Australian Energy Market Commission

RULE

Consultation paper

National Gas Rule Amendments 2026 (Gas networks in transition)

Proponents

Energy Consumers Australia

Justice and Equity Centre

18 September 2025

Inquiries
Australian Energy Market Commission
Level 15, 60 Castlereagh Street
Sydney NSW 2000

E aemc@aemc.gov.au
T (02) 8296 7800

Reference:

About the AEMC
The AEMC reports to the energy ministers. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the energy ministers.

Acknowledgement of Country
The AEMC acknowledges and shows respect for the traditional custodians of the many different lands across Australia on which we all live and work. We pay respect to all Elders past and present and the continuing connection of Aboriginal and Torres Strait Islander peoples to Country. The AEMC office is located on the land traditionally owned by the Gadigal people of the Eora nation.

Citation
To cite this document, please use the following:
AEMC, Gas networks in transition, National Gas Rule Amendments 2026, Consultation paper, 18 September 2025

Summary

1 Natural gas has been an important source of reliable and affordable energy for Australians for many decades. Today, many households and small commercial consumers rely on gas to cook food and for heating and cooling purposes. Some industrial customers also use natural gas as a feedstock.

2 Natural gas is likely to continue to play an important role in industrial processes into the future. Gas-fired power generation is likely to build its role as an important 'firming' tool supporting Australia's transition to an energy system that is largely based on variable renewable energy resources. However, there is currently uncertainty about the future role of gas distribution networks in supplying gas to households and small commercial customers. This is due to both increasing rates of household and small commercial customer electrification and jurisdictional policies and net zero targets.

3 The Australian Energy Market Commission (AEMC, or Commission) is seeking feedback from stakeholders on rule change requests from Energy Consumers Australia (ECA) and the Justice and Equity Centre (JEC) (together, the proponents). The proponents propose changes to the National Gas Rules (NGR) to ensure that the economic regulatory framework that applies to gas distribution networks supports the long term interest of consumers in light of the uncertain outlook for gas demand by residential and small commercial consumers. The consultation paper is also seeking feedback on whether changes to other interrelated elements of the regulatory framework may be required. We are interested in stakeholder feedback in relation to whether the specific issues identified by ECA and JEC relate to the issues with the NGR or application thereof and if the proposed solutions would support the long-term interests of consumers.

4 The Commission will consider whether the current economic regulatory framework continues to be 'fit for purpose'. In other words, is the current regulatory framework, which is predicated on the assumption of growing gas demand, flexible enough to support the long-term interest of consumers throughout the transition or are changes needed?

5 The Commission has examined a range of different approaches that regulators in other jurisdictions and industries have applied to manage the risks of uncertain or declining demand. Appendix A outlines our findings based on the case studies that we have examined. Appendix B provides a Summary of the regulatory framework under the NGR as it currently applies to gas pipelines (which comprise gas transmission and distribution networks).

Gas distribution networks are facing an uncertain outlook under the energy transition

6 The energy sector in Australia is experiencing a period of profound change. All Australian governments have committed to a net zero emissions target by 2050 (or earlier). A key part of achieving this target is the need to manage the emissions produced from the combustion of natural gas by reducing our use of natural gas, either through electrification or substituting natural gas with renewable gases.

7 As the energy transition progresses, an increasing number of residential and small commercial gas users are expected to electrify, replacing gas appliances with electric appliances. In some jurisdictions, government policies are driving the electrification trend. In other jurisdictions, consumers are leading the electrification trend as they seek to maximise the value of their consumer energy resources, such as rooftop solar and batteries. This outlook is driving projections by the Australian Energy Market Operator (AEMO) and gas distributors, forecasting a

significant decline in gas demand in the residential and small commercial customer segment into the future.

8 Projected changes in future gas demand are likely to impact both the volume of gas used by consumers and, potentially, the number of connections to the gas network. While there appears to be general consensus that the volume of gas demand in the residential and small commercial customer segment will decline, based on AEMO and gas distributors' own forecasts, there is a significant degree of uncertainty surrounding both the rate and extent to which it will decline. In part, this is due to differences in jurisdictional decarbonisation policies. But it also reflects differences in consumer preferences and a recognition that some consumers will find it difficult to electrify. Some gas distributors also envisage a future in which their gas networks are repurposed to supply renewable gases.

The challenges of the gas transition will grow, impacting consumers and gas distribution networks

9 A decline in gas demand is likely to have a range of adverse effects on network users and gas distributors. For network users, decreasing demand would place upward pressure on network charges, because the largely fixed costs of providing services must be recovered over declining volumes per connection (and potentially, a declining customer base). These price increases may, in turn, incentivise more customers to leave the network, leading to further increases in prices and, potentially, further disconnections. Unless governments and businesses develop transition plans, households and small commercial customers that choose not to, or are unable to, electrify will bear a greater portion of costs to meet changes in gas usage. The disparity in how small consumers engage with the energy market creates the risk of growing inequities that must be carefully managed to avoid undermining confidence in the energy market.

10 For gas distributors, the prospect of declining demand increases the risk that they may be unable to fully recover the costs of their efficient capital investments. The perceived inability to recover costs may affect the incentives of gas distributors to continue to operate the network and provide a safe and reliable service to remaining users. If a critical mass of customers leave the network, then the option of repurposing the gas network to supply renewable gases may no longer be feasible, potentially prompting inefficient decisions around the decommissioning of the gas network.

11 The uncertain outlook for gas demand in the residential and small commercial customer segment is already posing challenges for regulators, gas distributors and network users. This is likely to become more challenging over time as the energy transition progresses. The key challenge presently is how to efficiently manage capital cost recovery risks and the risk of materially higher gas prices for consumers. Beyond this, 'unmanaged' declining gas demand could have implications for the safe and reliable supply of gas services with demand reduction affecting gas pressure levels. Loss of supply and lower reliability may also result from gas network financial distress and gas retailers exiting the market.

The regulatory framework must be flexible and capable of adapting to an uncertain future

12 The increasingly complex and uncertain gas transition poses the question of whether the gas regulatory framework set out in the NGR continues to be fit for purpose to manage gas networks in transition. By 'fit for purpose' we mean: Is the current regulatory framework, which is predicated on the assumption of growing gas demand, flexible enough to support the long-term interest of

consumers throughout the transition or are changes needed?

13 It is in this context that ECA and JEC have submitted rule change requests to address issues with particular elements of the regulatory framework in relation to gas distribution networks. We note that the current NGR framework regulates scheme and non-scheme pipelines and does not specifically distinguish between transmission and distribution networks.

14 The changes proposed by ECA and JEC would predominantly affect scheme pipelines (i.e. gas networks subject to the economic regulatory framework in the NGR). However, we note that some of the changes will also affect non-scheme pipelines, and we draw this out in this paper where relevant.

15 The rule change requests considered in this consultation paper are:

- **Capital expenditure criteria.** ECA propose changes to the criteria used by scheme pipelines that are gas distribution networks to propose, and the regulator to determine, whether capital expenditure is justifiable. ECA consider that the current criteria do not adequately account for declining demand and could result in investment in new assets that subsequently risk becoming underutilised.
- **Depreciation.** ECA propose changes to the depreciation criteria to impose stronger conditions on when scheme pipelines that are gas distribution networks can propose, and the regulator can approve, the accelerated recovery of the capital base. ECA consider that the current use of accelerated depreciation shifts all risk and costs for assets at risk of becoming increasingly underutilised to gas consumers, while imposing no costs or risks to gas distributors.
- **Accelerated depreciation and redundancy.** JEC propose changes to prohibit the use of accelerated depreciation to manage capital cost recovery for assets at risk of becoming increasingly underutilised unless the regulator has undertaken a redundancy assessment. On this basis, service providers and the regulator can only use accelerated depreciation if the asset meets the proposed definition of a redundant asset, or anticipated redundant asset, and the regulator has determined how the redundant asset costs should be shared between users and a gas distributor. JEC has proposed this as an alternative to ECA's proposal to amend the depreciation criteria.
- **Planning requirements.** ECA propose changes to impose new planning and reporting obligations on all gas distribution networks. ECA consider that stakeholders currently have limited information to understand the opportunities to minimise expenditure and energy system costs, including through the strategic decommissioning of (parts of the) gas distribution networks.

We are proposing to consolidate the rule change proposals and consider related issues as part of this rule change process

16 The Commission is jointly consulting on the ECA and JEC rule change requests due to the interrelated nature of the issues raised and the solutions proposed. We consider that the breadth of issues and potential solutions means there is value in taking a holistic approach. At a high level, the economic regulatory framework for gas pipelines comprises various interrelated elements that operate as a package to promote the NGO. The key components of the package are a combination of ex-ante estimates of efficient costs over a fixed regulatory period, the regulated rate of return and a service provider's ability to receive a higher return from outperforming in conjunction with financial incentive mechanisms. A change to one element has implications for the other components of the package. The Commission must consider changes to individual elements of the package in the context of the broader economic regulatory framework to ensure that it

continues to operate effectively, as a whole, to promote the National Gas Objective (NGO). On this basis, we will determine whether changes are required to ensure the regulatory framework remains fit for purpose and continues to promote the long-term interests of gas consumers through the energy transition.

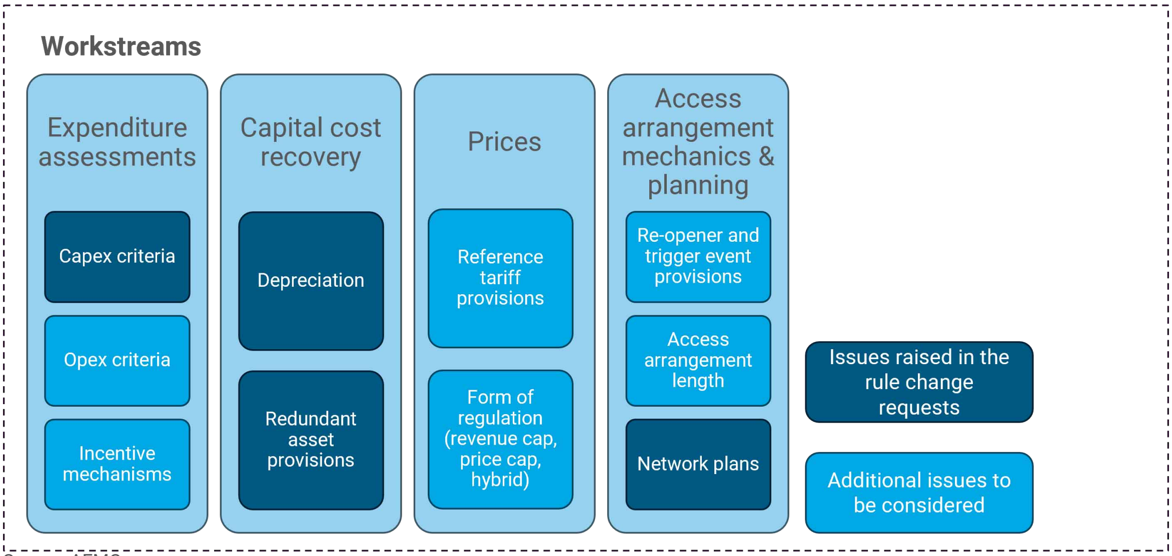
17 Therefore, we propose to consolidate the ECA and JEC rule change requests and consider whether other changes to interrelated elements of the regulatory framework may be required. To explore the need for change to interrelated elements of the economic regulatory framework, we are asking the following questions:

- **Would a longer-term outlook support better decisions?** We are interested in understanding whether a longer-term outlook period for demand and expenditure forecasts would improve regulatory decision-making. A longer-term outlook as part of each access arrangement process could enable the regulator to better understand how future decisions are impacted by decisions in the current access arrangement.
- **Are additional regulatory tools needed to manage demand risk?** We are interested in understanding whether the regulatory tools available to manage demand risk are appropriate. Providing more guidance to the regulator on the use of tariff variation mechanisms could assist them in better accounting for demand risk, and changes to the tariff rules could ensure more efficient price signals are provided to consumers.
- **Are additional regulatory tools needed to manage unforeseen events or material changes?** We are interested in understanding whether existing access arrangement variation mechanisms to manage these risks remain fit for purpose. Providing the regulator with more flexibility to respond in a rapidly changing environment may improve consumer outcomes, but could also undermine the access arrangement process and reduce investment certainty.
- **Are the existing incentives appropriate to support the transition?** We are interested in understanding whether changes to the existing or additional incentives are required for gas distributors to maintain service levels in the context of uncertain gas demand.

We have organised the issues into four workstreams

18 Due to the breadth and interrelated nature of the issues we are considering in this consultation paper, the Commission has grouped the issues into four broad workstreams: expenditure assessments, capital cost recovery, prices, and access arrangement mechanics and planning (see Figure 1 below).

Figure 1: Gas networks in transition - workstreams



Source: AEMC.

19 As Figure 1 highlights, the Commission is conscious of two important considerations as we examine the appropriateness of the gas economic regulatory framework to support the long-term interests of gas consumers:

- While the changes proposed by ECA and JEC focus on gas distribution networks, declining gas demand could have implications for transmission pipelines. This is because the costs of operating the transmission pipelines may need to be spread across lower volumes. It may also affect investment incentives more generally across the energy sector. The Commission will need to consider what, if any, implications declining demand could have for transmission pipelines connected to the gas distribution networks and users of those transmission pipelines. We note that with some limited exceptions, scheme transmission and distribution pipelines are subject to the same regulatory framework in the NGR. Any changes that are made to the regulatory framework would therefore need to consider the implications for transmission pipelines.
- The Commission notes that there are limits to what can be achieved through changes to the NGR in terms of addressing the challenges that gas distributors and network users are likely to face through the transition. Other solutions outside the NGR, including governmental policies, changes to the national gas law, etc. may be necessary to comprehensively address the impacts of uncertain gas demand. However, we note that these are decisions that are not within the Commission's remit. The Commission will continue to closely engage with jurisdictions throughout this rule change process to inform our considerations.

The National Gas Objective will guide our decision-making

20 Our objective is to ensure that, as a whole, the regulatory framework remains fit for purpose through the energy transition and continues to support the long-term interests of energy users. The national gas objective will guide our decision-making process.

21 We propose to assess the solutions proposed by ECA and JEC in their rule change request/s and any alternative solutions to address the issues resulting from declining gas demand against the following six assessment criteria:

- **Outcomes for consumers**. Would the solution protect small customers from unnecessary cost burdens, including vulnerable and 'hard to electrify' consumers that remain on the gas network? Importantly, we will consider whether a solution is consistent with our work on equity for energy consumers. An energy system that supports equitable outcomes across households regardless of their energy choices will empower households to choose if, how, and when to participate in energy markets.
- **Safety, security and reliability**. Would the solution preserve incentives on service providers to efficiently invest in their assets to provide a safe, secure, and reliable gas service in the context of a projected decline in gas demand and increasing uncertainty as to the prospect of recovering efficient costs?
- **Emissions reduction**. Would the solution support emissions reduction?
- **Principles of market efficiency.** How would different solutions to address cost recovery risk balance incentives on service providers to invest efficiently in their networks and potentially plan for strategic decommissioning? We will assess how different solutions would result in an efficient allocation of risks and costs to appropriate parties: whether a solution would provide for service providers to continue to invest efficiently in their networks or whether a solution would inefficiently bring forward the closure of pipeline assets.
- **Implementation considerations.** The changes to the gas economic regulatory framework could profoundly change how scheme pipelines are regulated. We will need to consider the appropriateness of the regulatory framework during different stages of the energy transition. We will also consider how our reforms interact with other energy transition-related reforms and, importantly, how they interact with specific jurisdictional policies and gas transition pathways. We will also ask what would be the impacts of a solution on investment in the industry more broadly, including in the electricity market?
- **Principles of good regulatory practice**. We will assess how the solution contributes to a predictable and stable regulatory framework and how it aligns with the broader direction of gas market reform. Importantly, we will consider if a solution provides the regulator with sufficient flexibility to adapt its approach accordingly as the energy transition progresses.

Our related work program

22 The Commission is progressing several related rule change requests that are relevant to the to ECA and JEC rule change requests. You can find more information about these rule change projects by visiting our website.

- **Updating the regulatory framework for gas connections**. ECA submitted a rule change request on 14 February 2025 proposing changes to gas connection charges. ECA noted that, under current arrangements, many customers face no upfront cost to establish a new gas connection and the cost is socialised among all gas distribution network customers. ECA considered that this results in inequitable cost sharing, as it contributes to increasing costs for remaining gas customers in the context of a future declining customer base. The current arrangements also contribute to a growing capital base and thus increase the issues around cost recovery. The Commission published a draft determination and draft rule on 18 September 2025.
- **Establishing a regulatory framework for gas disconnections and permanent abolishments.** JEC submitted a rule change request on 9 May 2025 proposing a new regulatory framework for temporary disconnections and permanent abolishments. JEC consider the current absence of a framework is leading to inconsistent regulatory decisions, and that there is a need for regulatory guidance on what services gas distributors should provide and cost recovery. JEC's

proposal seeks to ensure customers are paying no more than they need to disconnect from the gas network (either temporarily or permanently). The Commission will publish our draft determination and draft rule (if made) at the end of October.

Submissions are due by 30 October 2025 with other engagement opportunities to follow

23 Stakeholders can help shape the solutions by participating in the rule change process. Engaging with stakeholders helps us understand the potential impacts of our decisions and, in so doing, contributes to well-informed, high quality rule changes.There are multiple options to provide your feedback throughout the rule change process.

24 Written submissions responding to this consultation paper must be lodged with Commission by **30 October 2025** via the Commission's website, www.aemc.gov.au.

25 We have included questions in each chapter to guide feedback, and the full list of questions is below. However, you are welcome to provide feedback on any additional matters that may assist the Commission in making its decision.

26 The Commission notes the large number of questions included in this joint consultation paper covering four rule change proposals from ECA and JEC, and identifying other areas of the economic regulatory framework that the Commission proposes to consider due to their interrelated nature. We encourage stakeholders to only respond to the consultation questions that they have a particular interest in and view on. Stakeholders should also specify which rule change proposals their submission relates to.

27 There are other opportunities for you to engage with us, such as one-on-one discussions or industry briefing sessions. See section of this paper about "How to engage with us" for further instructions and contact details for the project leader.

Full list of consultation questions

Question on proposed scope of the project

Question 1: What are the issues impacting consumers and gas distributors under the energy transition?

1. Do stakeholders agree that there is value in considering the additional NGR issues we have identified alongside the issues raised in the rule change requests?
2. Are there any other additional issues that we should consider within the NGR framework? If so, why?
3. Noting the AEMC's role is to consider and make changes to the energy rules, are there changes outside the NGR regulatory framework that are required to address the issues raised in the rule change requests?

Questions on ECA's and JEC's rule change proposals

Question 2: What changes, if any, should be made to the NGR capital expenditure criteria?

1. Are changes required to the current capital expenditure criteria to better account for uncertainty in future gas demand? If so, would ECA's proposed amendments better account for uncertain demand outlooks than the current criteria?

2. What do you consider would be the benefits and costs of ECA's proposed approach (for consumers, service providers and the regulator)?
3. Are there any alternative, preferable solutions to address the issues identified by ECA with the current capital expenditure criteria?
4. Do you consider changes are required to the rules in relation to advance determinations on capital expenditure in the context of the energy transition (rule 82)? If so, what are your views on the changes proposed by ECA (removing the provision or requiring the regulator to undertake consultation on proposals for advance determinations)?
5. Do you consider that additional types of expenditure may need to be recognised as capital expenditure in the context of the energy transition (e.g. decommissioning expenditure)?

Question 3: Are any changes required for operating expenditure?

1. Do you consider the current definition of operating expenditure (which includes expenditure for increasing long-term demand for pipeline services) is fit for purpose in the context of the energy transition?
2. Do you consider there are additional types of operating expenditure that may need to be recognised in the context of the energy transition?
3. Do you consider the regulatory framework appropriately balances the incentives between capital intensive solutions and asset management/maintenance solutions so that service providers have incentives to consider the most efficient options to address network needs? If not, what changes would be required to balance these incentives?

Question 4: Does the current framework effectively manage and allocate risk and costs between consumers and network service providers in the context of uncertain demand?

1. Do you agree with ECA and JEC that the current rules do not provide for appropriate consideration and management of assets at risk of becoming increasingly underutilised in the context of the energy transition, including consideration of how risk and costs are allocated between network service providers and consumers (including present and future consumers)?
2. Are there alternative solutions to those proposed in the ECA and JEC's rule change requests that would more effectively address cost recovery risks for efficient past and future investments?

Question 5: How does ECA's proposal impact the recovery of capital costs for new and existing assets?

1. Do you consider changes are required to the depreciation provisions in the context of the uncertain outlook for gas demand (in terms of limiting variations to the rate of cost recovery and changes to asset lives)?

2. What do you consider would be the benefits and costs of ECA's proposed approach to restrict the use of accelerated depreciation through variations to the rate of cost recovery and changes to asset lives (for consumers, service providers and the regulator)?
3. What are your views on ECA's alternative solution of prohibiting the regulator from varying the depreciation rates for existing assets?

Question 6: How does JEC's proposal impact the recovery of capital costs ?

1. Do you consider changes are required to the capital redundancy provisions in the context of the energy transition and an uncertain gas demand outlook? If so, what amendments do you consider are necessary?
2. Do you consider the definition of redundant assets should be amended as proposed by JEC to include:
   a. assets that are economically inefficient to use?
   b. anticipated redundant assets?
3. Do you agree with JEC's proposal that service providers and the regulator should use accelerated depreciation in conjunction with the redundant asset provisions only if used to address capital cost recovery risks or redundancy?
4. What do you consider would be the benefits and costs (for consumers, service providers and the regulator) of JEC's proposed approach to:
   - defining and assessing asset redundancy, and
   - allowing for accelerated depreciation to address capital cost recovery risks only in conjunction with the redundant asset provisions ?
5. What are your views on JEC's alternative solution to outright prohibit the use of accelerated depreciation?

Question 7: Are new planning requirements necessary?

1. Do you consider new planning-related reporting obligations for network service providers are required in the NGR to support more efficient decision-making by stakeholders? If so,
   a. what information should be reported and for what purpose?
   b. what should be the reporting frequency?
   c. what pipelines should the requirements apply to,: scheme, non-scheme, distribution, transmission?
2. What do you consider would be the benefits and costs of ECA's proposed reporting requirements (for consumers, industry, gas and electricity network businesses and the regulator)?
3. Do you consider that any alternative solution would better promote the long term interest of consumers?

Other issues that may impact the effectiveness of the overall economic regulatory framework

Question 8: Would a longer-term outlook on the gas transition support better regulatory decision-making?

What do you consider would be the costs and benefits of requiring service providers to provide demand and expenditure forecasts over a longer period than the relevant access arrangement period? What would be an appropriate longer-term period (e.g. 10, 15 or 25 years)?

Question 9: Are changes to reference tariff variation mechanisms necessary?

1. Do you consider the NGR should provide more guidance to the regulator on when different reference tariff variation mechanisms (e.g. revenue cap vs price cap) should be used by service providers to appropriately allocate intra-period demand risk between the service provider and users?

2. If so, what would be the costs and benefits to consumers, service providers and regulators of providing more guidance in the NGR and/or bringing forward the regulator's decision on the applicable reference tariff variation mechanism?

Question 10: Are changes to the tariff rules necessary?

Do you consider the NGR should include more or different guidance to service providers on how reference tariffs should be structured in the context of the energy transition?

Question 11: Should the regulator be able to require shorter or longer access arrangement (AA) periods?

1. Do you consider the regulator should have more discretion to require a shorter or longer AA period than that proposed by the service provider? If so, what should be the criteria/principles to guide a regulator's decision on requiring a different AA period?
2. What do you consider would be the benefits and costs of aligning the timing of electricity and gas distribution decisions in relevant jurisdictions? What impacts would the alignment of the timing of these decisions have on regulators, service providers and stakeholders engaging in these processes?

Question 12: Are changes required to the re-opener provisions?

1. Do you consider changes are required to the current re-opener provisions? If so, what changes do you consider are appropriate in the context of the energy transition?
2. What would be the costs and benefits of making changes to the re-opener provisions?

Question 13: Should there be changes to the existing or additional incentive mechanisms?

Do you consider modified or additional incentive mechanisms should apply to service providers in the context of the energy transition?

Question 14: Could the proposed changes inefficiently incentivise pipeline elections?

Would any of the changes considered in this consultation paper alter the incentive for non-scheme pipelines to elect to become scheme pipelines?

Question 15: What can we learn from other jurisdictions/sectors?

Do you consider other changes to the regulatory framework for scheme pipelines are necessary to provide the regulator with the tools and appropriate level of discretion to manage the gas transition? If so, what would be beneficial?

Proposed Assessment Criteria

Question 16: Assessment framework

Do you agree with the proposed assessment criteria? Are there criteria that you consider are not directly relevant to the issues raised in the rule change requests and the proposed solutions?

How to make a submission

How to make a written submission

Due date: Written submissions responding to this consultation paper must be lodged with Commission by **30 October 2025**.

How to make a submission: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code **GRC0082**.[1]

Tips for making submissions are available on our website.[2]

Publication: The Commission publishes submissions on its website. However, we will not publish parts of a submission that we agree are confidential, or that we consider inappropriate (for example offensive or defamatory content, or content that is likely to infringe intellectual property rights).[3]

Other opportunities for engagement

We encourage stakeholders to engage with us through this consultation process through one-on-one discussions. Please contact the AEMC if you would like to arrange a meeting.

For more information, you can contact us

Please contact the AEMC with questions or feedback at any stage.

Email: submissions@aemc.gov.au

Telephone: 02 8296 7800

1 If you are not able to lodge a submission online, please contact us and we will provide instructions for alternative methods to lodge the submission.

2 See: https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request/submission-tips.

3 Further information is available here: https://www.aemc.gov.au/contact-us/lodge-submission.

Contents

Tables

Figures

1 Context and overview

The Australian Energy Market Commission (AEMC or Commission) is consulting on four separate rule change requests from Energy Consumers Australia (ECA) and the Justice and Equity Centre (JEC) (together, the proponents).[4] The proposed changes to the National Gas Rules (NGR) seek to:

- address issues with particular elements of the regulatory framework in relation to gas distribution networks, to ensure that the economic regulatory framework that applies to gas distribution networks remains fit for purpose in the context of Australia's energy transition
- improve outcomes for consumers in light of the uncertain outlook for and projected decline in gas demand by residential and small commercial consumers.[5]

The proposed changes are relevant to scheme pipelines. Most distribution networks are scheme pipelines that service the major demand centres in Victoria, New South Wales (NSW), the Australian Capital Territory (ACT), South Australia, and Western Australia (WA).

The gas pipeline regulatory framework shares some similarities with the regulation of electricity networks. However, there are some key differences. For example, the gas pipeline regulatory framework is based on a negotiate-arbitrate regulatory model. Another key difference from the approach to electricity is that they are not subject to any specific planning requirements (e.g., they are not required to produce annual distribution planning reports).

Box 1: Scheme and non-scheme pipelines under the regulatory framework

Under the current regulatory framework, pipelines are classified as either scheme or non-scheme pipelines, noting that this classification applies to distribution and transmission pipelines. Appendix B provides more detail.

- **Scheme pipelines** are subject to a **stronger form of regulation** that requires the service provider to have its proposed access arrangement approved by the regulator on a periodic basis. The access arrangement sets out the prices and other terms and conditions of access to the reference service(s) offered by the pipeline. Under this form of regulation, prospective users can either procure reference services on the terms and conditions set out in the access arrangement, or negotiate access to alternative services, prices and/or conditions of access.
- **Non-scheme pipelines** are subject to a **lighter form of regulation**, which does not involve any form of regulatory approval of prices or terms and conditions of access. This is instead left to commercial negotiations. Under this form of regulation, service providers must comply with the same access related obligations, disclosure requirements and negotiation framework as scheme pipelines to support commercial negotiations.

Source: AEMC.

This consultation paper considers the following rule change requests::

- **Capital expenditure criteria** (GRC0083): ECA propose changes to the criteria used to determine whether capital expenditure proposed by scheme pipelines that are gas distribution

4 ECA and JEC have separately submitted two rule change requests on connections and disconnections.ECA propose to charge customers upfront for a new gas connection, while JEC propose to establish a regulatory framework for temporary disconnections and permanent abolishment. The Commission is separately consulting on these rule change requests, and you can find out more by visiting the project page https://www.aemc.gov.au/rule-changes/establishing-regulatory-framework-gas-disconnections-and-permanent-abolishment.

5 Declining gas demand, when used throughout this consultation paper, refers to the projected decline in gas demand in the residential and small commercial customer segment.

networks is justifiable. ECA's proposal would require, amongst other things, the service provider and the regulator to give explicit consideration to the impacts of declining demand.[6]

- **Depreciation** (GRC0082): ECA propose stronger conditions on when scheme pipelines that are gas distribution networks and the regulator can accelerate the recovery of capital costs through changes to the depreciation criteria.[7]
- **Accelerated depreciation and redundancy** (GRC0088): JEC propose changes to the depreciation and redundant asset provisions applying to gas distribution networks. JEC's proposal would prohibit service providers and the regulator using accelerated depreciation for the purpose of managing capital cost recovery for assets at risk of becoming unused or increasingly underutilised, unless the regulator has undertaken an assessment of asset redundancy and determined how the redundant asset costs should be shared.[8] JEC has proposed this as an alternative to the ECA's Depreciation rule change proposal.
- **Planning requirements** (GRC0084): ECA propose new planning reporting obligations on all distribution networks. ECA's proposal would provide regulators, governments, electricity networks and other stakeholders with information required to understand the opportunities to minimise expenditure and energy system costs.[9]

The proposed changes to the capital expenditure, depreciation, and asset redundancy provisions would apply to scheme pipelines. The proposed changes to planning requirements would apply to both scheme and non-scheme pipelines.[10] Figure 1.1 below outlines the proponents' proposed application of the rule changes.

6 ECA, Rule change request - Capital expenditure, p. 5.

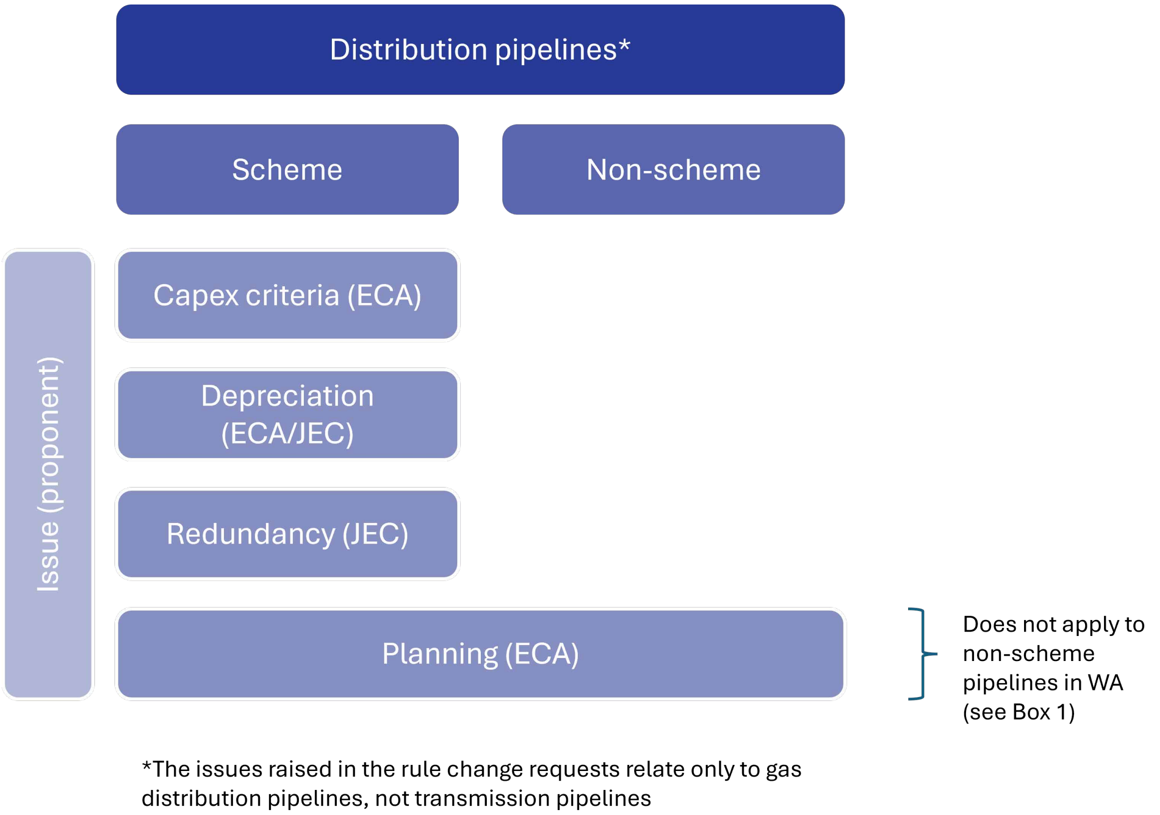
7 ECA, Rule change request - Depreciation, p. 5.

8 JEC, Rule change request - Accelerated Depreciation and Redundancy, pp. 9 and 13.

9 ECA, Rule change request - Planning requirements, p. 5.

10 Appendix B provides an overview of the gas pipeline regulatory framework and highlights the differences between scheme and non-scheme pipelines.

Figure 1.1: Application of the rule changes



Source: AEMC.

The Commission is jointly consulting on the rule change requests due to the interrelated nature of the issues raised and solutions proposed. We consider that the breadth of issues and potential solutions requires a more holistic assessment to determine whether changes to the regulatory framework are required – to ensure it remains fit for purpose and continues to promote the long-term interests of gas consumers through the energy transition. By fit for purpose, we mean: Is the current regulatory framework, which is predicated on the assumption of growing gas demand, flexible enough to support the long-term interest of consumers throughout the transition or are changes needed?

We are therefore seeking feedback on:

- the four rule change requests submitted by ECA and JEC (see chapter 2)
- whether changes to other interrelated aspects of the economic regulatory framework may be required (see chapter 3).

This consultation paper should be read together with the four rule change requests, which can be found on our website.[11]

11 www.aemc.gov.au.

1.1 The energy transition will pose a number of challenges for gas distributors, consumers and regulators

1.1.1 AEMO and gas distributors forecast declining demand from residential and small commercial network users

As the transition to net zero progresses and the energy system transforms, an increasing number of residential and small commercial gas users are expected to replace gas appliances with electric appliances and leave gas distribution networks. In some jurisdictions, including the ACT and Victoria, government policies drive the electrification trend, e.g. by restricting new connections to the gas distribution network and providing financial incentives to consumers to switch from gas to electricity.[12] In these jurisdictions, reduced reliance on gas forms part of their decarbonisation plans to meet emissions reduction targets. In other jurisdictions, consumers choosing to electrify lead the shift away from gas as they seek to maximise the value of their consumer energy resources, such as rooftop solar and batteries, and to reduce their carbon footprint.

The Australian Energy Market Operator's (AEMO) latest Gas Statement of Opportunities (GSOO) provides some insight into the projected impact of electrification and other factors on residential and small commercial demand in gas networks over the next 10-20 years:

- The East Coast GSOO projects distribution connected residential and small commercial demand will fall by around 70% over the next 20 years, with a 30% reduction projected in the next 10 years.[13]
- The West Coast GSOO projects that distribution connected demand will fall by around 20% over the next 10 years.[14]

Gas distributors' own demand forecasts also indicate that residential demand in South Australia, Victoria, NSW, and the ACT has either started to fall, or is expected to do so in the upcoming access arrangement periods.Figure 1.2 below provides a selection of residential demand projections from scheme networks across Australia. These have been indexed for comparability. Some networks located on the east coast are also starting to experience higher rates of disconnection.[15]

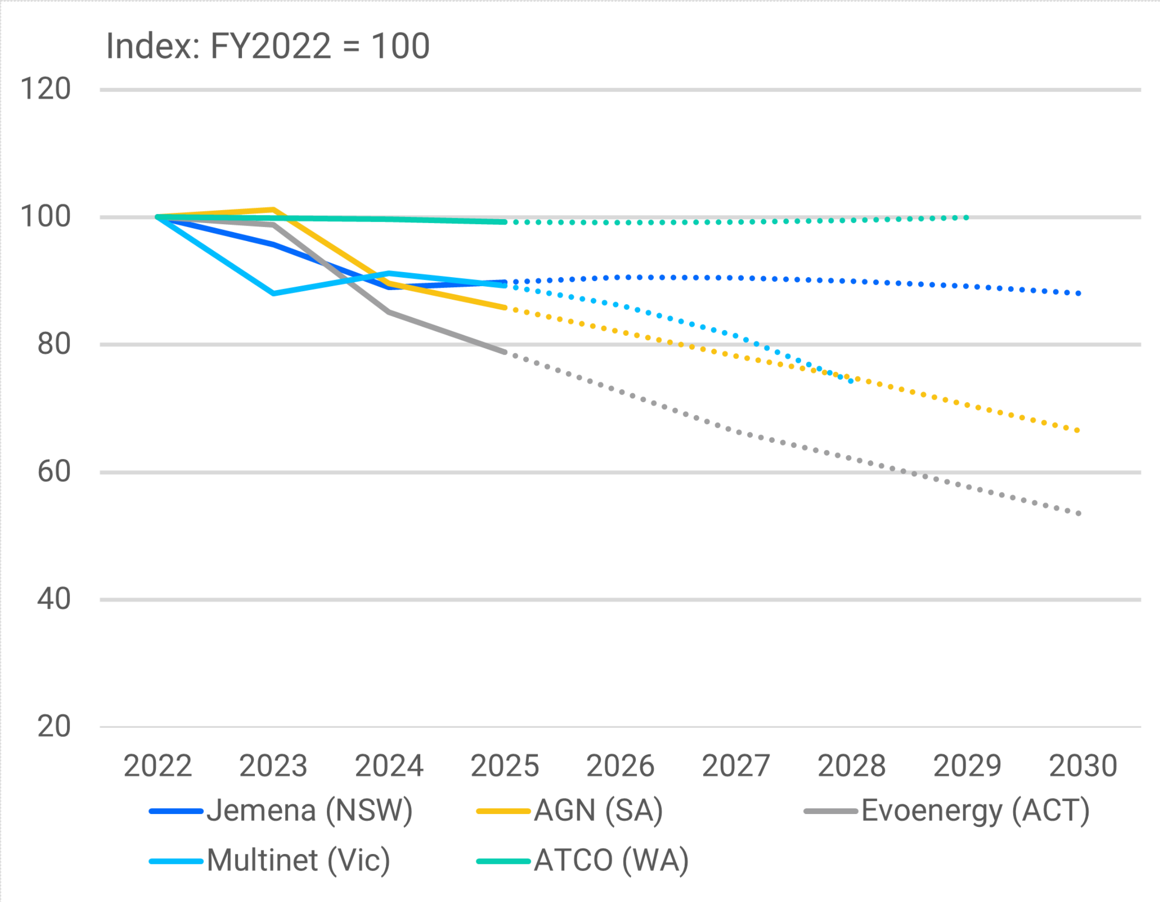
12 For example, the ACT Government has committed to transitioning away from gas to renewable electricity by 2045 and banned new connections. The Victorian Government has also prohibited gas connections for new dwellings and provided financial support to help gas users transition to electricity. Other jurisdictions have not yet indicated whether, or if so how, government policy will influence the future use of gas distribution networks.

13 AEMO, Gas Statement of Opportunities, March 2025, p. 23. These projections are based on AEMO's Step Change Scenario, which forecasts that residential and small commercial demand will fall from 169 P in 2024 to 116 PJ in 2034 and down to 51 PJ in 2044.

14 AEMO, Western Australian Gas Statement of Opportunities, December 2024, p. 9. These projections are also based on AEMO's Step Change Scenario, which forecasts that distribution connected demand will fall from 74 TJ/day in 2024 to 58 TJ/day in 2034. Note that AEMO only produces 10 year forecasts in the Western Australian GSOO.

15 For example, data published by the AER indicates that the number of residential abolishments and disconnections in the Victorian and South Australian gas distribution networks increased by around 12-25% between 2023 and 2024. See AER, Gas quarterly disconnection reporting, 29 July 2025.

Figure 1.2: Forecast residential gas demand for selected scheme pipelines, indexed

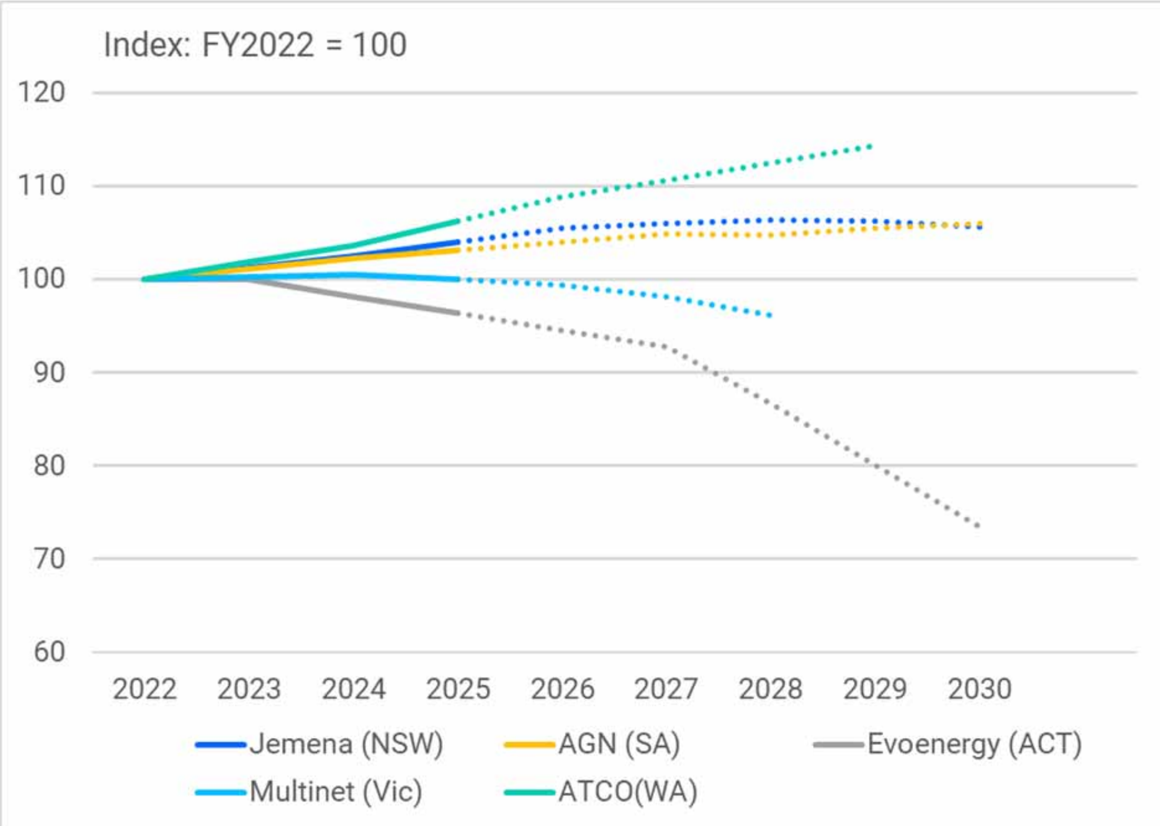


Source: AEMC, based on the following data sources: **Jemena**. 2022-2024: Regulatory Information Notices; 2025: Interpolation; 2026-2030: AER, Jemena Access Arrangement 2025-2030 Final Decision Attachment 12 Demand; **AGN (SA)**. 2022-2024: Regulatory Information Notices; 2025-2026: Interpolation; 2027-2030: AGN (SA), Final Five Year Plan 2026-2031; **Evoenergy**. 2022-2024: Regulatory Information Notices; 2025:-2026: Interpolation; 2027-2030: Evoenergy, Five-Year Gas Plan 2026-2031 Overview; **Multinet**. 2022-2023: Regulatory Information Notice data normalised from calendar year to fiscal year; 2024-2028: AER, Multinet Access Arrangement Final Decision 2023-2028 Attachment 12 Demand (note, forecasts only available until 2028. We observe that low demand volumes in 2023 may have potentially resulted from unseasonably high winter temperatures. See AEMO, Victorian Gas Planning Report Update March 2024, p.31; **ATCO**. 2022: Regulatory Information Notice; 2023: Interpolated; 2024-2029: ERA, ATCO Access Arrangement Final Decision 2025-2029 (note, forecasts only available until 2029).

Some annual data has been linearly interpolated between demand reported and the projections used by the regulator and/or the network service provider. . Projections displayed reflect available and most recent data.

There appears to be general consensus that the volume of gas demand in the residential customer segment will decline, based on AEMO and gas distributors' own projections. The Commission observes, however, that the number of new residential connections in NSW, SA and WA is expected to grow in the short term, as shown in Figure 1.3 below. We note that consumers may seek new gas connections even as the average volume of gas used per consumer reduces. This is likely explained by new homes continuing to connect to gas and households continuing to prefer gas for specific uses, such as cooking, while electrifying other uses of energy, for example central heating. However, there is emerging evidence that the rate of new residential connections is slowing, with some gas distribution networks (outside the ACT) projecting a declining trend of new connections within the decade. The Commission further acknowledges that its draft rule to introduce cost-reflective connection charges may accelerate the rate of decline in connections or halt the rate of increase.[16]

Figure 1.3: Forecast residential gas connections for selected scheme pipelines, indexed



Source: AEMC, based on the following data sources: **Jemena**. 2022-2024: Regulatory Information Notices; 2025: Interpolation; 2026-2030: AER, Jemena Access Arrangement 2025-2030 Final Decision Attachment 12 Demand; **AGN (SA)**. 2022-2024: Regulatory Information Notices; 2025-2026: Interpolation; 2027-2030: AGN (SA), Five Year Plan, Final 2026-2031; **Evoenergy**. 2022-2024: Regulatory Information Notices; 2025:-2026: Interpolation; 2027-2030: Evoenergy, Five Year Gas Plan 2026-2031 Overview; **Multinet**. 2022-2024: Regulatory Information Notices; 2025-2028: AER, Multinet Access Arrangement Final Decision Attachment 12 Demand (note: forecasts only available until 2028); **ATCO**. 2022: Regulatory Information Notice; 2023: Interpolated; 2024-2029: ERA, ATCO Access Arrangement Final Decision 2025-2029 (note, forecasts only available until 2029).

Some annual data has been linearly interpolated between demand reported and the projections used by the regulator and/or the network service provider. Projections displayed reflect available and most recent data.

This points to a significant degree of uncertainty surrounding both the rate and extent to which demand will decline. Due to differences in jurisdictional policies, there is likely to be a significant degree of variation between gas distribution networks. Additional factors impacting the rate and extent of declining demand are consumer preferences and some gas distributors' efforts to transition to renewable gases. The potential for some gas distribution networks to be repurposed to supply renewable gases, while others are planning for decommissioning, highlights some of the challenges that the regulatory framework will need to accommodate.

1.1.2 Declining demand is likely to have a range of adverse effects on network users and gas distributors

Decreasing gas demand would place upward pressure on network charges for network users, because the largely fixed costs of providing services must be recovered over declining volumes.

16 Draft National Gas Amendment (Updating the regulatory framework for gas connections) Rule 2025. See the project page for more information https://www.aemc.gov.au/rule-changes/updating-regulatory-framework-gas-connections.

Over time, consumers would pay a higher (effective) per unit cost of gas as volumes decrease to ensure networks are able to recover their past efficient investments. These increasing per unit costs is likely to bring forward some consumers' decisions to disconnect from the gas network, potentially by completely electrifying their energy needs. This dynamic could see further increases in per unit prices and, potentially, more disconnections. Where the rate of disconnections outstrips new connections, consumers remaining on the network will need to make increasing contributions to network cost recovery. Higher prices can also adversely affect network users that are less able to disconnect due to financial, technical or other barriers. These users may include:

- renters, people living in community or social housing, low income households and other vulnerable customers
- residents in apartments, body corporate or strata, mixed use buildings
- commercial and industrial customers that face more challenges switching to alternative fuels.

For gas distributors, the prospect of declining demand can also increase the risk that they may not fully recover the capital costs associated with assets that they have efficiently invested in. This could be because there are no, or too few, consumers to feasibly charge to recover those costs. Several gas distributors refer to this as the risk of asset stranding.[17] The Commission uses the term 'stranded' or 'stranding' throughout this paper to refer to unused or underutilised assets for which a regulated business is unable to recover a full return of and on capital. [18]

The risk of being unable to recover costs may also affect the ability and/or incentive gas distributors have to:

- continue to operate the network and provide a safe and reliable service to remaining users
- transition to renewable gases if that is a viable option, or otherwise decommission the network.

If the network cannot transition to renewable gases and demand falls in an uncontrolled or unplanned manner, it may also pose a risk to the safe and reliable operation of the network.

While these effects are likely to be felt most acutely by gas distribution networks and users that remain connected to the network, a decline in gas demand may also affect the transmission pipelines connected to the gas distribution networks and users of those transmission pipelines. This is because the costs of operating the transmission pipelines will need to be spread across lower volumes. It may also affect investment incentives more generally across the energy sector.

To mitigate these adverse impacts, the AEMC is considering whether changes are required to the regulatory framework as part of this rule change process to ensure it continues to be fit for purpose and supports outcomes that are in the long-term interests of consumers of gas services.

1.1.3 The increasing uncertainty in demand is already posing challenges for regulators, gas distributors and network users and has prompted a number of rule change requests

For some time now, the Australian Energy Regulator (AER), the WA Economic Regulation Authority (ERA), gas distributors and other interested parties have been grappling with the challenges posed by the uncertain demand outlook on scheme pipelines that are gas distribution networks.

17 For example, AusNet's revised 2024-28 proposal sought to carefully balance stakeholder concerns "against the stranding risk" they face in an uncertain environment. See AusNet, Gas access arrangement review 2024-28, Revised AA proposal 24 January 2023, p. 8. Jemena has also acknowledged that "Future demand for gas networks is expected to decline due to changing consumer behaviours, and as a direct result of government policy ... [which] may lead to our network becoming stranded ..." See Jemena Gas Networks 2025 Plan, June 2024, p. 5. See also Jemena Gas Networks (NSW) Revised 2020-25 Access Arrangement Proposal, Attachment 8.3, Response to the AER's draft decision - Using asset lives to manage stranded asset risks.

18 The AER has referred to the economic stranding of assets in a similar fashion. See AER, Information Paper, Regulating gas pipelines under uncertainty, November 2021, p. 26.

Regulators in other jurisdictions have experienced similar challenges (see case studies in Appendix A).

The AER first considered the issue in 2020-21 when assessing the implications of the ACT Government's legislated 2045 net zero greenhouse gas emissions target and intended phase out of natural gas on Evoenergy's 2021-2026 access arrangement.[19] Shortly after this, the AER published an information paper on *Regulating gas pipelines under uncertainty*, which identified a number of potential options to manage the pricing and stranding risks associated with declining demand and the costs and benefits of each. [20] The options identified in the AER's paper included a number of options that are already available under the regulatory framework (e.g. accelerated depreciation, capital redundancy and removing capital base indexation) and some that it considers are not (e.g. revaluing assets). Following the publication of this information paper, the AER has had to consider how to manage the impacts of the projected decline in demand in both the Victorian and New South Wales gas distribution networks.[21] The ERA has also had to consider similar issues in WA, including in its recent decision on ATCO's 2025-2029 access arrangement.[22]

In the most recent round of access arrangement decisions, the AER has focused on trying to reduce the risk of asset stranding, while also minimising the extent of price increases for consumers. That is, by allowing distributors to bring forward the recovery of capital while there are still a relatively large number of customers (through accelerated depreciation), but placing a cap on what can be brought forward so that prices for consumers do not materially escalate. The uncertain outlook for gas demand and the future of gas distribution networks through the energy transition is challenging the ability of the regulatory framework to manage the risk of cost recovery and consumer price impacts. New regulatory challenges are also likely to emerge as the transition progresses. Regulators are, for example, likely to have to consider how to ensure that distributors:

- continue to provide services in a safe and reliable manner to those customers that remain connected to the network, while also minimising capital expenditure
- undertake decommissioning that may be required by a jurisdiction in a prudent and efficient manner.

The regulation of gas distribution networks is therefore likely to become more challenging over time, which underscores the importance of ensuring that the regulatory framework remains fit for purpose through the transition.

1.2 We propose a consolidated approach to considering whether the regulatory framework is fit for purpose

The issues raised in the ECA and JEC rule change requests point to a potentially broader underlying problem with the regulatory framework. This problem is whether the framework can adequately deal with the uncertain outlook in gas demand and how this might impact gas distributors, network users and (potentially) connected gas transmission pipelines.

Our objective is to ensure that, as a whole, the regulatory framework remains fit for purpose through the energy transition and continues to support the long-term interests of consumers, as

19 AER, Final Decision - Evoenergy Access Arrangement 2021-2026, April 2021.

20 AER, Information Paper - Regulating gas pipelines under uncertainty, November 2021.

21 For example, in the AusNet variation proposal on its 2023-28 gas access arrangement, questions were raised about the use of accelerated depreciation and the operation of the access arrangement variation provision in rule 65 of the NGR. See AER, Final Decision - AusNet Gas Networks Access Arrangement Variation Proposal 2023-2028, March 2025. The AER's final decision on Jemena Gas Networks access arrangement 2025-2030 has also raised questions around the use of accelerated depreciation and permanent abolishments.

22 ERA, Final Decision - Mid-West and South-West Gas Distribution Systems Access Arrangement 2025-2029, November 2024.

set out in the National Gas Objective (NGO). We propose therefore to consolidate the rule change requests and to consider whether any other changes to interrelated elements of the regulatory framework may be required. To explore the need for change to interrelate elements of the economic regulatory framework, we are asking the following questions:

- **Would a longer-term outlook support better decisions?** We are interested in understanding whether a longer-term outlook period for demand and expenditure forecasts would improve regulatory decision-making. A longer-term outlook as part of each access arrangement process could enable the regulator to better understand how future decisions are impacted by decisions in the current access arrangement.
- **Are additional regulatory tools needed to manage demand risk?** We are interested in understanding whether the regulatory tools available to manage demand risk are appropriate. Providing more guidance to the regulator on the use of tariff variation mechanisms could assist them in better accounting for demand risk, and changes to the tariff rules could ensure more efficient price signals are provided to consumers.
- **Are additional regulatory tools needed to manage unforeseen events or material changes?** We are interested in understanding whether existing access arrangement variation mechanisms to manage these risks remain fit for purpose. Providing the regulator with more flexibility to respond in a rapidly changing environment may improve consumer outcomes, but could also undermine the access arrangement process and reduce investment certainty.
- **Are the existing incentives appropriate to support the transition?** We are interested in understanding whether changes to the existing or additional incentives are required for gas distributors to maintain service levels in the context of declining gas demand.

Figure 1.4 below outlines the issues that are considered in this consultation paper.

Figure 1.4: Overview of issues that are considered in this consultation paper

Core issues raised in the JEC's and ECA's rule change requests	
1 Tightening the criteria for conforming capex and definition of opex	▪ Insufficient scrutiny of expenditure forecasts in the context of uncertain gas demand outlooks and risk of assets becoming increasingly underutilised, propose-respond model is asymmetric ▪ Existing capex criteria may lead to inefficient investment decisions, resulting in unnecessary expansion of the capital base and creating unacceptable price risk for gas consumers ▪ Definition of operating expenditure should be updated to recognise declining demand
2 Restricting the use of accelerated depreciation	▪ ECA propose the NGR should restrict service providers' and regulators' use of accelerated depreciation to address capital cost recovery risk ▪ JEC propose for the NGR to only allow for accelerated depreciation to be used in conjunction with an asset redundancy assessment
3 Providing clarity around the use of the capital redundancy provisions	▪ The current test for asset redundancy is too narrow and customers are required to fund cost recovery for assets that do not efficiently contribute to the provision of pipeline services ▪ Distributors require stronger incentives to optimise and rationalise their infrastructure
4 Introducing gas network planning requirements	▪ Service providers do not make investment decisions based on rigorous planning ▪ Stakeholders have limited visibility of investment decision-making ▪ There is a lack of coordination between gas planning/investment decisions and electrification initiatives
The Commission proposes to consider interrelated issues as part of this rule change process	
A Longer term outlook	▪ A longer term outlook (demand and expenditure forecasts) may be required to support good regulatory decision-making in the context of demand uncertainty

B Tools to manage demand risk and unforeseen events	▪ Additional regulatory tools may be required to manage:
	  ▪ demand risk with an access arrangement (AA) period
	  ▪ unforeseen events or material changes within an AA period

C Changes to existing or need for additional incentives	▪ Additional incentives for service providers may be required to support the gas transition

Source: AEMC.

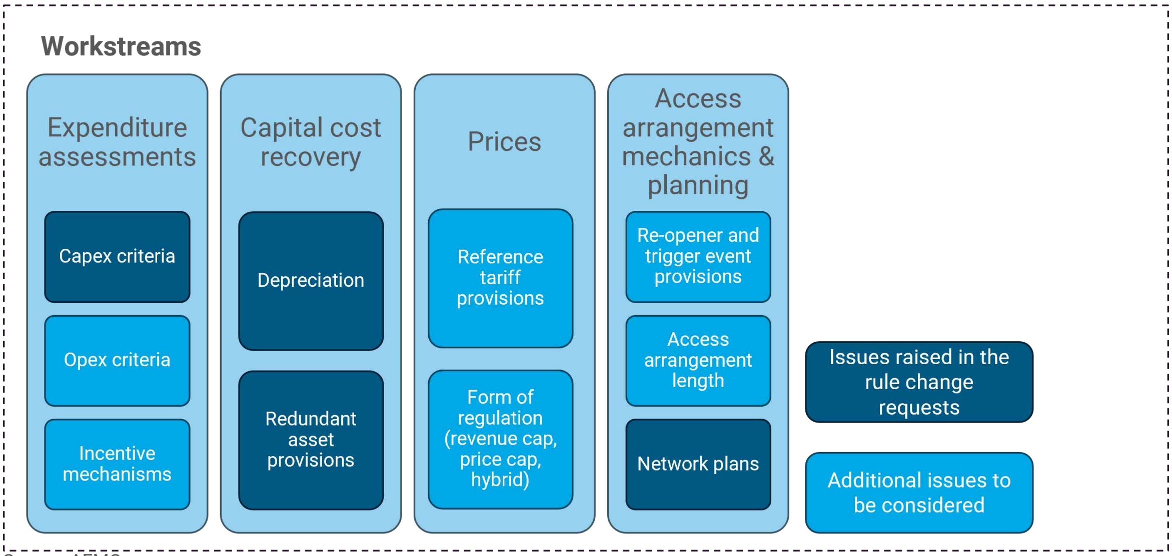
As the discussion in section 1.1 highlights, it will be important to ensure any changes that are made to the regulatory framework:

- recognise the diversity of positions that individual gas distribution networks may be facing and are sufficiently flexible enough to accommodate different future paths (e.g. some networks being decommissioned while others potentially being repurposed)
- carefully consider the potential impacts on all network customers, including those may be constrained in their ability to electrify
- enable distributors to remain financially viable and able to provide safe and reliable services through to any decommissioning that may be required
- support jurisdictions' emissions reduction targets
- consider the broader implications for investment across the energy sector
- contribute to the NGO and take into account the revenue and pricing principles set out in section 24 of the NGL.

We note that while the changes proposed by ECA and JEC focus on gas distribution networks, declining gas demand could have implications for transmission pipelines, as discussed in section 1.1.2. With some limited exceptions, scheme transmission and distribution pipelines are subject to the same regulatory framework in the NGR.[23] If the Commission decides to make any changes to the regulatory framework, we will therefore need to consider the implications for transmission pipelines.

Due to the breadth of issues we consider in this consultation paper, the Commission has grouped the issues into four broad workstreams: expenditure assessments, capital cost recovery, prices, and access arrangement mechanics and planning (see Figure 1.5 below).

Figure 1.5: Gas networks in transition - workstreams



Source: AEMC.

As Figure 1.5 shows, the focus of this rule change process is on ensuring the regulatory framework set out in the NGR is fit-for-purpose through the transition. There are, however, limits to

23 These differences include the type of information that the service provider must publish under Part 10 of the NGR. There are also additional connection and retail obligations that apply to distribution pipelines, but not transmission.

what we can achieve through changes to the NGR in terms of addressing the challenges that distributors and network users are likely to face through the transition.

We will consider whether other solutions outside the NGR may be required to help address these. This could potentially involve changes to the national energy legislation. It may also involve state and territory governments playing a more active role in the planning for and management of the transition of distribution networks in their respective jurisdictions.[24] The Commission will continue to closely engage with jurisdictions throughout this rule change project to inform our considerations, noting the solutions mentioned above lie outside of the Commission's decision-making remit..

The Commission is interested in understanding what these other potential solutions could involve and is therefore seeking stakeholder feedback on this issue.

1.3 Our related work program

The Commission is progressing several related rule change requests that are relevant to ECA and JEC's rule change requests.

- **Updating the regulatory framework for gas connections**. ECA submitted a rule change request on 14 February 2025 proposing changes to gas connection charges. ECA noted that, under current arrangements, many customers face no upfront cost to establish a new gas connection and the cost is socialised among all gas distribution network customers. ECA considered that this results in inequitable cost sharing, as it contributes to increasing costs for remaining gas customers in the context of a future declining customer base. The current arrangements further contribute to a growing capital base, which in turn increases the issues around cost recovery. The Commission published a draft determination and draft rule on 18 September 2025.[25]
- **Establishing a regulatory framework for gas disconnections and permanent abolishments.** JEC submitted a rule change request on 9 May 2025 proposing a new regulatory framework for temporary disconnections and permanent abolishments. JEC consider the current absence of a framework is leading to inconsistent regulatory decisions, and that there is a need for regulatory guidance on what services distributors should provide and cost recovery. JEC's proposal seeks to ensure customers are paying no more than they need to disconnect from the gas network (either temporarily or permanently). The Commission will publish our draft determination and draft rule (if applicable) at the end of October.[26]

1.4 We have started the rule change process

This paper is the first stage of our consultation process.

24 For example, to enable service providers to pursue a strategic decommissioning of their network, changes to the National Energy Retail Rules may be required to ensure consumers are protected and gas distributors continue to meet their service obligations.

25 Please visit the project webpage for more information https://www.aemc.gov.au/rule-changes/updating-regulatory-framework-gas-connections.

26 Please visit the project webpage for more information https://www.aemc.gov.au/rule-changes/establishing-regulatory-framework-gas-disconnections-and-permanent-abolishment.

Figure 1.6: Gas networks in transition - timeline

Source: AEMC.

Given the complexity of the issues raised in the rule change requests, the Commission is proposing to undertake a longer than standard rule change process for this project, with the following formal stages:

- the Commission commences the rule change process by publishing a consultation paper and seeking stakeholder feedback (this paper)
- stakeholders lodge submissions on the consultation paper (due by 30 October 2025) and engage through other channels to make their views known to the AEMC project team
- the Commission publishes a directions paper (Q1 2026)
- stakeholders lodge submissions on the directions paper and engage through other channels to make their views known to the AEMC project team
- the Commission publishes a draft determination and draft rule (if applicable) (by mid 2026)
- stakeholders lodge submissions on the draft rule determination and engage through other channels to make their views known to the AEMC project team
- the Commission publishes a final determination and final rule (if applicable) (Q4 2026).

Information on how to provide your submission and other opportunities for engagement is set out at the front of this document.

The Commission notes the large number of questions included in this consultation paper covering four rule change proposals from ECA and JEC, and other areas of the economic regulatory framework that we propose to consider due to their interrelated nature. We encourage stakeholders to only respond to the consultation questions that they have a particular interest in and view on. Stakeholders should also specify which rule change proposals their submission relates to.

You can find more information on the rule change process on our website.

The Commission will consider whether to consolidate the four ECA and JEC rule change requests following the close of submissions to this consultation paper.

Question 1: What are the issues impacting consumers and gas distributors under the energy transition?

1. Do stakeholders agree that there is value in considering the additional NGR issues we have identified alongside the issues raised in the rule change requests?

2. Are there any other additional issues that we should consider within the NGR framework? If so, why?
3. Noting the AEMC's role is to consider and make changes to the energy rules, are there changes outside the NGR regulatory framework that are required to address the issues raised in the rule change requests?

2 ECA and JEC propose a number of changes to specific aspects of the regulatory framework to address declining demand

This chapter outlines the issues identified by the proponents in their rule change requests and the proposed solutions to address the issues. Figure 2.1 below highlights the core issues and proposed solutions.

Figure 2.1: Core issues raised in the JEC and ECA rule change requests

1 Tightening the criteria for conforming capex and definition of opex	▪ Insufficient scrutiny of expenditure forecasts in the context of uncertain gas demand outlooks and risk of assets becoming increasingly underutilised, propose-respond model is asymmetric ▪ Existing capex criteria may lead to inefficient investment decisions, resulting in unnecessary expansion of the capital base and creating unacceptable price risk for gas consumers ▪ Definition of operating expenditure should be updated to recognise declining demand
2 Restricting the use of accelerated depreciation	▪ ECA propose the NGR should restrict service providers' and regulators' use of accelerated depreciation to address capital cost recovery risk ▪ JEC propose for the NGR to only allow for accelerated depreciation to be used in conjunction with an asset redundancy assessment
3 Providing clarity around the use of the capital redundancy provisions	▪ The current test for asset redundancy is too narrow and customers are required to fund cost recovery for assets that do not efficiently contribute to the provision of pipeline services ▪ Distributors require stronger incentives to optimise and rationalise their infrastructure
4 Introducing gas network planning requirements	▪ Service providers do not make investment decisions based on rigorous planning ▪ Stakeholders have limited visibility of investment decision-making ▪ There is a lack of coordination between gas planning/investment decisions and electrification initiatives

Source: AEMC.

ECA and JEC's main concern is that the risk of stranded assets is being inappropriately shifted to consumers under the current regulatory framework. The proponents contend that the current framework is no longer fit for purpose in an environment of uncertain demand because it is predicated on an assumption of continuing growth. While the proponents' issues are identified in separate rule changes requests, we recognise the issues are inter-dependent and that any change will need to complement the existing rules.

The rule change requests propose changes to address issues in specific areas of the regulatory framework:

- **Capital expenditure criteria** (section 2.1). ECA propose changes to the criteria that scheme pipelines that are gas distribution networks use to propose and the regulator uses to determine whether capital expenditure is justifiable. ECA consider that the current criteria do not adequately account for declining demand and could result in investment in new assets that subsequently risk becoming stranded.
- **Depreciation** (section 2.3). ECA propose changes to the depreciation criteria to impose stronger conditions on when scheme pipelines that are gas distribution networks can propose and the regulator can approve the accelerated recovery of the capital base. ECA consider that the current depreciation criteria shift all risk and costs for assets with stranding risk to gas consumers, while imposing no costs nor risks to gas distributors.
- **Depreciation and redundancy** (section 2.4). JEC propose changes to prohibit the use of accelerated depreciation for assets at risk of stranding unless the regulator has undertaken a redundancy assessment. That is, accelerated depreciation can only be used if the asset meets the proposed definition of a redundant asset or anticipated redundant asset, and the regulator

has determined how the redundant asset costs should be shared. JEC has proposed this as an alternative to ECA's proposal to amend the depreciation criteria.
- **Planning requirements** (section 2.5). ECA propose changes to impose new planning reporting obligations on all distribution networks. ECA consider that stakeholders currently have limited information to understand the opportunities to minimise expenditure and energy system costs, including through the strategic decommissioning of the gas distribution networks.

Appendix A sets out the range of different approaches regulators internationally and in other industries have applied to:

- the recovery of capital costs where demand is uncertain or declining.
- expenditure assessments to encourage efficient decisions about ongoing asset use and decommissioning
- network planning.

The issues raised and changes proposed by ECA and JEC focus on gas distribution networks, to which residential and small commercial customers are connected to (along with some industrial customers). The projected decline in gas demand in this segment and any capital cost recovery risk would, therefore, have greater implications for gas distributors than they may have for transmission pipelines. Nevertheless, there could be implications for transmission pipelines (to which gas distribution networks are connected) due to decreased load. The Commission notes that in the context of the target of net zero by 2050, transmission pipelines may, at a future point in time, also experience a decline in demand. The Commission further notes that transmission and distribution pipelines are subject to the same economic regulatory framework types of obligations under the NGL and NGR.

If we decide to make any changes to the framework for economic regulation of gas pipelines, the Commission will need to consider the implications for transmission pipelines, The Commission therefore welcomes stakeholder views on the application of the proposed solutions to transmission pipelines.

2.1 ECA consider that new capital expenditure should account for the declining use of the gas network

2.1.1 Gas consumers could be exposed to unnecessary costs if there is over investment in the network

ECA's concern is that the regulatory framework is not protecting consumers against the risk of over investment in the network in an environment where demand is projected to decline, exposing gas consumers to the risk of stranded assets.

To support its view, ECA point to the fact that gas distributors have recently made relatively large claims for capex (at levels similar to previous access arrangements) while also claiming accelerated depreciation to manage the risk of asset stranding.[27] According to ECA, this demonstrates that potential capital expenditure is not being considered through the lens of declining demand and the implications for cost recovery in that context.

ECA considers the current capital expenditure criteria are too broad and predicated on an assumption of demand growth, which ECA submits "creates irresistible incentives for networks to seek ever-higher capital expenditure allowances".[28] It also considers that:[29]

27 ECA, Rule change request - Capital expenditure, p. 15.

28 ECA, Rule change request - Capital expenditure, p. 15.

29 ECA, Rule change request - Capital expenditure, p. 15.

> The propose-respond model provides distributors with too much discretion in their presentation of capex business cases. While such a model may be appropriate for a network that is growing and expected to grow indefinitely, networks projected to decline should invest in capital sparingly and only when absolutely necessary. Otherwise, they may increase the risk to consumers by over-investing in a network at risk of stranding.

Based on its review of recent access arrangements, ECA identified some key themes that it considers point to the deficiencies of the current rules for allowing capital expenditure.[30] For example, ECA submits that capital expenditure business cases are difficult for stakeholders to assess as they do not always consider alternative, lower cost options and provide limited information (due to confidentiality claims and qualitative cost benefit analysis) that prevent a proper evaluation of options. ECA further states that distributors rarely consider strategic decommissioning as an alternative to capital expenditure. Instead, according to ECA, distributors are proposing capital expenditure to support the use of renewable gases, despite electrification being a lower cost route to avoid natural gas emissions.[31]

While the ECA proposal raises a number of different themes behind their concerns on the current rules, their issues can be grouped into 3 core issues:

1. the capex criteria do not provide sufficient prescription to ensure that only efficient capex is added to the RAB
2. the regulator is limited in considering the implications of declining demand under the propose-respond model
3. stakeholders cannot adequately input into the regulator's considerations due to a lack of information.

2.1.2 ECA's proposed solution would impose stricter capital expenditure criteria

To address the issue outlined above, ECA propose amendments to tighten the capital expenditure criteria to enable what it considers more 'careful and constrained' capital expenditure "in the context of network retreat". In ECA's view, more prescriptive rules around conforming capital expenditure will be most effective at reducing the risk to consumers of over-investment by a network in the face of uncertainty and the projected decline in gas demand.[32]

ECA's proposed amendments are also intended to drive greater rigour and better information around the gas distributors' capital expenditure proposals to enable stakeholders, including the regulator, to better respond to the proposals. ECA's intent is to ensure that the current criteria are sufficiently effective in constraining capital expenditure in the context of declining demand.[33]

The proposed amendments include requirements for:

- capital expenditure to explicitly consider the impacts of declining demand
- distributors to consider alternatives to investment
- distributors to consider the value that gas consumers place on reliability
- distributors to account for future abolishment costs in their cost benefit analysis
- distributors to explore lower cost options to meet regulatory obligations
- the regulator to closely scrutinise replacement capital expenditure

30 ECA, Rule change request - Capital expenditure, pp. 16-18.
31 ECA, Rule change request - Capital expenditure, p. 18.
32 ECA, Rule change request - Capital expenditure, p. 18.
33 ECA, Rule change request - Capital expenditure, p. 21.

- reference tariffs to exclude capital expenditure on renewable gases.

We outline ECA's proposed amendments and suggested changes to the rules in the following sections.

Gas distributors should explicitly consider the impacts of declining demand when proposing capital expenditure

ECA propose amendments to ensure that distributors more explicitly consider the impacts of declining demand in their capital expenditure proposals. ECA suggest that this could be achieved by clarifying rule 79(1)(a) so that gas distributors must also account for the impact of declining gas demand by considering the impact national and jurisdictional targets would have on projected demand for services.[34] In ECA's opinion, this would result in a more robust quantitative cost analysis that includes a realistic assessment of asset lives and utilisation levels.

ECA also propose amendments to rule 79(2)(c)(iv) to remove the reference to existing levels of demand and substitute in forecast levels of demand, to support gas distributors' consideration of declining gas demand in their capital expenditure proposals.[35] This would limit the ability of networks to seek replacement expenditure to maintain capacity on the basis of existing demand levels.

Gas distributors should consider alternatives to investment

ECA propose several amendments to mandate that gas distributors consider alternatives to investment in replacement or new network equipment. ECA suggest that this could be achieved by:[36]

- requiring distributors to consider alternatives to investment when assessing whether the overall economic value of expenditure is positive and hence justifiable under rule 79(2)(a) and 79(3)
- amending rule 79(2)(c)(v) to clarify that the 'supply of services' could include the provision of energy services by other means, whether by the service provider or another party

Gas distributors should consider the value that gas consumers place on reliability

ECA propose amendments to require gas distributors to weigh the costs of capital expenditure to maintain reliability against the value that customers place on avoiding loss of supply.[37] ECA suggest that this could be achieved by amending rule 79(2)(c)(ii) to clarify that the capital expenditure incurred to maintain the reliability of the network should not exceed the value that customers place on reliability. This would mean that when assessing whether the proposed capital expenditure is necessary for the integrity of the services, the AER would also need to consider if the costs of improving reliability of the service are lower than the value customers will get from that improvement.[38]

Gas distributors should account for future abolishment costs in cost benefit analysis

ECA propose amendments that would clarify that distributors should account for future abolishment costs in any cost benefit analysis they undertake in relation to capital expenditure.[39]

34 ECA, Rule change request - Capital expenditure, p. 20.

35 ECA, Rule change request - Capital expenditure, p. 20.

36 ECA, Rule change request - Capital expenditure, p. 20.

37 ECA, Rule change request - Capital expenditure, p. 19.

38 On 28 August 2025, the AEMC published a directions paper in response to a rule change request from the Chair of the Energy Senior Officials and the Victorian Minister for Energy and Resources seeking the implementation of a reliability standard and related reliability tools for the East Coast Gas System. You can find more information on this project here: https://www.aemc.gov.au/rule-changes/ecgs-reliability-standard-and-associated-settings.

39 ECA, Rule change request - Capital expenditure, p. 19.

The Commission understands that the intent of this proposal is to improve the assessment of the relative costs and benefits of proposed investments against a range of alternatives. These alternatives could include decommissioning, which would avoid any further capital expenditure and the risk of additional abolishment costs. Given the uncertainty of future demand, ECA is concerned that any new capital expenditure would result in extra future costs for customers if the resulting asset was decommissioned.

Gas distributors should explore lower cost options to meet regulatory obligations

ECA propose to require gas distributors to explain the steps they have taken to explore lower cost options with the relevant regulatory agency[40] where there is a regulatory driver/obligation for new expenditure. In this regard, ECA suggest amendments to rule 79(2)(c)(iii) to specifically provide for distributors meeting a regulatory obligation through discontinuance of a service.[41] The rule change request is not clear what is envisaged through this amendment. However, we observe that the amendment proposed by ECA could be aimed at eliciting more information from distributors about the options it has considered to meet its regulatory obligations, which could include capital expenditure to discontinue a service (e.g. capital expenditure associated with strategic decommissioning).

The regulator should be required to closely scrutinise replacement capital expenditure

ECA propose to require the regulator to assure itself that the service provider has acted prudently in its previous investment decisions before allowing capital expenditure to replace assets due to obsolescence, or where the current asset is no longer fit for purpose. Where a distributor seeks asset replacement before end of life, ECA's proposal would require gas distributors to provide more information on:[42]

- why replacement is required, including a comparison to a do-nothing approach
- why this eventuality was not foreseeable at the time of the original investment (and thus why customers are expected to pay in full for both the old and new asset)
- how many consumers benefit from the replacement and the impacts on the value of the replacement expenditure if significant declines in consumers served by the asset occur, and
- how the gas distribution network intends to ensure similar issues do not arise with the new asset.

The NGR should exclude capital expenditure on renewable gases from reference tariffs

ECA propose that capital expenditure on renewable fuel projects be excluded from reference tariffs, so that distributors can only recover such expenditure (to the extent it is conforming capital expenditure) from customers who wish to take renewable fuels in the future.[43] ECA consider that distributors should recover capital expenditure on renewable fuel projects from non-reference tariffs so that the general customer pool does not fund this expenditure. ECA suggest that this could be achieved by including a new subrule that defines the circumstances in which capital expenditure is not justifiable and including capital expenditure on transitioning to renewable gases within this definition. In relation to this proposal, the Commission notes that the basis of the capital expenditure criteria in rule 79 is tied to the provision of services and not the nature of the gas used in such services.

40 The Commission understands that the relevant regulatory agency would depend on the nature of the regulatory obligation. This may be a jurisdictional safety regulator, the entity responsible for licencing (e.g., IPART in NSW), or a responsible Department.

41 ECA, Rule change request - Capital expenditure, p. 20.

42 ECA, Rule change request - Capital expenditure, p. 19.

43 ECA, Rule change request - Capital expenditure, p. 20.

The regulator should publicly consult on advance determinations on capital expenditure proposals

ECA also question whether it is appropriate to allow the AER to make advance determinations under rule 80(2) of the NGR that capital expenditure conforms with the new capital expenditure criteria. At the very least, ECA consider that the AER must be required to consult on expenditure proposals before determining that the capital expenditure is conforming. The AER currently has discretion on whether it publicly consults.[44] The Commission notes that the regulator's ability to approve capital expenditure without consultation is limited to cases where the service provider applies, within an access arrangement period, for a determination that capital expenditure not captured in the ex ante forecast will meet the new capital expenditure criteria. We note that this provision has rarely been used.

2.1.3 What are the benefits and costs of ECA's proposal to impose stricter capital expenditure criteria?

ECA consider that its proposal would benefit consumers by constraining new capital expenditure to only that which is necessary in the context of declining gas demand. As a result, ECA expect that capital and operating expenditure will be lower, resulting in lower network charges than otherwise, and minimising the risk of asset stranding. ECA also note that there may be an emissions reduction benefit to the extent their proposed rule changes facilitate alternatives to network investment.[45]

ECA state that the direct costs of requiring gas distributors to provide more robust justification for their capex proposals will be minimal, with some minor incremental costs associated with more fulsome consideration of non-pipeline and other alternative options.[46]

ECA note that there could be other impacts that could affect the benefits and costs to consumers, highlighting the risk that lower capital expenditure may reduce reliability and result in higher amounts of unserved energy. However, ECA contend that this would only occur if it is clear that the avoided cost of the capital expenditure outweighs the cost of additional outages.[47]

Question 2: What changes, if any, should be made to the NGR capital expenditure criteria?

1. Are changes required to the current capital expenditure criteria to better account for uncertainty in future gas demand? If so, would ECA's proposed amendments better account for uncertain demand outlooks than the current criteria?
2. What do you consider would be the benefits and costs of ECA's proposed approach (for consumers, service providers and the regulator)?
3. Are there any alternative, preferable solutions to address the issues identified by ECA with the current capital expenditure criteria?
4. Do you consider changes are required to the rules in relation to advance determinations on capital expenditure in the context of the energy transition (rule 82)? If so, what are your views on the changes proposed by ECA (removing the provision or requiring the regulator to undertake consultation on proposals for advance determinations)?

44 ECA, Rule change request - Capital expenditure, pp. 20-21.
45 ECA, Rule change request - Capital expenditure, p. 21.
46 ECA, Rule change request - Capital expenditure, p. 21.
47 ECA, Rule change request - Capital expenditure, p. 21.

5. Do you consider that additional types of expenditure may need to be recognised as capital expenditure in the context of the energy transition (e.g. decommissioning expenditure)?

2.1.4 ECA consider that changes to the definition of operating expenditure may also be necessary

While ECA's rule change request focuses on capital expenditure, ECA note that keeping operating expenditure to the efficient minimum level could help dampen the price impacts associated with capital recovery approaches, such as accelerated depreciation.

Operating expenditure is currently defined to mean operating, maintenance and other costs and expenditure of a non-capital nature incurred in providing pipeline services. The (non-exhaustive) list of expenditure falling within that definition includes "expenditure incurred in increasing long-term demand for pipeline services and otherwise developing the market for pipeline services".[48] ECA consider that this limb of the definition is obsolete and should be deleted, given it is predicated on an assumption of growing demand.[49] That is, expenditure to increase long-term demand for pipeline services and develop the market for pipeline services may still be permitted unless this type of expenditure is specifically carved out of the definition of operating expenditure. ECA consider that this kind of expenditure seeking to increase demand would be inconsistent in an environment where gas demand is projected to decline.

The Commission notes that gas distributors' decisions on capital expenditure and operating expenditure are likely to become more interrelated given replacement, maintenance and decommissioning needs. In addition, the regulatory framework should balance the incentives between capital intensive solutions and asset management and maintenance solutions as far as practicable so that gas distributors have incentives to consider the most efficient options to address network needs. We are interested in understanding if the regulatory framework should explicitly recognise the types of operating expenditure that are likely to be required to manage the effects of declining gas demand, including expenditure on decommissioning.

Question 3: Are any changes required for operating expenditure?

1. Do you consider the current definition of operating expenditure (which includes expenditure for increasing long-term demand for pipeline services) is fit for purpose in the context of the energy transition?
2. Do you consider there are additional types of operating expenditure that may need to be recognised in the context of the energy transition?
3. Do you consider the regulatory framework appropriately balances the incentives between capital intensive solutions and asset management/maintenance solutions so that service providers have incentives to consider the most efficient options to address network needs? If not, what changes would be required to balance these incentives?

48 NGR, rule 69.

49 ECA, Rule change request - Capital expenditure, p. 18.

2.2 ECA and JEC consider that accelerated depreciation, as currently used, inappropriately shifts the risk of stranded assets entirely onto consumers

ECA and JEC share similar concerns that consumers are being unfairly burdened with the risk and costs of stranded assets, but differ in their proposed solutions to address the issue. The proponents state that the NGR provides limited guidance to the regulator as to how accelerated depreciation should be used to manage stranded asset risk. ECA and JEC also raise fundamental questions about who should bear the risks and costs of stranded assets.

ECA's concern is that accelerated depreciation, as it is currently used by the regulator and gas distributors, implies consumers are the only entity that must pay for the costs of assets that are at risk of stranding, while imposing no costs to network investors.[50]

According to ECA, gas distributors are not automatically entitled to shift all their investment risks onto consumers under the NGL and NGR. ECA points to two aspects of the regulatory framework to highlight that service providers bear at least some of the risk of their investments. ECA note that:[51]

- gas distributors are only afforded a 'reasonable opportunity' to recover their efficient costs.[52]
- the asset redundancy provisions indicate that full cost recovery is not automatic in the case of redundancy or a decline in demand.[53]

In any event, ECA note that accelerated depreciation, by itself, will not fully address stranded asset risk.[54] ECA's proposed solution is set out in section 2.3.

JEC has similar views, noting that the use of accelerated depreciation to manage the broad and undefined future risk of stranding is inconsistent with the long-term interests of consumers. It "unfairly" shifts these "unquantified risks and costs to consumers".[55] According to JEC, accelerated depreciation (as currently allowed by the regulator) transfers a distributor's future redundancy risks and costs to consumers without robustly defining the scope of that risk, demonstrating what that cost relates to, and how consumers' fair share has been determined.[56] JEC's proposed solution is set out in section 2.4.

The proponents also consider the AER's approach to manage consumer price impacts through a 'price path approach' as problematic.[57] ECA note that this approach still fails to consider what proportion of risks consumers should bear.[58] Similarly,JEC note that the regulator has adopted this approach in place of determining what consumers' fair share of stranded risk is, based on transparent and consistent principles.[59]

The Commission notes that the ECA and JEC proposals do not distinguish between or propose different approaches for capital cost recovery of and risk allocation for:

50 ECA, Rule change request - Depreciation, p. 15.

51 ECA, Rule change request - Depreciation, p. 15.

52 Under the revenue and pricing principles in section 24 of the NGL.

53 NGR, rule 85.

54 ECA, Rule change request - Depreciation, p. 17.

55 JEC, Rule change request - Accelerated depreciation and redundancy, p. 4.

56 JEC, Rule change request - Accelerated depreciation and redundancy, pp. 5-6.

57 In the most recent round of access arrangement decisions, the AER has focused on trying to reduce the risk of asset stranding while also minimising the extent of price increases for consumers, by allowing accelerated depreciation but placing a cap on what can be brought forward. See section 1.1.3.

58 ECA, Rule change request - Depreciation, p. 16.

59 JEC, Rule change request - Accelerated depreciation and redundancy, p. 6.

- sunk costs, i.e. past investments that the regulator has determined to be prudent and efficient, and
- new investments that service providers will make in the future.

The Commission further observes that in our reviewed case studies, all regulators have used some form of accelerated depreciation to help mitigate the risk of capital cost recovery for assets that could become unused or underutilised.[60] The regulator and businesses may need flexibility and access to different regulatory tools to manage consumer impacts and promote the long-term interests of consumers.

Question 4: Does the current framework effectively manage and allocate risk and costs between consumers and network service providers in the context of uncertain demand?

1. Do you agree with ECA and JEC that the current rules do not provide for appropriate consideration and management of assets at risk of becoming increasingly underutilised in the context of the energy transition, including consideration of how risk and costs are allocated between network service providers and consumers (including present and future consumers)?
2. Are there alternative solutions to those proposed in the ECA and JEC's rule change requests that would more effectively address cost recovery risks for efficient past and future investments?

2.3 ECA propose to impose conditions on the use of accelerated depreciation

ECA has considered different options in response to the issue of using accelerated depreciation to allocate undue risk for stranded asset risk to consumers:

- Option 1: 'Contingent' accelerated depreciation (ECA preferred approach)
- Option 2: Introduce a prohibition on varying the depreciation rates for existing assets.

2.3.1 ECA's preferred approach advocates for network businesses to propose and the regulator to approve 'contingent' accelerated depreciation

ECA's preferred option is 'contingent' accelerated depreciation. Under this approach, the NGR would only allow for accelerated depreciation if certain conditions are met.[61] ECA consider that the most appropriate conditions are those that would protect consumers from higher prices associated with accelerated depreciation. The intent of these conditions is to encourage gas distributors to act in the interest of gas consumers as "a quid pro quo" for consumers paying to help protect gas distributors from this risk.[62]

ECA broadly distinguishes between 1) broader policy conditions and 2) conditions specified in the NGR.

1) Broader policy conditions could include:

- policies or regulations that ensure existing customers do not bear the cost of any new connections that are still allowed.

60 See Appendix A.

61 ECA, Rule change request - Depreciation, pp. 17-18.

62 ECA, Rule change request - Depreciation, p. 18.

- established policies for ensuring sufficient funding to support permanent consumer disconnection and overall gas network decommissioning.

In relation to these broader policy conditions, ECA note that not all of them are within the control of a gas distributor to implement, but that gas distributors would have an incentive to advocate for such policies on behalf of their customers if depreciation is linked to such conditions.

2) ECA notes that regarding the conditions/criteria specified in the NGR, these could be based on demonstrable actions and behaviour consistent with a service provider that is facing a material risk of stranded assets, including:[63]

- conservative assumptions about effective asset lives and demand projections in cost benefit assessments
- a reduction in debt gearing
- active consideration of non-network options such as demand management or decommissioning
- engagement with the jurisdictional safety regulator on how to meet safety requirements while minimising investment.

ECA's rule change request outlines amendments to the depreciation criteria in rule 89 to give effect to their proposed solution, including:[64]

- Addressing the presumption of indefinite growth in gas networks, by removing the words "promotes efficient growth in the market for reference services" in rule 89(1)(a), and deleting rule 89(2), which ECA consider is only appropriate in the context of ongoing demand growth.
- Expressly limiting the allocation of depreciation to customers to their 'fair and reasonable' share. The rule change request is silent on the considerations that the regulator would need to consider when determining what proportion of stranded asset risk should be fairly and reasonably borne by consumers. ECA also propose consequential amendments to rule 89(1)(e) to ensure that a distributor's reasonable needs for cash flow do not lead to consumers funding cash flow beyond what is fair and reasonable.
- Inserting a new rule 89(3) that would contain the conditions that the service provider would need to meet before the regulator could allow accelerated depreciation. Consequential amendments to rule 89(1)(c) would be required to limit changes to asset lives unless the conditions in proposed new rule 89(3) are met. ECA's proposed amendments suggest that *all* conditions would need to be met, and the types of conditions envisaged by ECA include:
  - where the relevant legislation or regulations of a participating jurisdiction support strategic decommissioning and electrification
  - there is no connections expenditure in the distributors conforming capital expenditure
  - timely publication of the proposed Gas Annual Planning Report (see section 2.5)
  - factors leading to proposed adjustment to economic life are also recognised in forecast of conforming capex
  - the distributor has reduced its capital base by a value that is commensurate with the cost of accelerated depreciation. That is, a gas distributor needs to have demonstrated that they are incurring the same or similar costs as their customers. The Commission notes the similarities of this proposal with the JEC proposal discussed below (section 2.4).

63 ECA, Rule change request - Depreciation, p. 18.

64 ECA, Rule change request - Depreciation, p. 19.

The main objective of the proposed amendments is to constrain the application of accelerated depreciation to where it can clearly be demonstrated to be in the long-term interest of customers and does not result in an inefficient shift in risks from the networks to customers.

2.3.2 ECA's alternative solution is to prohibit varying depreciation rates for existing assets

ECA propose an alternative approach that would prohibit any variation to depreciation schedules for existing assets. ECA contend that gas distributors have been aware of, and have made investments in light of, Australia's emissions reduction commitments[65] for many years and should therefore alone bear the risks of investment decisions over this period.[66] However, this is not ECA's preferred option because the ECA consider it may be unduly inflexible and may also affect the incentives of distributors to recover capital costs through other levers.

2.3.3 What are the benefits and costs of ECA's proposed solution?

ECA consider that its proposal would benefit consumers by minimising consumers' exposure to stranded asset risks and creating a fairer approach for assessing and allocating the costs of stranded assets between consumers and gas distributors.[67] A clearer and consistent approach for managing stranded asset risk would also minimise expenditure and constrain network prices.

ECA have not identified any direct costs associated with their rule change. ECA acknowledge that there could be impacts on distributors as it would expose them further to the costs of stranded assets. However, they emphasise that accelerated depreciation on its own will not address stranded asset risk.

Question 5: How does ECA's proposal impact the recovery of capital costs for new and existing assets?

1. Do you consider changes are required to the depreciation provisions in the context of the uncertain outlook for gas demand (in terms of limiting variations to the rate of cost recovery and changes to asset lives)?
2. What do you consider would be the benefits and costs of ECA's proposed approach to restrict the use of accelerated depreciation through variations to the rate of cost recovery and changes to asset lives (for consumers, service providers and the regulator)?
3. What are your views on ECA's alternative solution of prohibiting the regulator from varying the depreciation rates for existing assets?

2.4 JEC propose to limit the use of accelerated depreciation unless used in conjunction with a process for dealing with redundant assets

JEC's rule change request proposes changes to the depreciation and asset redundancy provisions in the NGR. Their concern is that "while accelerated depreciation is a potential tool by which to share or transfer costs, absent a robust measure to define those costs, it involves an unacceptable risk to consumers that they will be assuming an unreasonable share of costs".[68]

65 Including a domestic climate change target since 1990 and ratification of the Kyoto Protocol in 2007.

66 ECA, Rule change request - Depreciation, p. 19.

67 ECA, Rule change request - Depreciation, p. 21.

68 JEC, Rule change request - Accelerated depreciation and redundancy, p. 5.

JEC's issue with the depreciation provisions (NGR rule 89) is that they do not involve or require an assessment of which assets will become stranded, when they will become stranded, and what the costs of these assets are.[69] JEC submits that in the absence of this assessment, it would not be in the long-term interest of gas consumers to use the depreciation provisions to accelerate recovery of capital to manage stranded asset risks.

According to the JEC, stranded asset risks are more appropriately managed via the specific rule on redundancy (NGR, rule 85). JEC propose amendments to ensure that gas network redundancy risks and costs are more accurately identified and appropriately allocated to consumers. The key elements of the JEC proposal are to:

- clarify and strengthen the redundant asset process by providing for (see section 2.4.1):
  - an expanded and more detailed definition of redundancy
  - a principles based decision-making framework to guide the apportionment of stranded asset costs
- prohibit accelerated depreciation (for the purpose of managing stranded asset risk) unless used with the redundant asset process (see section 2.4.2).

2.4.1 JEC propose to more clearly define 'redundant assets' and improve the framework for determining asset redundancy

Amendments to the definition of 'redundant assets'

JEC consider that the definition of 'redundant asset' is too absolute to be of practical application, requiring that an asset cease to contribute in any way to the delivery of pipeline services.[70] JEC note that this does not recognise the reality where a pipeline is no longer able to provide services in an economically efficient way. In the context of the projected decline in demand, JEC note that this could be a pipeline to which only a handful of customers remain connected.[71] In addition, JEC note that there is no mechanism for gas distributors to identify assets that are likely to become redundant in the future.

To address this, JEC propose amendments to rule 85(1) to broaden the definition of 'redundant assets' to include assets "no longer economically efficient to use in the delivery of pipeline services". JEC propose that the parameters of the assessment of economic efficiency would be defined in guidelines to be developed by the regulator (redundancy guidelines).[72]

JEC also propose adding a new definition of 'anticipated redundant assets' and providing additional incentives to encourage gas distribution businesses to identify assets likely to become redundant in advance of redundancy. JEC's intent is to encourage gas distributors to efficiently identify which assets are likely to become redundant in the context of projected declining gas demand. The incentive to do so is that a greater proportion of costs would be able to be apportioned to consumers.[73]

Develop a principles-based framework to guide regulator decisions on redundancy

JEC note that there is currently no guidance to the regulator on how or when to undertake an assessment of redundancy for the purposes of sharing costs with consumers. According to JEC,

69 JEC, Rule change request - Accelerated depreciation and redundancy, p. 9.

70 NGR, rule 85(1).

71 JEC, Rule change request - Accelerated depreciation and redundancy, p. 11.

72 JEC, Rule change request - Accelerated depreciation and redundancy, p. 11.

73 JEC, Rule change request - Accelerated depreciation and redundancy, pp. 11-12.

the lack of a more comprehensive decision-making framework to guide the regulator undermines the utility of the asset redundancy process.[74]

To address this issue, JEC propose adding a principles-based decision-making framework in rule 85 to guide a gas distributor's 'redundancy assessment' and the regulator's determination and apportionment of redundancy costs (via the cost sharing mechanism proposed or required by the regulator under rule 85(1)). The regulator's decision-making would be supported by the 'redundancy guidelines' to be developed by the regulator. The key elements of JEC's proposed framework are:[75]

- A requirement for gas distributors to prepare a 'redundancy assessment' as part of their access arrangement proposals that identifies redundant assets (including any assets that are anticipated to become redundant). The gas distributor would be required to provide a range of supporting information to enable the regulator to make an assessment of redundancy in relation to the asset, including:
    - specific economic information relating to that asset (e.g. costs already recovered, remaining asset life, expected utilisation)
    - identified reasons the asset is redundant, or anticipated to become redundant
    - quantum of stranded asset costs for the identified assets.
- The regulator must develop redundancy guidelines that set out guidance on the contents of a redundancy assessment and on the establishment and use of a cost sharing mechanism.
- The regulator must make a determination of redundancy, having regard to the information provided in the redundancy assessment. The regulator is required to determine the remaining capital base as part of this assessment (i.e. asset stranding cost).
- In determining whether to approve a cost sharing arrangement proposed by the gas distributor, the regulator must ensure that;
    - a conforming redundancy assessment has been provided by the gas distributor
    - the proportion of costs to be transferred does not exceed 50% of the redundancy cost. JEC emphasise the importance that some limit is imposed on the share of redundancy costs that can be assigned to consumers.
    - the cost sharing arrangement represents an equitable sharing of costs between the service provider and users. The regulator must make a decision in respect of each individual asset and must have regard to the redundancy guidelines and the information provided in the redundancy assessment.

2.4.2 JEC propose to prohibit the use of accelerated depreciation to manage stranded asset risk

JEC propose to amend the depreciation criteria in rule 89 to prohibit accelerated depreciation by inserting a new subrule 89(1A) that prohibits the adjustment of depreciation schedules for assets unless undertaken in conjunction with the proposed redundant asset process in rule 85. JEC clarifies that their rule change proposal does not seek to limit the general ability of service providers to request, and the regulator to approve, changes to depreciation schedules for reasons unrelated to redundancy or stranded asset risk.[76]

74 JEC, Rule change request - Accelerated depreciation and redundancy, p. 12.

75 JEC, Rule change request - Accelerated depreciation and redundancy, p. 14.

76 JEC, Rule change request - Accelerated depreciation and redundancy, p. 9.

JEC's rule change request provides two alternative options for amending rule 89 to demonstrate the intent of their proposal:[77]

- prohibit outright any accelerated depreciation – by either shortening the economic life of assets or front-loading depreciation with a lump sum payment so there is a more rapid paydown of the capital base
- rule 89 is substantially amended, or possibly even deleted in its entirety, to create a requirement that only straight-line depreciation from the point of investment is allowed. The possibility to vary depreciation schedules is removed.

2.4.3 What are the benefits and costs of JEC's proposed solution?

JEC consider their proposed solution would provide a more stable and transparent set of regulatory arrangements that would enable consumers, market participants and network service providers to make efficient decisions.[78]

According to JEC, economic efficiency would be promoted by providing for a 'principled mechanism' to consider possible cost sharing and enable the costs and risks of redundancy and asset stranding to be borne equitably between gas distributors and network users.[79] The proposal to allow and incentivise gas distributors to identify anticipated redundant assets would also promote economic efficiency by facilitating more efficient decisions around network planning, investment and operation.[80] According to JEC, this would result in more stable prices for current and future consumers.

JEC note that its proposal would have a positive impact on emissions reduction by assisting with the orderly retreat and repurposing of the network.[81]

JEC acknowledge that their proposal would have cost implications for gas distributors as they will be required to share the costs of redundancy and asset stranding. JEC note this would be mitigated by the increased scope to use redundancy rules to manage these risks under their proposal.[82]

JEC also note that their proposal would impact the regulator, who would be required to develop new guidelines. However, the cost to the regulator would be offset by the benefits of more fit-for-purpose regulatory tools to identify and allocate the risks and costs of stranded assets equitably.

Question 6: How does JEC's proposal impact the recovery of capital costs ?

1. Do you consider changes are required to the capital redundancy provisions in the context of the energy transition and an uncertain gas demand outlook? If so, what amendments do you consider are necessary?
2. Do you consider the definition of redundant assets should be amended as proposed by JEC to include:
    a. assets that are economically inefficient to use?
    b. anticipated redundant assets?

77 JEC, Rule change request - Accelerated depreciation and redundancy, p. 10.
78 JEC, Rule change request - Accelerated depreciation and redundancy, p. 17.
79 JEC, Rule change request - Accelerated depreciation and redundancy, p. 18.
80 JEC, Rule change request - Accelerated depreciation and redundancy, p. 18.
81 JEC, Rule change request - Accelerated depreciation and redundancy, p. 19.
82 JEC, Rule change request - Accelerated depreciation and redundancy, p. 19.

3. Do you agree with JEC's proposal that service providers and the regulator should use accelerated depreciation in conjunction with the redundant asset provisions only if used to address capital cost recovery risks or redundancy?
4. What do you consider would be the benefits and costs (for consumers, service providers and the regulator) of JEC's proposed approach to:
   - defining and assessing asset redundancy, and
   - allowing for accelerated depreciation to address capital cost recovery risks only in conjunction with the redundant asset provisions ?
5. What are your views on JEC's alternative solution to outright prohibit the use of accelerated depreciation?

2.5 Information gathering provisions for gas distribution networks inadequately address declining network utilisation

2.5.1 ECA consider planning requirements on gas distribution networks are insufficient in the context of declining demand

ECA is concerned that planning requirements for gas distributors are insufficient to allow stakeholders to make informed decisions about the future of the gas networks in the context of projected declining demand. According to ECA, the problem is exacerbated by gas distributors' limited provision of public information in their access arrangement proposals.[83]

ECA identify a broad range of stakeholders that would benefit from improved planning and better information. These include jurisdictional and local governments, non-government organisations, businesses offering products and services that support the energy transition, and electricity networks planning for electrification.

According to ECA, gas distributors do not provide enough granular and regular information over an adequate time horizon to enable these stakeholders to better understand the future of the gas distribution networks. This is in contrast to electricity transmission and distribution networks that are required to provide more comprehensive information as part of their annual planning reports. In ECA's view, requiring gas distributors to provide similar levels of information would improve stakeholders' understanding of emerging issues and constraints and opportunities for strategic decommissioning of the networks. ECA contend that the lack of appropriate information is inhibiting a coordinated response from stakeholders to successfully manage the energy transition.[84]

ECA acknowledge that the current information provisions, which are spread across the NGL and NGR, may be flexible enough to allow for changes. However, they contend that any changes would be limited to existing processes for which information is collected, namely the access arrangement every five years, Regulatory Information Notices issued by the AER, and the annual GSOO.[85] According to ECA, none of these provide a longer-term outlook that would more suitably inform planning decisions for gas distribution networks.

83 Appendix B.2.1. outlines the access arrangement information required to be submitted with an access arrangement proposal.
84 ECA, Rule change request - Planning requirements, p. 15.
85 ECA, Rule change request - Planning requirements, p. 16.

2.5.2 ECA's proposed solution would require gas distributors to publish a Gas Annual Planning Report

ECA propose that gas distributors release a Gas Annual Planning Report (GAPR) to address the need for stakeholders to have more granular and regular information to enable a coordinated approach to reduced gas use.[86] ECA suggest that the that new planning requirements on gas distributors could be split into two rules: one rule setting out the process for producing the GAPR – the Gas Annual Planning Review - and another rule setting out the parameters for publication of the GAPR.[87]

ECA suggest that the GAPR would provide stakeholders (such as jurisdictional and local governments, electricity networks, consumer groups and businesses) with a multi-year forecast for each gas distribution network that includes:[88]

- a 20-year planning horizon with scenario-based analysis
- expected useful life for all assets
- demand forecast numbers of connections/ disconnections
- energy consumption, relevant laws and regulations that may impact forecasts
- potential augmentation/ replacement projects and the relevant drivers for these
- alternative investment projects
- a consumer engagement strategy for the review and a strategy for eliciting demand response (like electricity).

In addition to helping to inform the interaction between declining gas demand and the shift to electrification, such a report may also assist stakeholders in assessing capital expenditure business cases and enable parties to offer potential alternatives to new investment (such as demand management).

ECA suggest that the GAPR should be published, and include mandatory consultation with relevant stakeholders, including specifically the relevant electricity network who may need to plan for an increase in demand on their network if a strategic decommissioning and electrification project is carried out. Consultation with local councils and state governments in areas with fast-declining customer numbers should also be mandatory.[89]

ECA also suggest that the frequency of all outputs in a GAPR may not need to be annual to minimise administrative costs and burden. For example, in even years, the GAPR could include simple statistics on current gas use and rates of disconnection. In odd years, it could include a more complete forecast and plan for the future of the gas network.[90]

The Commission notes that there is a need to consider both the extent and the quality of the planning information that gas distributors would be required to publish under this rule change. Releasing more information by itself may have limited value if it does not enable stakeholders and policy makers to fully understand, assess and input into gas distributors' decisions. Therefore, any planning document would need to be based on a transparent planning methodology set out in the rules to ensure effectiveness plus consistency across the networks. How this interacts with the access arrangement process is another consideration.

86 ECA, Rule change request - Planning requirements, p. 16.
87 ECA, Rule change request - Planning requirements p. 17.
88 ECA, Rule change request - Planning requirements, p. 17.
89 ECA, Rule change request - Planning requirements, p. 17.
90 ECA, Rule change request - Planning requirements, p. 17.

ECA note that its proposal would increase the amount of information available for stakeholders such as government agencies and electricity networks to identify opportunities for strategically decommissioning the gas network in the context of the projected decline in gas demand. The Commission's initial assessment is that the decommissioning of gas assets may need to be subject to a specific planning assessment and consultation framework (and not just additional information requirements on gas distributors). There are questions relating to designing the appropriate criteria, responsibilities on who performs the necessary analysis, the approval process for decommissioning and the regulatory treatment of associated costs. It is not clear how ECA sees the GAPR as playing a role in any decommissioning process or whether this should be subject to separate reporting.

2.5.3 What are the benefits and costs of ECA's proposal?

ECA outline a range of benefits that would arise from better gas distribution network planning, including:[91]

- better quality information would support policy makers to design electrification pathways, including support programs for consumers.
- costs of the energy transition on consumers would be minimised, as consumers would have advance notice of planned decommissioning and be able to avoid further investments in replacing gas appliances.
- the GAPR would provide an additional publicly available source of relevant information such as demand forecasts and assumptions underpinning gas distributors access arrangement proposals.
- positive contribution to emissions reduction, where the GAPR facilitates strategic decommissioning.

ECA consider the costs of their proposal are modest, related to the development of forecasts and modelling tasks, and identifying and evaluating alternatives to investment (including demand management and strategic decommissioning). We note that there is a need to consider consistency across the networks in both the presentation and the methodologies behind any new information which could add to the preparation costs.

Question 7: Are new planning requirements necessary?

1. Do you consider new planning-related reporting obligations for network service providers are required in the NGR to support more efficient decision-making by stakeholders? If so,
    a. what information should be reported and for what purpose?
    b. what should be the reporting frequency?
    c. what pipelines should the requirements apply to,: scheme, non-scheme, distribution, transmission?
2. What do you consider would be the benefits and costs of ECA's proposed reporting requirements (for consumers, industry, gas and electricity network businesses and the regulator)?
3. Do you consider that any alternative solution would better promote the long term interest of consumers?

91 ECA, Rule change request - Planning requirements, p. 19.

3 The Commission proposes to also consider other interrelated aspects of the economic regulatory framework

This chapter outlines the additional, interrelated issues that the Commission is consulting on as part of this rule change process, as highlighted in the diagram below.

Figure 3.1: The Commission proposes to consider interrelated issues in this rule change process

A Longer term outlook	▪ A longer term outlook (demand and expenditure forecasts) may be required to support good regulatory decision-making in the context of demand uncertainty
B Tools to manage demand risk and unforeseen events	▪ Additional regulatory tools may be required to manage: ▪ demand risk with an access arrangement (AA) period ▪ unforeseen events or material changes within an AA period
C Changes to existing or need for additional incentives	▪ Additional incentives for service providers may be required to support the gas transition

Source: AEMC.

The economic regulatory framework for gas pipelines comprises various interrelated elements that operate as a package to promote the NGO. The combination of ex-ante estimates of efficient costs and a fixed regulatory period, the regulated return and the ability to get higher return from outperforming plus financial incentive mechanisms are key components of the package. A change to one element has implications for the other components of the package. The Commission must consider changes to individual elements in the context of the broader economic regulatory framework to ensure that it continues to operate effectively, as a whole, to promote the NGO,

ECA and JEC's rule change requests identify specific areas where the proponents consider that the current rules are failing to adequately promote the NGO in the context of projected declining gas demand. The Commission has identified other interrelated aspects that may impact the effectiveness of the overall economic regulatory framework in the context of an uncertain future outlook for gas demand. The Commission will consider and is interested in stakeholder feedback on whether any changes to the NGR are required or whether the rules provide for sufficient discretion and flexibility to address the questions we have identified below. To manage consumer impacts, the regulator and service providers may need more flexibility as well as increased guidance and/or additional regulatory tools and incentives to promote the long term interest of consumers. We consider this is particularly the case in the absence of consistent jurisdictional policies and an uncertain future. Our objective is to ensure that the changes proposed in the rule change requests are considered holistically within the broader framework for the economic regulation of gas pipelines,

To explore the need for change to interrelated elements of the economic regulatory framework we are asking the following questions:

- **Would a longer-term outlook support better decisions?** section 3.1 explores whether a longer-term outlook for demand and expenditure forecasts could improve regulatory decision-making.
- **Are additional regulatory tools needed to manage demand risk?** section 3.2 explores whether the regulatory tools available to manage demand risk are appropriate.

- **Are additional regulatory tools needed to manage unforeseen events or material changes?** section 3.3 explores whether existing access arrangement variation mechanisms to manage these risks remain fit for purpose.
- **Are the existing incentives appropriate to support the transition?** section 3.4 explores whether changes to existing or additional incentives are required for gas distributors to maintain service levels in the context of an uncertain future.
- **Are there other changes that we need to consider?**section 3.5 highlights some of the different approaches adopted by regulators in other jurisdictions and sectors for managing demand uncertainty. See appendix Afor more information.

3.1 A longer-term outlook on the transition may support regulatory decision-making

The access arrangement review process currently requires both the regulator and service provider to focus on what is expected to occur in the upcoming access arrangement period. The NGR does not specify the length of an access arrangement period; instead a service provider proposes a ‘review submission date’ as part of their access arrangement proposal, which determines the length of the access arrangement.[92] Currently, the access arrangement period for all distribution scheme pipelines is five years.

In an environment of uncertain demand, a longer-term outlook on the transition may better support the regulator’s assessment of a proposed access arrangement. A longer-term outlook could enable the regulator to better understand how future decisions are impacted by decisions in the current access arrangement (e.g., how current expenditure decisions would impact strategic decommissioning in the future). This approach may also enable customers to engage more effectively on access arrangement proposals. A longer-term outlook could provide a clearer and more transparent picture of gas distributors’ views of the future of their networks. This may enable stakeholders to better assess the credibility of network customer growth forecasts given current customer behaviour and jurisdictional policy settings.

Regulators in other jurisdictions have introduced requirements to support a longer-term outlook in decision-making. For example, the principal wholesale provider of fixed line telecommunications in Aotearoa, New Zealand, is required to provide an ‘Integrated Fibre Plan’ that spans two regulatory periods (see appendix A).

Amending the NGR could support a longer-term outlook in decision-making. The NGR could require gas distributors to:

- provide demand and expenditure forecasts over a period that aligns with net zero targets or jurisdictional decommissioning plans in relevant jurisdictions
- capture more granular information on changes in customer usage patterns in parts of their networks in their demand forecasts and model the impacts of different demand scenarios across their networks
- provide options for immediate actions which secure pathways and optionality around decommissioning and redundancy, and pricing options which could deliver the lowest cost transition to consumers.

These requirements could be reflected in how the regulator and a service provider use the building block method to determine a scheme pipeline’s revenue requirement over the next access arrangement period. For example, the NGR could require a service provider and the regulator to

92 See section 3.3.1

consider the capital expenditure requirements over the relevant outlook period when proposing and assessing a capital expenditure proposal for the access arrangement period.

> **Question 8: Would a longer-term outlook on the gas transition support better regulatory decision-making?**
>
> What do you consider would be the costs and benefits of requiring service providers to provide demand and expenditure forecasts over a longer period than the relevant access arrangement period? What would be an appropriate longer-term period (e.g. 10, 15 or 25 years)?

3.2 Additional regulatory tools may be required to manage demand risk within an access arrangement period

3.2.1 The regulator may need more guidance to account for demand risk

Under the current regulatory framework, the reference tariff variation mechanism applied to a service provider determines who bears the risk that demand within the access arrangement period will be more or less than what is forecast (demand risk).[93]

The Commission is seeking feedback on whether changes to the current arrangements relating to tariff variation mechanisms are necessary to better account for uncertainty in the outlook for gas demand. We are interested in stakeholders' views on whether the current arrangements allocate demand risk to the party best able to manage that riskin a context of uncertain demand.

The Commission could consider changes to the NGR to:

- provide more guidance to the regulator on when the different tariff variation mechanisms should be used and how intra-period demand risk should be allocated between the service provider and users
- require the service provider to include a proposed reference tariff variation mechanism in its reference service proposal[94] and allowing or requiring the regulator to decide the applicable reference tariff variation mechanism as part of its reference service proposal decision.[95] Subject to a material change in circumstances that justified a departure, a service provider would need to reflect in its access arrangement the regulator's decision on the applicable reference tariff variation mechanism under the reference service proposal decision.

Bringing forward a decision on the applicable reference tariff variation mechanism to the reference service proposal stage could provide benefits through enabling earlier consultation on the approach with the gas distributor and stakeholders. The regulator making a decision on the applicable reference tariff variation mechanism at the reference service proposal stage would also provide more certainty to the gas distributor. However, in considering whether to bring forward this decision, the Commission will need to consider whether all information relevant to this decision is available at that stage of the access arrangement process. For example, until building block and demand inputs are known it may be difficult to have meaningful engagement with stakeholders on the form of the reference tariff variation mechanism.

93 NGR, rule 97(3)(d1). See also appendix B.2.3.

94 NGR, rule 47A.

95 This would be equivalent to the decision on control mechanisms made under the framework and approach paper for electricity distribution businesses under the National Electricity Rules (NER), clause 6.8.1.

Question 9: Are changes to reference tariff variation mechanisms necessary?

1. Do you consider the NGR should provide more guidance to the regulator on when different reference tariff variation mechanisms (e.g. revenue cap vs price cap) should be used by service providers to appropriately allocate intra-period demand risk between the service provider and users?

2. If so, what would be the costs and benefits to consumers, service providers and regulators of providing more guidance in the NGR and/or bringing forward the regulator's decision on the applicable reference tariff variation mechanism?

3.2.2 Consumers may need more efficient price signals

Service providers recover their revenue requirement through reference tariffs. Service providers structure these tariffs using different "charging parameters", which are specific factors or variables that determine how a customer assigned to that tariff is charged. Common charging parameters include fixed (supply) and variable (consumption) charges. Gas distributors have to design their tariffs in accordance with the requirements in the NGR. This includes taking into account the long run marginal cost of providing the relevant service or how tariffs can be set to minimise the distortion to efficient consumer decisions.[96]

Different tariff structures may provide different price signals to customers, depending on how they are passed through to customers by retailers. For example, tariff structures that allocate more costs to fixed charges than variable charges may provide additional incentives for small-volume gas customers to electrify (e.g. switch their last remaining gas appliances to electricity). A declining block tariff (where per unit charges decrease with increasing levels of consumption) may also incentivise consumers to increase consumption, while an inclining block tariff may have the opposite effect.

The Commission is interested in understanding whether changes are required to the tariff rules in the context of the uncertain outlook for gas demand and the potential reduction of network asset economic lives. These changes to the NGR may be required to ensure that more efficient price signals are provided to consumers (by retailers) and to manage the potential impacts of projected declining demand on the prices networks users pay. Options the Commission could consider include providing more or different guidance in the NGR on how service providers should:

- structure their tariffs, or
- the matters they should consider when deciding how to structure tariffs.

Question 10: Are changes to the tariff rules necessary?

Do you consider the NGR should include more or different guidance to service providers on how reference tariffs should be structured in the context of the energy transition?

96 NGR, rule 94. See also appendix B.2.3.

3.3 Additional regulatory tools may be required to manage unforeseen events or material changes

The regulatory framework currently includes several mechanisms to manage material changes in circumstances or unforeseen events that may arise within an access arrangement period. These mechanisms include the ability of service providers to:

- propose the length of an access arrangement period[97]
- include a trigger event mechanism in their access arrangement[98] or seek a variation during the access arrangement period[99] (jointly referred to as re-opener mechanisms).

In the context of uncertainty about future demand, it is prudent to consider whether these existing mechanisms are sufficient or if changes would provide additional flexibility to respond to unforeseen events and changes. For example, shifts in jurisdictional policy could impact a service provider's revenue requirement. These shifts might involve the imposition of new regulatory obligations relating to network performance in the context of declining demand, jurisdictional adoption of renewable gas, or the provision of revenue support for strategic decommissioning.

The case studies (see appendix A) identify examples where regulators have introduced additional mechanisms to enable the framework to adapt to changing circumstances over the regulatory period. For example, the UK regulator (Ofgem) can open price controls for gas distribution businesses where the pace of change in the transition to net zero differs from what was envisaged at the start of the period. This could be due to changes in government policy or recommendations by the system operator in its regional planning (the Net Zero re-opener) and in response to a government decision on hydrogen for heat (the Heat Policy Re-opener). We also note that, in comparison, the NER has extra mechanisms such as contingent project arrangements and more specification on permitted cost pass through events to manage uncertainty.

3.3.1 The regulator may need more flexibility to determine access arrangement length

Access arrangements for scheme pipelines do not have an expiry date but must include a date at which the access arrangement will be reviewed – the review submission date - that then determines the length of an access arrangement period.

Typically, service providers propose a review submission date that is five years after the commencement date of the current access arrangement, but they can propose longer or shorter dates.[100] The regulator must approve the review submission date if:

- it is satisfied that the date is consistent with the NGO and the revenue and pricing principles, and
- the proposed revision commencement date is not less than 12 months after the proposed review submission date.

The regulator must determine an alternative review submission date if it considers that the date proposed by the service provider is not consistent with the NGO and the revenue and pricing principles.[101]

An uncertain demand outlook increases the risk of unforeseen events or material changes within an access arrangement period. Accordingly, there may be merit in providing the regulator with

97 NGR, rule 50.
98 NGR, rule 51.
99 NGR, rule 65.
100 NGR, rule 50.
101 NGR, rule 50.

more flexibility to set a different access arrangement period than that proposed by the relevant service provider. Shorter access arrangement periods may reduce the risk that material changes occur within an access arrangement period; conversely, longer access arrangement periods could increase the risk but support a longer-term outlook in decision-making.[102]

Providing the regulator greater flexibility to set access arrangement periods may also assist the regulator in aligning its gas and electricity distribution decisions over time. Greater alignment could facilitate a better understanding of gas and electricity sector interactions if gas and electricity access arrangement periods are aligned in a jurisdiction. For example, in a future where gas distribution customers are increasingly electrifying, the regulator's decision-making could be improved by understanding how a reduction in the use of gas distribution networks would correspond with the potential need for investment in electricity distribution networks.

Against this background, the Commission considers there would be benefit in exploring whether amendments are required to the regulatory framework to:

- provide the regulator with greater guidance on when a shorter or longer access arrangement period would be required, or
- enabling the regulator to set review submission dates for the purpose of aligning gas and electricity decisions in a relevant jurisdiction.

Question 11: Should the regulator be able to require shorter or longer access arrangement (AA) periods?

1. Do you consider the regulator should have more discretion to require a shorter or longer AA period than that proposed by the service provider? If so, what should be the criteria/principles to guide a regulator's decision on requiring a different AA period?
2. What do you consider would be the benefits and costs of aligning the timing of electricity and gas distribution decisions in relevant jurisdictions? What impacts would the alignment of the timing of these decisions have on regulators, service providers and stakeholders engaging in these processes?

3.3.2 The regulator may need more flexibility to manage access arrangement variations

Currently, when the regulator reviews an access arrangement depends on the review submission date specified in an access arrangement. This date can only be brought forward if the access arrangement specifies a trigger event to bring forward a review and that trigger event occurs.[103]

The NGR also allows the service provider to submit an access arrangement variation proposal within the access arrangement period.[104] If the regulator considers the variation to be non-material, it can approve the variation without consultation.[105] But if it considers the proposed variation to be material, it must be dealt with as if it was an access arrangement proposal. The NGR does not allow for the regulator to propose a variation to an access arrangement within the access arrangement period.

102 See section 3.1.
103 NGR, rule 51.
104 NGR, rule 65.
105 NGR rule 66(2).

The current framework for access arrangement variations may not provide sufficient flexibility for the regulator to respond to a rapidly evolving policy environment that may impact consumer behaviour and demand for gas. This is in contrast to other jurisdictions and under the NER. As noted above for example, the UK regulator (Ofgem) has greater flexibility to re-open a gas distributor's price control where there are policy changes during the price control period.

However, the benefits of introducing greater flexibility to respond to changing circumstances need to be carefully weighed against the potential to undermine the access arrangement process. For example, investment certainty could be reduced if there is increased scope for changes to be made within an access arrangement period.

The Commission is interested in stakeholders' views on potential changes to the access arrangement variation mechanism, including:

- giving the regulator the ability to propose a variation to an access arrangement in specified circumstances, to address the current asymmetry in the NGR relating to access arrangement variations
- constraining the service provider's ability to trigger a review, so that a variation is not triggered unnecessarily
- empowering the regulator to conduct a narrowly scoped review of the access arrangement, rather than being required to review the whole access arrangement in response to a variation proposal.

Question 12: Are changes required to the re-opener provisions?

1. Do you consider changes are required to the current re-opener provisions? If so, what changes do you consider are appropriate in the context of the energy transition?
2. What would be the costs and benefits of making changes to the re-opener provisions?

3.4 Changes to incentives may be required to support the transition

3.4.1 Gas distributors may need additional incentives to maintain service levels

An access arrangement may include (and the regulator may require it to include) one or more incentive mechanisms to encourage efficiency in the provision of services by the service provider.[106] The NGR does not define the types of incentive mechanisms that may be applied to gas distributors.

In contrast, the AER must develop certain incentive mechanisms to apply to electricity distributors under the NER. This includes an efficiency benefit sharing scheme (EBSS),[107] a capital expenditure incentive scheme (CESS),[108] a service target performance incentive scheme (STPIS),[109] a demand management incentive scheme,[110] and a demand innovation allowance mechanism.[111] In the NER context, the STPIS is intended to balance the incentives to reduce expenditure provided under the EBSS and CESS and to "drive expenditure reductions through efficiency gains rather than at the expense of service levels to customers"[112].

106 NGR, rule 98. See also appendix B.

107 NER, clause 6.5.8

108 NER, clause 6.5.8A

109 NER, clause 6.6.2.

110 NER, clause 6.6.3.

111 NER, clause 6.6.3A.

Currently, the incentive schemes applied to gas distributors relate to expenditure.[113] There are no incentive mechanisms relating to service standards or demand management currently applied to gas distributors. In 2023, the AER reviewed the incentive schemes applicable to networks but did not recommend any additional schemes be developed and applied to gas networks.[114]

The costs of providing a safe and reliable service to remaining customers may increase if customers leave parts of the gas network. In this context, it may be relevant to consider whether there is a need to incentivise gas distributors to balance expenditure efficiency and service levels to customers. In addition, incentive mechanisms or allowances may be a means of promoting strategic decommissioning if doing so would reduce overall consumer costs in the longer term. In this regard, aligning network and customer incentives with jurisdictional decarbonisation goals could support more efficient and strategic decision-making around gas exit.

As noted in the case studies (appendix A), regulators in other jurisdictions and sectors have changed their approach to incentives to manage declining demand for services. For example:

- in Spain, gas transmission businesses are incentivised to continue operating assets that are fully depreciated but still technically able to operate. Businesses can receive a fixed reward linked to the operating expenditure maintenance values of such assets to incentivise keeping them in operation and thus avoid incurring unnecessary new investment costs. The reward is calculated as a percentage of operating expenditure (20% to 40%). The strength of the incentive increases the longer the asset can remain in operation after its regulatory life
- in Europe, regulators are considering how to develop better incentives on gas transmission network to optimise the timing of decommissioning.

Question 13: Should there be changes to the existing or additional incentive mechanisms?

Do you consider modified or additional incentive mechanisms should apply to service providers in the context of the energy transition?

3.4.2 Changes to the regulatory framework could create incentives for non-scheme pipelines to elect to become scheme pipelines

Most, if not all, the changes to the economic regulatory framework raised specifically in the rule change requests and considered in this chapter would only apply to scheme pipelines.[115] However, there is a potential for changes to the regulatory framework to create incentives for non-scheme pipelines to elect to become scheme pipelines (for example, because they perceive the changes would provide better protection from the risks that capital costs for past efficient investments would be underrecovered).

Under the current framework, service providers may voluntarily elect for their pipelines to be regulated as a scheme pipeline.[116] The AER does not make an assessment of whether a non-scheme pipeline should become a scheme pipeline, with the only decision being the date on which the election is to take effect.[117] Given this context, the Commission also intends to consider

112 AER - Final decision - Review of incentive schemes for networks - 28 April 2023 | Australian Energy Regulator (AER), p. 23.

113 See appendix B.2.2.

114 AER - Final decision - Review of incentive schemes for networks - 28 April 2023.

115 See Appendix B,Figure B.1Figure B.1

116 Section 95(1) of the NGL.

117 Section 96 of the NGL.

whether to recommend any changes to the pipeline election framework under the NGL to ensure there are no adverse incentives for non-scheme pipelines to elect to become scheme pipelines.

Question 14: Could the proposed changes inefficiently incentivise pipeline elections?

Would any of the changes considered in this consultation paper alter the incentive for non-scheme pipelines to elect to become scheme pipelines?

3.5 Regulators in other jurisdictions are adopting alternative approaches to managing demand uncertainty

It is important that the NGR provide the regulator with the appropriate discretion and tools to enable it to optimise the outcomes under the regulatory framework in the context of demand uncertainty. As set out in the case studies (see appendix A), regulators in other jurisdictions have implemented alternative approaches to managing demand uncertainty. Some of the approaches adopted by other regulators are already open to the regulator under the current regulatory framework in the NGR (e.g., application of different depreciation approaches, introduction of mechanisms to incentivise longer use of assets), while others could only be implemented if changes were made to the NGR (e.g., compensation for decommissioned assets).

We are keen to understand stakeholders' views on other approaches and how they relate to the issues identified by the proponents.

Question 15: What can we learn from other jurisdictions/sectors?

Do you consider other changes to the regulatory framework for scheme pipelines are necessary to provide the regulator with the tools and appropriate level of discretion to manage the gas transition? If so, what would be beneficial?

4 Making our decision

When considering a rule change proposal, the Commission considers a range of factors. This chapter outlines:

- factors the Commission must take into account (section 4.2)
- our proposed assessment criteria (section 4.3)
- our options for making rules (section 4.4)
- our ability to make rules for Western Australia (section 4.5).

4.1 The Commission must act in the long-term interests of consumers

The Commission is bound by the National Gas Law (NGL) to only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national gas objective.[118] The NGO is:[119]

> to promote efficient investment in, and efficient operation and use of, covered gas services for the long term interests of consumers of covered gas with respect to—
>
> (a) price, quality, safety, reliability and security of supply of covered gas; and
>
> (b) the achievement of targets set by a participating jurisdiction—
>
> (i) for reducing Australia's greenhouse gas emissions; or
>
> (ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

The targets statement, available on the AEMC website, lists the emissions reduction targets to be considered, as a minimum, in having regard to the NGO.[120]

4.2 We must also take these factors into account

The Commission must take into account the revenue and pricing principles set out in section 24 of the NGL in making certain rules.[121] Relevantly for this rule change request, we must take those principles into account in making rules with respect to pipeline service operators providing services that are the subject of an access arrangement. This includes the regulation of revenues earned, or prices charged by owners, controllers or operators of a scheme gas pipeline.

Relevantly, the revenue and pricing principles provide that;

- a scheme pipeline service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in providing reference services and complying with a regulatory obligation
- a scheme pipeline service provider should be provided with effective incentives to promote economic efficiency with respect to reference services the service provider provides
- regard should be had to the capital base with respect to a pipeline adopted in any previous access arrangement decision.

118 Section 291 of the NGL.

119 Section 23 of the NGL.

120 Section 72A(5) of the NGL.

121 Section 293 of the NGL.

4.3 We propose to assess the rule change using six assessment criteria

4.3.1 Assessment criteria and rationale

Considering the NGO and the issues raised in the rule change request, the Commission proposes to assess this rule change request against the set of criteria outlined below. These assessment criteria reflect the key potential impacts – costs and benefits – of the rule change request. We consider these impacts within the framework of the NGO.

Consistent with good regulatory practice, we also assess other viable policy options - including not making the proposed rule (a business-as-usual scenario) and making a more preferable rule - using the same set of assessment criteria.

The proposed assessment criteria and rationale for each is as follows:

- **Outcomes for consumers**: What are the potential impacts of various solutions on consumers who continue to rely on gas services in the context of declining gas demand? And how are the costs of past efficient investments that may become unused or underutilised allocated and recovered? We will assess the outcomes for consumers of different policy solutions by considering several elements, including:
  - Consumer protections - Would the solution adequately protect small customers from unnecessary cost burdens including, in particular, vulnerable and 'hard to electrify' consumers that remain on the gas network?
  - Equity considerations - Would the solution be consistent with the AEMC's work on equity for energy consumers, particularly if present customers are being asked to shoulder a proportionally greater cost burden than future customers?
  - Consumer insights/behaviours - Would the solution be compatible with consumer wants and needs? Would it distort efficient signals and incentives on gas consumers to electrify?
- **Safety, security and reliability**: Do network service providers continue to invest in their assets to preserve safety, security and reliability of gas services - in the context of declining gas demand in the residential and commercial customer segment and increasing uncertainty as to the prospects of recovering efficient costs? We will assess safety, security and reliability by considering several elements, including:
  - Outcomes - Would the solution enable reliable, secure and safe provision of energy to consumers (including vulnerable and hard to electrify consumers) at efficient cost?
  - Services - Would the solution promote efficient operation and use of, and investment in, networks and other system service capability? Would the solution avoid incentivising unnecessary expenditure? Are network service providers providing enough information in their expenditure proposals so that regulators can make this assessment?
- **Emissions reduction**: Would the solution support emissions reduction?
- **Principles of market efficiency:** Solutions to address capital cost recovery risks, including changes to risk allocation and capital expenditure criteria, will need to preserve balanced incentives on network service providers to invest efficiently in their networks and potentially plan for strategic decommissioning. The rule change requests raise key issues around principles of market efficiency, including:
  - Risk allocation - Would the proposed rule changes allocate the costs and risks to the appropriate parties?
  - Incentives - Would the solution provide appropriate incentives to drive efficient investment decisions? Will businesses have incentives to maintain a safe and reliable service? Would

it bring forward inefficient and early closure of pipeline assets, and is this in the long-term interests of gas consumers?
    - Transparency - Would the solution increase information transparency? Will stakeholders have the information they need to respond to changes in the planning and operation of the gas network?
- **Implementation considerations:** The changes to the gas economic regulatory framework could result in profound changes to the way scheme pipelines are regulated. We will assess the rule change requests against this criterion by considering several elements, including:
    - Timing and uncertainty - Will we need to consider staging the implementation of reforms to ensure the economic regulatory framework is fit for purpose during different stages of the energy transition? What are the drivers for implementing the solution now versus later? How do our reforms interact with other reforms?
    - Whole-of-market success - Would the solution achieve gas market-wide success, taking into account specific jurisdictional conditions, issues and benefits? What would be the impacts of a solution on investment in the industry more broadly, including in the electricity market? We will also ask what would be the impacts of a solution on investment in the industry more broadly, including in the electricity market?
    - Flexibility - Is the solution future-proofed, resilient, and able to accommodate market, policy, and other changes?
- **Principles of good regulatory practice**: Solutions to change the tools that the regulator has available to manage uncertain gas demand and capital cost recovery risks will need to maintain a predictable and stable regulatory framework and align with the broader direction of gas market reform. The rule change proposals raise key questions around principles of good regulatory practice, including:
    - Predictability and stability - Do the proposed changes to redundant assets and depreciation provisions contribute to a predictable and stable regulatory framework?
    - Prescription vs a principles-based approach - Do the proposed changes provide sufficient flexibility to the regulator to adapt its approach as appropriate, given uncertainty in future gas demand while maintaining predictability?
    - Broader direction of reform - Do the rule changes align with the general direction of reforms being implemented by jurisdictions and the projected decline in gas use by residential and commercial customers?
    - Transparency and simplicity - Does the proposal maintain transparency and simplicity in away that enables all consumer groups to understand and engage?

Question 16: Assessment framework

Do you agree with the proposed assessment criteria? Are there criteria that you consider are not directly relevant to the issues raised in the rule change requests and the proposed solutions?

4.4 We have three options when making our decision

After using the assessment framework to consider the rule change request, the Commission may decide:

- not to make a rule

- to make the rule as proposed by ECA and JEC[122], or
- to make a rule that is different to the proposed rule (a more preferable rule), as discussed below.

The Commission may make a more preferable rule (which may be materially different to the proposed rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule is likely to better contribute to the achievement of the NGO.[123]

4.5 Making gas rules in Western Australia

The versions of the NGL and NGR that apply in Western Australia differ from the NGL and NGR as they apply in other participating jurisdictions.[124]

As a result the Commission's power to make rules for Western Australia differs from its rule-making power under the NGL.[125]

The rule change requests for depreciation (GRC0082), capital expenditure criteria (GRC0083) and accelerated depreciation and asset redundancy (GRC0088) relate to existing price and revenue regulation provisions in Part 9 of both the NGR and the NGR that applies in Western Australia.

The rule change request for planning requirements (GRC0084) seeks to introduce a "Gas Annual Planning Report" to complement current planning provisions in the NGL and NGR, including access arrangements, regulatory information notices and the gas statement of opportunities. While the WA Gas Law provides that the AEMC may make rules for or with respect to regulating the collection use, disclosure, copying, recording, management and publication of information in relation to natural gas services,[126] the WA Gas Law does not regulate WA's gas statement of opportunities. The Commission will take these differences into account in the process of considering the proposed rule or a more preferable rule.

122 We have described the proponents' proposed rules in Chapter 3 of this consultation paper.

123 Section 296 of the NGL.

124 Under the *National Gas Access (WA) Act 2009* (WA Gas Act), a modified version of the NGL, known as the National Gas Access (Western Australia) Law (WA Gas Law), was adopted. Under the WA Gas Law, the National Gas Rules applying in Western Australia are version 1 of the uniform NGR as amended by the SA Minister under an adoption of amendments order made by the WA Minister for Energy and by the AEMC in accordance with its rule making power under section 74 of the WA Gas Law. See the AEMC website for further information, https://www.aemc.gov.au/regulation/energy-rules/national-gas-rules/western-australia.

125 See section 74 of the WA Gas Law for the subject matters for the AEMC's rule making power in Western Australia.

126 Section 74(1)(a)(iii) of the WA Gas Law.

A Case studies on regulatory approaches to managing capital cost recovery risks in an environment of declining demand

A.1 Regulators around the world are grappling with how to address demand uncertainty

Regulators around the world are starting to recognise the risks faced by gas networks in fully recovering past efficient investments as a result of declining residential and small commercial demand (i.e. asset stranding risk), due to electrification and jurisdictional policies to meet emissions reduction targets. This is a developing area that many regulators are just starting to grapple with, so there is not yet substantial precedent or an established approach. Further, based on the divergence of jurisdictional policies in the international context, there are question marks around the future of gas networks. For example, whether they will be repurposed to transport renewable gases or potentially need to be decommissioned. Regulators are having to consider how best to address the potential for asset stranding in this uncertain environment.

The asset stranding risk will depend on consumer usage patterns, the pace and scale of technological change and how much of the network needs to be retained or can be repurposed e.g. to transport hydrogen or biomethane. Importantly, it also depends on government policy. In jurisdictions where policy makers have set clear, defined goals for decarbonisation with bans on new connections and a detailed plan to transition customers off natural gas, the regulator has responded with a suite of measures to address the corresponding asset stranding risk. In other jurisdictions, where the policy and hence the extent of asset stranding risk remains uncertain, regulators have taken more limited action.

This appendix sets out three detailed case studies and additional precedents to provide examples of how governments and regulators internationally and in other sectors have tackled the issue of declining demand for regulated services. The purpose of this appendix is to illustrate alternative approaches and solutions to address the impacts of uncertain gas demand and providing ‘food for thought’ for stakeholders when considering our consultation questions and thinking about potential amendments to the regulatory framework.

The three detailed case studies are:

- **Gas distribution networks in Great Britain**. We selected this case study due to the similarities with Australia, including a similar regulatory framework and uncertainty about the future use of gas distribution networks.
- **Gas networks in the Netherlands**. This case study provides an example of how the regulator has approached asset stranding risk in the context of clear government policy on the future role of gas networks.
- **Telecommunications in Aotearoa New Zealand**. This case study provides an example of how the regulator approaches asset stranding risk in an industry that is characterised by a high degree of technological change and so high risk of asset stranding.

The key factors the case studies consider are:

- how regulators have approached the issue of enabling regulated businesses to recover their capital costs where demand is declining or uncertain
- approaches to expenditure assessments to encourage efficient decisions about ongoing asset use and decommissioning

- where relevant, the case studies also consider factors such as re-opening regulatory determinations, approaches to network planning, the ability of businesses to attract finance and equity considerations.

The ability of regulators to implement various regulatory tools depends on the scope of their discretion and overarching legislative objectives, which may differ from the discretion and objectives that Australian regulators have under the National Gas Rules (NGR) and National Gas Law (NGL). Some of the measures considered in this appendix are already permissible within the scope of the NGR, while others would require action by governments or amendments to the NGL. Nonetheless, they provide a useful starting point for considering the suite of regulatory tools and solutions that are theoretically available to address the issues raised in the rule change requests.

A.2 Regulators have adopted a similar overarching approach in considering how to address declining demand

Based on the case studies, we have observed some similarities in how regulators have approached the issue of declining demand and the associated asset stranding risk. However, the specific measures that regulators have adopted to compensate for asset stranding risk differ. In considering what measures to adopt, regulators generally have:

- considered the regulatory framework holistically
- sought to preserve the ability of regulated businesses to recover their efficient costs
- balanced price impacts for consumers with advancing capital cost recovery.

A.2.1 Regulators consider the economic regulatory framework holistically

When considering how to address the asset stranding risk associated with declining demand, the regulators we reviewed have considered the economic regulatory framework within which a business operates holistically. In practice, this means examining how the various components of the framework — such as depreciation, the regulatory asset base (including capital expenditure), allowed rates of return, and revenue-setting mechanisms — interact over time. This allows regulators to consider the extent to which asset stranding risks are already compensated for within these various components, as well as consider through which component any remaining risk is best addressed.

A.2.2 Regulators seek to preserve the *opportunity* (not guarantee) for regulated businesses to recover their efficient costs

A key regulatory principle underpinning approaches by regulators around the world to address asset stranding risk is that a regulated service provider should have a *reasonable opportunity* to recover its prudent and efficient costs. That is, over the economic lifetime of an asset,[127] the service provider should have a *reasonable opportunity* to:

- earn a return commensurate with the risk of the investment, and
- fully recover the capital invested in the asset (i.e. through depreciation).

Importantly, service providers should only be compensated once for the prudent and efficient costs of providing regulated services. This requires careful coordination across regulatory framework elements to avoid both under- and over-recovery.

127 The economic lifetime of an asset is the period over which a regulated asset is expected to generate economic returns, and hence the period over which an asset remains in the regulated asset base, allowing the regulated business to recover depreciation and earn a return on the asset: Frontier Economics (2022) Economic life for the purposes of setting the regulatory depreciation allowance: a report prepared for Sydney Desalination Plant. See here. Note that the economic lifetime of an asset can change over time in response to actual and forecast changes in the use of the asset.

Importantly, regulated businesses are not *guaranteed* cost recovery through the regulatory framework. Rather, the regulatory framework provides and opportunity for businesses to recover their efficient costs. [128]

A.2.3 Regulators have balanced price impacts on consumers with capital cost recovery

Addressing the asset stranding risk by regulators providing regulated businesses with an opportunity to advance cost recovery, can trigger adverse customer impacts. Material increases in prices (including as a result of costs being brought forward, e.g. through accelerated depreciation) may prompt more customers to disconnect, resulting in further rounds of price increases and potential disconnections. Apart from having a range of adverse effects on those users that are unable to disconnect, this can also increase the risk of asset stranding for gas distributors. This may in turn affect the ability and/or incentive of network owners to continue to operate and provide safe and reliable services to remaining users.

An observation from the case studies is that regulators have brought forward the cost recovery process while there are as many customers as possible from whom to recover costs. For example, in addition to Australia, the following countries have implemented policies to bring forward cost recovery for gas transmission and/or distribution businesses: UK, Netherlands, Germany, Belgium and Austria.

A.3 Capital cost recovery is only one of many considerations associated with declining demand on gas networks

From the case studies, we have observed four main areas where regulators have amended their approach to address (the risk of) asset stranding from declining demand:

- capital cost recovery
- treatment of stranded asset costs
- incentives for decommissioning
- incentives for extended use of assets
- providing an additional ex ante risk premium on the WACC in recognition of the risk of stranding.

Many regulators have stated the need to monitor and revisit approaches over time as the future of gas becomes clearer.

A.3.1 Accelerating capital cost recovery

In the majority of examples we considered, regulators have brought forward capital cost recovery to address asset stranding risk from declining demand. The most common way that regulators have brought forward cost recovery – including in Australia – is by accelerating depreciation. This can be done by:

- **Front-loading the depreciation profile** to recover a higher proportion of depreciation while there are a larger number of customers, rather than using a straight line approach. There are many ways that regulators can implement a front-loaded depreciation profile e.g. the “sum of digits” method used in Great Britain and “declining balance” or “degressive” approach used in the Netherlands. Irrespective of how it is implemented, all these methodologies have the same effect of bringing forward recovery of depreciation, with differences in the exact profile.

128 See, for example, the Revenue and Pricing Principles relating to scheme pipelines set out in the NGL.

- **Reducing economic asset lives** to recover depreciation over a shorter time period. Regulatory, or economic, depreciation may be recovered over the technical life of the asset where the asset is expected to continue to be used to the end of its technical life, at which point it is replaced. However, an asset may be depreciated over a shorter period if it is not expected to remain in use for its full technical life (e.g. because demand is expected to cease before the end of the technical life).
- **A combination of both front-loading the depreciation profile and shortening asset lives.**

Networks are in theory indifferent between different depreciation profiles because they account for the value of money over time ('net present value neutral'). However, networks' indifference may be challenged where changing circumstances introduces the risk that historical investment cannot be recovered from a consumer base.[129]

In several countries (e.g. Great Britain, Belgium), the regulator has applied different depreciation approaches to different assets depending on when the assets entered the regulatory asset base (RAB), with new investments being depreciated more quickly.

While less common in the cases we considered, another option to accelerate the recovery of capital is by compensating for inflation via the weighted average cost of capital (WACC) instead of the RAB. Using a nominal WACC has the effect of bringing forward the timing of when the business is compensated for inflation. Conversely, no longer indexing the RAB means it will not grow as quickly, reducing future revenue requirements.

Accelerated depreciation and using a nominal WACC are not mutually exclusive, and some regulators have adopted more than one of these measures. For example, the regulator in the Netherlands has adopted both approaches, where due to clear government policy there is greater certainty that parts of the gas network will be decommissioned and so the need to address asset stranding is clearer.

As noted above, regulators have tended to moderate the extent to which capital cost recovery is advanced to minimise price increases for customers.

A.3.2 Clarifying how stranded assets will be treated once decommissioned

Where regulators have clarified how stranded assets will be treated once decommissioned, they have taken different approaches. These approaches include:

- a one-off compensation payment in the year the asset is decommissioned (e.g. the Netherlands, Croatia)
- a case-by-case assessment of whether stranding costs can be passed through to consumers (e.g. France)
- allowing stranded assets to remain in the RAB until the asset is fully written off, depending on when the assets entered the RAB (e.g. Austria)
- In some cases, stranded asset costs are treated as a loss for the service provider and are not compensated for (e.g. Estonia, Sweden, Slovakia, Italy)
- Austria, Belgium, Germany, Italy, and the UK treat gas networks as permanent, with no explicit regulations for dismantling, meaning that assets stay in the RAB until fully written off.

129 Henry Ergas (2008) *Depreciation*, Concept Economics (2008), p. 4.

A.3.3 Allowing regulated businesses to decommission assets where efficient to do so

Some regulators in Europe, such as in Sweden, Germany, Estonia, Slovakia, France and Denmark, provide incentives for gas transmission businesses to decommission assets where decommissioning is the most efficient outcome. This includes explicitly allowing gas transmission businesses to recover the operating costs associated with decommissioning assets. Telecommunication service providers in Aotearoa New Zealand and the United Kingdom are permitted to stop providing, and ultimately withdraw, services provided via their copper network once fibre is available or a sufficient proportion of customers have switched to an alternative technology. This contrasts with regulatory regimes that treat regulatory assets as permanent and where there is no certainty of cost recovery for decommissioning assets.

A.3.4 Providing incentives to encourage extended use of assets

In one case we considered (Spain), the regulator provides an incentive for the regulated business to continue to operate assets that have been fully depreciated but are still technically able to operate to avoid inefficient new investment.

A.3.5 Uplift on WACC

In some very limited cases (Aotearoa New Zealand, Austria) regulators have also provided an additional ex ante risk premium on the WACC in recognition of the risk of asset stranding. The use of this approach has been limited because most regulators do not consider a WACC uplift to be an appropriate tool to manage asset stranding risk.[130] Rather, regulators consider accelerated capital recovery to be the more appropriate tool. However, if the regulator considers that the network is unlikely to fully recover all its past efficient and prudent investments via other mechanisms, then it may allow a WACC uplift to compensate for the extra risk (see the Aotearoa New Zealand case study).

A.4 Gas distribution networks: Great Britain

Box 2: Summary of key findings:

- Ofgem is balancing policy aims to protect both current and future customers while allowing gas networks to recover past costs to preserve regulatory stability and predictability.
- Ofgem has front-loaded the depreciation profile and, for new assets, has shortened the economic lives. However, the UK Government has noted that there are challenges with relying on accelerated depreciation and indicated it will consider other options to support cost recovery outside the regulatory framework.
- While credit ratings currently remain strong, gas networks have raised concerns about their ability to attract investment, arguing that accelerated depreciation and setting an end date to the RAB can discourage innovation and undermine investor confidence.
- Due to government policy uncertainty, Ofgem has not committed to allowing decommissioning costs other than through re-openers that may be triggered by changes in government policy or if the pace of change differs from that envisaged at the start of the regulatory period.

130 This is because most regulators agree that the WACC is intended to compensate investors for 'systematic' risk and not non-systematic or diversifiable risks, such as asset stranding risk. They have also observed that a WACC uplift is a comparatively blunt and imprecise solution that brings with it a higher risk of windfall gains or losses for the asset owner. If used alongside accelerated capital recovery, it can also result in 'double dipping'.

- New planning obligations require gas and electricity distribution networks to collaborate with the system operator to develop plans that support cost-effective decarbonisation outcomes.

A.4.1 Context

There are eight gas distribution networks (GDN) in the UK, operated by four private distribution system operators. In total, more than 23 million homes, businesses, industry and power stations are connected to the gas grid. Household and industrial demand is relatively stable, although lower than over the 2017-2021 period. Household consumption rose by 4.6 per cent in 2024 compared to 2023, after higher costs and temperatures saw lower demand in 2022 and 2023. Industrial consumption remained stable but low, following the trend of the past 5 years.[131]

The UK Government has introduced a target to fully decarbonise all sectors by 2050. To support this target, the government intends to phase out gas boilers from 2035 for 80% of homes, with a goal of ensuring that all heating systems are low carbon by 2050. It remains unclear how the 20% of homes exempt from the phase-out plans will be decarbonised.

Ofgem outlines two main policy aims in relation to a diminishing user base:

- that consumers tomorrow do not pay a significantly higher charge than consumers today for their use of the gas network
- that consumers today pay no more than is necessary.

While there is no explicit guarantee of cost recovery, Ofgem has interpreted its statutory objectives in a way that protects recovery of past costs. It has noted that exposing investors in gas networks to stranding risk could undermine regulatory stability and predictability and is likely not in the consumer interest.

Ofgem has modelled the development of the Regulatory Asset Value (RAV)[132] and customer bills and found that, if the existing depreciation policy is followed, gas networks' RAVs will not fully depreciate by 2050. There is estimated to be about £3bn of residual RAV in 2050 based on existing assets, and the charges per user will increase substantially from the 2030s onwards. Ofgem has adapted its policy for new assets which means any new investment during the next period and beyond should be fully recovered. That is, new investments will not add to the residual RAV (see discussion in appendix A.4.2 below).[133]

Others have estimated that around £4bn to £5bn will remain in the RAV in 2050 under existing arrangements even if there is no further capex after 2026. Current combined RAV for the GDNs is around £33bn.[134]

The UK Energy Networks Association (UK ENA) submitted a confidential review of material from the three main credit rating agencies (S&P, Moody's, and Fitch) to Ofgem during the most recent regulatory determination (RIIO-3) process. This showed that, while the agencies currently base their credit quality assessment on the expectation of regulatory support allowing for a full RAV recovery, longer-term uncertainties around gas demand evolution are well-recognised and closely monitored by all agencies. In their publications, agencies mention that the risk around possible reduction in network utilisation became more acute but to date have not adjusted their ratings.

131 Department for Energy Security and Net Zero, *Energy Trends UK October to December 2024 and 2024*, 27 March 2025.

132 The RAV is equivalent to the RAB in Australia.

133 Ofgem, *RIIO-3 Sector Specific Methodology Consultation – Finance Annex*, 13 December 2023.

134 Aqua Consultants and Frontier Economics, *Future Regulation of the Gas Grid*, 1 June 2016.

A.4.2 Regulatory measures

Capital cost recovery

Since the 2013 price control period, Ofgem has applied accelerated depreciation to existing assets by front-loading the depreciation profile, based on a 45-year asset life assumption. Ofgem's view was that this approach would depreciate the RAV at a rate that broadly approximates the useful economic life of the assets and incentivises investment efficiency. For the next price control period (RIIO-3), this policy will remain with the addition that new assets will be depreciated to zero by the government's net zero target date (i.e. 2050), effectively shortening the economic lives of new assets compared to existing assets for the purpose of depreciation.[135]

Ofgem has not introduced any further measures, such as a change in the way inflation is treated or a WACC uplift to compensate for asset stranding risk. Ofgem is explicit about seeking to address risk 'at source' through depreciation[136] rather than through, for example, an increase in the return on capital allowance as compensation for the asset stranding risk perception.

Expenditure assessments and incentives

To date, Ofgem has not materially amended its approach to cost assessments or incentives for efficient expenditure compared to the 2021-2026 price control (RIIO-2). Its totex methodology and benchmarking approach remains the same. However, Ofgem has noted that it would be prudent to continually assess if major gas investment programs, including the "Iron Mains Risk Reduction Programme" which targets safety and represents the vast majority of capex, could be scaled back.

Ofgem made no clear commitment in respect of the regulatory treatment of the repurposing and decommissioning of gas assets given the significant uncertainty surrounding the future of gas. However, Ofgem provides a 'use it or lose it' allowance for gas distribution networks to conduct early design and pre-construction work for net zero related projects. The maximum funding is £2m per project, with a proposed total funding pool of £40m for the next price control period across all gas distributors. The strategic innovation fund (SIF) also provides funding for projects that will help transform gas (and electricity) networks for a low-carbon future.

In relation to decommissioning, Ofgem has decided not to create a decommissioning liabilities fund or to provide upfront funding for this as part of RIIO-3, due to significant uncertainty around scope, timelines and funding sources. While it will not fund decommissioning costs through baseline allowances, Ofgem signalled that decommissioning costs would be recoverable through the Heat Policy Re-opener and/or net zero uncertainty mechanisms (see below).

Re-openers

Two separate mechanisms are permitted for reopening a price control due to uncertainty arising from the transition to net zero:

1. **Net Zero re-opener**: triggered by Ofgem to cover changes in government policy or recommendations by the system operator in its regional planning. This measure may also apply if the pace of change differs than envisaged at the start of the period.
2. **Net Zero Pre-Construction and Small Projects (NZASP) re-opener**: triggered by Ofgem, allows a GDN to undertake design and pre-construction work that is too material for the funding allowance. This was introduced in RIIO-2 to enable GDNs to progress small to medium projects which seek to facilitate net zero, including hydrogen feasibility studies. Funding provided per project must not exceed £100m.

135 Ofgem, *RIIO-3 Draft Determinations Overview Document*, 1 July 2025.

136 Ofgem, *RIIO-3 Sector Specific Methodology Decision – Finance Annex*, 18 July 2024, para. 3.304.

3. **Heat Policy Re-opener**: can be triggered by Ofgem in response to a government decision on using hydrogen for domestic heating and/or changes to specific regulations and connection charging methodologies that support the transition to low carbon heat. It enables both upward and downward adjustments. Revenue adjustment must be more than the materiality threshold of 0.5% of base revenue.

Planning

In 2025, Ofgem introduced Regional Energy Strategic Plans (RESPs) to improve local energy planning and support the transition to net zero. Gas and electricity distribution networks, in collaboration with the independent energy system operator (NESO), are required to work together to develop RESPs that support cost-effective decarbonisation outcomes. The plans will include cross-sector strategic planning; technical coordination activities (e.g. energy demand modelling, whole system optioneering, conflict resolution); local engagement and coordination, and support for local actors. Individual businesses remain responsible for network plans, but with a common strategic approach.

Financeability of gas networks

Ofgem is required to have regard to the need for gas networks to be able to finance the activities which are the subject of obligations imposed by or under a range of legislation. It does this through looking at both: a) debt financeability i.e. can the network generate cashflows to meet its debt financing needs; and b) equity investability, and whether the financial parameters in the cost of capital allowance adequately supports the scale of equity investment required.[137]

During the recent RIIO-3 process, the gas networks sought to prove the case for potential asset stranding risks and the need for additional allowance to support financeability in the networks given concerns about their ability to attract the investment required for their capital programs. They argued that accelerated depreciation and setting an end date to the RAV can discourage innovation and undermine investor confidence. Further they stated that there was significant risk of asset stranding regardless of accelerated depreciation.

In addition to accelerated depreciation, Ofgem also looked to address the increased risks by including five new company comparators in its beta calculations for rate of return in order to capture general market trends towards funding of gas networks. It considered that these changes to the beta comparators, the accelerated depreciation proposals, and project incentives to be sufficient to reflect any changes to the risk profile of RIIO-3 relative to RIIO-2 and to be superior approaches relative to applying subjective uplifts to the allowed cost of equity. It also noted that networks will also be looking to repurpose gas assets (e.g. for hydrogen, carbon capture or biomethane) and will likely see long-term value in these assets beyond 2050.

In its draft determination, Ofgem considered that based on their balance sheets, gas distribution networks are all financeable on a notional capital structure basis, taking account of cost and incentive allowances, cost recovery and allowed returns. It found that the baseline credit quality of an efficient gas network adopting the notional capital structure is, in the round, generally stronger than BBB+/Baa1, which was the target rating most commonly proposed by gas networks. Gas networks have, however, raised concerns about Ofgem's methodology stating that it is too narrow and backward focused, lacking a realistic appreciation of the risks and uncertainties under the energy transition. It was also noted that the introduction of accelerated depreciation, which precisely aims to return the RAV (i.e. return of capital, rather than return on capital) to investors

137 The financeability test is based on a notional capital structure and not any individual network's particular financial arrangements. Investability is tested by cross-checking and benchmarking the proposed decisions against other relevant precedents in other sectors and considering any additional risk factor to ensure that the equity return is competitive and efficient.

faster than under the status quo, will put further upward pressure on the dividend yields by increasing the cash available for distribution in the short to medium term.

Equity considerations

While Ofgem has a general consumer vulnerability strategy there is not yet any explicit arrangements to protect vulnerable customers from transition impacts. In the RIIO-GD3 consultation document, Ofgem noted that local governments have the primary role in addressing fuel poverty and encouraged gas distribution networks to coordinate with local governments.

Potential for further reforms

Existing pipeline infrastructure may be repurposed to support both hydrogen and carbon capture and storage, depending on government policy.[138] Ofgem has recently consulted on the asset valuation methodology for the transfer of the natural gas RAV to another regulated network RAV if assets are repurposed for use in future hydrogen and CO_2 transport and storage networks.[139]

On 30 June, the UK Government issued an Update to Market policy paper on the future of the gas system.[140] In that paper it noted that there are challenges with relying on accelerated depreciation and that it is important to balance infrastructure investment and affordability. The paper states that there are credible longer-term alternatives to support cost recovery—including options that could distribute costs more fairly, be more sustainable and have a greater role for government – and that these options will be developed and consulted on in coming months. These options could complement or replace the existing cost recovery mechanism, but the paper notes that price control would remain a matter for Ofgem.

A.5 Gas networks: Netherlands

Box 3: Summary of key findings

- The Netherlands has implemented legislative change to support reduced reliance on natural gas and decommissioning of parts of the gas grid, including a strategy to support disconnection of consumers from the gas grid under certain circumstances.
- This has allowed the regulator to implement significant changes to bring forward capital cost recovery to recognise declining demand, including by both accelerating depreciation and shifting to a nominal weighted average cost of capital. Parts of the network that are expected to be repurposed for hydrogen are exempt from accelerated depreciation.
- The Netherlands is one of a small number of countries that has a process defined in legislation to decommission assets. For gas transmission assets, once the asset is decommissioned, the business receives one-off compensation in that year equal to the residual value less any proceeds from disposal.
- The legislative framework allows for decommissioning of gas distribution networks at the district level, with protections for consumers. Dutch gas distribution networks are compensated for dismantling costs.

138 The UK Government is considering options including a Hydrogen Transport Business Model (HTBM) to facilitate and support the development of hydrogen pipeline infrastructure, using hydrogen for domestic heating and blending up to 20% hydrogen in the existing gas network.

139 Ofgem, *Consultation on Asset repurposing valuation methodology*, 20 May 2025.

140 Department for Energy Security & Net Zero, *Policy paper, Midstream gas system: update to the market*, 30 June 2025.

While several countries in the European Union have considered what regulatory measures might be required to reduce the risk of potential asset stranding of natural gas transmission network assets, only a few have adopted measures to date. The Netherlands is one of two primary cases to have done so, along with Belgium. In contrast to many other European countries, the Netherlands also has a clear policy for the reduced use of natural gas.

A.5.1 Context

The gas grid in the Netherlands is owned and operated by six publicly owned gas distribution system operators (DSOs). These are controlled by regional and local governments. There is a single gas transmission system operator (TSO), Gasunie, which is owned by the Dutch State. Currently, approximately 90% of the around 8 million households and more than 1.1 million commercial buildings are connected to gas.[141]

The Netherlands has a climate policy objective of reducing CO_2 emissions by 95% by 2050. Reducing natural gas use is one measure being used to meet this objective. The Netherlands has adopted legislation that supports reduced reliance on natural gas and decommissioning of parts of the gas grid, including:

- The connection of new buildings to the gas network has been prohibited since mid-2018. Prior to this, DSOs were obliged to connect all buildings on request.
- All municipalities must develop local decarbonisation plans outlining gas-free heating strategies for each district.
- The Dutch Parliament has recently adopted changes to the legislative framework that support the disconnection of consumers from the gas grid under certain conditions. In areas in which the municipal heat plans foresee a transition to gas-free districts, disconnection from gas grids is possible with a time frame of 8 years, provided that the alternative is cost-effective for consumers.

The Netherlands also has a clear National Hydrogen Strategy under which some of the existing high pressure natural gas infrastructure is expected to be repurposed to transport hydrogen.

A.5.2 Regulatory measures

The Dutch regulator (ACM), implemented several changes to the regulatory framework for gas transmission in advance of the 2022-2026 regulatory period to address asset stranding risk. These changes recognised the decline in the number of users on the gas network as businesses and households disconnect and the consequential higher tariffs to be recovered from remaining customers for the TSO to recover its costs. The measures adopted by ACM aim to limit a potential increase of natural gas network tariffs in the long-term. ACM has adopted similar measures for gas DSOs.

There is no formal definition of stranded assets or decommissioned assets in the regulatory framework, but the ACM has distinguished between the two as follows:[142]

- stranded assets are assets that are no longer in use due to having no users, but are part of the network and have costs associated with them, and
- decommissioned assets are assets that are no longer in use and no longer part of the network.

141 Regulatory Assistance Project and Institute for Applied Ecology, *Connecting reality with climate goals: case studies of gas distribution system planning and regulation, Country Report Netherlands*, 30 October 2024.

142 DNV report for ACER, *Future Regulatory Decisions on Natural Gas Networks: Repurposing, Decommissioning and Reinvestments on future regulation*, 28 October 2022, p.86.

The ACM considers that, although a significant decline in the use of the natural gas transmission network is expected, the network is still likely to be in use in 2050. This suggests that cost recovery from users will remain possible. However, the ACM anticipates a substantial reduction in the number of users over time, which would lead to markedly higher tariffs for those who remain. Under the ACM's approach, the assets would not be considered stranded as they continue to be used. However, tariffs would be disproportionately high for remaining users.

Recovering the cost of stranded assets

ACM introduced two key changes for the most recent gas transmission regulatory period 2022-2026 to address stranded asset risks. These measures are designed to bring forward cash flows and include accelerated depreciation and shifting to a nominal WACC.

In respect of depreciation, ACM has adopted a front-loaded depreciation approach that ensures that the value of an asset is depreciated at a gradually smaller rate throughout its useful life.[143] It is calculated by depreciating the net book value of the asset (i.e., the gross value minus previous years' depreciation) by a fixed percentage each year.[144]

A key reason for the ACM to adopt front-loaded depreciation and not shorter asset lives, was their belief that there will still be some gas users who are willing to pay for efficient costs in 2050. Therefore, it considered that there was no risk of assets becoming stranded and that large parts of the natural gas network are not expected to be taken out of use. The asset lifetimes have therefore not been reduced, but depreciation is being front-loaded.

Parts of the natural gas transmission network that, in the future, are expected to be transferred to the hydrogen network, and which, consequently, will remain in use, are exempted from the accelerated depreciation. ACM applied a 10% portion of the RAB to be excluded from the accelerated depreciation to account for repurposing.

For gas distribution, it was recognised that there was greater risk of asset stranding and more flexible approaches for depreciation have been used including a 'degressive' depreciation approach, which is intended to align cost recovery with network usage and lower connections.

In addition to accelerating depreciation, ACM decided to shift from applying a real WACC for the return on capital to a nominal WACC for both gas transmission and distribution. Under this approach, the RAB and depreciation is no longer escalated for inflation.

The purpose of RAB indexation is to maintain the regulatory value of the RAB in real terms over time so that current network users pay the same amount in real terms for the same service as future users. With the expected decrease in the use of the natural gas network this may lead to a situation in which a decreasing number of natural gas network users bear the cost of the inflation compensation. By using a nominal WACC instead, this has the effect of bringing forward the timing of when the business is compensated for inflation. ACM considered this approach better suited the expected decline in the use of the natural gas network.

S&P Global Ratings was generally supportive of the revised regulatory approach and noted that the Netherlands benefits from a long track record of predictable regulation. It considered the amendments to be favourable in the short term due to the acceleration of cash flows. However, it

143 This is known as a "declining balance" approach.

144 Within this framework the natural gas TSO should manage the risk of stranded assets, considering that the risk premium in the cost of equity calculation already considers the unforeseeable risk of asset stranding. If stranded costs arise in this framework, they should not be borne by the natural gas network users.

also noted that the approach would result in a lower RAB over time and lead to largely depreciated assets, resulting in less remunerative assets in the longer term.[145]

Treatment of decommissioned assets

The Netherlands is one of a handful of European countries to have a process defined in legislation to decommission assets. This contrasts with Austria, Belgium, Germany, Italy, and the UK, where gas networks are treated as permanent, with no explicit regulations for dismantling.

ACM defines divestments as assets that are decommissioned or sold before the end of a regulatory lifetime, and so the asset has not yet been fully depreciated. A divestment leads to costs because the decommissioned asset loses its value.

For gas transmission assets, once the asset is decommissioned, the business receives one-off compensation in that year, either through an opex allowance or a depreciation allowance that is intended to fully compensate the business for any unrecovered value (less any proceeds from the disposal of the asset). The asset is then removed from the RAB. The current network users therefore bear the risk of these costs, although the gas business also bears a risk because they will not have a rate of return during the foreseen regulatory lifetime of the asset.

For gas distribution, the legislative framework foresees that decommissioning of gas grids is organised at the district level, thus transforming whole districts to gas-free districts at a time. This approach avoids small groups of consumers remaining connected with very low connection densities, but still requiring all the connecting and upstream assets to support that consumption. The framework also considers the costs for consumers, requiring cost-effective alternatives to gas to be in place before the district's gas network is decommissioned. Dutch gas distribution networks are compensated for dismantling costs.

A.6 Telecommunications: Aotearoa New Zealand

Box 4: Summary of key findings

- The New Zealand Government implemented legislation to support the decommissioning of the copper network, including a requirement for the regulator to develop a code for the managed shutdown of the copper network that includes customer protections.
- Copper assets are written down once they are no longer revenue generating, but the regulatory framework provides several protections to reduce asset stranding risk including accelerating depreciation via shortened asset lives.
- The risk of asset stranding of the fibre network is viewed as high. In addition to allowing accelerated depreciation, the regulator has allowed cash flows to be brought forward via a multiple of the RAB (10 basis points) on the basis that accelerated depreciation alone is insufficient to compensate for the risk.
- The regulator has an extensive set of criteria it considers when assessing capex proposals for the fibre network including, among other things, service quality considerations, treatment of uncertainty and risk, consideration of alternative options and trade-off between capex and opex.

145 S&P Global Ratings, Dutch Electricity and Gas Transmission and Distribution Framework: Supportive, March 7, 2023.

A.6.1 Context

This case study explores two interrelated developments in New Zealand's fixed telecommunications services sector: the transition from copper to fibre and the regulation of the fibre network. The framework for fixed telecommunications services provided via the copper network provides an example of infrastructure that is being progressively deregulated and decommissioned. The framework for the fixed fibre network is of interest because it is regulated in a similar way to energy businesses in Australia, and the New Zealand Commerce Commission (NZCC) has explicitly considered asset stranding risks in its approach.

Chorus is the principal wholesale provider of fixed line telecommunications services in New Zealand. It owns and operates the legacy copper network. Chorus was also one of four companies to win a competitive contract with the NZ Government to roll out fibre and now has the largest footprint in the national fibre network. Chorus is a publicly listed company.

The *Telecommunications Act 2001* provides for the regulation of certain telecommunications services. The Act was amended in 2018 to allow for the deregulation of services provided via the legacy copper network in areas served by fibre (Part 2AA). The revised Act also introduced a new regulatory regime for providers of regulated fibre fixed line access services (FFLAS) following the roll-out of fibre to much of the country.

Services provided via the legacy copper network

The transition from copper to fibre reflects a network modernisation trend driven by:

- technological advancement
- consumer preferences for higher bandwidth, more reliable internet services
- government policy objectives, particularly the Ultra-fast Broadband (UFB) initiative, which initially aimed to develop fibre-to-the-premises broadband networks connecting 75% of New Zealanders.[146]

A key challenge for the regulator has been how to encourage investment in fibre while allowing recovery of cost of copper services and preserving service standards for remaining copper customers.

Prior to amendments to the Telecommunications Act, Chorus's prices for access to its wholesale copper phone and broadband network were regulated using a Total Service Long Run Incremental Cost (TSLRIC) methodology. Under this approach – common in telecommunications – maximum prices are based on the forward-looking costs that a hypothetical efficient operator would incur using modern technologies, with inputs valued at current prices. Prices set under the TSLRIC approach are intended to allow for the recovery of the capital costs incurred in building the network as well as ongoing operating costs.[147]

The last pricing review determinations published by the NZCC under the TSLRIC approach for Chorus' wholesale copper phone and broadband services were published in 2015 and applied for a five year period. Amendments to the Telecommunications Act in 2018 required prices to be capped at the 2019 prices (the final year of the previous regulatory determination) and adjusted each year for inflation. The NZCC was required to review Chorus's maximum prices no later than 2025.[148]

Services provided via the fibre network

146 *Telecommunications Act 2001*, definition of UFB initiative. This connection goal was subsequently updated.

147 Commerce Commission, *Final pricing review determination for Chorus' unbundled bitstream access service, Final determination*, 15 December 2015.

148 *Telecommunications Act 2001*, cl.69AG.

The fibre network was deployed under partnership with the NZ Government's Crown Infrastructure Partners. Four partners were selected, with Chorus responsible for the largest network footprint (approximately 70%), including Auckland and Wellington. Three other Local Fibre Companies are responsible for smaller network areas.[149]

Initially, FFLAS were not subject to regulation to encourage investment in the network. In 2018 changes were made to the Telecommunications Act to allow the Commerce Commission to develop a new regulatory framework for providers of regulated FFLAS.

A.6.2 Regulatory measures - legacy copper network

Chorus's costs associated with the copper network continue to be recovered through regulated access charges while services continue to be provided. As noted above, prices were last reviewed in 2015 using the TSLRIC methodology and since 2019 have been escalated by CPI.

Copper assets are written down once they are no longer revenue generating, creating a commercial stranding risk for Chorus. However, several elements of the regulatory framework provide some protection against this risk:

- the Commerce Commission's 2015 determinations for Chorus's wholesale copper phone and broadband services included an ex ante allowance for the risk of asset stranding due to technological change by adopting asset lives that recognised the risk of asset stranding[150]
- repurposed copper assets may be included in Chorus' fibre RAB[151]
- the cost of shared infrastructure – used by both copper and fibre networks – may be allocated proportionally to Chorus's fibre RAB based on a cost sharing approach determined by the NZCC[152]
- the Copper Withdrawal Code (CWC) provides for the managed shutdown of the copper network, allowing Chorus to retire copper assets area by area and so manage stranding risk through staged withdrawal.[153]

Part 2AA of the *Telecommunications Act 2001* allows for the deregulation of copper fixed line access services where FFLAS are available. It also includes protections for end users of copper fixed line access services and certain other services in these areas. Under these provisions, the NZCC was required to:

- determine "specified fibre areas" – geographic areas where a specified fibre service is available to end users in the area[154][
- develop the CWC to set out the minimum requirements that Chorus must meet before it can withdraw wholesale copper phone and broadband services.

Chorus may choose to cease supplying copper service in specified fibre areas when it becomes uneconomic to continue to supply an area, rather than the end-user choosing to disconnect the service. However, Chorus must first comply with the CWC to ensure consumers are appropriately protected. These requirements include providing customers with:[155]

149 Ultra Fast Fibre supplies the central North Island; Northpower Fibre covers Whangarei and Enable Networks covers Christchurch, Rangiora and Rolleston.

150 See, for example NZ Commerce Commission, Final pricing review determination for Chorus' unbundled copper local loop services: Final determination, 1 December 2015, p.125, para 477.2. The same approach was taken for Chorus' unbundled bitstream access service under a separate decision.

151 NZ Commerce Commission, Fibre Input Methodologies: Main final decisions – reasons paper, 13 October 2020, p.8 para X16.

152 NZ Commerce Commission, Fibre Input Methodologies: Main final decisions – reasons paper, 13 October 2020, chapter 4.

153 The Copper Withdrawal Code is available on the Commerce Commission's website.

154 *Telecommunications Act 2001*, s.69AB.

155 NZ Commerce Commission, *Copper Withdrawal Code: Decisions and Reasons Paper*, 10 December 2020, pp. 7-8, para X12.

- notice of the proposed withdrawal of copper services
- information about the copper withdrawal process to allow customers to make informed choices
- a connection to a fibre service at no cost to the customer if the customer wishes to switch.

The NZCC also had responsibility for developing requirements relating to the ability of consumers to contact emergency services during a power cut to protect vulnerable consumers.[156]

A.6.3 Regulatory measures - Chorus' fibre network

In 2020 the NZCC issued a set of Input Methodologies specifying how Chorus and other FFLAS providers would be regulated. For Chorus, this marked a significant shift to a more prescriptive regulatory approach, similar to that applied to energy networks. Other FFLAS providers are currently subject to a light-handed information disclosure regime.

Capital cost recovery

In developing its Input Methodologies paper, the NZCC considered there is a real risk of asset stranding due to the dynamic nature of the telecommunications market and the risk that technology advances resulting in lower cost alternatives could create the risk of asset stranding.

The NZCC considered its regulatory approach addressed this risk to some extent by allowing Chorus flexibility in its proposed approach to depreciation and in determining asset lives. However, the NZCC identified that, even with flexibility around depreciation, accelerated depreciation was "unlikely to fully mitigate" the asset stranding risk. To address this residual risk, the NZCC has provided Chorus with ex ante compensation in the form of a 10-basis point allowance added to cashflow. This is an additional building block component added to Chorus' annual revenues, rather than an increase in the WACC. That is, Chorus' cashflows were increased by 0.001 multiplied by the RAB.

The approach to estimating the level of uplift was based on calculating what additional return an investor would need in order to invest in an asset with an assumed probability of stranding.[157]

The NZCC considered several alternatives to compensating for asset stranding risk. However, it considered that an advantage of an ex ante compensation mechanism is that it allocates "some or all of the asset stranding risk to regulated providers". The NZCC noted:[158]

> We consider an important aspect of an ex-ante mechanism is the risk it transfers to the regulated providers… Clearly allocating some of the risk to regulated providers also ensures asset stranding will have a negative financial impact on them. From a forward-looking basis, this provides better incentives to manage this risk in terms of what, where and when they invest. This will likely again best give effect to the outcome in s 162(b) of regulated providers having incentives to improve efficiency.

The NZCC has also acknowledged the possibility of asset stranding in energy networks and has allowed electricity distribution businesses to apply for a discretionary NPV neutral shortening of asset lives (up to a cap of a 15% reduction in remaining average asset lives)[159]

156 The Commission 111 Contact Code is available on the NZCC website

157 Similarly, in the United Kingdom, Ofcom has allowed an uplift in the WACC to compensate for the potential for downside risks associated with technology change in telecommunications.

158 NZ Commerce Commission, Fibre Input Methodologies: Main final decisions – reasons paper, 13 October 2020, p.573 para 6.1108.

159 NZ Commerce Commission, Input methodologies review decisions, Topic paper 3: The future impact of emerging technologies in the energy sector, 20 December 2016, para 84-86.

Expenditure assessments

The NZCC defined the primary role of the framework regulating Chorus' capex as "to mitigate over-spending and over-forecasting risks".[160] It does this by allowing for scrutiny of the efficiency of proposed capex and the potential impact on market outcomes before costs may be included in the maximum allowable revenue that Chorus may recover.

To support its assessment of proposed capex, the NZCC has set out the factors that it will have regard to in assessing proposed capex. Among other things, these include:[161]

- the linkages between the proposed capex and service quality
- consideration and analysis of alternatives to the proposed capex and the impact of alternatives on quality outcome
- the extent of the uncertainty related to the need for the proposed capex, the economic case justifying the proposed capex, and the timing of the proposed capex
- the extent that a risk-based approach has been applied
- the dependency and trade-off between the proposed capex and related operating expenditure to ensure least whole-of-life cost for managing assets and cost-efficient solutions.

Compared to the new capital expenditure criteria set out in Australia's National Gas Rules, the factors the NZCC considers in assessing proposed capex provide a greater emphasis on service quality considerations, treatment of uncertainty and risk, consideration of alternative options and trade-off between capex and opex.

Chorus must also submit an Integrated Fibre Plan that covers five regulatory years as part of its capex proposal: the first regulatory period (three years duration) plus an additional two years into the second regulatory period. The Integrated Fibre Plan comprises seven reports that together explain the proposed forecast expenditure: an overview, a quality report, a governance report, a demand report, an investment report, a delivery report and an engagement plan. The Integrated Fibre Plan must be consulted on.[162]

A.7 Other precedents

Several other jurisdictions and industries have introduced reforms to better manage the impacts of declining utilisation and asset stranding risks on customer bills. These examples have been grouped by the following areas:

1. Use of Depreciation Policy to bring forward cost recovery
2. Providing compensation for decommissioned assets
3. Approaches to replacement investment and encouraging extended use of assets
4. Increasing the WACC to compensate for stranded asset risks.

A.7.1 Use of Depreciation Policy to bring forward cost recovery

Various approaches to adjusting the depreciation profile are being used. Some countries' policies have been influenced by their government targets for net zero, with Belgium (2050), Denmark (2052) and Germany (2045) setting depreciation profiles to align with national decarbonisation goals.

160 NZ Commerce Commission, Fibre Input Methodologies: Main final decisions – reasons paper, 13 October 2020, p.612, para 7.13.

161 NZ Commerce Commission, Fibre Input Methodologies: Main final decisions – reasons paper, 13 October 2020, Chapter 7.

162 NZ Commerce Commission, Fibre Input Methodologies: Main final decisions – reasons paper, 13 October 2020, see from p.656.

Germany introduced accelerated depreciation via shorter asset lives and front-loaded depreciation

The regulatory authority (BNetzA) has recently introduced a regulation, effective from 2025, authorising accelerated depreciation for gas infrastructure. This decision permits network operators to apply shorter depreciation periods, with components of gas networks depreciable by 2035 in exceptional cases, and generally until 2045. In specific instances, the depreciation profile is able to be front-loaded to align with declining gas sales, assisting operators in amortising investments and sustaining financial stability. Similar to the methodology employed in the Netherlands, the depreciation rate is calculated to optimise cost recovery taking into account forecast demand and the risk of disconnections from increased tariffs. This methodology complements the previous policy where any new investment was constrained to a depreciation period until 2045 to align with government target for achieving climate neutrality.

Belgium has established a regulatory fund to support accelerated depreciation

In Belgium, there are multiple regional distribution networks each with their own regulator. In response to the connection ban for new buildings from 2025, the regulator for the Brussels region (BRUEGEL) has proposed introducing an approach to manage asset stranding which classifies assets by the following four categories:

1. assets fully recovered by 2050
2. strategic investments to support energy transition and avoid stranding (i.e., repurposing)
3. investments with stranding risks but deemed essential and efficient (these assets are subject to faster depreciation rates to reduce stranding risks.)
4. investment with stranding risks and non-recoverable due to suboptimal investments (these assets are removed from the RAB).

The regulator wanted to maintain the principle of affordability. A regulatory fund will be established to help limit tariff impacts to reasonable levels and ensure equitable distribution of costs across current and future users. The fund is raised from a networks' consumers and:

- may be used to compensate for stranded costs related to investment made between 2020 to 2024 caused by the energy transition.
- accumulates any over-recovery from tariffs caused by differences between forecast costs and volumes and actuals.
- is administered by the regulator and does not require any additional contribution from users.[163]

In Belgium, targeted depreciation percentages are applied, so that all natural gas transmission assets are phased out by 2050 and the residual asset value will be zero in 2050. Natural gas pipelines which may be repurposed are not subject to this accelerated depreciation scheme.

Austria's alignment of depreciation period to accounting values

In 2021 Austria changed its depreciation method for gas transmission so that the regulatory depreciation time now equals the depreciation used for accounting purposes, effectively using the accounting life as a proxy for the economic life. As a result, shorter depreciation periods are applied, to address the potential risk of asset stranding. For gas distribution assets, it had previously made the decision to reduce depreciation periods from 40 years to 30 years to address uncertainty on the future of the gas network.[164]

163 BRUGEL, *Study 44 on the risk of stranded assets in the gas distribution network by 2050*, 20 January 2023 (in French).

164 E-Control, Regulatory framework for the third regulatory period of gas distribution network operators, 23 October 2017 (in German)

Recent Australian gas pipeline decisions on depreciation

The table below provides a summary of the decisions recently made by the AER and ERA on the use of depreciation to manage stranding risk. As it shows, all of the recent decisions have allowed for the recovery of capital to be accelerated, either through shortened asset lives (Evoenergy, Victorian Transmission System (VTS) and Dampier to Bunbury Natural Gas Pipeline (DBNGP)) or changes to the depreciation profile (Victorian distributors).

Table A.1: Recent gas pipeline regulatory decisions in Australia dealing with capital cost recovery risk

Decision	Service provider's proposal	Regulator's decision
Evoenergy 2021-2026 access arrangement	Evoenergy, claimed the ACT Government's legislated 2045 net zero target exposed it to asset stranding risk and proposed to accelerate the recovery of capital through shorter asset lives for certain assets.	The AER accepted Evoenergy's claim and that greater depreciation in future periods would increase costs to future consumers and potentially accelerate the stranding risk. The AER decided therefore to allow the use of the shortened asset lives proposed by Evoenergy.[1]
Victorian Transmission System 2023-2027 access arrangement	APA proposed a 30 year cap on asset life to "help address" the "uncertainty investment environment for gas infrastructure".	The AER expressed concerns about the limited analysis presented to justify the reduced asset lives, but ultimately decided to accept the proposal. In doing so, it noted that the Victorian Government's Gas Substitution Roadmap indicates that the government is committed to the net zero emissions target by 2050 and will likely mean a limited role for gas beyond this date. The AER went on to note that:[2] *"While these changes are likely to eventuate, the pace of change remains uncertain. Our final decision to accept the proposed cap is guarding against risk of an earlier wind down of the network and the price spike that may result if demand falls faster than expected.* *Accepting the proposal to accelerate depreciation leaves open the option to change course at future reviews. Although we may be approving acceleration now, reversals at a future date may also be required to promote efficient growth (including negative growth) of the market as required under the NGR.16 If it becomes apparent that the VTS will still have significant role beyond 2050 then we consider that such a reversal may be required, potentially as soon as the next review."*
Victorian gas distribution networks 2023-2028 access arrangements	AusNet, AGN and Multinet, claimed that the significant uncertainty surrounding the future of gas mean that there was a risk their distribution networks would	The AER accepted that the Victorian Government's Gas Substitution Roadmap signalled a limited role for gas beyond 2050 and modelling undertaken by the networks to support their proposals for accelerated depreciation. The level of acceleration was capped by a real price path

Decision	Service provider's proposal	Regulator's decision
	become stranded and proposed an acceleration of depreciation.	of 1.5% p.a. to provide a:[3] *"balance between what consumers pay now to mitigate future price increases, and the risk of greater price increases in the future if mitigation is delayed".*
Dampier to Bunbury Natural Gas Pipeline (DBNGP)2021-2025 access arrangement	AGIG, claimed that the pipeline was at risk of stranding due to technological change (including competition from renewables) and policy change associated with transition to net zero. To address this risk, the asset owner suggested that either: • the asset life be shortened from 2077-2081 to 2063; or • the depreciation profile be changed from a straight line approach to a 'kinked depreciation profile' (with acceleration applied for a defined period and then reverts to a straight line approach).	The ERA in this case accepted that there was a likelihood that demand for DBNGP's services would decline over time due to technological and policy changes and allowed the asset life to be reduced to 2063. The ERA did not, however, allow for the proposed use of the 'kinked depreciation profile' because it was not included in the asset owner's regulatory model.[4]

Source: [1]AER, *Final Decision – Evoenergy Access Arrangement 2021–26*, Attachment 4, 20 April 2021; [2] AER, *Final Decision – APA VTS gas access arrangement 2023–27*, Attachment 4, December 2022, pp. 8-9; [3]AER, *Final Decision – Multinet Gas Networks Gas distribution access arrangement 1 July 2023–30 June 2028*, Attachment 4, December 2022, pp. 9; [4] ERA, *Final decision on proposed revisions to the Dampier to Bunbury Natural Gas Pipeline access arrangement 2021–2025*, April 2021, pp. 350-357.

A.7.2 Whether to provide compensation for underutilised and decommissioned assets

Regulators are starting to recognise the possibility of infrastructure being no longer required and therefore needing to be decommissioned prior to the defined asset life. This means that depreciation approaches may not be sufficient by themselves to fully manage the stranded asset risks, creating challenges in terms of both how such stranded costs should be valued and treated under the regulatory framework.

This then leads to the question of who should bear the risks as this is directly linked to full or partial recovery. The financial implication on the asset owners is related to the recovery of stranded costs and the financial burden if there is no compensation at all. Some regulators may have already compensated for such risks through an uplift to the WACC.

Denmark's strategy for decommissioning

Denmark has clear decommissioning strategies for parts of its distribution networks. The Danish government offers a scheme for free disconnection of private residences using gas for heating noting that operators cannot disconnect households involuntarily if the local grid is no longer economically viable.

In 2016, the Danish government took a decision to consolidate and take over ownership of all gas distribution grids, a process which concluded in 2021. This means that taxpayers will carry any stranded asset risk. Recently Denmark announced its objective for all homes currently served by the gas grid, around 400,000, to electrify heating by 2030. This initiative is designed to end the country's dependence on Russian gas .

Some parts of the distribution network may remain and be repurposed to supply biomethane. However, a study conducted by the distribution system operator identified 28% of subnetworks are not covering their costs, and that these subnetworks should be given priority for decommissioning.[165][

No consensus in treatment of stranded asset costs for transmission pipelines

In Europe, there is a mixture of approaches on this issue for gas transmission. In Estonia, Sweden, Slovakia and Italy, the stranded costs are a loss for the TSO and are not compensated either through the tariffs or other sources. In France, the regulator (CRE) adopts a case-by-case approach whereby stranded costs can be passed-through to consumers via the clawback account[166] if deemed efficient and duly justified by the network.

In Croatia, similar to the Netherlands, once the asset is decommissioned, the business receives one-off compensation in that year, either through an opex allowance or a depreciation allowance. While the network users therefore bear the risk of these costs, the gas business also bears a risk because they will not have a rate of return during the foreseen regulatory lifetime of the asset.[167]

In Austria, the current treatment differs for investments up to 2020 and after 2021. For investments up to 2020, the asset remains in the RAB until it is completely written off. For investments from 2021, only the book value is kept in the RAB. If a decommissioned asset is still

165 Regulatory Assistance Project and Institute for Applied Ecology, *Connecting reality with climate goals: case studies of gas distribution system planning and regulation: Country report Denmark*, 30 October 2024, p.20.

166 A clawback account is an ex post adjustment mechanism that that resolves differences between actual expenses and income and projected expenses and income for elements which are difficult for gas network businesses to predict and control.

167 Although some regulators have taken into account that the asset owner would receive the residual asset value and could invest it elsewhere and receive a return from this other investment.

in the books and justified from an accounting purpose this also means it remains in the RAB and therefore the socialisation of the residual asset value is passed onto the users of the network.

Treatment of decommissioning costs

In relation to the treatment of dismantling and decommissioning costs, the emerging consensus in Europe is to recognises these as an operating expenditure subject to the normal reasonable and efficiency assessments conducted by the regulator. For example, regulators in Sweden, Germany, Estonia, Slovakia, France and Denmark recognise the costs associated with dismantling an asset and returning the land to its original state.[168] However, this is still very early in the considerations and other approaches such as developing better incentives on the network to optimise the timing of decommissioning and applying specific regulatory assessments to these costs are being explored. The treatment of such costs is also complicated if the asset is being repurposed at the same time, creating challenges on which groups of customers should contribute to these costs.

In the UK, the Government has established an offshore decommissioning regime for CO_2 transport and storage network infrastructure. Operators of CO_2 networks are required to contribute to a dedicated decommissioning fund, which ensures that future dismantling and site remediation costs are properly financed. Set up under the Energy Act 2023, subsidiary regulations define, among other things, how decommissioning costs are to be estimated and verified and how the decommissioning fund is to be administered.[169]

Approaches to replacement investment and encouraging extended use of assets

In the future, regulators will increasingly be required to assess and take a decision on whether natural gas network assets at the end of their regulatory lives are to be replaced by infrastructure of similar or smaller size (re-investment), or whether the assets can be kept in operation (after the end of their regulatory asset life). Another approach therefore is to help manage the risk of future assets stranded is to try to keep any future investment to the essential minimum and consider how best to extend the useful life of existing assets which have been fully recovered.

It is standard practice for regulators to apply a robust economic assessment to any future expenditure plans. This could include cost benefit analysis of alternative options, including whether to keep assets in operations after their regulatory life, subject to safety and technical requirements. However, as the network does not earn a return on such assets, some jurisdictions have explored creating specific incentives mechanisms to keep fully depreciated assets in operation instead of replacing them, when this could be done in compliance with the overall service safety and efficiency requirements.

For example, Spain[170] has introduced such a mechanism for gas transmission businesses, where assets whose regulatory lifetime has expired (and that are still effectively available to operate) receive a fixed reward linked to the opex maintenance values to incentivise keeping them under operation and thus avoid incurring new (unnecessary) investment costs. This is calculated as a percentage of opex (20% to 40%). As the percentage of opex increases, the gas transmission businesses has a stronger incentive to continue using the asset beyond the end of its regulatory life.

168 DNV report for ACER, *Future Regulatory Decisions on Natural Gas Networks: Repurposing, Decommissioning and Reinvestments on future regulation*, 28 October 2022, p.117.

169 UK Energy Act 2023, cl. 92.

170 National Commission on Markets and Competition, *Establishing the methodology for determining the remuneration of natural gas transmission facilities and LNG plants*, Circular 9/2019, 12 December 2019 (in Spanish).

A.7.3 Adapting WACC to compensate for stranded asset risks

There are instances internationally where an uplift to the WACC has been used to compensate for future asset stranding risks. However, this approach is not common, and regulators in Australia have noted that they do not consider it an appropriate method to compensate for asset stranding. For example, the AER noted that it is difficult to identify fair compensation for asset stranding risk due to uncertainty and unpredictability of the consequence of asset stranding risk, and that this approach can therefore lead to windfall gains and losses. Further, asset stranding is not a systematic risk, and so the AER does not consider it appropriate to compensate for this risk through the rate of return.[171]

Austria risk premium for transmission to account for future contracting risk

In Austria an individual risk premium on the cost of equity is applied for transmission pipelines to volume risk from revenue shortfall resulting from the expiry of existing contracts and the gap between termination of contracts and the remaining useful life of the asset. The premium essentially accounts for the risk of the natural gas TSO of not being able to market capacity after the expiration of long-term contracts which would result in a potential revenue shortfall. This also helps to avoid a sharp increase of tariffs in the long-term if lower quantities will be contracted in future periods. This is in addition to a changed depreciation approach whereby regulatory depreciation time is now the same as depreciation used for accounting purposes, with the effect of reducing the period over which depreciation is recovere.

A.7.4 Additional examples from Australia

ACCC's treatment of the impact of declining demand for fixed line telecommunications services and Telstra's Universal Service Guarantee

In Australia, the Australian Competition and Consumer Commission (ACCC) regulates a range of legacy fixed line wholesale access services supplied by Telstra via its copper networks. In its 2015 final access determinations for fixed line services in 2015, the ACCC recognised the cost impacts of declining demand for these services. In its decision, the ACCC distinguished between the treatment of declining demand due to National Broadband Network (NBN) migration and for other reasons.

In respect of NBN migration, the ACCC did not consider it appropriate for access seekers to bear the costs of declining demand. This was because Telstra had entered into commercial arrangements with NBN Co for the use of parts of the copper network in the rollout of the NBN. As such, the ACCC considered Telstra had been adequately compensated through these arrangements.

In contrast, the ACCC determined that the effect on unit costs of declining demand due to substitution of mobile services should be shared proportionally across all network users. The ACCC considered that all access seekers should bear a share of the costs of consumer choice, and that this approach would promote competition and encourage use of and investment in the infrastructure used to provide the regulated services.

Telstra has a Universal Service Obligation to provide standard telephone services and make payphones reasonably available nationally. This obligation is set out in both legislation and in a contract with the Australian Government to manage Telstra's performance. In areas outside of the NBN, these services are delivered over copper and other networks, and Telstra is required to maintain its copper network until 2032.

171 AER, *Regulating gas pipelines under uncertainty, Information paper*, November 2021, p.33.

State regulators' approaches to addressing declining demand in rail and ports

Table A.2 sets out examples from other recent rail regulatory decisions in Australia where the issue of stranding risk has been raised in the context of expected closure of coal fired generation plants or projected reductions in coal exports. As it shows, accelerated depreciation has been the key tool used by regulators to mitigate the risk of asset stranding, with both IPART and Queensland Competition Authority (QCA) making clear that in their view stranding risk should be dealt with in this manner rather than through a WACC uplift.

Table A.2: Examples from other recent regulatory decisions in rail and ports in Australia

Network		TAHE - Hunter Valley coal network	Queensland Rail - West Moreton coal	Aurizon Rail
Regulator		IPART	QCA	QCA
Capital recovery	Asset life	Based on remaining life of Hunter Valley coal mines using that sector(s) to be reviewed and, if necessary, revised every 5 years by IPART. IPART's 2024 decision estimated a remaining mine life of 5 yrs bringing the asset life forward from 1 July 2040 to 1 July 2029.	All assets to be depreciated over a maximum of 19 years.	Assets included in 2006 RAB assumed to have a maximum 50 year asset life, while assets included since 2010 assumed to have a rolling 20-year life, reset at start of each period.
	Profile	Straight line	Straight line	Straight line
RAB indexation		Indexed RAB	Indexed RAB	Indexed RAB
WACC uplift for stranding risk		No	No	No
Form of regulation		Prices negotiated directly between owner and access seeker, bounded by floor and ceiling limits, with unders and overs mechanism.	Price cap + temporary loss capitalisation as alternative to unders and overs mechanism.	Revenue cap with unders and overs mechanism.
Regulator's rationale for approach to asset stranding		In its 2024 decision on mine life, IPART decided to bring forward the terminal date of the network servicing the coal fired power stations (Eraring and Vales Point) by 11 years to 2029. In doing so, iPART noted that:[1] *"The terminal date of 30 June 2029 represents a mine life that is 11 years*	In its most recent decision, QCA noted that:[3] *"Accelerated depreciation will mitigate Queensland Rail's exposure to the risk of volumes not being sustained by access holders, or reallocated to new coal-handling access seekers, over the long term."*	In its 2019 decision on Aurizon's draft access undertaking, the QCA did not accept Aurizon's claims of asset stranding risk. However, it did note

Network	TAHE - Hunter Valley coal network	Queensland Rail - West Moreton coal	Aurizon Rail
	shorter. This change will lead to an access revenue ceiling that is higher because the depreciation charge will increase by 220%." *"The impacts of our final decisions on TAHE will be:* *• If the terminal date turns out to be 2029, then TAHE would have the opportunity to recover its remaining RAB from future access prices.* *• If the terminal date turns out to be sooner than 2029, then TAHE would under-recover its RAB from future access prices. However, we note that TAHE has an over-recovery balance of approximately $7m at present in its Overs and Unders Account. This represents 56% of the RAB.* *• If the terminal date turns out to be later than 2029, then TAHE would over-recover its RAB before then. However, the Overs and Unders Account provides a mechanism for that overrecovery to be returned to customers."* IPART also decided against adjusting the WACC to deal with stranding risk, noting that: [2] *"Through the mechanism of an increased depreciation allowance, driven by a reduced*	QCA has also previously observed the following:[4] *"We consider that this longer-term asset stranding risk West Moreton coal faces is potentially significant, but it is principally non-systematic in nature. As a consequence, we have not provided compensation within the return on equity for the longer-term stranding risk that West Moreton coal faces.* *Stranding risk need not be compensated for within the WACC, provided that the underlying regulatory framework or adjustments to the firm's cash flows adequately account for this risk….* *We note that the typical approach amongst regulators is to address stranding risk by adjusting a firm's cash flows, most commonly through some form of accelerated depreciation profile. With respect to other below-rail operators, we note that some form of accelerated depreciation was adopted by IPART for the RailCorp HVCN, by the ACCC for the ARTC HVCN, and by us in the case of Aurizon Network."*	that Aurizon already has access to a range of mechanisms to mitigate the risk:[5] • *accelerated depreciation—Aurizon Network is able to recover a greater proportion of the depreciation of its assets during the initial years of the asset life for investments made after 2009, as well as truncated asset lives implemented in the 2006 Undertaking* • *access conditions—Aurizon Network has the ability to seek access*

Network	TAHE - Hunter Valley coal network	Queensland Rail - West Moreton coal	Aurizon Rail
	mine life estimate, the Undertaking makes a specific provision for this stranding risk and therefore no [WACC] risk premium is necessary for the TAHE HVCN."		*conditions for expansion projects. For example, it could assume asset stranding risks in return for above-regulated returns* *limited asset optimisation—which mitigates the risk that capital expenditure previously undertaken by Aurizon Network is not included in the RAB used for pricing purposes…"*

Source: [1] IPART, *NSW rail access undertaking – review of the rate of return and remaining mine life 2024-2029 – Final Report*, September 2024, pp.23-24; [2] IPART, *NSW rail access undertaking – review of the rate of return and remaining mine life 2024-2029 – Final Report*, September 2024, p.14; [3] QCA, *Queensland Rail's 2025 Draft Access Undertaking – Final Decision*, March 2025, p. 120; [4] QCA, *Queensland Rail's 2020 Draft Access Undertaking – Final Decision*, February 2020, pp. 24-26, 49-50; [5] QCA, *Aurizon Network's 2*

B Gas pipeline regulatory framework

This chapter provides an overview of the gas pipeline regulatory framework [172] and how scheme pipelines are currently regulated. This represents the status quo against which the Commission will consider any potential changes to the regulatory framework.

B.1 Overview of the gas pipeline regulatory framework

B.1.1 The regulatory framework provides for two forms of regulation: scheme and non-scheme pipelines

The current regulatory framework was implemented in 2023 and is based on the negotiate-arbitrate regulatory model. Pipelines are classified as either scheme pipelines or non-scheme pipelines (noting that this classification applies to distribution and transmission pipelines). This classification then determines the form of regulation a pipeline is subject to:[173]

- **Scheme pipelines** are subject to a **stronger form of regulation** that requires the service provider to have its proposed access arrangement approved by the AER on a periodic basis.[174] The access arrangement, which sets out the prices and other terms and conditions of access to the reference service(s) offered by the pipeline, must comply with the Parts 8-9 of the NGR. Under this form of regulation, prospective users can either procure reference services on the terms and conditions set out in the access arrangement, or negotiate access to alternative services, prices and/or conditions of access.[175] To facilitate negotiations and access, the NGL and NGR require service providers to comply with a range of access related obligations, access related information disclosure requirements and a common negotiation framework.[176] If negotiations fail, either party can trigger the regulatory-oriented dispute resolution mechanism.[177]
- **Non-scheme pipelines** are subject to a **lighter form of regulation**, which does not involve any form of regulatory approval of prices or terms and conditions of access. This is instead left to commercial negotiations. Under this form of regulation, service providers must comply with the same access related obligations, disclosure requirements and negotiation framework as scheme pipelines[178] to support commercial negotiations. If negotiations fail, either party can trigger the commercially-oriented arbitration mechanism[179] set out in the NGL and NGR.[180]

Figure B.1 provides a high level overview of key elements of the current regulatory framework, followed by a detailed description of the components of the framework and key terms.[181]

172 The gas pipeline regulatory framework regulates scheme and non-scheme pipelines, which comprise gas transmission and distribution networks.

173 In 2022, Energy Ministers agreed to amend the NGL and NGR to implement a "simpler regulatory framework that will continue to support the safe, reliable and efficient use of and investment in gas pipelines". The current regulatory framework came into effect in all jurisdictions except Western Australia (WA) in 2023 (see Box 2.1 for more detail on WA). Please refer to Energy Ministers, Information paper - Improving gas pipeline regulation, 22 April 2022 - see here.

174 See Parts 8-9 of the NGR.

175 See s. 115 of the NGL.

176 See Parts 5-7, 10-12 of the NGR and Chapters 4-5 of the NGL.

177 See Part 12 of the NGR and Chapter 5 of the NGL.

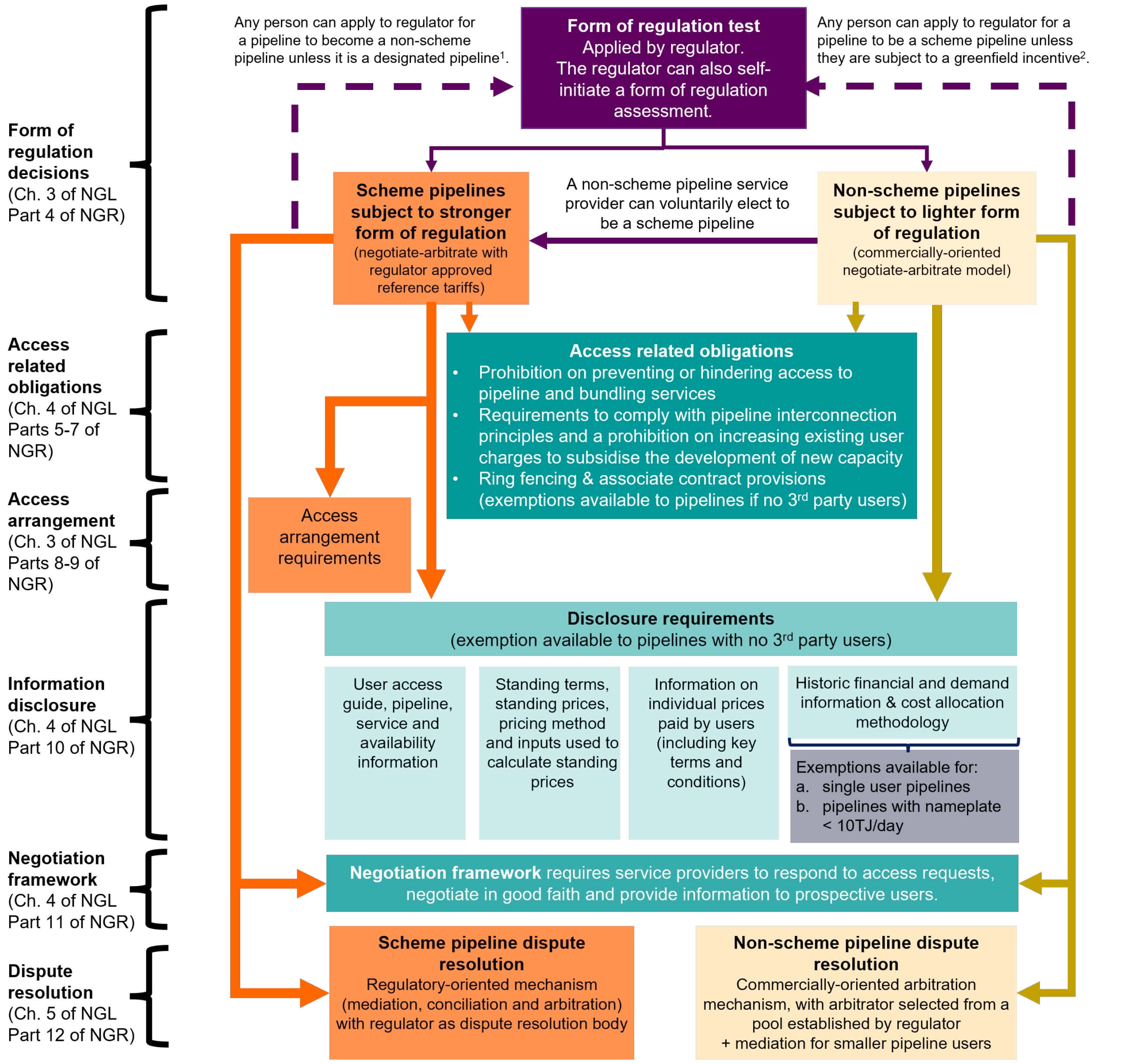
178 See Parts 5-7, 10-12 of the NGR and Chapters 4-5 of the NGL.

179 In contrast to scheme regulation where the regulator is the dispute resolution body, the arbitrator under non-scheme regulation must be selected from a pool of commercial arbitrators established by the regulator. The principles that must be considered in an arbitration under non-scheme regulation are also more commercially focused and the timelines for arbitration are also shorter than under scheme regulation.

180 See Parts 5-7, 10-12 of the NGR and Chapters 4-5 of the NGL.

181 In addition to the obligations outlined in Figure 2.1, Gas distributors can be subject to a range of regulatory related service and other obligations under the national gas regulatory framework and jurisdictional legislation, including obligations to: provide customer connection services, subject to and in accordance with energy laws; meet safety, technical and reliability requirements under jurisdictional energy laws and related instruments (these obligations vary from jurisdiction to jurisdiction); and meet service standards under the National Energy Retail Rules and jurisdictional guaranteed service level schemes.

Figure B.1: Overview - key components of the current regulatory framework for gas pipelines



Source: AEMC

Any pipeline that is not a scheme pipeline is classified as a non-scheme pipeline under the regulatory framework. However, as the top of Figure B.1 shows, the regulatory framework allows for the classification of most pipelines to be changed over time through a form of regulation determination process[182] and, in the case of non-scheme pipelines, through a voluntary election by the service provider to become a scheme pipeline. The only non-scheme pipelines that cannot have their classification changed to scheme pipelines are pipelines that have been designated as scheme pipelines by the relevant jurisdiction[183] and pipelines with a greenfield incentive.[184]

182 The AER can self-initiate a review to either increase or decrease the level of regulation of a gas pipeline, generally where it appears that the level of regulation of a pipeline may not be appropriate, having regard to the principles in section 112 of the NGL, the form of regulation factors in section 16 of the NGL, and the NGO. See *AER, Pipeline Regulatory Determinations and Elections Guide*.

183 At the time the NGL was implemented, jurisdictions were allowed to classify pipelines as designated pipelines through Regulations or in their application Act.

184 This incentive entitles the holder to an exemption from becoming a scheme pipeline for up to 15 years. See sections 100-102 of NGL.

Box 5: Western Australian gas pipeline regulatory framework

The regulatory framework in WA is based on the same framework that applied in other jurisdictions until early 2023.[1] The WA regulatory framework provides for pipelines in WA to be classified as either covered or non-scheme pipelines. Covered pipelines can be subject to full or light regulation, and full regulation pipelines in WA are subject to similar forms of regulation as scheme pipelines in other jurisdictions. For instance:

- covered pipelines subject to full regulation must have their proposed access arrangements approved by the Economic Regulation Authority (ERA)
- the rules applying to access arrangements, which are set out in WA's version of the NGR, are largely the same as those applying to scheme pipelines in the remainder of Australia.[2]

Although not central to the consideration of the ECA and JEC rule change requests, we note that there are some differences between the WA regulatory framework and other jurisdictions: the access related obligations, disclosure requirements, negotiation frameworks and dispute mechanisms.[3] There are also differences in the governance arrangements, with the WA Minister responsible for determining whether a pipeline's classification should change, rather than the regulator.

Source: AEMC.

Note: [1] A more detailed description of this framework can be found in the Energy Ministers, Regulation Impact Statement on options to improve gas pipeline regulation, 2021.

Note: [2] the WA version of the NGR can be found here.

Note: [3] For example, non-scheme pipelines in WA are not subject to the access related obligations set out in Figure B.1. Similarly, covered pipelines in WA are not subject to the upfront publication requirements set out in Figure B.1 and are also subject to a different negotiation framework.

B.1.2 Most of the major gas distribution networks in Australia are currently classified as scheme pipelines and subject to the stronger form of regulation

Table B.1 sets out the current classification of gas distribution networks in Australia. Gas distribution networks servicing major demand centres in the ACT, NSW, South Australia, Victoria and WA are currently classified as scheme pipelines and subject to the stronger form of regulation. The remainder, which are located in Queensland, the Northern Territory, Tasmania and regional areas of NSW, Victoria and WA, are non-scheme pipelines and subject to the lighter-handed form of regulation.

Table B.1: Current classification of gas distribution networks

	Scheme pipelines	Non-scheme pipelines	
ACT	• Evoenergy network	n.a.	
NSW	• JGN NSW network	• Central Ranges network • Monaro network • Nowra network	• Riverina network • Tumut Valley network • Wagga Wagga network
NT	n.a.	• Alice Springs network	• Darwin network
Queensland	n.a.	• Allgas network • AGN network •	• Grantham network • Moura network • Wide Bay network

	Scheme pipelines	Non-scheme pipelines	
		• Bundaberg network • Dalby network	
SA	• AGN SA network*	• Murray Valley network	• Tonsley network
Tasmania	n.a.	• Tasmanian network	
Victoria	• AGN Victorian and Albury networks* • AusNet network* • Multinet network*	• Gas Networks Victoria • Loddon Murray network	• Mildura network • East Gippsland network
WA	• Mid-West and South-West network*	• Kalgoorlie network	

Source: AEMC Gas Pipeline Register, accessed August 2025.
Note: * These gas distribution networks have been designated as scheme pipelines by the relevant jurisdictions so cannot apply to have the form of regulation changed.

B.2 Regulation of scheme pipelines

Service providers of scheme pipelines (transmission and distribution) are required to have their access arrangements approved by the relevant regulator on a periodic basis. The ERA is the relevant regulator for pipelines located in WA, while the AER is the relevant regulator in other jurisdictions.

The rules applying to access arrangements are set out in Parts 8 and 9 of the NGR, with Part 8 dealing with a range of access arrangement related content, process and decision-making related matters, while Part 9 sets out how a scheme pipeline's revenue and prices are to be determined. With some limited exceptions, the rules in these parts of the NGR apply to both gas transmission and distribution pipelines.

The remainder of this section provides a high level overview of the key features of the economic regulatory framework applying to scheme pipelines relevant to the issues we propose to consider in this rule change process:

- the **access arrangement review process** and the matters the regulator is required to have regard to when deciding whether or not to approve an access arrangement (appendix B.2.1)
- the **determination of a scheme pipeline's revenue requirement** (appendix B.2.2)
- the determination of a scheme pipeline's **reference tariffs** (appendix B.2.3)
- the **existing tools within the regulatory framework to manage demand risks and uncertainty** (appendix B.2.4).

B.2.1 Access arrangement review process

Scheme pipeline service providers are required by the NGL and NGR to submit:

- A **reference service proposal (RSP)** to the regulator for approval no later than **12 months before** the access arrangement proposal submission date.[185] An RSP must, amongst other

185 NGR, rule 47A.

things, set out the services the pipeline can reasonably provide and identify at least one as a reference service (see Box 6 for more detail on pipeline services). The regulator must consult on the RSP and make its decision on whether to approve the RSP at least 6 months before the access arrangement review submission date.

- An **access arrangement proposal**[186] to the regulator for approval by the submission date[187] along with access arrangement information[188] by the submission date. An access arrangement must, amongst other things, set out:[189]
  - the reference services to be provided by the pipeline, which must be consistent with what the regulator has approved through the RSP process unless there has been a material change in circumstances
  - for each reference service, the reference tariff and the other terms and conditions on which the reference service will be provided
  - the term of the access arrangement.[190]

  The regulator must consult on the access arrangement proposal and its draft decision. The final decision must be made within 8 months of the receipt of the access arrangement proposal.

Box 6: Categorisation of pipeline services

The services provided by scheme pipelines can be categorised as one of the following:

- **Reference service:** A pipeline service specified by, determined or approved by the regulator, as being a reference service and therefore subject to the reference tariffs and other terms and conditions in an access arrangement.
- **Non-reference service:** A pipeline service that is not a reference service. The price and other terms and conditions of access to these services must be negotiated directly between a user and the service provider.

Source: AEMC.

Parts 8 and 9 of the NGR set out the specific matters the regulator must consider when deciding whether or not to approve a RSP and an access arrangement proposal. Section 28 of the NGL also requires the regulator to:

- perform or exercise its economic regulatory functions and powers in a manner that will or is likely to contribute to the achievement of the NGO
- take into account the revenue and pricing principles (see Box 7) when exercising discretion in approving or making parts of an access arrangement relating to reference tariffs.

186 An access arrangement proposal means an initial access arrangement, revisions to an access arrangement, or variations to an access arrangement. See NGR, rule 3.

187 See section 113 of the NGL, and rules 43, 46 for new scheme pipelines, or rule 52 and 65 for scheme pipelines with an existing access arrangement.

188 Rule 72 of the NGR requires the Access Arrangement Information to include, amongst other things, information on: (a) actual expenditure and use of the pipeline over the prior access arrangement period; (b) how the opening capital base for the next access arrangement period has been calculated; (c) forecast expenditure, depreciation, rate of return, tax and demand for the next access arrangement period; (d) the proposed approach to setting tariffs; (e) the rationale for the proposed reference tariff variation mechanism; and (f) the rationale for any proposed incentive mechanisms.

189 Rule 48 of the NGR.

190 The NGR does not specify the length of the access arrangement period, instead the review submission date for an access arrangement is proposed by the service provider as part of their access arrangement proposal. Currently, the access arrangement period for all distribution scheme pipelines is five years.

Box 7: Revenue and pricing principles

The revenue and pricing principles set out in section 24 of the NGL are as follows:

- A scheme pipeline service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in:

(a) providing reference services; and

(b) complying with a regulatory obligation or requirement or making a regulatory payment.

- A scheme pipeline service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides. The economic efficiency that should be promoted includes:

(a) efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and

(b) the efficient provision of pipeline services; and

(c) the efficient use of the pipeline.

- Regard should be had to the capital base with respect to a pipeline adopted: (a) in any previous: (i) access arrangement decision; or (ii) decision under the Gas Code; or (b) Rules.
- A reference tariff should allow for a return commensurate with the regulatory and commercial risks involved in providing the reference service to which that tariff relates.
- Regard should be had to the economic costs and risks of the potential for under and over investment by a scheme pipeline service provider in a pipeline with which the service provider provides pipeline services.
- Regard should be had to the economic costs and risks of the potential for under and over utilisation of a pipeline with which a scheme pipeline service provider provides pipeline services.

Source: Section 24 of the NGL.

B.2.2 Determination of a scheme pipeline's revenue requirement

Part 9 of the NGR provides for the application of incentive-based regulation to scheme pipelines. This is intended to incentivise efficient investment in, and efficient operation and use of pipeline services for the long term interests of gas consumers. The rules in Part 9 of the NGR require the regulator and a pipeline business to use the building block method to determine a scheme pipeline's revenue requirement over the next access arrangement period.[191]

At a high level, the building block methodology involves summing the costs (building blocks) that a prudent and efficient service provider would incur in providing services (see Figure B.2 for further detail).

191 Rule 76 of the NGR.

Figure B.2: Building block methodology

	Building block	Rules
A	**Return on projected capital base (Value of capital base x Rate of return)**	**Value of capital base** **Rules 77-79:** Projected capital base to be calculated as: Opening capital base (excluding redundant assets)* + conforming capex - forecast depreciation – forecast disposals. Conforming capex is capex that conforms with the following criteria: • It must be such as would be incurred by a **prudent service provider acting efficiently,** in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services • It must be justifiable on one of the following grounds (or a combination of (b) and (c)): 1.the overall economic value of the expenditure is positive; 2.present value of expected incremental revenue from the expenditure > present value of expenditure; 3.the capex is necessary to maintain and improve safety of services, to maintain the integrity of services, to comply with a regulatory obligation or requirement or to maintain the capacity to meet demand. Redundant assets: **Rule 85:** Allows an access arrangement to include a mechanism: -To ensure assets that cease to contribute in any way to the delivery of pipeline services are removed form capital base -For sharing the costs associated with a decline in demand for pipeline services between the service provider and user. **Rate of return** **Rule 87:** Rate of return to be calculated using allowed rate for regulatory year, calculated in accordance with rate of return instrument.
+		
B	**Depreciation on projected capital base (Return of Capital)**	**Rules 88-89:** The depreciation schedule should be designed so: • that reference tariffs will vary over time, in a way that promotes efficient growth in the market for reference services • that each asset or group of assets is depreciated over the economic life of that asset or group of assets • as to allow, as far as reasonably practicable, for adjustments in the expected economic life • subject to the capital redundancy rules, an asset is only depreciated once • as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.
+		
C	**Forecast operating expenditure (Opex)**	**Rules 69 and 91:** Operating expenditure means operating, maintenance and other costs and expenditure of a non-capital nature incurred in providing pipeline services and includes expenditure incurred in increasing long-term demand for pipeline services and otherwise developing the market for pipeline services and expenditure, in providing pipeline services, that contributes to meeting emissions reduction targets. Operating expenditure must be such as would be incurred by a **prudent service provider acting efficiently**, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivery pipeline services.
+		
D	**Estimated cost of corporate income tax**	**Rule 87A:** Estimated for each regulatory year based on the estimate of taxable income for regulatory year that would be earned by a **benchmark efficient entity** providing the reference services, the statutory income tax rate for that regulatory year determined by the regulator and allowed imputation credits for the regulatory year (stated or calculated in the way stated in rate of return instrument).
+		
E	**Increments or decrements from incentive mechanisms**	**Rule 98:** An access arrangement may include (and the regulator may require it to include) 1 or more incentive mechanisms to encourage efficiency. An incentive mechanism must be consistent with the revenue and pricing principles.

Source: AEMC.

Note: * Opening capital base to be calculated in accordance with rule 77 as follows: 1) Opening value from commencement of the prior access arrangement period (adjusted for any difference between estimated and actual capex), *plus* 2) conforming capex from the prior period + any inclusions allowed by the regulator (including to reflect capital contributions from users, amounts from the speculative capex account if they become complying capex, the re-use of redundant assets), *less* 3) depreciation from the prior access arrangement + redundant assets identified in the prior access arrangement period + asset disposals in the prior access arrangement period.

The rules relating to capital and operating expenditure, depreciation, asset redundancy and incentive mechanisms are of particular relevance to this rule change process.

Capital and operating expenditure. The capital expenditure criteria define what capital expenditure is considered 'conforming capital expenditure', which is capital expenditure that is added to the capital base.

As ECA observed in its rule change request, the **capital expenditure criteria** currently implicitly assume that a service provider can propose and justify 'conforming capital expenditure' on the basis that the service provider's capacity should be maintained to meet an existing level of demand.[192] The definition of **operating expenditure** similarly assumes that expenditure may be incurred to increase "long-term demand for pipeline services and otherwise develop the market for pipeline services". These aspects of the expenditure criteria are discussed further in section 2.1 in relation to the ECA rule change proposal.

Depreciation. Depreciation is the process by which the capital invested in a pipeline can be recovered by the service provider, with the key determinants of depreciation being:

- the economic life of the assets (i.e. the period over which the asset is expected to provide services, which may be shorter than the technical life of the assets)
- the depreciation profile (i.e. the rate at which depreciation occurs over time, which may be constant over time (straight line depreciation), diminishing over time (front loaded depreciation) or increasing over time (back loaded depreciation)).

Until recently, depreciation for most gas distribution networks was recovered on a straight line basis with the economic asset lives largely assumed to be the same as the technical lives. This has started to change though, with an increasing number of distributors seeking to accelerate the recovery of capital in response to the projected decline in demand. Distributors are seeking to accelerate depreciation through either a reduction in the economic life of their assets[193] and/or a movement from a straight line depreciation profile to more of a front-loaded profile.[194]

While accelerating the recovery of capital can help to mitigate the risk of asset stranding for service providers, it can alter the allocation of risk between service providers and consumers, and between current and future consumers. This issue is discussed further in section 2.2.

Capital redundancy. Rule 85 of the NGR allows an access arrangement to include a mechanism:

- to ensure that assets that cease to contribute in any way to the delivery of pipeline services (redundant assets) are removed from the capital base
- for sharing the costs associated with a decline in demand for pipeline services between the service provider and user.

Before the regulator requires or approves a mechanism under this rule, the regulator must "take into account the uncertainty such a mechanism would cause and the effect the uncertainty would have on the service provider, users and prospective users".[195]

Rule 86 of the NGR also allows assets that have previously been identified as redundant to be added back into the capital base if they later contribute to the delivery of pipeline services.[196]

While the capital redundancy rules have not been utilised since the NGR commenced in 2008, the Independent Pricing and Regulatory Tribunal (IPART) did have recourse to similar provisions in the National Third Party Access Code for Natural Gas Pipeline Systems (the predecessor to the NGR) when it was responsible for regulating gas distribution networks in NSW (see Box 8).

192 ECA, Capital expenditure rule change request, p. 18.

193 For example, in Evoenergy's 2021-2026 access arrangement, it proposed the adoption of shorter economic lives for a number of assets, which the AER approved. See AER, Final decision – Evoenergy Access Arrangement 2021-26, p. 38.

194 For example, for Evoenergy's 2026-2031 access arrangement, it is proposing to move to a front-loaded depreciation profile to "share the recovery of the gas network over a larger customer base". See Evoenergy, Our draft five year gas plan 2026-2031, p. 43. The Victorian gas distribution networks and JGN also sought to accelerate the recovery of depreciation, which the AER accepted subject to a price constraint of 1.5% p.a. for the Victorian networks and 0.5% for JGN. See AER, Final decision – AusNet Gas Services 2023-2028, p. 24 and AER, Final decision – JGN access arrangement 2025-30, May 2025, p. iv.

195 Rule 85(4) of the NGR.

196 Rule 86(1). This is subject to the capital expenditure criteria.

Box 8: Use of the capital redundancy and re-use of redundant asset provisions

IPART used the capital redundancy provisions in s. 8.27 of the National Third Party Access Code for Natural Gas Pipeline Systems[1] in 2005 when it was responsible for regulating gas distribution networks in NSW.

At the time, IPART decided to use the provisions to remove the value of underutilised assets from the NSW gas distribution network's capital base. IPART decided to remove from the capital base the value of underutilised assets relating to excess capacity on the Wilton to Wollongong trunk line. Use of the trunk line had decreased following the construction of the Eastern Gas Pipeline. This resulted in the value of the Wilton to Wollongong trunk line being reduced by 20%.[2]

In 2010, Jemena sought to have the value of the assets that had been removed from the capital base added back into the capital base under rule 86 of the NGR. However, the AER rejected the proposal on the basis that Jemena had not demonstrated that the value of the redundant assets were contributing to the delivery of pipeline services.[3]

Source: AEMC.
Note: [1] The National Third Party Access Code for Natural Gas Pipeline Systems was the predecessor of the National Gas Rules.
Note: [2] IPART, Revised Access Arrangement for AGL Gas Networks, April 2005
Note: [3] AER, Jemena Gas Networks - Access arrangement proposal for the NSW gas networks, 1 Jly 2010 - 30 June 2015, June 2010, p. 46.

JEC has suggested in its rule change request that the capital redundancy provisions in rule 85 are the most appropriate way to help deal with the challenges posed by declining gas demand, subject to amendments to strengthen its operation. This is discussed further in section 2.4.

Incentive mechanisms. The NGR allows for, but does not require, the inclusion of one or more incentive mechanisms in an access arrangement where this is consistent with the revenue pricing principles.[197] Unlike the National Electricity Rules (NER), the NGR does not specify the types of incentive mechanisms that may be applied to gas distribution networks. This is instead left to the service provider and regulator to determine.

The incentive mechanisms that have been used in access arrangements to date include.[198]

- The operating expenditure efficiency benefit sharing scheme (EBSS). This mechanism is intended to provide service providers an incentive to undertake efficient operating expenditure throughout the access arrangement period. The mechanism allows service providers to retain the benefit (or to incur the cost) of outperforming (underperforming) against operating expenditure forecasts for a period before being passed through to users.
- The capital expenditure sharing scheme (CESS). This mechanism is intended to provide service providers an incentive to undertake efficient capital expenditure throughout the access arrangement period. The mechanism rewards (or penalises) service providers that spend less (more) than their capital expenditure allowance. The CESS also provides a mechanism to share efficiency gains and losses between the service provider and users.

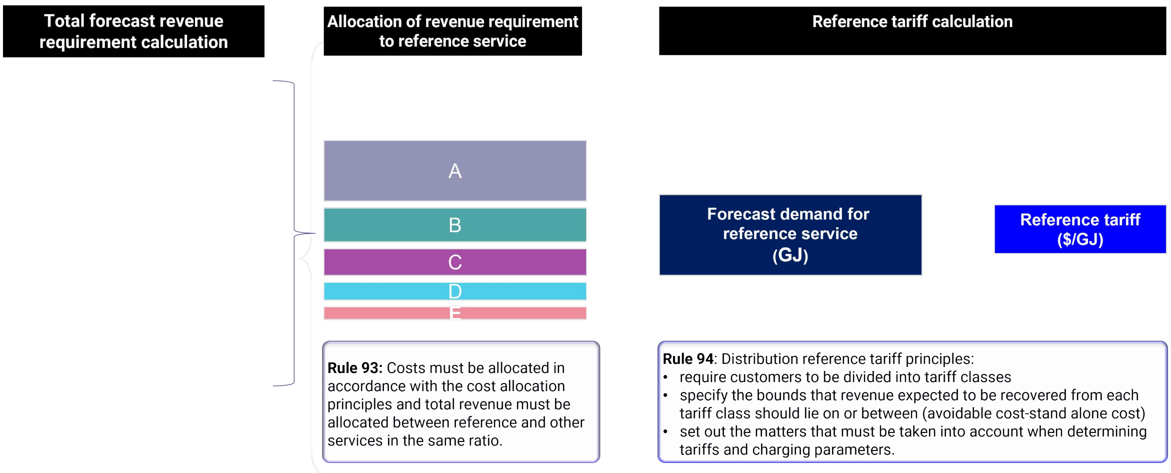
Beyond the incentive mechanisms in access arrangements, competition from electricity and other energy sources may also provide some gas pipeline service providers with a strong efficiency incentive.

197 NGR, rule 98.
198 AER, Review of incentives schemes for networks – Final Decision, April 2023, pp. 80-86.

B.2.3 Determination of a scheme pipeline's reference tariffs

The reference tariffs for each reference service can be calculated once the revenue requirement is determined through the building block approach, having regard to the revenue equalisation, cost allocation and tariff principles set out in Part 9 Division 8 of the NGR (see Figure B.3).

Figure B.3: Reference tariff methodology



Source: AEMC.

The NGR also requires an access arrangement to include a reference tariff variation mechanism, which specifies how reference tariffs can vary over the access arrangement period including as a result of a pass through of costs for a defined event. Examples of the forms that this mechanism can take include:[199]

- revenue caps,
- price caps
- combinations of these.

The choice between these options will determine how demand risk is allocated between service providers and users and the stability of revenue and prices within the access arrangement period (see Table B.2).

Table B.2: Forms of reference tariff variation mechanism

Mechanism	Description	Who bears demand risk?
Revenue cap	A cap is placed on the revenue that a service provider can earn in each year, resulting in stable revenue but potentially variable reference tariffs if actual demand differs from forecast demand.	Customers
Price caps	**Individual price caps**. A cap is placed on the extent to which a service provider can increase reference tariffs, resulting in stable prices but potentially variable revenue if actual demand differs from forecast demand.	Service provider

199 NGR rule 97.

Mechanism	Description	Who bears demand risk?
	Weighted average price cap. A cap is placed on the extent to which a service provider can increase the weighted average price of all its reference services, but the service provider can determine the structure and level of tariffs within the weighted average price cap.	
Hybrid price-revenue cap	Contains elements of both price and revenue cap. Under this option, revenue and prices can vary if actual demand differs from forecast demand.	Service provider and customers share risk

Source: AEMC

B.2.4 Existing tools to manage demand risks and uncertainty

Parts 8-9 of the NGR include a number of tools to help try and mitigate the impacts of the following sources of risk and uncertainty on service providers:

- demand risk within an access arrangement period
- unforeseen events or material changes within an access arrangement period
- longer-term demand and asset stranding risks.

These tools are set out in Figure B.4. Further detail on these tools and their relevance to the current rule change process can be found in chapters 2-3.

Figure B.4: Tools to manage demand risks and uncertainty

Tools to manage demand risk within an access arrangement period (i.e. the risk actual demand deviates from forecasts)

Part 9 of the NGR includes the following tools to deal with demand risks arising within an access arrangement period:

- **Reference tariff variation mechanism:** Rule 97 recognises that the reference tariff variation mechanism may provide for the use of a number of different types of tariff variation mechanisms (e.g. revenue caps, price caps, hybrids of the two), which can, to varying extents, be used to allocate demand risk within the access arrangement period.
- **Tariff charging parameters:** Rule 94 allows the service provider to propose the charging parameters to be used to recover its revenue requirement (e.g. fixed charges, variable charges, declining or inclining blocks etc). Fixed charges may provide some protection from demand risk because users must pay irrespective of how much they consume.
- See also tools to manage unforeseen events or material changes below.

Tools to manage unforeseen events or material changes within an access arrangement period

Part 8 of the NGR provides for a number of ways to manage unforeseen events or material changes in circumstances within an access arrangement period, including.

- **Shorter access arrangement periods:** While access arrangement periods are typically 5 years, rule 50 allows service providers to propose different periods
- **Access arrangement re-opener mechanisms:**
  - Rule 51 allows the review submission date to be advanced to an earlier date if the access arrangement specifies a trigger event (i.e. any significant circumstance, or conjunction of circumstances) and that event occurs..
  - Rule 65 allows the service provider to submit a variation within the access arrangement period.

Tools to manage longer term demand & asset stranding risks

Part 9 of the NGR includes the following tools to deal with longer-term demand and asset stranding risk:

- **Accelerating the recovery of capital** through changes to**:**
  - **Depreciation:** Rule 89 allows capital recovery to be accelerated through the use of shorter economic lives and/or changing the profile.
  - **The treatment of inflation in the capital base:** According to the accounting method approved by the regulator.
- **Sharing the costs of asset stranding between the service provider and users:** Rule 85 allows an access arrangement to include a mechanism to ensure that assets that cease to contribute to the delivery of pipeline services are removed from the capital base and a mechanism for sharing the costs associated with a decline in demand for pipeline services between the service provider and users.
- **Tariff charging parameters**: See above.

Source: AEMC

Abbreviations and defined terms

AA	Access arrangement
ACCC	Australian Competition and Consumer Commission
ACM	The Netherlands Authority for Consumers and Markets
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CESS	Capital expenditure sharing scheme
Commission	See AEMC
CPI	Consumer price index
CWC	Copper Withdrawal Code
DBNGP	Dampier to Bunbury National Gas Pipeline
DSO	Distribution system operator
EBSS	Efficiency benefit sharing scheme
ECA	Energy Consumers Australia
ERA	Economic Regulation Authority
ENA	Energy Networks Association
FFLAS	Fibre fixed line access services
GAPR	Gas Annual Planning Report
GDN	Gas distribution network
GSOO	Gas Statement of Opportunities
IPART	Independent Pricing and Regulatory Tribunal
JEC	Justice and Equity Centre
NBN	National Broadband Network
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NERL	National Energy Retail Law
NERO	National Energy Retail Objective
NERR	National Energy Retail Rules
NESO	National Energy System Operator
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NPV	Net present value
NSW	New South Wales
NZ	New Zealand
NZCC	New Zealand Commerce Commission
Ofgem	Office of Gas and Electricity Markets

Proponents	The proponents of the rule change request
QCA	Queensland Competition Authority
RAB	Regulatory Asset Base
RAV	Regulatory Asset Value
RESP	Regional Energy Strategic Plan
RIIO	Revenue = Incentives + Innovation + Outputs
RSP	Reference service proposal
STPIS	Service target performance incentive scheme
TSLRIC	Total service long run incremental cost
UFB	Ultra-fast broadband
UK	United Kingdom
VTS	Victorian Transmission System
WA	Western Australia
WACC	Weighted average cost of capital