and the changes required to the NGL.

The challenge

The energy system is in the midst of a fundamental transformation. Decarbonisation, propelled by consumer choice and enabled by policy and technological changes, will require that the energy system of the future to be very different to the energy system of today.

We see gas distribution networks, including the Jemena Gas Network (**JGN**) in NSW, playing a crucial role in tomorrow's energy system by:

1. Providing consumers and industry with an alternative decarbonised source of energy – with many of the natural gas characteristics that they value today, such as instantaneous heat as well as the reliability and security from a dual source of energy.

2. Avoiding costly upgrades to the electricity networks and generation fleet providing a lower cost whole of system decarbonisation pathway.

3. Supporting the decarbonisation of other sectors such as transport, and playing a role in energy storage and grid firming.

However, this is not guaranteed. In many feasible future scenarios, including in what some other stakeholders consider the default scenario, gas networks will play a much smaller role. For instance, in each of AEMO's 2050 net-zero scenarios, residential gas heating loads will be entirely (or almost entirely) electrified by 2050.[1] Given that residential customers make up 98% of JGN's customer base this outcome will result in substantial economic stranding.

While the future is uncertain, what is clear is that in any net-zero future the status quo for gas networks cannot remain the same. Gas networks must transition to green gas to unlock the potential benefits that can be delivered for consumers and industry as well as prepare for a future in which their role is a shade of their current role.

A smaller role for gas networks will have significant consumer repercussions. It would require price increases (as our largely fixed costs will be spread over a smaller customer base and recovered over shorter period of time) and a reduction in consumer choice, as it will be uneconomic to continue to provide gas pipeline services in many areas.

It would also mean that consumers will loose access to the benefits that gas, such as system resilience, energy storage and the ability to match supply with demand. These factors are particularly important given that there are unresolved questions on how to fully decarbonise the electricity network, for instance on how to match supply with demand, meet peak demand and manage renewable energy droughts and seasonal fluctuations.

How JGN is responding

We are taking steps now to increase the likelihood that gas networks can continue to deliver whole of system benefits for consumers by facilitating the development of green gases.

At this stage our focus is on green gases which are suitable for use in existing natural gas appliances (biomethane and low level hydrogen blends) as these gases meet Australian Standard 4564 for general-purpose natural gas. These gases require no change to the physical operation of our network or to customer appliances. In respect of 100% hydrogen, we are positioning to be a 'fast follower' so that we can take advantage of this technology as it progresses.

[1] 2021 AEMO, 2021 Inputs, Assumptions and Scenarios Report, July, p.41

The key challenge is ensuring that a market and supply chain for green gases develops fast enough to satisfy the needs of gas customers who want a decarbonised source of energy. This 'wicked problem' requires the development of up and down stream markets to produce and consume green gases – in addition to the possible reconfiguration of existing networks.

To be clear, JGN's strategy is not to enter up and down stream markets and expand our role in the supply chain. Rather, it is to facilitate these markets to allow other parties to invest and provide the necessary capital and relevant expertise to deliver a green gas future.

The role of economic regulation as the energy system transforms

The purpose of economic regulation is to resolve the hold-up problem where customers, pipelines and upstream producers need to make material sunk and relationship specific investments.[2] In the case of gas networks, customers need to invest in gas specific appliances (which have a life of about 15-20 years, or longer for industrial customers) while pipelines need to make infrastructure investments (with asset lives of generally 50 but up to 80 years).

Given the long-term nature of the investments required and the extent to which the characteristics of the service change over time (for instance, in respect of cost, demand, quality etc) it is impossible to write a complete contract. This has never been truer than with the current transformation of the energy system.

Economic regulation resolves this problem by providing price and access governance mechanisms to manage the incomplete nature of the arrangement to provide consumers, pipelines and upstream producers with sufficient certainty to invest while allowing adaption to changing market conditions over time. Regulation works to ensure that pipelines are provided with an opportunity to recover efficient costs, while providing mechanisms (such as 5-year price reviews) to reflect changes in the environment in which services are provided.

While economic regulation cannot solve the wicked problem gas networks (and the broader community) face, adjustments to the framework are required to ensure that regulation remains fit-for-purpose and networks can continue to provide services that meet the changing needs of consumers and up-stream producers.

Changes to the National Gas Law to enable economic regulation to work

Currently, the regulatory framework is premised on a series of assumptions which no longer hold, such as:

- That pipelines will only transport natural gas.
- That all possible up and down-stream markets for gas already exist.
- That gas networks provide an established, mature service.
- That gas networks will provide services into perpetuity.

Many of these assumptions are reflected in rigid definitions in the NGL. The need for change and greater flexibility is recognised by the Energy Ministers decision to bring renewable gases into the framework.

[2] Regulation and Administered Contracts Revisited: Lessons from Transactions-Cost Economics for Public-Utility Regulation, K. Crocker and S. Masten, Journal of Regulatory Economics, Vol. 9 (1996), No. 2, 5-39

In extending the regulatory framework to renewable gases it is crucial to keep in mind the wider context in which these changes are being introduced. The drive for renewable gas isn't an isolated phenomena but a result of the wider transformation of the energy system.

Broader changes are required to ensure that the regulatory framework is sufficiently flexible to accommodate and facilitate changes in the market structure, as well as allocation of roles and functions which will accompany the introduction and growth of renewable gas in tomorrow's energy system.

An example of this is the situation where a pipeline blends a stream of 100% hydrogen into a natural gas stream to produce a NGE. It is currently unclear whether the activity would be characterised as production and could not be considered as an ancillary pipeline service.

Another example is that the production of natural gas is historically considered to be upstream of pipelines and is therefore explicitly excluded from the definition of pipeline service. However, to most efficiently provide services in the future, pipelines may produce renewable gas to perform ancillary services, such as undertaking research and development or in undertaking network support functions (see attachment B).

We consider that flexibility can be introduced by amending the definitions of pipeline service, related business, production, processable gas and with the introduction of new definitions for functions such as blending. This will ensure that gas networks are able to undertake the functions ancillary to a pipeline service to facilitate a renewable gas future and that the price and terms of access to these new or expanded services can be governed through the regulatory process (see appendix B).

In turn, this will allow gas network operators, customers and producers of renewable gas to work together to produce a solution in how these new or expanded services are provided – with the AER as the ultimate decision maker.

Attachment B. How JGN is facilitating the development of green gases

In practical terms, we are:

- Seeking to shape and develop the policy environment – For instance by seeking regulatory change to allow Australian Carbon Credit Units (ACCU) to be awarded where biomethane is injected into our network (as they are currently awarded for flaring but not end-use consumption).

- Supporting the development of a green gas certification scheme – allowing consumers to access independently-certified green gas – just as they can now for electricity.

- Building industry and consumer knowledge of the potential for green gases. For instance, in August 2021 we held a Renewable Gas Workshop with consumers, large users, Governments, investors and other stakeholders to provide greater visibility on renewable gas pathways, general market update and identify barriers and impediments.

- Delivering demonstration projects to test concepts and identify technical issues to support the future development of similar projects by other parties.

We are also looking at options to:

- Procure gas used for network operations from renewable gas producers to underwrite upstream renewable gas projects.

- Procure localised green gases injection or build assets enabling green gas injection or storage to support the delivery of our haulage service, for instance to defer or avoid network augmentation to supply loads at peak times.[3]

- Allow the injection of 100% hydrogen into our network – and using our existing network (with some upgrades) to provide instream blending so that end users are provided with a NGE.

- Undertake a trial blending different renewable gases into conventional gas to understand the impact of changing gas characteristics.

- Undertake additional trial projects to test and demonstrate the technical and economic feasibility of green gas options using our network.

Depending on technological developments and customer support, we anticipate that in the future we may also look to:

- Trial the delivery of 100% hydrogen to large users and/or customers in a new or existing network section.

- Build a new hydrogen pipeline (or convert an existing section of our network) to operate as a hydrogen backbone to our existing network. This could work with 100% hydrogen being delivered to particular customers and a hydrogen/biomethane blend provided to other (likely smaller) customers.

[3] We note that it may not be possible for a 3rd party to provide this services where the safety and security of our network is dependant in supply a key times and/or where the most economic solution is to 'insource' production and operation of a green gas facility.

- Provide a storage service allowing green producers to store renewable gas in parts of our network.

- Reconfigure large parts of our network to provide 100% hydrogen.

Attachment C. Blending hydrogen into a pipeline

How can blending occur?

Hydrogen can be added to a natural gas stream via:

1. Direct injection – where the composition and flow of the upstream natural gas is known and hydrogen is metered, hydrogen can be blended in the network through commingling. This approach only requires a single physical connection to an existing gas main. The heating value of the resultant gas blend can then be adjusted based on the composition and flow rate data.
2. In-stream blending – where the composition and flow of the hydrogen is measured for the purposes of controlling and metering the composition. This involves diverting the path of natural gas to an above ground facility, where the hydrogen is blended with natural gas. To install on an existing gas main it would typically require two physical connections.

Typically, blending will require a control system, testing regime, validation of gas dilution as well as operational controls such as detection of hydrogen leakage, development of protocols for emergency response, SCADA and active fault morning, and potentially the establishment of new heating zones to reflect the new heating values.

Chapter 4: Extending the NGL and NERL to natural gas equivalents

No.	Questions	Feedback
Section 4.3: Potential approach to extending the NGL		
Section 4.2.1: Extension to NG equivalents and related facilities and activities		
1	What are your views on the potential approach to extending the application of the NGL to NG equivalents and related facilities and activities? Are there any other approaches that you think would better achieve the objectives of Energy Ministers (see section E.3)?	Jemena supports the proposed approach to extend the existing NGL regulatory framework to NGEs on the basis that NGEs can be delivered to, and used by customers, by the same equipment and facilities that currently deliver and consume natural gas. The current regulatory framework provides a legal and regulatory impediment for NGEs rather than a technical or operational restraint. However, careful consideration and analysis needs to be given to the facilities and activities involved in the creation of NGEs as the industry develops and evolves. We are supportive of a framework that promotes the development of a market for production of renewable gas while also recognising that in the early stages, the activities may not be easily distinguishable from provision of existing pipeline services and there may be safety, technical and other benefits from allowing pipeline service providers to have a role in those activities as the industry develops.
2	What are your views on the policy intention to enable all elements of the national gas regulatory framework to apply to NG equivalents and their related facilities and activities in the same way that they do to natural gas?	Jemena is generally supportive of a 'light' touch approach that does not introduce additional, prescriptive requirements for a NGE product and service which will be substitutable for a natural gas product and service. Similarly, we consider that where there is an existing regulatory mechanism or approach, this would, and should, be, the mechanism that apply to NGE and related facilities. Only where additional flexibility is needed should further changes be required. An example of this is where curtailment may be required for producers who directly inject hydrogen into a pipeline and the pipeline approaches the blending limit. This is analogous to the situation where a pipeline needs to curtail deliveries of gas where there is an incident limiting or restricting gas deliveries. The current framework accommodates this sort of consideration - a process for curtailment of deliveries is already addressed through JGN's Access Arrangement

No.	Questions	Feedback
		(and similarly for many other pipelines). A similar process to apply to injection of hydrogen could be developed with the input of users and submitted to the AER for approval in a future Access Arrangement. This regulatory mechanism remains the most appropriate forum for any curtailment issues (such as who has firm curtailment rights and whether these rights should be priced in some way) to be explored with users and resolved.
3	What are your views on the NGL requiring jurisdictions to make a local regulation to confirm when a gas or gas blend authorised for supply through a pipeline (or part of a pipeline) is an NG equivalent?	Jemena supports the approach that jurisdictions with responsibility for safety and technical licensing are best placed to determine the gas or gas blends that should be supplied through a pipeline. This is consistent with the current economic and technical framework and there seems no reason why a different approach is required in relation to NGEs. Industry led organisations such as Standards Australia will remain the primary mechanism for creating and amending technical specifications, both in relation to gas quality specification and also technical/operating specifications. Having regard to the evolving nature of this function as further gases and blends could be introduced, consideration needs to be given to: • ensuring the regulation making power is sufficiently broad to allow jurisdictions to determine the application of gas or gas blends to pipelines, networks and customers; • ensuring cross border pipelines, networks and associated facilities are adequately addressed.
4	Who is likely to operate the blending facilities involved in the creation of NG equivalent blends?	Whether blending is undertaken by a pipeline operator or a third party will depend on a number of matters, including the configuration of the connection assets which connect the constituent gas equipment to the pipeline. Like any other connection, the process is largely at the discretion of the connection applicant with the pipeline operator specifying requirements in relation to the technical envelope for the connection. This is reflected in the current market where receipt points on transmission or distribution pipelines are sometimes owned by the pipeline operator or the producer.

No.	Questions	Feedback
		Different pipeline operators and producers may have different preferences for development of blending facilities where a facility is required to create a NGE blend (either a new receipt point or a blending facility). Pipelines could provide a blending function if a connection application requests a single receipt point is built on the network. The pipeline could then construct the assets to allow hydrogen to be injected through direct injection or in-stream blending. Blending in this circumstance should be considered to be part of the pipeline service. Alternatively if the connection application requests both a delivery and receipt point it could withdraw natural gas from then network, blend in the hydrogen then reinject the gas as a NGE, in this case, the upstream facilities and blending will not form part of the pipeline service. Lastly, an NGE could be created upstream of a pipeline. This arrangement is no different to how current connections work. Connection applicants can (and do) choose the configuration that meets their needs – which in some cases (particularly where the customer has an ability to store gas) means choosing whether they request a delivery point or both a delivery and receipt point. In our view, 'blending' is something distinct from other mid-stream activities such as compression and processing. It does not neatly fall within the current definitions of either production or a pipeline service.
5	Do you think blending facilities should be subject to the same economic regulatory framework that applies to pipelines? Please explain your response to this question.	<u>Blending provided by a pipeline</u> We consider that blending provided by a pipeline is indistinguishable from a pipeline service. Allowing a connection of a 100% hydrogen flow of gas into a network is no different to allowing a connection for injection of natural gas or a NGE as it requires a new connection asset to be constructed (albeit with additional equipment and operating requirements). We consider that the definition of pipeline service should be amended so that it is clear pipelines can perform this function if they are ancillary to the operation of a pipeline.

No.	Questions	Feedback
		Accordingly, in the case where this service is provided by a scheme pipeline, the setting of price and access terms to this service will be regulated by the AER as part of the usual price review process. Establishing the access terms as part of an Access Arrangement review will provide comfort to the market that the terms are reasonable, including that the pipeline operator does not discriminate between hydrogen producers. Further consideration may also be required on how to allocate limited blending capacity (which may require the use of price signals). For example, JGN's Access Arrangement sets out the technical and commercial conditions for establishing of a new injection point or withdrawal facility, and also the priority of service to customers where there is an incident limiting gas supply. We consider that the AER has sufficient tools with respect to the economic regulation of those activities as part of its regulation of pipeline services. However, a review of the ringfencing provisions in the NGL including the definition of 'related business', the interaction with the definition of 'pipeline service' and the exemptions available for pipelines should be undertaken. The primary purpose of this review would be to ensure that the ringfencing rules are sufficiently flexible to allow the efficient development of the future energy system. <u>Blending not provided by a pipeline</u> In relation to external facility blending – that is not ancillary to a pipeline – careful consideration needs to be given to how these facilities are defined by reference to the gas supply chain. Given that the adoption of a OGs into the NGL framework is at its inception, a firm categorisation has the danger of deterring innovation and investment.
6	Are there any specific physical characteristics of NG equivalents or the supply chain for these products that you consider should be taken into account when extending the natural gas regulatory framework to NG equivalents?	
7	Are there any other observations you would like to make about the potential approach to extending the application of the NGL to NG equivalents and related facilities and activities?	Jemena can see the merits in the Energy Ministers' approach to not amending the definition of 'natural gas' in order to preserve the ordinary meaning of 'natural gas'.

No.	Questions	Feedback
		However, as this consultation process demonstrates, the role of 'natural gas' in the NGL framework is evolving and the application of the definition of 'natural gas' and the related definition of 'processable gas' are no longer reflective of the gas supply chain. The success in extending the NGL to other types of gas (as those gases are defined in jurisdictional instruments) will rely on ensuring that the framework is sufficiently agile to accommodate the different sources and processes used to produce those gases. As part of the review to extend the framework to NGEs, consideration should also be given to the purpose of the definition of 'processable gas' and how that definition will be impacted by those proposed reforms. This is particularly relevant to mid-stream activities and the formal introduction of blending into the NGL framework and draws attention to existing ambiguities with how this term is applied across the framework particularly with respect to ringfencing.
8	Are there any other changes that you think need to be made to the NGL to accommodate NG equivalents and related facilities and activities?	See response to question 14.
Section 4.2.2: Extension to constituent gases and related facilities and activities		
9	What are you views on the proposal to amend the NGL to enable the national gas regulatory framework to apply to the constituent gases and related facilities and activities involved in the supply of NG equivalents (where appropriate to do so) set out in section 4.2.2?	The application of economic regulation under the NGL and NGR to constituent gases and related facilities, including pipelines, is a significant and complex issue which requires careful consideration given the long-term consequences which may result from these decisions. While it may be appropriate in some cases, it will not be true in all circumstances and in all future scenarios that constituent gas pipelines 'are likely to be natural monopolies and have a significant degree of market power' or that the current national regulatory framework is fit-for-purpose. In the context of an emerging market where investment in constituent gases and their related facilities will be critical to achieving Energy Ministers' objectives, the regulatory framework must provide flexibility to accommodate a range of potential market participants, facility types and commercial models. Accordingly, a robust analysis of the unique market dynamics faced by these assets is required to
10	What are your views on the proposal that pipelines involved in the transportation of a constituent gas (e.g. a hydrogen pipeline) be subject to economic regulation under the NGL and NGR?	
11	Are there any other observations you would like to make about the potential approach to extending the application of the NGL to constituent gases and related facilities and activities?	
12	Are there any other approaches that you think would better achieve the objectives of Energy Ministers (see section E.3)?	

No.	Questions	Feedback
13	Are there any other changes that you think need to be made to the NGL to accommodate constituent gases and related facilities and activities?	determine whether regulation will deliver the best outcomes for consumers and other market participants. For example, where it is preferable to integrate a constituent gas facility into an existing pipeline owned by a single service provider the application of economic regulation to the constituent gas facility may be appropriate. However, the framework should also recognise the potential risks to longer-term market development of applying economic regulation to constituent gas facilities owned and operated by third parties and which are potentially subject to competition. We believe that an appropriate degree of flexibility in this regard is likely to be best achieved by providing a constituent gas facility owner the ability to elect (or for a set of criteria to apply) to determine whether the facility should be integrated into an existing pipeline (and therefore potentially subject to economic regulation) or considered to be a 'standalone' facility (not subject to economic regulation).
Section 4.2.2: Extension of market bodies' functions and powers		
14	What are your views on the potential approach to extending market body functions and powers set out in section 4.2.3 to: NG equivalents and related facilities and activities? constituent gases and related facilities and activities?	Market bodies will play a key role in relation to the development of the renewable gas industry while also acting as a gatekeeper on ensuring that the national gas objective is met. However, in these early stages, it is not possible to identify how the market will develop and it is therefore not possible to identify with certainty the kinds of regulatory oversight that may be required. A degree of flexibility is required to ensure that the regulatory bodies can adapt to the renewable energy transition while not preventing or inhibiting the development of the market. Jemena considers that of the market bodies AEMO will play a key role in the renewable energy transition as ultimately many key issues are likely to be operational in nature. AEMO should have sufficient flexibility in the exercise of its statutory functions to be able to administer the relevant markets including the ability to grant exemptions (including temporary exemptions) from facilitated market registration requirements or from retail market procedures. Such exemptions are important to allow for trials and other innovative solutions to be considered.

No.	Questions	Feedback
		While we consider that the AEMC should have the powers to make rules to support and facilitate the renewable gas transition, we consider that such rules should only be made where a need arises for such rules. In our view, it is too early in the transition to establish prescriptive rules for NGEs and constituent gases until there has been sufficient time to test whether the existing framework can accommodate NGs and constituent gases.
15	Do you think arrangements are needed for distribution pipelines attached to the DWGM and STTM to provide for independent management of blending limits (or gas specification requirement) imposed by a jurisdiction? If you think AEMO or another third party should be responsible for this function, please explain what costs and benefits you think would be associated with it doing so.	The successful operation of pipelines to date has been underpinned by the respective roles of service providers, technical regulators and AEMO in relation to the operation of the pipelines, setting of technical specification and the operation of the related STTM. We see no reason to change these arrangements. As is the case presently, JGN has obligations under its jurisdictional licensing obligations to manage the safety and technical specifications of its gas network including ensuring any matter blended with natural gas meets the specification. We expect that these processes and protocols will continue. To the extent that additional technical and safety protections are required, these should be managed at the jurisdictional level. In NSW, there is an existing framework in place to address any additional arrangements for managing blends. For example, this could be addressed through the safety regulations, the general natural gas regulations, market operation rules or changes to the quality specification in AS4564. We understand that other jurisdictions have a similar framework.
16	Are there any other changes to market body functions and powers required to accommodate NG equivalents, their constituent gases, or related facilities and activities?	
17	Are there any other approaches that you think would better achieve the objectives of Energy Ministers?	
Section 4.3: Potential approach to extending the NERL		
18	What are your views on the potential approach to extending the application of the NERL to NG equivalents set out in section 4.3?	Customers of gas purchase energy which is delivered to them in the form of natural gas. Accommodating NGEs will not change the service or product a customer will

No.	Questions	Feedback
19	What are your views on the potential approach to extending the AER's and AEMC's functions and powers under the NERL to NG equivalents set out in section 4.3?	be receiving and therefore should not require material changes to the underlying framework. It's important to keep in mind that the a retailer does not purchase specific molecules of gas - the retailer purchases a quantity of gas to meet the quantity of gas consumed by their customers. As is the current situation, the molecules a customer consumes (and whether they form part of a blend or not) will change day to day based on localised injections and use of the pipeline. This is no different to the electricity market. However, we do consider that as the energy system transforms to provide renewable gas, distributors, retailers and governments all have a role to play to ensure customers receive transparent information regarding changes in the nature of gas that they may be receiving. The existing disclosure provisions in the NERL supported by the Australian Consumer Law provide a robust framework to ensure that customers receive accurate and clear information.
20	Are any other changes to the NERL or the market bodies' functions and powers under the NERL required to accommodate NG equivalents?	
21	Are there any other approaches that you think would better achieve the objectives of Energy Ministers (see section E.3)?	

Chapter 5: Accommodating other gas products in the NGL and NERL over time

No.	Questions	Feedback
Section 5.1: Potential approach to accommodating other gas products in the NGL		
22	What are your views on the potential approach to allowing the NGL to accommodate OG products over time, as described in section 5.1?	See our response to questions 9-11.
23	Could amending the NGL in the manner described in section 5.1 lead to any unintended consequences? If so, please explain what those unintended consequences may be.	
24	What are your views on the proposal to apply the economic regulatory provisions to pipelines involved in the haulage of OG products and their constituent gases?	
25	Are any other changes to the NGL required to accommodate OG products?	
26	Are there any other approaches that you think would better achieve the objectives of Energy Ministers (see section E.3)?	

Section 5.2: Potential approaches to accommodating other gas products in the NERL		
27	What are your views on the potential approach to allowing the NERL to accommodate OG products, as described in section 5.2?	The NERL already operates as a 'dual fuel' framework and has sufficient consumer protections in place to address customers electing to buy different energy fuels (i.e. electricity and gas). On the presumption that a OG product/service will be something separate from natural gas and electricity, we consider the same framework can be applied to those OG products and service. From a distributor perspective, we consider the AER approved connection contract process can adequately address customer led OG connections. The area of consumer protection that requires most consideration is the role that customer choice plays in the election of a particular fuel during the transition period but also over the long term. Some issues that require further consideration are: • Will customers or class of customers be entitled to a particular fuel source (electricity, NGE or OG)? • Where OG products and services are not the result of a Government mandate, how does the obligation to connect a customer apply? • Do distributors have the ability to reject applications to connect where it is not economically feasible (e.g. a particular part of the network is to be upgraded to a hydrogen only network)?
28	What are your views on the second potential approach to allowing the NERL to accommodate OG products, as described in section 5.2?	
29	Could amending the NERL in the manner described in section 5.2 lead to any unintended consequences? If so, please explain what those unintended consequences may be.	
30	Are any other changes to the NERL required to accommodate OG products?	
31	Are there any other approaches that you think would better achieve the objectives of Energy Ministers (see section E.3)?	

14 October 2021

Mr Sean Sullivan
Chair
Energy Senior Officials
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Sent by email

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Dear Mr Sullivan

Gas pipeline reforms – draft legal package

Jemena Gas Networks (NSW) Ltd welcomes the opportunity to provide a submission on the draft legal package for the gas pipeline reforms. Our network distributes gas to over 1.4 million residential, business and industrial sites in Sydney, Newcastle, the Central Coast, Wollongong and more than 20 regional centres.

Overall we understand the objective to implement a more efficient, effective and integrated regulatory framework that supports the efficient operation of the gas market and the long term interests of gas users; and is fit for purpose, targeted and proportionate to the issues it is intended to address.

However, we have identified several unintended consequences in regards to how the draft legal package applies to scheme distribution networks. These consequences arise as the one-size-fits-all approach doesn't take into account key differences between both scheme and non-scheme pipelines or distribution networks and transmission pipelines.

While we are supportive of making information more readily accessible for users, the adoption of a single information disclosure regime presumes all pipelines and networks have the same scope, size, form of regulation and types of users. A uniform approach is unlikely to meet all user needs, is duplicative and requires scheme pipelines to unnecessarily publish commercially sensitive customer information. Further, it will result in a greater administrative burden for the AER and service providers as well as creating additional complexity for users, who will have to navigate multiple information sources and publications.

Imposing the same information disclosure obligations on scheme and non-scheme pipelines and in particular, distribution networks, dismisses the strengths of the current regulatory framework which:

- features an existing robust information disclosure regime (including a standardised set of demand and financial information from 2011 – with an ongoing obligation to provide annual updates until at least 2030[1]); and

[1] Available here.

- places a general emphasis on the importance of including customer and stakeholder voices in the ongoing running of a covered (scheme) pipeline and the development of an access arrangement proposal.

It also fails to recognise that given our customer base, distribution networks (and in particular gas distribution networks) are experienced in communicating key information to users and customers as well as identifying deficiencies in those information communication channels. This is demonstrated by the last two Energy Network Consumer Engagement awards being won by scheme distribution pipelines, Jemena in 2019 and AGIG in 2020.

We consider that an alternative approach that capitalises on existing, well established regulatory processes can better achieve the policy goals of a more efficient, effective, targeted and proportionate regulatory framework.

We propose that information disclosure commitments be developed by scheme pipelines in conjunction with their customers, users and other stakeholders and submitted to the AER for approval as part of the access arrangement process. This will address user needs while being sufficiently flexible to account for the information differences between scheme pipelines – leading to better outcomes for customers, users, the AER and service providers. The information disclosure requirements would work as a backstop where the access arrangement process failed to attain the requisite information disclosure objectives.

Overall we consider that targeted consultation with scheme distribution networks is required to ensure the pipeline reforms are workable, fit-for-purpose and proportionate. As an example, amendments are required to align financial disclosure reporting years with regulatory years. As it stands, JGN would be required to publish financial information on a January-to-December basis as part of the disclosures while reporting information in the RIN on a June-to-July basis. This differences will cause confusion and increases costs (for example, two rather than a single audit would be required).

Attachments 1 and 2 provides further detail on the information flows that are already occurring, differences in requirements between scheme distribution and transmission pipelines (particularly around the nature of non-reference services) and our concerns with a single information disclosure framework. We also provide comments on the definition of small shipper. Attachment 3 and 4 provides suggested drafting to implement a solution that better addresses the information disclosure objectives with respect to distribution networks and to align reporting years.

Should you have any questions please do not hesitate to contact James Turnley, Gas Networks Regulation Manager, on (02) 9867 8659.

Yours sincerely,

Ana Dijanosic

General Manager Regulation

Attachment 1 – Further information

Information disclosure requirements

The policy problem to be addressed

The Decision Regulation Impact Statement (**Decision RIS**) outlined that the purpose of information disclosure requirements in the current regulatory framework is to:

- enable shippers to make a more informed decision about whether to seek access and to assess the reasonableness of a service provider's offer; and
- reduce the degree of information asymmetry and imbalance in bargaining power that shippers can face in negotiations with service providers and, in so doing, facilitate more timely and effective negotiations.

The Decision RIS noted that full regulation pipelines are not required to publish any information on non-reference services and that there are some inconsistences in what information they are required to report (compared to pipelines subject to Part 23 and light regulation). The RIS concluded (emphasis added):[2]

> *...the lack of information on non-reference services can hinder the ability of shippers to negotiate effectively, impose additional search and transaction costs on shippers and make them more susceptible to exercises of market power, particularly on transmission pipelines where non-reference services are more commonplace.*

The policy decision

Under option 3B, the preferred option, service providers will be required to disclose the following information:[3]

- basic information, including pipeline information, pipeline service information, service availability information, service usage information and standing terms for each offered service;
- historical financial and demand information; and
- information on the prices paid by other shippers to be based on the individual prices (including key terms and conditions) paid by shippers.

Further disclosure requirements have been amended to address alleged information deficiencies, improve the quality and reliability of information and improve accessibility and usability of the information disclosed.

Information currently provided

Attachment 2 sets out the information scheme distribution networks already provide. It is clear when a comparative analysis is undertaken that distribution networks largely already provide the information proposed to be required in Part 10 of the NGR.

[2] Energy Ministers, Decision Regulation Impact Statement, Options to Improve Gas Pipeline Regulation, p.70

[3] Unless an exemption is obtained. See Energy Ministers, Decision Regulation Impact Statement, Options to Improve Gas Pipeline Regulation, p.85

Non-reference services provided by distribution pipelines

Ultimately in the context of a scheme pipeline, the information disclosure requirements support access negotiations for non-reference services. In contrast the prices, terms and conditions for reference services are set under the access arrangement process.

It is important to take into account the context of, and the kind of, non-reference services that are provided by scheme distribution networks.

For JGN non-reference services are extremely uncommon. We only provide a single non-reference service (the operation and maintenance of a bespoke facility) with reference services making up around 99.98% of JGN's pipeline service revenue.

We have not sought to publish information on non-reference services (such as standing terms) as these services are rarely sought and rather than being on offer are developed *in response* to customer needs or a bespoke request.

Accordingly, we consider the comprehensive information disclosure regime proposed is not targeted or proportionate given the context and materiality of non-reference services offered by scheme distribution networks.

Inconsistencies in reporting requirements across pipelines are not regulatory gaps

The decision RIS has identified inconsistencies between the information disclosure requirements for pipelines subject to full regulation and those subjection to Part 23 and light regulation pipelines.

In reviewing these inconsistencies, it is clear from the perspective of scheme distribution pipelines, there is no regulatory gap. In particular:

- while scheme pipelines do not currently publish weighted average prices, this would have no value as all users pay the price listed on our tariff schedule for reference services;
- while there is no rule requirement for scheme pipelines to publish detailed historical demand and financial information, extensive information is reported to the AER and published as part of the reset and annual RIN processes; and
- while we do not have standing prices and terms and conditions for non-reference services, these are rare and developed in response to user needs.

The draft legal package

The draft legal package implements the policy decision via the introduction of a single information disclosure regime applying uniformly to scheme and non-scheme pipelines and distribution and transmission pipelines.

We understand that the intention is to apply an effective and efficient solution to reducing complexity, confusion and avoiding imposing unnecessary costs on service providers and shippers. A single information disclosure regime does not achieve these aims.

Instead, it has the potential to create issues in regulatory processes that are otherwise well established and are fit for purpose with no material benefits to regulatory transparency or for users. In particular the single information disclosure regime:

- does not take into account user needs (e.g. price, terms and conditions for access to reference services provided by scheme distribution networks are not negotiated);
- requires scheme pipelines to unnecessarily publish commercially sensitive customer information in relation to capacity and usage, putting our self-contracting users at a

disadvantage compared to their competitors which may contract through a retailer or use alternative energy sources. Publishing this information is not needed as all users pay the prices listed on our tariff schedule (as prices are not individually negotiated);

- duplicates several elements of information which is provided elsewhere in more meaningful forms (see Attachment 2 for the information that is already provided and which will be provided as part of the information disclosure requirements); and
- creates a secondary set of information and disclosures which will result in unnecessary confusion and, contrary to the intent of the reforms, reduce accessibility. An unintended effect of duplicating information reporting is that it will increase rather than reduce search costs. Including scheme and non-scheme distribution and transmission pipelines will also increase the complexity of the information disclosure guideline and the administrative costs of the AER.

Adopting a one-size-fits-all approach also fails to recognise the strengths of the regulatory framework which includes:

- an existing robust information disclosure regime; and
- focuses on customer and stakeholder voices in the development of access arrangement proposals.

An alternative approach

We have identified an alternative approach to achieve the information disclosure policy objectives while retaining the strengths of the current regulatory framework.

We propose that scheme pipelines engage with their users on what information would be useful to be disclosed as part of the established and well tested access arrangement process which allows for both user feedback and AER approval.

This approach will enable service providers to:

- develop a set of information disclosures which fits user requirements and individual pipeline circumstances. This can include how information on non-reference services will be provided including how price and cost information will be reported or standing terms and conditions' and
- take into account the existing robust information disclosure requirements to avoid duplication.

Importantly, this will provide the flexibility to apply a proportionate and targeted approach for both scheme distribution pipelines (which may offer no or limited non-reference services) and scheme transmission pipelines (where non-reference services are more common). In the case of the latter, the AER would have the power to impose the entirety of the information disclosure requirements set out in the Rules if it was not satisfied that the information disclosure commitments proposed satisfied user needs.

Accordingly and in any event, the new information disclosure requirements should come into effect for the next access arrangement.

Proposed drafting to implement this approach is set out in Attachment 3.

Further consultation is required

Overall we consider that further scheme distribution network specific consultation is required to ensure the pipeline reforms are workable, fit-for-purpose and proportionate.

While our alternative approach resolves most issues, we note that there are several areas where changes should be made so that the pipeline information disclosures work for scheme distribution networks. Examples include:

- aligning the reporting years of the information disclosures with regulatory years. While JGN's financial year operates on a January-to-December basis, regulatory reporting is on a June-to-July basis. Reporting the same information but across

different timeframes will lead to discrepancies and increase confusion as well as costs, as any synergies in reporting (for instance audit costs) will not be able to be realised; and

- extending the reporting timeframe from 4 months to 5 months, consistent with the AER's RINs, to account for distribution network periodic meter reading and billing. For instance, JGN reads most meters on a quarterly basis. As a result, actual demand usage and revenue is not known until at least 3-4 months after the end of a year (once all meters have been read and billing has occurred). This means that this information cannot be collated, reviewed, audited and published until 5 months after the end of the year. If a 4 month reporting timeframe is maintained greater reliance on assumptions and estimates will be required.

Proposed changes are set out in Attachment 4.

Small shippers

We do not support the proposed definition of a small shipper with a daily capacity of threshold of 5 TJ/day for several reasons:

1. The proposed threshold takes no account of the size or sophistication of the prospective user—what is defined is not a 'small shipper' but a 'small access request'. This therefore does not appear to reflect the policy intent behind the introduction of the 'small shipper' measures.
2. Large users do not need to initially seek access for a large amount of capacity or to supply a large number of customers. For instance, a retailer may seek access to a network before running a large campaign to encourage a large number of customers to switch from other retailers.
3. It is not clear how the thresholds apply to distribution networks where there is often no daily capacity right.

Accordingly, we suggest that a measure which accounts for the size of a shipper's business is more appropriate.

If this approach is not adopted then an alternative test for distribution networks could be a developed based on annual throughput and customer numbers (or delivery points). For instance a threshold of less than 10,000 customers and annual throughput less than 0.75 PJs – which is about the median consumption of our self-contracting users.

Attachment 2 – Information currently provided by distribution scheme pipelines

Scheme distribution networks already provide most, if not all, of the information that the proposed reforms require distribution networks to duplicate as part of the Part 10 information disclosure obligations. In JGN's case we provide the information through the following channels:

- Access Arrangement Proposals / Access Arrangement Information – Sets of documents which provide the information for users and prospective users to understand the background to the access arrangement and to understand the basis and derivation of various elements of the Access Arrangement;
- Access Arrangement and Reference Service Agreement – Documents which set out the terms and conditions of access to our reference service (as approved by the AER);
- Tariff variation notices / tariff schedules – Documents which reveal the prices paid by all customers to use our reference service;
- Basic information – Pipeline information, pipeline service information, service usage information.
- Additional pipeline information – Information frequently requested by customers, for instance average gas consumption by Local Government Area.[4]
- RINs responses which:
    - provide extensive sets of information covering our expenditure, network characteristics (customer numbers, throughput, network length, city gates/regulators), service quality (reliability etc.) and financial information (income, revenue, capital base etc.).
    - are provided in a manner set by the AER, including information quality assurance controls such as audit requirements and the reporting on the application of Cost Allocation Methodologies;
    - are fit-for-purpose for distribution pipelines;
    - imposes consistency in reporting across both scheme pipelines[5] and time – data has been reported on a consistent basis from 2011 and will be required to be provided annually until at least 2030;
    - empowers users to engage in the Access Arrangement process; and
    - are reported and analysed by the AER as part of its preparation of its annual distribution performance report (first report to be published by the end of 2021) and profitability reports, in addition to the usual analysis conducted as part of a access arrangement process.

In addition, JGN also provides additional information in a variety of forums. These include:

- our annual large customer forum[6];
- Ad-hoc virtual workshops (for instance on renewable gas in August 2021 or on-going engagement on the development of a Gas Network Innovation Scheme).

[4] This information is available here.

[5] It is not the case as suggested in the Decision RIS that "RINs tend to reflect the systems and processes that individual service providers have in place which differ markedly across service providers." as can be seen in the RIN responses published on the AER's website here.

[6] Invitees to the large customer forum also include shippers and consultants.

- ad-hoc information requests from the AER, Governments, users, customers, other stakeholders;
- regular Customer Council meetings.
- one-on-one engagements (including regular meetings with all shippers, including retailers and self-contracting users);
- AEMO forums such as the Gas Retail Consultative Forum.
- customer, stakeholder and retailer engagement as part of the development of our access arrangement proposal (we note that our most recent engagement program won the 2019 customer engagement award); and
- on request by users or customers. For instance, we are currently developing a standard set of performance standards on service orders which we intend to regularly report on direct to users.

Additional information is also published by the AER in making its Access Arrangement decision.

Attachment 3 – Proposed alternative to address information disclosure objectives

See proposed amendments in red to the relevant provisions of the proposed National Gas Rules.

48 Requirements for full access arrangement (and full access arrangement proposal)

(1) A full access arrangement must:

…

(j) if there is to be an *expiry date* – state the *expiry date*;

(k) in relation to a *distribution pipeline*, having regard to the *pipeline information disclosure guidelines* and information already provided to *users* and *prospective users*, identify the form and location for publishing the following additional information for *users* and *prospective users*:

(i) the kind of service and access information in rule 101B;

(ii) the kind of financial information, historical demand information and a cost allocation methodology specified in rule 101D;

(l) include a user access guide that meets the requirements of rule 105B(6).

Note:

A full access arrangement may contain an *expiry date* if it is a voluntary access arrangement (but not otherwise) – See rule 49.

Part 10 Prescribed Transparency Information

Subdivision 2 Exemptions from information disclosure requirements

New 102(8)

(8) A service provider for a scheme pipeline is taken to be exempt from this Part 10 if the service provider's access arrangement specifies an alternative form of information disclosure for some or all of the information required to be disclosed in accordance with this Part.

(9) Notwithstanding rule 102(8), the *AER* may exempt a service provider for a scheme pipeline from the requirement to comply with Part 10 where there will be no material benefit to a user from the service provider complying with this Part 10.

Part 11 Access negotiation framework

105 Definitions and interpretation

New (5)

(5) For the purposes of this Part, a service provider for a scheme pipeline will be taken to have complied with this Part if any required information is published in accordance with the service provider's access arrangement.

Attachment 4 – Proposed alternative to align reporting years

See proposed amendments in red to the relevant provisions of the proposed National Gas Rules.

100 Definitions and interpretation

(1) In this Part:

…

… **financial information, historical demand information and cost allocation methodology** means the information published under rule 101D.

financial year means:

(a) in the case of non-scheme pipelines, the financial year of the service provider; and

(b) in the case of scheme pipelines, the relevant regulatory year as determined by reference to the scheme pipeline's access arrangement.

flow rate means the rate at which gas flows past a point on a pipeline in an hour, expressed in GJ/hour

…

101A Obligation to publish information

…

(2) The information referred to in subrule (1) must be published at the following times.

…

financial information, historical demand information and cost allocation methodology	Annually no later than ~~four~~ five months after the end of the financial year.~~ of the service provider for the pipeline.~~

…