Australian Energy Market Commission

AEMC
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RULE

Directions paper

National Gas Amendment (Gas Networks in Transition) Rule

Proponents
Energy Consumers Australia
Justice and Equity Centre

19 March 2026

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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 live and work. The AEMC office is located on the land of the Gadigal people of the Eora nation. We pay respect to all Elders past and present, and to the enduring connection of Aboriginal and Torres Strait Islander peoples to Country.

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Summary

1 Natural gas has played an important role in Australia's energy system for many decades, providing a reliable and affordable source of energy for residential, small commercial and industrial consumers. While gas will continue to play a role for some consumers, the energy transition is changing the outlook for gas demand, particularly in the residential and small commercial customer segment. Declining and increasingly uncertain demand is creating new challenges for the economic regulation of gas pipelines and risks for both gas consumers and gas distribution service providers (service providers).

2 The gas pipeline economic regulatory framework in the National Gas Rules (NGR) has promoted the long-term interests of gas consumers under stable and growing demand conditions by delivering safe, secure and reliable gas services and efficient reference tariffs. However, as demand becomes more uncertain, the ability of the existing regulatory framework to continue to promote the long-term interests of gas consumers is being tested.

3 This directions paper sets out the Commission's proposed policy direction for strengthening the gas pipeline economic regulatory framework to ensure it continues to promote the long-term interests of gas consumers through the energy transition. The Commission has developed the proposed direction having regard to the National Gas Objective (NGO), which promotes the long-term interests of gas consumers through economic efficiency. Our proposed direction also gives effect to the Revenue and Pricing Principles (RPPs).

The changing demand outlook and emerging risks to gas consumers and service providers

4 Forecasts from the Australian Energy Market Operator (AEMO) and service providers indicate that gas demand in the residential and small commercial customer segment is expected to decline over the medium to long term, although the pace and extent of decline varies significantly across jurisdictions. Differences in jurisdictional policy settings, consumer preferences, technology uptake and the potential role of renewable gases contribute to this variation and uncertainty.

5 Declining demand creates a shared risk dynamic for consumers and service providers. As demand and customer numbers fall, the largely fixed costs of the network must be recovered over a smaller customer base, placing upward pressure on reference tariffs and customer bills. Higher bills may, in turn, accelerate customer exits, increasing the risk of further price escalation for remaining customers (including vulnerable customers, renters, and commercial and industrial customers) that are less able to switch to alternative energy sources due to financial, technical or other barriers. At the same time, service providers face increased risk that they may be unable to recover the efficient costs of past investments, leading to stranding risks (i.e., the risk that service providers will not be able to recover a full return of and on capital) and potentially undermining their incentives to continue to invest in, and to maintain and safely operate the network.

6 The Commission has worked with Cambridge Economic Policy Associates (CEPA) to illustratively model the impacts on gas consumers and service providers under a range of plausible demand scenarios. The modelling highlights that while efficient use of existing regulatory tools can help manage some risks to gas consumers and service providers, the rate of demand decline remains a key driver of outcomes. Even with accelerated capital cost recovery and expenditure constraints, the regulatory framework has limits in its ability to fully mitigate price and stranding risks for gas consumers and service providers. We note that the modelling is necessarily simplified and is intended to be illustrative only. It is not comparable with any modelling that may be undertaken by

service providers or the regulator to support a regulatory determination.

Reform is needed to help manage uncertainty

7 The increasingly uncertain outlook for gas demand in the residential and small commercial customer segment and the potential impacts of this uncertainty on gas consumers prompted Energy Consumers Australia (ECA) and the Justice and Equity Centre (JEC) to submit a number of rule change requests. The rule change requests relate to the following aspects of the gas pipeline economic regulatory framework:

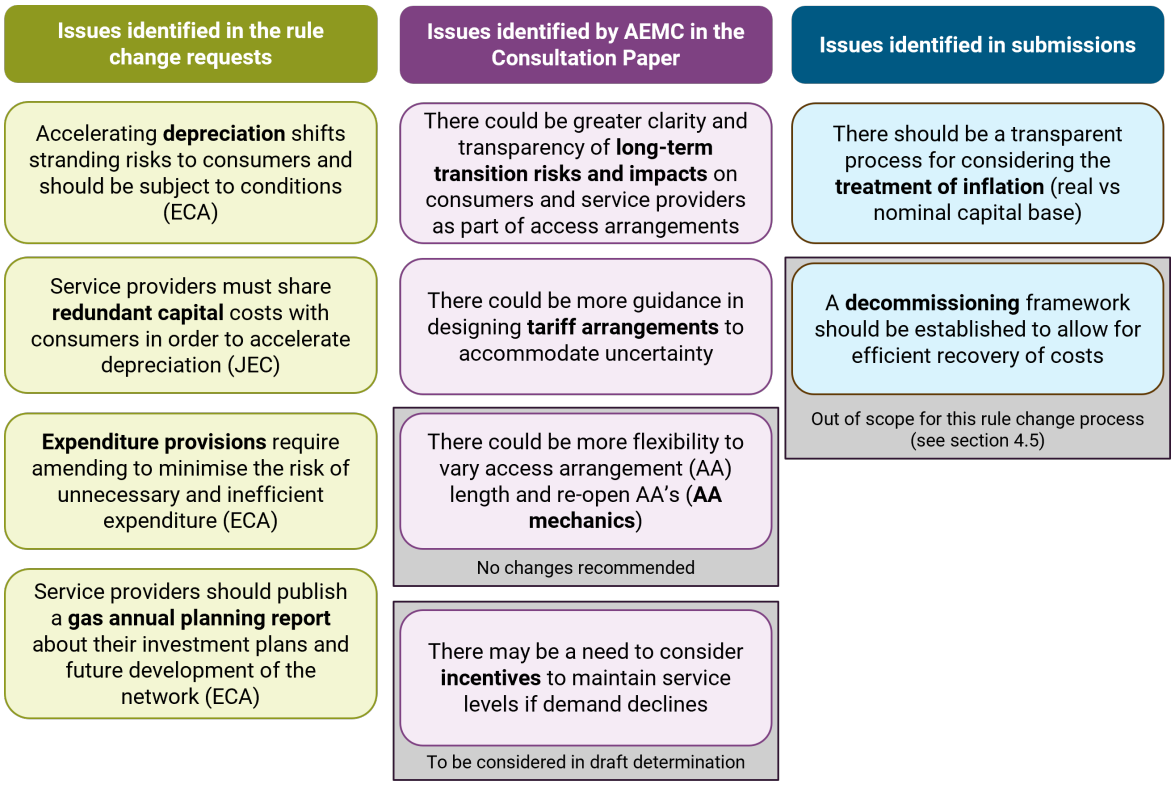
- **Depreciation**. ECA propose stronger conditions on when service providers and the regulator can accelerate the recovery of capital costs through changes to the depreciation criteria.
- **Capital and operating expenditure**. ECA propose changes to the capital expenditure (capex) provisions and operating expenditure (opex) definition to ensure that only efficient expenditure is incurred and paid for by gas consumers in the context of declining demand.
- **Accelerated depreciation and redundancy**. JEC propose changes to the depreciation and redundant asset provisions. Their proposed changes would prohibit the use of accelerated depreciation to manage stranding risks unless used in combination with the capital redundancy provisions. JEC further propose to cap the customer contribution to 50 per cent, in the case of a cost sharing arrangement.
- **Planning requirements**. ECA propose new planning reporting obligations on service providers to provide regulators, governments, electricity networks, and other stakeholders with information required to understand the opportunities to minimise expenditure and energy system costs.

8 The proponents have proposed that the first three of these rule changes apply to scheme pipelines (i.e. gas networks subject to the economic regulatory framework in the NGR) and the latter rule change apply to both scheme and non-scheme pipelines.

9 The Commission considers that changes to the NGR are necessary to ensure the economic regulatory framework remains fit for purpose in an environment of uncertain and potentially declining demand. Many provisions in the NGR were established based on expectations of stable or growing demand and encouraging demand growth. The framework has delivered strong outcomes for gas consumers under stable demand conditions by allowing, for example, revenue recovery to be spread evenly over long timeframes, ensuring costs are recovered in line with expected use of the assets, promoting intergenerational equity and maintaining incentives for efficient investment. However, in the context of uncertain and/or declining demand, the framework may no longer be fit for purpose. The ECA and JEC rule change requests, stakeholder feedback, recent regulatory decisions and the CEPA modelling point to opportunities to strengthen the framework to better manage transition risks and support an orderly energy transition.

10 In our consultation paper, we noted that the NGR economic regulatory framework needs to be considered holistically given the interrelated nature of its components. As such, the Commission's starting proposition is that all key aspects of the economic regulatory framework for gas pipelines should be considered. Figure 1 summarises the key issues raised in the rule change requests, the additional issues the Commission explored in its consultation paper for this rule change project and issues raised in response to this by stakeholders.

Figure 1: Summary of key issues

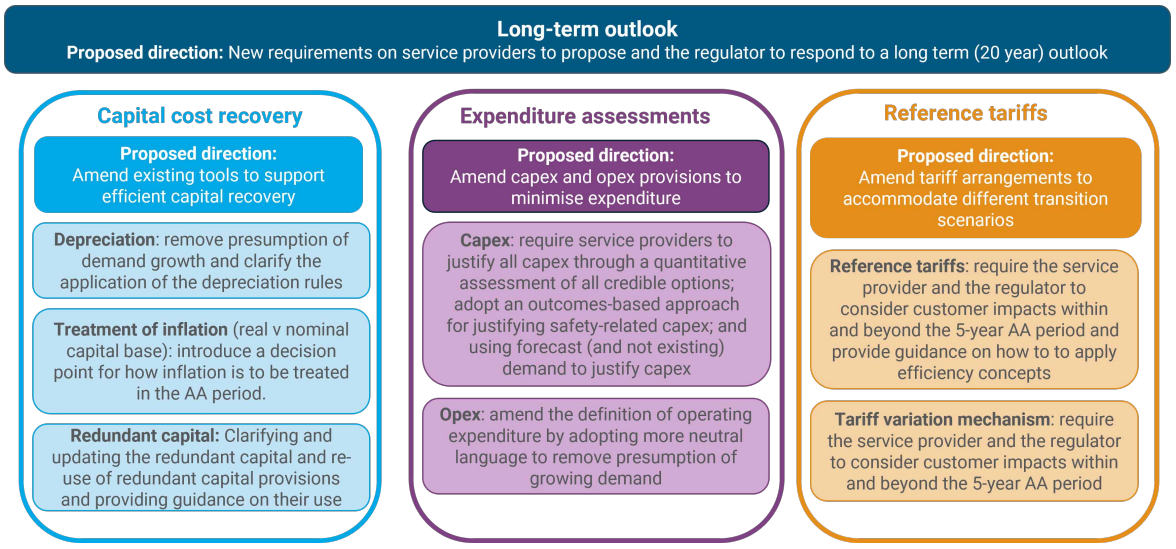


The Commission has developed a proposed direction for reform to the NGR

11 The Commission's proposed direction is a balanced package of targeted reforms that seeks to ensure the gas pipeline economic regulatory framework continues to promote economic efficiency for the long-term interests of gas consumers with respect to price, quality, safety, reliability, security of supply and emissions reduction.

12 Figure 2 summarises the Commission's proposed direction on the aspects of the economic regulatory framework that we have determined would benefit from change to better promote the long-term interests of gas consumers.

Figure 2: Our proposed direction



13 The Commission's proposed direction focuses on four key reform areas:

1. **Employing a longer-term outlook to manage uncertainty.** Requiring service providers and the regulator to demonstrate how they have considered long-term energy transition risks and impacts in the access arrangement (AA) period and beyond. This would support more efficient and internally consistent proposals and decisions and increase transparency over how service providers and the regulator have considered the longer-term implications of their AA proposals and decisions.
2. **Amending capital cost recovery provisions to support efficient capital recovery.** Providing clearer guidance on the use of depreciation, compensation for inflation, redundant capital and re-use of redundant capital provisions to support efficient capital recovery that promotes the long-term interests of consumers. Earlier and more transparent use of these tools, where justified, can help mitigate price and stranding risks, while preserving incentives for service providers to continue providing safe and reliable services.
3. **Amending capital and operating expenditure provisions to minimise expenditure while continuing to support safety and reliability.** Amending the capex provisions and opex definition to reduce expenditure and better align investment decisions with uncertain demand conditions and improve regulatory clarity. This includes removing references to demand growth, tightening justification requirements, and strengthening accountability for expenditure choices.
4. **Amending reference tariff provisions to ensure tariff arrangements can accommodate a broader range of demand scenarios.** Supporting service providers and the regulator in proposing and approving reference tariffs and tariff variation mechanisms that are economically efficient while also reflecting the impact tariff arrangements may have on customer consumption and investment decisions under different demand scenarios, both within and beyond the AA period.

14 We acknowledge that our proposed direction for the capital cost recovery tools may result in more capital recovery being brought forward and today's gas consumers facing higher prices. The Commission must, however, have regard to the long-term interests of gas consumers when considering changes to the NGR. We do not consider that consumers' long-term interests would

be promoted if there was a disorderly energy transition that resulted in consumers facing escalating prices and/or the service provider deciding to cease providing services leaving customers without access to gas. Such an outcome could occur if the price impacts and stranding risks associated with declining demand are not carefully managed through the use of the capital cost recovery tools. In the Commission's view, these tools are an important element of the regulatory framework and the regulator should use these tools to bring forward the recovery of capital where it is feasible to do so and to remove redundant capital when stranding risk materialises.

15 This is illustrated in CEPA's modelling, which shows that efficient use of the capital cost recovery tools, including bringing forward the recovery of capital while there are still a relatively large number of customers connected to a network to spread the capital costs across, would result in marginal price increases in the near term, but allows for more even revenue recovery over time and stable prices for consumers over the longer term. It would also reduce the capital at risk of stranding and the risk that service providers decide to cease their operations earlier than expected. Timely use of the capital cost recovery tools can therefore help to mitigate the adverse impacts that declining demand could otherwise have on gas consumers and service providers, and, in so doing, help support a more orderly energy transition.

16 Importantly, consumers that face financial or technical barriers to electrify (or switch to alternative energy sources) would be protected from being exposed to escalating bills. Achieving equitable energy outcomes for all consumers, including the most vulnerable, is a key challenge and opportunity for the Commission, governments and the energy sector as a whole. It will be essential for building and maintaining the social licence that is necessary to enable a timely and least-cost energy transition.

17 The Commission is not proposing changes to AA period lengths or re-opener provisions at this stage, and does not propose to establish a decommissioning framework as part of this rule change process. However, the Commission recognises that decommissioning raises complex issues that may require coordinated action by governments, regulators and other stakeholders beyond the NGR. We will also consider the need for additional or modified incentives after considering stakeholder submissions on our package of proposed NGR amendments.

18 The Commission's proposed changes would apply to scheme transmission and distribution pipelines regulated under the NGR, as adopted in each jurisdiction. This includes scheme pipelines in the east coast gas system, regulated by the Australian Energy Regulator (AER), and scheme pipelines in Western Australia, regulated by the Western Australian Economic Regulation Authority (ERA).

Government will play a role to support gas consumers and service providers through the energy transition

19 The Commission's analysis indicates that the NGR economic regulatory framework alone cannot fully address all the impacts of uncertain and declining gas demand on consumers and service providers. There will be a role for governments in supporting gas consumers and service providers through the energy transition, including through clearer jurisdictional policy signals, addressing service obligations, supporting consumers and planning for potential network decommissioning, where appropriate.

Next steps

20 This directions paper seeks stakeholder feedback on the Commission's proposed direction for reform. Submissions will inform the development of a draft determination and draft rule. The Commission will continue to assess whether the proposed reforms, as a package, would promote the NGO and give effect to the RPPs, while supporting an orderly and efficient energy transition.

Questions for stakeholders

Question 1: Our proposed package of reforms

1. What are stakeholder views on our assessment of the proposed direction and how it better promotes the NGO and is consistent with the RPP, in comparison to the status quo and the ECA and JEC rule change proposals?

Question 2: Implementation considerations

1. Do stakeholders consider that there are any barriers to implementing our proposed package of reforms considering the planned publication of the final determination in December 2026? Do you consider some form of transitional arrangements are required for any element?
2. Do stakeholders consider there are any significant implementation costs associated with our proposed package of reforms that the Commission should consider?

Question 3: Application to transmission and distribution

1. What are your views on our proposed direction that reforms should apply to distribution and transmission pipelines (where relevant)?

Question 4: Our proposed direction on a longer-term outlook (detailed in appendix A)

1. What are your views on our proposed direction to require service providers and the regulator to consider a longer-term outlook and longer-term consequences?
2. Do you have any views on the information or analysis that should be included in a service provider's 20-year outlook?

Question 5: Our proposed direction on capital cost recovery (detailed in appendix B)

1. What are your views on our proposed direction for capital cost recovery tools in the NGR?
2. Do you have any views on the decision-making model options explored for:
   a. depreciation and treatment of inflation?
   b. redundant capital provisions?
3. In relation to our proposed direction for redundant capital, do you have any views on:
   a. the materiality threshold that should apply to partial redundancy?
   b. the constraints that could apply to the regulator's use of partial redundancy?

Question 6: Our proposed direction on expenditure (detailed in appendix C)

1. What are your views on our proposed direction to amend the NGR capex provisions? For example:
   a. Clarifying that service providers must justify all capex through a quantitative assessment of all credible options that support the provision of regulated pipeline services.
   b. Amending the justification for safety-related capex to be necessary for the safe operation of pipelines and use of services in NGR rule 79(2)(c)(i).
   c. Amending the justification for capex to maintain capacity to meet forecast (instead of existing) demand for services under NGR 79(2)(c)(iv).
2. What are your views on the need for the NPV test in rule 79(2)(b)?
3. What are your views on our proposed direction to amend the NGR opex definition?

Question 7: Our proposed direction on tariff arrangements (detailed in appendix D)

1. What are your views on our proposed direction for amending the reference tariff arrangements?
2. What are your views on our proposal to provide guidance on applying the concepts of long run marginal cost, standalone and avoidable costs?
3. What are your views on our proposal to require service provider and the regulator to give greater consideration to customer impacts in setting tariffs and tariff variation mechanisms?

Question 8: Incentive mechanisms (detailed in appendix F)

1. Having regard to our proposed direction, do you consider there is a need for additional or modified incentive mechanisms for service providers?

How to make a submission

We encourage you to make a submission

Stakeholders can help shape the solution by participating in the rule change process. Engaging with stakeholders helps us understand the potential impacts of our decisions and contributes to well-informed, high quality rule changes.

How to make a written submission

Due date: Written submissions responding to this directions paper must be lodged with Commission by 30 April 2026.

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 on rule change requests 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, defamatory, vexatious or irrelevant content, or content that is likely to infringe intellectual property rights).[3]

Public forum: In addition to seeking feedback through submissions to the discussion paper, we will be holding a public forum on 9 April 2026.

Next steps and opportunities for engagement

Figure 1: *Gas networks in transition* timeline

This directions paper is the next stage of the *Gas networks in transition* rule change process.

Our current statutory timeframe for publishing a final rule and final determination is no later than 17 December 2026.

This would allow for the rule change package to be in place for the next round of gas distribution AA reviews. We note that the AA process for Victorian gas distribution service providers will commence on 1

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/our-work-3.

3 Further information about publication of submissions and our privacy policy can be found here: https://www.aemc.gov.au/contact-us/lodge-submission.

June 2026, which is when service providers have to submit reference service proposals to the AER, while AA proposals are due to the AER on 1 June 2027. The Commission will engage further with the Victorian gas distribution service providers and the AER on our implementation timeframes and is interested in stakeholder feedback on the scope for any changes to the NGR economic regulatory framework applying to the upcoming next round of AA reviews.

For more information, you can contact us

Please contact us with questions or feedback at any stage, noting the project code.

Email:	aemc@aemc.gov.au
Telephone:	(02) 8296 7800

Contents

Tables

Figures

1 Introduction

The purpose of this directions paper is to test our proposed policy direction for improving the gas pipeline economic regulatory framework under the National Gas Rules (NGR) to ensure that it continues to promote the long-term interests of gas consumers through the energy transition.

This directions paper provides a high-level overview of the Commission's reasoning for proposing changes to the NGR. Chapter 2 outlines the increasingly uncertain and/or declining outlook for gas demand in the residential and small commercial customer segment, providing the context for our proposed direction. Chapter 3 discusses the key risks to gas consumers and gas distribution service providers (service providers) resulting from this increasingly uncertain outlook. Chapter 4 identifies the key opportunities for strengthening the NGR and the scope of this rule change project. Chapter 5 sets out the Commission's proposed direction for reforms and how this would better promote the National Gas Objective (NGO).

This paper is supported by six appendices that provide more detailed information about our proposed direction for reform:

- Appendix A - Our proposed approach to require service providers and the regulator to consider a long-term outlook
- Appendix B – Our proposed approach to amend the capital cost recovery provisions
- Appendix C – Our proposed approach to amend the expenditure provisions
- Appendix D – Our proposed approach to amend the reference tariff provisions
- Appendix E – Our proposal to not amend the access arrangement period or re-opener provisions
- Appendix F - Incentives in the gas regulatory framework.

Stakeholders should read this paper and the appendices together. In addition, stakeholders should refer to our consultation paper[4] which provides more detail on the issues identified by the rule change proponents and their proposed changes. We have also published a modelling report prepared by Cambridge Economic Policy Associates (CEPA) providing more detail on the inputs, assumptions, and modelling approach used to assess the impact of different combinations of regulatory settings on network users and illustrative networks under a range of demand scenarios.[5]

The *Gas networks in transition* rule change process to date

The Commission initiated the *Gas networks in transition* rule change process in response to four rule change requests submitted by Energy Consumers Australia (ECA) and the Justice and Equity Centre (JEC). ECA submitted its rule change requests on 14 February 2025, and JEC submitted its rule change request on 4 June 2025. The rule change requests touch on the following aspects of the economic regulatory framework for gas pipelines:

- **Depreciation**. ECA propose stronger conditions on when service providers and the regulator can accelerate the recovery of capital costs through changes to the depreciation criteria.
- **Capital and operating expenditure**. ECA propose changes to the capital expenditure (capex) provisions and operating expenditure (opex) definition to ensure that only efficient expenditure

4 AEMC, *Gas networks in transition, Consultation Paper*, 18 September 2025. Please see here https://www.aemc.gov.au/sites/default/files/2025-09/Consultation%20paper%20-%20GRC0082%20-%20Gas%20networks%20in%20transition.pdf.

5 CEPA, *Gas networks in transition: Modelling results*, 6 March 2026.

is incurred and paid for by gas consumers in the context of uncertain and/or declining demand.

- **Planning requirements**. ECA propose new planning reporting obligations on all service providers (that own and operate scheme and non-scheme gas pipelines) to provide regulators, governments, electricity networks, and other stakeholders with information required to understand the opportunities to minimise expenditure and energy system costs.
- **Accelerated depreciation and redundancy**. JEC propose changes to the depreciation and redundant asset provisions. Their proposed changes would prohibit the use of accelerated depreciation to manage stranding risks unless in combination with the use of the capital redundancy provisions. JEC further propose to cap the customer contribution to 50 per cent, in the case of a cost sharing arrangement.

On 18 September 2025, the Commission published a consultation paper jointly consulting and seeking stakeholder feedback on the issues raised by the two rule change proponents. We also sought stakeholder feedback on whether there was a need to address several interrelated aspects of the gas pipeline economic regulatory framework. We received 26 responses to our consultation paper, with some stakeholder submissions also identifying a range of additional issues.

The Commission has decided to consolidate the ECA and JEC rule change requests.[6] We consider that the breadth and interrelated nature of the issues considered in our consultation paper and raised by stakeholders requires a holistic approach when considering changes to the NGR. The gas pipeline economic regulatory framework comprises various interrelated elements that operate as a package to promote the NGO. In developing our proposed direction for reform, we have considered the implications of our proposed changes holistically across the gas pipeline economic regulatory framework.

In January 2026, the Commission conducted a series of stakeholder roundtable discussions. We held roundtable discussions with consumer and user groups, pipeline and pipeline industry groups, retailers, and jurisdictions. We also held bilateral discussions with the Australian Energy Regulator (AER) and the Western Australian Economic Regulation Authority (ERA), and the Commonwealth Department of Climate Change, Energy, the Environment and Water.

We have also continued to engage with stakeholders individually throughout our process.

Stakeholder engagement and feedback throughout this rule change process has helped to shape our proposed direction for reform. The Commission thanks stakeholders for taking the time to provide their views and relevant evidence through their submissions and for participating in our processes to date.

Related work and reform

The Commission has recently made a final determination and rule for *Updating the regulatory framework for gas connections*.[7] Our more preferable final rule requires gas distribution service providers to charge newly connecting retail gas customers cost-reflective connection charges upfront, limiting the growth of distributors' capital bases. The final rule will commence on 1 October 2026 and applies to scheme and nominated non-scheme pipelines in jurisdictions subject to the National Energy Customer Framework (NECF) for gas.[8]

6 The Commission published a statutory notice under section 300(1)(a) and under section 317 on 18 December 2025 consolidating the rule change requests and extending the time to make a draft determination to 27 August 2026 and extending the time to make a final determination to 17 December 2026.

7 See our project page for more information https://www.aemc.gov.au/rule-changes/updating-regulatory-framework-gas-connections

8 These jurisdictions are the ACT, NSW, South Australia, and Queensland.

The Commission has also made a draft determination and rule for *Establishing a regulatory framework for retail customer initiated gas abolishment*.[9] Our more preferable draft rule would require retail gas customers that request an abolishment of their gas connection to pay the prudent and efficient cost reflective charge of their abolishment, limiting the costs to be recovered from other network users. The draft rule does not apply to safety or other regulatory mandated abolishments, which can be undertaken by the distributor with costs recovered from all gas customers.

9 See our project page for more information https://www.aemc.gov.au/rule-changes/establishing-regulatory-framework-retail-customer-initiated-gas-abolishment.

2 Gas demand is becoming increasingly uncertain

2.1 The energy transition is changing the outlook for gas and creating uncertainty

The natural gas demand outlook is changing as the transition to net zero progresses and the energy system transforms. The changing outlook is creating uncertainty about the future demand for gas, particularly in the residential and small commercial customer segment.

The Australian Energy Market Operator's (AEMO) latest Gas Statement of Opportunities (GSOO) provides some insight into the projected outlook for gas demand for residential and small commercial customers over the next 10-20 years. AEMO's forecasts reflect broad expectations for a long-term decline in residential and small commercial customer gas use:

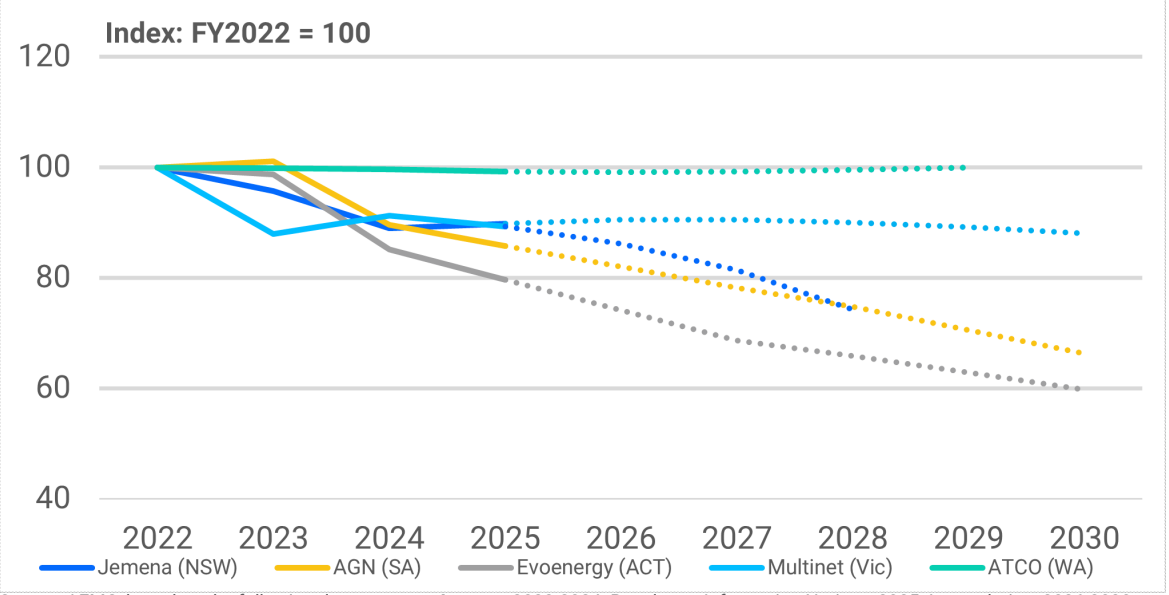
- The East Coast GSOO projects distribution connected residential and small commercial demand will fall by around 70 per cent over the next 20 years, with a 30 per cent reduction projected in the next 10 years.[10]
- The West Coast GSOO projects that distribution connected demand will fall by around 20 per cent over the next 10 years.[11]

The Commission's analysis of service providers' residential demand forecasts supports the broad expectation of a general long-term decline in demand in the residential customer segment but that there are jurisdictional variances. The figures below provides a selection of residential demand projections from a sample of scheme gas distribution networks across Australia. These have been indexed for comparability. Figure 2.1 shows that residential demand in most jurisdictions across the east coast of Australia has either started to fall, or is expected to do so in upcoming AA periods.

10 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.

11 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.

Figure 2.1: Forecast residential gas demand for selected scheme pipelines, indexed

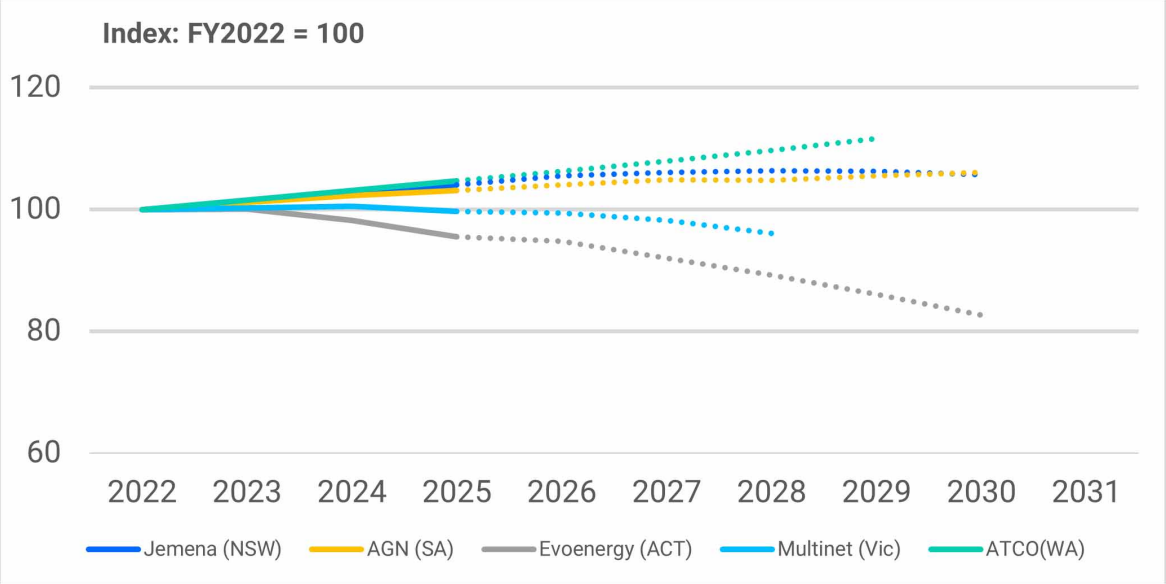


Source: AEMC, based on the following data sources: **Jemena**. 2022-2024: Regulatory Information Notices, 2025: Interpolation; 2026-2030: AER, Jemena Access Arrangement 2025-2030 Final Decision Attachment 12 Demand; **AGN (SA)**. 2022-2024: Regulatory Information Notices; 2025-2026: Interpolation; 2027-2030: AGN (SA), Final Five Year Plan 2026-2031; **Evoenergy**. 2022-2024: Regulatory Information Notices; 2025-2026: Interpolation; 2027-2030: AER, Draft decision - Evoenergy access arrangement 2026-2031, Attachment 4 - Demand; **Multinet**. 2022-2023: Regulatory Information Notice data normalised from calendar year to fiscal year; 2024-2028: AER, Multinet Access Araringement 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 higher 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).

Note: 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.

Some networks located on the east coast are also starting to experience slowing rates of new connections, as shown in Figure 2.2 below.

Figure 2.2: 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; 20025-2026: Interpolation; 2027-2030: AER, Draft decision - Evoenergy access arrangement 2026-31, Attachment 4 - Demand; **Multinet**. 2022-2024: Regulatory Information Notices; 2025-2028: AER, Multinet Access Arrangement Final Decision Attachment 12 - Demand (note forecasts only available under 2028); **ATCO**. 2022: Regulatory Information Notice; 2023: Interpolated; 2024-2029: ERA ATCO Access Arrangement Final Decision 2025-2029 (note forecasts only available until 2029).

Note: 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.

The charts above show that most service providers are forecasting lower volumes of gas and fewer new gas connections (in the residential customer segment) over the long term and that service providers face different rates and extent of declining demand. However, it also shows that some service providers are projecting short term growth in new gas connections.[12]

AEMO's and service providers' forecasts highlight the uncertainty surrounding the outlook for gas demand generally and in each jurisdiction. The Commission notes that the degree of variation between gas distribution networks is likely due to a combination of factors, including differences in jurisdictional policies, consumer preferences, and some gas distributors' efforts to transition to renewable gases. We note, however, that jurisdictional policies can have a significant influence over how consumers and service providers respond to the energy transition.

12 The Commission's recent decision to amend the NGR to require retail customers to pay cost reflective connection charges in NSW, ACT and SA, together with the equivalent decision by the Victorian Essential Services Commission, may accelerate the rate of decline in connections or halt the rate of increase in these jurisdictions. This means that service providers' projections in Figure 2.2 are likely to change given that the final rule will implemented after their forecasts were prepared. See AEMC, *Updating the regulatory framework for gas connections*, Final Rule 2025, accessible here.

2.2 Jurisdictions are on different transition pathways

Jurisdictional policies affecting residential and small commercial gas use vary substantially, ranging from explicit phase-out and electrification pathways to policies that emphasise customer choice and the continued role of gas.[13]

Only a small number of jurisdictions have adopted clear, economy-wide policy signals to transition households and small businesses away from natural gas (ACT and Victoria). In other jurisdictions, residential and small commercial gas demand is currently expected to decline primarily due to economics, technology change, consumer preferences and broader climate targets rather than explicit gas-specific policies.

Table 2.1: Overview of jurisdictional policies related to residential and small commercial gas use

Region	Mandate	Relevant Policy
ACT	Ban on new connections for residential and small commercial buildings.	Integrated Energy Plan Climate Change and Greenhouse Reduction Act (2010)
NSW	No state-wide mandate. Several local governments have introduced bans on connections for new developments and large commercial/hotel buildings.	Development Control Plans
Qld, SA, WA	No formal gas phase-out or ban on new connections.	N/A
Vic	Ban on new gas connections in new homes and most commercial buildings.	Gas Substitution Roadmap

This policy diversity is contributing to jurisdictional differences in the pace and extent of declining gas demand in the residential and small commercial customer segment. This in turn is creating challenges for the economic regulation of gas distribution networks and risks to both gas consumers and services providers, if the transition is not effectively managed. We explore these risks in further detail in chapter 3.

13 Some jurisdictions have adopted policies recognising a potential role for renewable gases, including hydrogen blends and biomethane, in gas distribution networks as part of decarbonisation pathways. For example, South Australia recognises and supports the use of renewable gases in reticulated gas supply, including hydrogen blending and biomethane, through its Hydrogen Action Plan and related renewable gas initiatives. New South Wales similarly recognises renewable fuels, including biomethane and hydrogen, as part of its broader decarbonisation framework under the NSW Renewable Fuels Strategy, which contemplates the production and use of renewable gases across multiple sectors, including gas networks, subject to safety and regulatory approvals. See South Australian Government, *South Australia's Hydrogen Action Plan* (Department for Energy and Mining, 2021) and New South Wales Government, *NSW Renewable Fuels Strategy* (Department of Climate Change, Energy, the Environment and Water, 2024).

3 Uncertain and/or declining gas demand creates a risk to an orderly energy transition

3.1 The uncertain gas demand outlook is creating risks for consumers and service providers

Gas consumers and service providers will face a shared demand-related risk dynamic through the energy transition. If this risk dynamic is not managed in a careful and coherent manner by policymakers, service providers and the regulator, then it could potentially trigger a disorderly energy transition.

The key risk for gas consumers is rising and volatile reference tariffs.[14] Falling gas demand will place upward pressure on reference tariffs, because the largely fixed costs of providing network services must be recovered over declining volumes and customer connections. This may, in turn, reduce the competitiveness of gas relative to electricity and other energy sources. For consumers able to electrify or switch to other energy sources, higher prices may bring forward their decision to exit the network. This dynamic could see further increases in prices and, potentially, further rounds of exits and price increases for those gas consumers that remain connected to the network. That is, consumers that face financial, technical or other barriers to switching.[15]

The key risk facing service providers is that they are unable to fully recover the capital that they have prudently and efficiently invested in the network, resulting in some or all of the network being at risk of stranding. The term 'stranded' or 'stranding' is used in this context to refer to unused or underutilised assets for which a service provider is unable to recover a full return of and on capital.

The risk of stranding may also affect the incentive and/or ability service providers have to continue to operate and maintain the network, invest where it is prudent and efficient to do so and provide a safe and reliable service to remaining customers. It may also affect their incentive and/or ability to transition to renewable gases where that is a viable option, or otherwise decommission the network. This could, in turn, have a range of adverse impacts on those customers that remain connected to the gas distribution network, particularly if it results in service providers ceasing operations early.[16]

The Commission has worked with CEPA to model consumer and service provider outcomes under different demand scenarios that represent a range of plausible futures for a set of illustrative networks. This modelling provides some insights into the impacts that declining demand could have on gas consumers and service providers, specifically the prices that consumers remaining on the network could face and the stranding risk to service providers.[17]

14 We note that gas reference tariffs are charged by gas pipeline service providers to pipeline users, typically retailers and large gas users that contract directly with service providers. Gas retailers may use reference tariffs as an input to the setting of their gas retail charges, which also includes the costs a retailer incurs in procuring gas and other services required to supply the retail customer. Retailers have some discretion as to how they recover distribution charges from their customers (e.g. they can employ a different tariff structure and/or level of charges to that used in a service provider's reference tariff).

15 Such as low income households and other vulnerable customers, renters, residents in some apartment buildings and industrial customers that can't easily switch to another source.

16 It could, for example, result in a far more expensive transition for those users that can switch to an alternative energy source. It could also result in some industrial customers having to cease operations if they are unable to switch. It may also result in welfare losses from reduced use of appliances that customers have invested in.

17 CEPA, *Gas networks in transition: Modelling results*, 8 March 2026.

Box 1: Modelled outcomes for average residential customer bills and capital base for an illustrative network facing a gradually declining or a rapidly declining demand outlook, over 2025-2050

Figures A.1 and A.2 show the modelled outcomes for an illustrative network under a gradual and a rapidly declining demand scenario (represented by the purple and blue lines respectively).

The two modelled outcomes in each figure show the impacts on average residential retail bills and the illustrative network's capital base of two policy options:

1. **Base case cost recovery**: solid lines. Under this option, a straight-line depreciation profile is used in combination with some shortening of economic asset lives (the proportion of which depends on demand scenario), and a real (indexed) approach is used to defer the recovery of compensation for inflation.
2. **Efficient cost recovery**: dashed lines. Under this option, depreciation is accelerated by shortening economic asset lives to match the expected use of the assets and to keep bills below the switching point. When economic asset lives cannot be shortened further without raising bills above the switching point, the value of the capital base is reduced (i.e., by applying the redundant capital provisions). This option also restricts expenditure (a cumulative two percent reduction in capex and opex per annum).

The switching point, shown by the red dashed line in Figure A.1, represents the price level at which residential consumers are likely to begin substituting away from gas to electricity. The switching point is derived using internal data from the Commission's Price Trends report and from payback rates from Institute for Energy Economics and Financial Analysis (IEEFA) analysis.[i]

Figure A.1: Modelled outcomes of average residential bills over 2025-2050 for an illustrative network facing either a gradual or rapidly declining demand outlook ($)

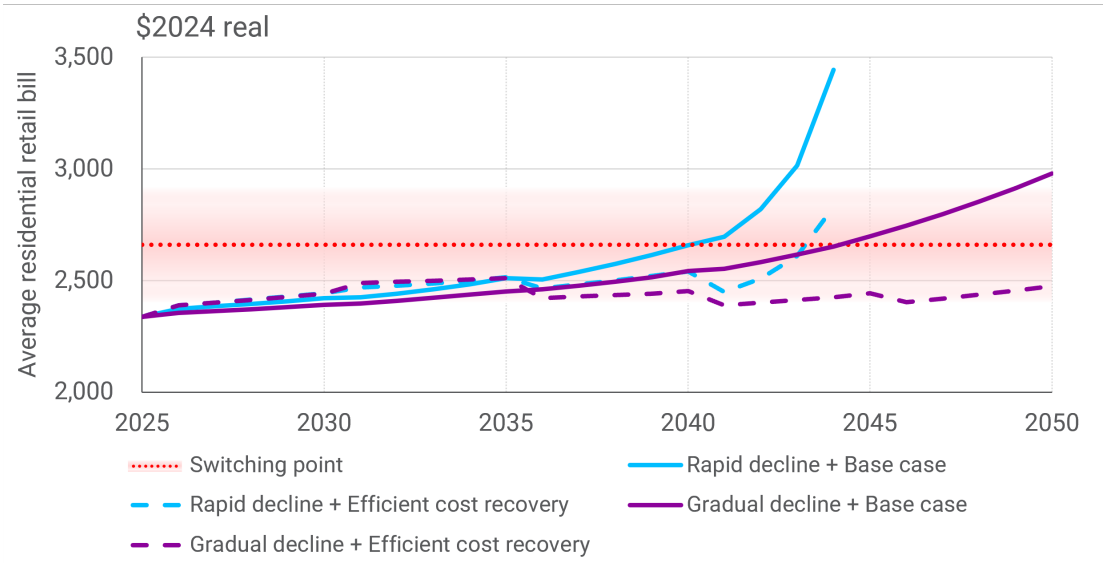
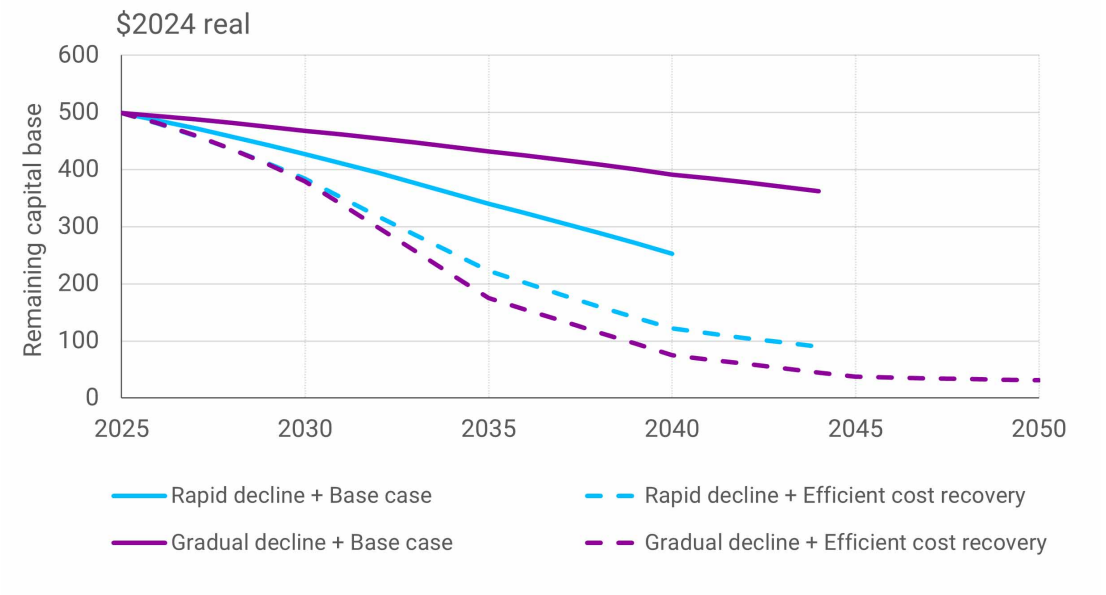


Figure A.2: Modelled outcomes of the capital base over 2025-50 for an illustrative network facing either a gradual or rapidly declining demand outlook ($m)



Figures A.1 and A.2 show the modelled outcomes for an illustrative network characterised by a low capital base-to-customer ratio. This ratio reflects how much of the capital base is left to be paid off by remaining customers. A low ratio means the network is less price-sensitive to changes in demand (i.e. because there are a greater number of customers to spread the costs across). For the purposes of this discussion, we selected the illustrative network with the lowest ratio to show the relative impacts of the base case and efficient cost recovery policy options on a relatively 'resilient' network (illustrative network 2 in the CEPA report).

Figure A.1 shows that average customer bills would hit the switching point first if economic asset lives were shortened marginally under a rapidly declining demand scenario (solid blue line), as cost recovery is spread across a shrinking consumer base. Figure A.1 shows that the point at which customer bills would hit the switching point would be deferred if economic asset lives were further shortened in combination with use of capital redundancy and expenditure restrictions (dotted blue line).

Figure A.2 shows the outcomes on the capital base when bills breach the switching point. Assuming that a disorderly customer exit is triggered when bills breach the switching point, Figure A.2 shows that under a rapidly declining scenario, there would be a residual capital base that remains unrecovered as there would be insufficient customers remaining to contribute to cost recovery. The size of the unrecovered capital base would be larger under policy option 1 (base case cost recovery) and smaller under policy option 2 (efficient cost recovery).

Source: [i] AEMC, Residential Electricity Price Trends 2025; Institute for Energy Economics and Financial Analysis, Managing the transition to all-electric homes, November 2023, p. 26.

The modelled outcomes highlight the boundaries of the regulatory framework in addressing the impacts of declining demand on both gas consumers and service providers. Although accelerating capital cost recovery in combination with capital redundancy and expenditure restrictions can defer the point at which a disorderly customer exit is triggered, the rate of demand decline remains a dominant factor. Even with efficient cost recovery, Figure A.1 shows bills under rapidly declining demand scenarios continue to trend upward toward the switching point (blue lines), whereas both gradual decline scenarios (purple lines) remain well below the switching point over the 2025-2050 reporting period.

The modelling outcomes show that efficient cost recovery (shortening economic asset lives combined with the use of redundant capital provisions and expenditure restrictions), would reduce the impacts on gas consumers and service providers. However, the regulatory framework cannot fully address the adverse impacts of declining demand on gas consumers and service providers under all demand scenarios. Consumer and network impacts are greater when demand declines more rapidly than expected, as demand-induced price escalation triggers earlier exits, bringing forward the point at which capital cost recovery is no longer possible.

While the impacts of declining demand are likely to be felt most acutely by service providers and consumers that remain connected to the network, a decline in gas demand in the gas distribution network may also adversely affect:

- connected transmission pipelines and users of those pipelines, because the decline in demand at the gas distribution network level would mean less gas has to be transported by any connected transmission pipelines, resulting in the cost of those transmission pipelines having to be recovered over a smaller volume of demand
- electricity networks and their customers in those areas served by the gas distribution network, if the investment required to absorb those gas customers that decide to electrify has not been undertaken.

3.2 The regulator and service providers face difficult challenges to manage these risks

For some time now, the AER, the 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.[18] Regulators in international jurisdictions have experienced similar challenges.[19]

The AER first considered the issue of uncertain demand 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 AA.[20] 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 option.[21]

The options identified in the AER's paper included several that are already available under the regulatory framework (e.g. accelerated depreciation, using a nominal (unindexed) approach and capital redundancy) and some options that are currently not available (e.g. revaluing the capital base).

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 the Victorian, New South Wales, ACT and South

18 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.

19 Please refer to Appendix A of our consultation paper for more information. AEMC, *Gas Networks in Transition,* Consultation paper 18 September 2025, Appendix A, accessible here.

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

21 AER, Information Paper – Regulating gas pipelines under uncertainty, November 2021.

Australian gas distribution networks.[22] The ERA has also had to consider similar issues in Western Australia, including in its recent decision on ATCO's 2025-2029 AA.[23]

In the most recent round of AA decisions, the AER has focused on trying to reduce stranding risks, while also minimising the extent of short term price increases for consumers.[24] That is, by allowing distributors to bring forward the recovery of capital by shortening economic asset lives while there are still a relatively large number of customers, but placing a 'price path' constraint[25] on what can be brought forward so that consumer prices do not materially escalate in the AA period. In recent regulatory decisions, the AER has also moved away from price caps to hybrid price-revenue caps, which provide for demand risk to be shared within an AA period between customers and service providers.

The uncertain outlook for gas demand and the future of gas distribution networks through the energy transition is posing challenges for the regulatory framework and its ability to manage the risks to both consumers and service providers. 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 service providers:

- 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, underscoring the importance of ensuring that the regulatory framework remains capable of promoting the long-term interests of gas consumers under the NGO and giving effect to the Revenue and Pricing Principles (RPPs) through the transition.

3.3 We sought stakeholder feedback on the key challenges posed by the energy transition

In response to these challenges, ECA and JEC submitted four rule change requests to address issues with specific elements of the regulatory framework in relation to declining demand for gas distribution networks.[26]

On 18 September 2025, the Commission published a consultation paper seeking feedback from stakeholders on the:

- issues raised and solutions proposed by the rule change proponents, and
- need for changes to interrelated aspects of the gas pipeline economic regulatory framework.

Stakeholder responses to the consultation paper highlighted several additional issues. Figure 1 below outlines the issues raised by ECA and JEC, the additional issues that the Commission

22 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.

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

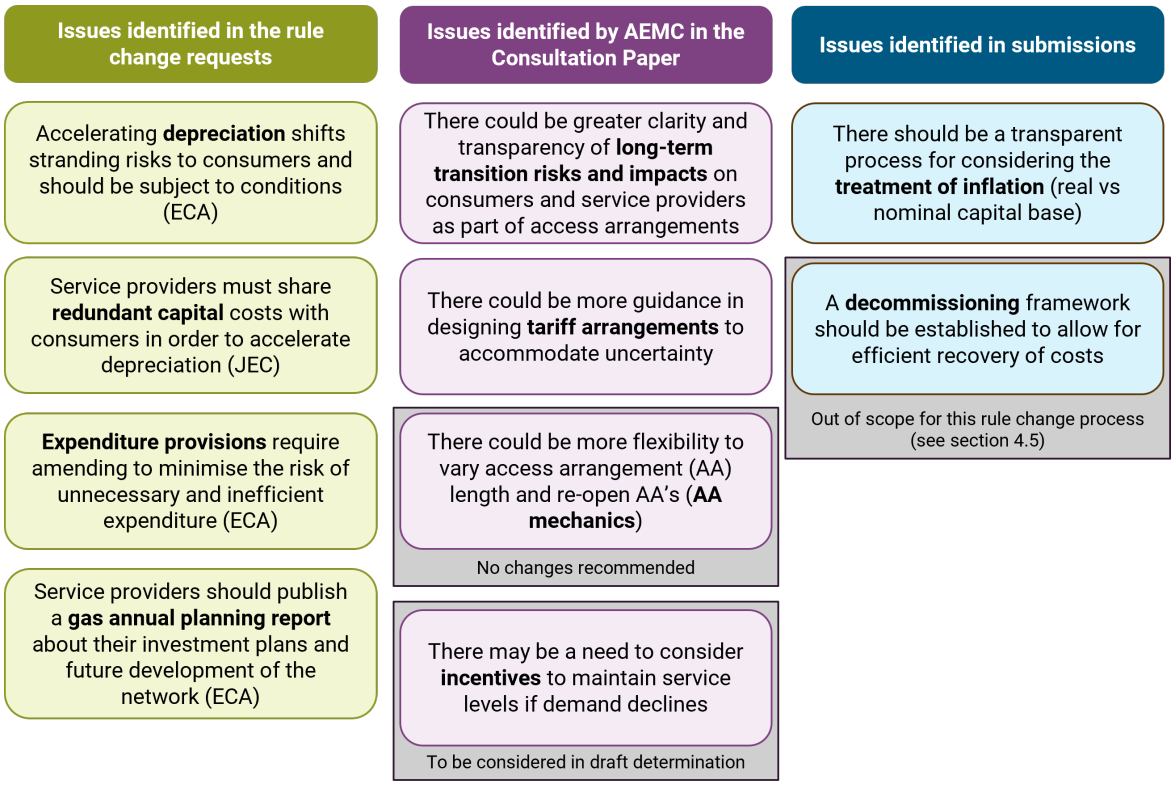
24 Table 4.1 outlines the use of capital cost recovery mechanisms in recent gas pipeline regulatory decisions.

25 It would appear, from the AER's decisions, that the price path approach involves calculating the service provider's revenue requirement based on the standard building blocks, and then it determines what additional accelerated depreciation could be allowed in the AA period subject to the cap imposed by the price path constraint being met.

26 We note that the current NGR framework regulates scheme and non-scheme pipelines and does not distinguish specifically between transmission and distribution networks. Section 4.2 outlines our proposed direction that any proposed reforms would apply to the transmission network unless there are strong reasons for it not to.

consulted on in the consultation paper, and the additional issues identified by stakeholders. Stakeholders should refer to our consultation paper and submissions for more detail.[27]

Figure 3.1: Summary of key issues



Stakeholder views on the need for NGR changes were broadly divided between service providers (represented by pipelines and pipeline industry groups) on the one hand,[28] and other stakeholders, such as consumer[29] and interest groups,[30] and retailers[31] on the other hand. Some stakeholders expressed mixed support[32] or did not provide a view on the rule change requests.[33]

Service providers generally considered the framework to be fit for purpose, and consider that changes would endanger the stability and predictability of the NGR that has underpinned investment and service provision. They opposed the ECA and JEC's proposed changes to depreciation and redundant capital provisions on the basis that it would deprive service providers of a reasonable opportunity to recover their efficient costs. Some service providers supported changes to include decommissioning costs in the regulatory framework and suggested the

27 The rule change requests, our consultation paper and stakeholder submissions can be found on our project page https://www.aemc.gov.au/rule-changes/gas-networks-transition.

28 See submissions from APA, ATCO, Australian Gas Infrastructure Group (AGIG), AusNet, Evoenergy, Jemena Gas Networks (JGN), Energy Networks Australia (ENA), and Australian Pipelines and Gas Association (APGA).

29 See submissions from ECA, JEC, Brotherhood of St Laurence (BSL), South Australian Council of Social Service (SACOSS).

30 See submissions from Institute for Energy Economics and Financial Analysis (IEEFA), Climateworks Centre, Rewiring Australia, Victorian Environment Friends Network (VEFN), Gippsland Climate Change Network (GCCN), Environment Victoria, Lighter Footprints, and Darebin Climate Action Now (DCAN).

31 See submissions from Alinta Energy, Energy Australia, and Origin Energy.

32 See submissions from Energy Users Association of Australia (EUAA) and the AER.

33 See submission from the NSW Department of Climate Change, Energy, the Environment and Water, which outlined their upcoming policy program.

removal of capital base indexation to support capital cost recovery in an uncertain demand environment.[34]

Most consumer groups, retailers, other interest groups and the AER supported changes to some elements of the NGR. Consumer groups, retailers and other interest groups considered the current rules 'unfairly' allocate stranding risks to consumers and consider changes to depreciation provisions and stricter capex criteria necessary. The Energy Users Association of Australia (EUAA) did not support changes to prohibit the use of accelerated depreciation but supported changes to remove the presumption of growth from the definition of opex.[35] The AER supported reform of the capital redundancy provisions and was open to more guidance in the rules around the use of depreciation, but did not support changes that introduced more prescription.[36] Some stakeholders emphasised the important role of jurisdictions in establishing clear jurisdictional policies to enable coordinated decisions by governments, regulators and industry[37] and addressing barriers outside the NGR, such as service obligations.[38]

3.4 The Commission considers there is a need to amend the NGR to address identified issues

The Commission has considered a range of factors in assessing the issues and developing our proposed direction for reform:

- The NGO, which any proposed changes must meet, and the RPPs, which we must take into account in making a rule for, or with respect to, regulatory economic methodologies as applied to scheme pipelines.
- The rule change requests from ECA and JEC, including the issues identified and solutions proposed by the rule change proponents.
- Submissions received in response to the consultation paper.
- The rules, extrinsic material, and how the rules have been applied in recent regulatory decisions.
- The assessment criteria identified in the consultation paper as being relevant to this rule change, which have guided our identification of the preferred options.

34 Submissions to the consultation paper: Evoenergy, p. 4; ENA, p. 21; JGN, p. 19.
35 EUAA, Submission to the consultation paper, pp. 3, 5.
36 AER, Submission to the consultation paper, p. 6.
37 Submissions to the consultation paper: ECA, p. 4; Climateworks, p. 1; VEFN, p. 4; SACOSS, p. 5.
38 AER, Submission to the consultation paper, p. 3.

4 Changes to the regulatory framework are necessary to ensure it continues to promote the long-term interests of consumers

4.1 The economic regulatory framework has delivered strong outcomes for gas consumers under stable and growing demand conditions

The gas pipeline economic regulatory framework has delivered benefits for residential and small commercial gas consumers who have enjoyed low and stable gas distribution network charges (relative to electricity). Through regulator-approved AAs, allowed revenues and the resultant reference tariffs have been set on the basis of the prudent and efficient cost of providing safe and reliable reference services and complying with regulatory obligations.

The AER's performance reporting for gas networks provides insights into the outcomes for consumers and service providers to date. In its 2023 *Gas network performance report*, the AER found that the regulatory regime has improved outcomes for consumers over time.[39] The AER reported that consumers paid, on average, less for scheme pipeline reference services in 2022 than in any other year since 2011,[40] with network revenue per customer for scheme distribution pipelines declining materially over time, falling from a peak of $455 per customer in 2015 to $328 per customer in 2022.[41] At the same time, outages reached record lows whilst scheme pipelines remained profitable.[42] These outcomes occurred over a period in which demand was relatively stable, with the AER reporting an average annual growth rate of 0.9 per cent from 2011-2022 in total gas delivered to residential customers and 0.1 per cent for commercial customers.[43] While the economic regulatory framework contributed to these outcomes, the AER noted that consumers also benefitted from an external environment comprising low interest rates and inflation.[44]

This dynamic has started to shift. In 2025, the AER reported that gas delivered by scheme gas distribution pipelines in 2024 was 10 per cent lower than in 2022, and 2024 revenue recovered and revenue per customer the second lowest in its operational performance dataset.[45]

The AER partially attributed the decline in demand to milder temperatures but identified structural factors, including jurisdictional policy-driven electrification and improved gas appliance efficiency, as more significant and enduring drivers. Looking ahead, the AER expects ongoing uncertainty and decline in demand to be the main upward pressure on network charges.[46]

39 AER, Gas network performance report 2023, December 2023, p. 1.

40 AER, Gas network performance report 2023, December 2023, p. 1.

41 AER, Gas network performance report 2023, December 2023, p.12.

42 AER, Gas network performance report 2023, December 2023, p. 1.

43 AER, Gas network performance report 2023, December 2023, p. 37. We note that gas delivered to industrial customers declined by 2.5 per cent on average over 2011-2022.

44 AER, Gas network performance report 2023, December 2023, p. 1.

45 AER, Electricity and gas networks performance report 2025, December 2025, pp 6, 8. The AER notes that while 2023 was the lowest year, reporting for the 2023 year was also affected due to the AER having to annualise reporting for the Victorian service providers to account for a 6-month transitional period.

46 AER,Electricity and gas networks performance report 2025, December 2025, p. 54.

4.2 Our proposed direction seeks to strengthen the framework to meet the challenges of uncertain and/or declining demand through the energy transition

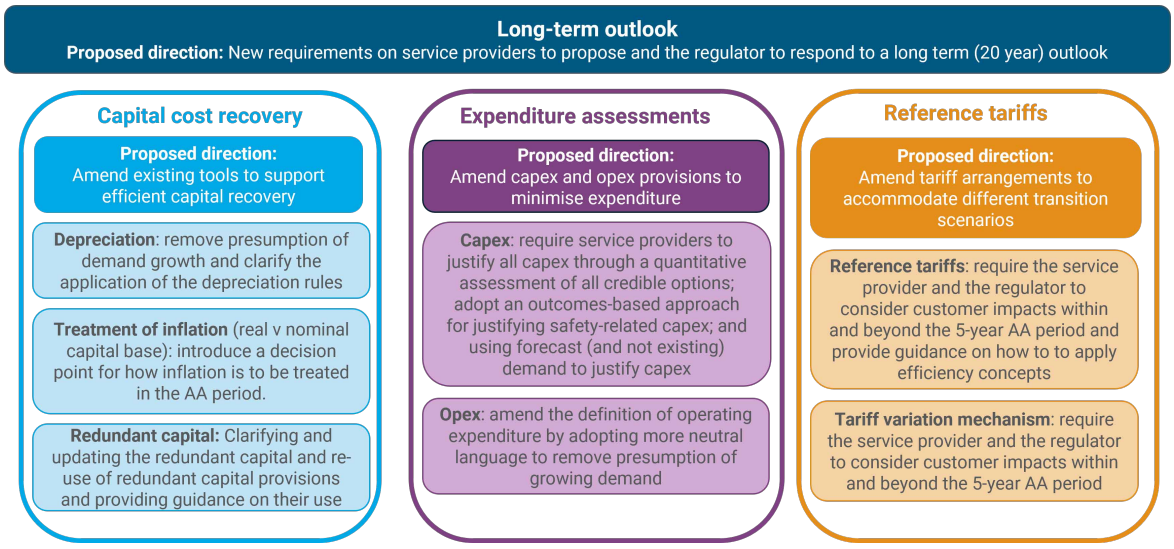
The gas pipeline economic regulatory framework has supported strong outcomes for gas consumers and service providers in an environment of stable and/or growing demand. Many provisions in the NGR were established based on expectations of stable or growing demand and encouraging demand growth. This has supported strong outcomes for consumers under stable and growing demand conditions by allowing, for example, revenue recovery to be deferred to share costs with future customers. However, in the context of uncertain and/or declining demand, the framework may no longer be fit for purpose. The ECA and JEC rule change requests, stakeholder feedback, recent regulatory decisions and the CEPA modelling highlight opportunities to strengthen the regulatory framework to meet the challenges posed by the energy transition and ensure it continues to promote the long term interests of gas consumers.

Long-lived regulated assets, combined with uncertain and declining utilisation and varying jurisdictional policy signals, create transition risk that is exposing some gaps in the ability of the current framework to continue to promote the long-term interests of gas consumers through the energy transition. Ensuring that the regulatory framework can manage this transition risk and support an orderly transition is key to addressing the challenges confronting gas consumers and service providers in this context, primarily price and service risk for consumers and stranding risk for service providers. However, the modelling outcomes highlighted in Box 1 suggest that these risks cannot be completely addressed through the economic regulatory framework, and that there will be a role for governments to support gas consumers and service providers through the energy transition.

The gas pipeline regulatory framework has always contemplated the potential for competition from alternative energy sources. Changing technology and opportunities that exist for gas consumers to reduce and offset their bills by their own electricity generation and storage assets has resulted in a reduction in the competitiveness of gas as a fuel source compared to electricity, potentially more rapidly than may have been contemplated. This is increasing service provider's exposure to demand risk and altering the economics of service provision.

Figure 4.1 summarises the Commission's proposed direction on the aspects of the economic regulatory framework that we have determined would benefit from change to promote long-term consumer outcomes.

Figure 4.1: Summary of proposed reform package



Our proposed direction focuses on four key reform areas to strengthen the regulatory framework in the NGR to mitigate the transition risks for both consumers and service providers:

- **Increase transparency and accountability of how longer-term energy transition risks and impacts to consumers and service providers are considered in the AA period and beyond.** While service providers and the regulator are already incorporating longer-term analysis of energy transition risks and impacts in some aspects of their AA proposals and decisions, the Commission considers that the current analysis could be strengthened to require service providers and the regulator to demonstrate how they have taken a longer term and more holistic view on how the demand related risks for gas consumers and service providers should be managed across the entirety of the AA (including capital cost recovery, expenditure and reference tariffs). The service provider and regulator should also be required to assess and report on the longer-term consequences of their AA proposals and regulatory decisions for gas consumers and service providers alike.
- **Amend and guide the use of capital cost recovery tools (i.e. depreciation, compensation for inflation, redundant capital and re-use of redundant capital provisions) to support efficient capital cost recovery that promotes the long-term interests of gas consumers.** The Commission considers that earlier use of the depreciation and compensation for inflation tools when stranding risks are identified can assist with managing longer-term price and service impacts for gas consumers and minimising stranding risks for service providers. We have also identified barriers that could be limiting the efficient use of the redundant capital and re-use of redundant capital provisions when stranding risks cannot be averted. More efficient use of the redundant capital provisions would mitigate the risk that gas consumers face inefficient prices that are in excess of what would prevail in a workably competitive market,[47] when stranding cannot be averted (i.e., the use of the redundant capital provisions recognises

47 At a high level, the term 'workably competitive market' is used to refer to a market where suppliers are constrained by their rivals from exercising market power over time and consumers can readily switch between alternative suppliers. In such a market, if gas prices started to exceed the price of electricity or other energy sources (i.e. the switching point), then gas consumers would switch to suppliers of the alternative energy sources. Gas distribution service providers would therefore need to respond by reducing their prices to ensure that, on a delivered basis, gas can continue to compete with these other energy sources. We discuss this further in Appendix 2 Box 3.

that stranding has occurred and that service providers are unable to recover a full return of and on capital).

- **Amend the capex provisions and opex definition to improve regulatory clarity and transparency and support the long-term interests of consumers under uncertain demand.** The Commission considers that the analysis required to support capex proposals can be strengthened through better guidance to service providers and the regulator on applying the conforming capex test. We have also identified several areas where the capex criteria could be tightened to minimise expenditure while continuing to support safe and reliable services. We also propose amendments to remove references to demand growth in the capex provisions and opex definition.
- **Amend the reference tariff provisions to help service providers and the regulator design reference tariffs and tariff variation mechanisms that promote the long-term interests of consumers in the context of demand uncertainty.** The design of reference tariffs and tariff variation mechanisms are supported by sound economic concepts (e.g. long-run marginal cost, standalone and avoidable cost) that have been interpreted and applied in a different context (i.e. one of stable or growing demand). While economic efficiency remains the primary consideration, there are increasing challenges in applying these concepts in the context of uncertain and potentially declining demand. We have also identified broader customer-related impacts that the regulator and service providers could consider in designing tariff arrangements to ensure they are more suited to the specific circumstances of an AA over the transition period.

The Commission's proposed direction would apply to scheme transmission and distribution pipelines. While our proposed direction is aimed at addressing issues facing scheme gas distribution pipelines, we consider that uncertain demand could also have implications for scheme gas transmission pipelines in the future. Therefore, we are not proposing to change the current approach in the NGR where, with some limited exceptions (e.g. distribution specific tariff provisions), scheme transmission and distribution pipelines are subject to the same regulatory framework. The Commission is interested in stakeholder views on the application of our proposed direction.

Our current statutory timeframe for publishing a final rule and final determination is no later than 17 December 2026. This would allow for the rule change package to be in place for the next round of gas distribution AA reviews. We note that the AA process for Victorian service providers will commence on 1 June 2026, which is when service providers have to submit reference service proposals to the AER, while AA proposals are due to the AER on 1 June 2027. The Commission will engage further with the Victorian service providers and the AER on our implementation timeframes, and is interested in stakeholder feedback on the scope for any changes to the NGR economic regulatory framework applying to the upcoming round of AA reviews.

4.3 We will consider the need for additional or modified incentives after considering stakeholder submissions on our package of proposed NGR amendments

As the energy transition progresses, explicit and implicit incentives in the gas economic regulatory framework will continue to play an important role for service providers and consumers in supporting the efficient, safe and reliable provision of pipeline services. It is therefore important that these tools are fit for purpose and can be used as and when required to promote the long-term interests of gas consumers.

The Commission has not yet considered whether any new or modified incentives are required. Instead, this directions paper focuses on proposing a package of reforms to the capital cost recovery, expenditure and reference tariff provisions and requiring service providers and the regulator to be more transparent in how they have considered the longer-term outlook and the longer-term consequences for service providers and gas consumers.[48]

We will consider stakeholder submissions on our proposed package of reform, as set out in this directions paper. For the draft determination, we will assess whether there is a need to also make any changes to the incentive regimes to promote the NGO and give effect to the RPPs. This will ensure that any proposed changes to explicit and implicit incentives complement the package of other proposed changes to the regulatory framework.

Neither ECA nor JEC proposed any changes to NGR provisions for incentive mechanisms in their rule change requests.

4.4 We do not consider that there is a need to amend AA mechanics

In our consultation paper, the Commission considered whether providing the regulator with additional tools would better support the regulator in managing uncertainty, such as greater flexibility to determine AA period lengths and providing the regulator with the ability to propose AA variations. We also considered whether constraining service providers' ability to propose variations to their AA, or granting the regulator discretion to conduct narrowly-scoped reviews in response to service providers' variation proposals would assist in managing uncertainty during the energy transition.

Based on stakeholder feedback to our consultation paper and our own analysis, the Commission is of the view that the existing arrangements continue to be fit for purpose. The regulator and service providers already manage uncertainty through established variation and information-gathering powers. Introducing broader discretion over AA lengths or re-opener provisions would add complexity and uncertainty without clear benefits for consumers and service providers.

For these reasons, we consider that maintaining the current AA period and re-opener settings best supports stable, predictable and efficient regulation at this stage of the energy transition.

4.5 We do not propose to consider the establishment of a decommissioning framework as part of this rule change process

The Commission received feedback from several stakeholders in response to our consultation paper, highlighting the need for an NGR decommissioning framework.[49] Stakeholders were responding to the ECA's proposal to require gas distribution service providers to publish a Gas Annual Planning Report to improve the information available to stakeholders to identify opportunities to strategically decommission networks and plan for this accordingly.

The Commission considers that clear regulatory guidance on decommissioning would support an orderly energy transition and that there is currently a gap in the regulatory framework. We have undertaken an initial assessment of the matters to be considered and note that decommissioning a gas network is a multi-faceted project with several distinct phases and a range of inter-related

48 See appendix A - Our proposed approach to require service providers and the regulator to consider a long-term outlook.

49 Some stakeholder submissions noted that jurisdictional governments should be responsible for determining if and when decommissioning is required (Jemena, Evoenergy, AGIG, ENA, AusNet, and the AER), and that decommissioning should be supported by safety regulations, consumer protection and economic transition mechanisms (AusNet). Other stakeholders noted that a proactive approach to decommissioning is required and governments and market bodies should develop a framework to decide which areas to strategically decommission (Brotherhood of St Laurence, Climateworks). One stakeholder noted that national decommissioning guidelines should be developed covering safety standards, site remediation expectations and repurposing (Gippsland Climate Change Network).

activities that need to be supported by national and jurisdictional action. There is a range of issues that need to be considered, with some of these issues potentially affecting the NGR and others requiring resolution outside of the NGR. Our own analysis and stakeholder feedback points to some fundamental questions to be resolved, including (but not limited to):

- What does decommissioning entail, how material are the costs likely to be and how should the costs be recovered? If future unknown costs are allowed to be recovered now, would the subsequent increase in prices incentivise customers to leave the network and how would the funds be managed (e.g. what would prevent a service provider from spending those funds for other purposes)?
- How should the incentives on service providers be balanced to ensure that they continue to provide safe and reliable services if there has been a decision to decommission the network?
- What amendments to the National Energy Retail Rules (NERR) might be required to ensure customers are protected if a service provider decides to decommission its network? This may involve, for example, amendments to the retailer-distributor notification requirements and providing support for customers to access alternative services.
- Jurisdictions will also need to consider their own regulatory barriers to decommissioning, which would include service obligations on distributors (e.g. to connect customers and provide services) and safety and technical related matters.

We consider that the establishment of a decommissioning framework would require a comprehensive identification and holistic assessment of the issues involved in decommissioning a network or parts of a network and involve wide stakeholder consultation with jurisdictions, the regulator, stakeholders, service providers and consumers.

Due to the breadth and complexity of the issues that would need to be considered, we do not propose to establish a NGR decommissioning framework as part of this rule change process. This rule change package focuses on whether the NGR gas pipeline economic regulatory framework continues to promote the long-term interests of gas consumers through the energy transition.

Nevertheless, we note the importance of ensuring that the legislative and regulatory frameworks (at the national and jurisdictional level) support decommissioning where this is efficient. The Commission will continue to engage with jurisdictions and service providers on the most appropriate approach to establishing a decommissioning framework.

4.6 There will be a role for government to support gas consumers and service providers through the energy transition

The Commission considers that addressing the opportunities we have identified to strengthen the economic regulatory framework for gas pipelines would ensure that the NGR continues to promote the long-term interests of gas consumers throughout the energy transition and give effect to the RPPs.

Our proposed amendments would help to manage the emerging risks to gas consumers and service providers in an environment of uncertain gas demand. Nevertheless, the NGR economic regulatory framework cannot fully resolve the impacts to gas consumers and service providers. The Commission's modelling work, undertaken with CEPA, exposes the boundaries of the regulatory framework in addressing consumer price and stranding risk impacts – even with the changes we are proposing.

There will therefore be a role for governments in helping to support an orderly transition. This could, for example, include governments providing more clarity around the future of gas and gas distribution networks in their respective jurisdictions. There may also be a role for governments in:

- reducing the scale of the capital cost recovery problem by removing obligations to connect customers and to continue to service customers (which would support commercial decisions to strategically decommission parts of gas distribution networks)
- addressing affordability concerns by providing more financial support to vulnerable customers
- supporting harder to abate and vulnerable customers to transition to alternative energy sources, where that is consistent with jurisdictional policy
- helping to plan for any gas distribution network decommissioning (supported by cost-benefit analysis), where that is consistent with jurisdictional policy
- in the case of South Australia and Victoria, their respective governments considering the appropriateness of retaining the designation classification for the AGN SA, AGN Victoria, Multinet and AusNet networks (which prevents changes to the form of regulation applied to these networks).

In addition, the Energy and Climate Change Ministerial Council (ECMC) may consider changes to the National Gas Law (NGL) to allow service providers to charge a reference tariff for services not provided by means of a pipeline (e.g. LGP tanks) or consider electrification options. This would be a matter outside of the AEMC rule change process, as explained further in appendix C.2.1.

If governments want service providers to continue to operate once stranding starts to occur, they may also need to consider providing financial support to ensure they can continue to provide safe and reliable services.

5 Our proposed direction: A balanced reform package to manage uncertainty

The Commission's proposed direction for reform recognises the continued importance of economic efficiency within the gas pipeline economic regulatory framework as the primary mechanism for promoting the long-term interests of gas consumers.[50] The proposed direction also gives effect to the RPPs.[51]

Our proposed reform package responds directly to the following risks of a disorderly and unmanaged energy transition:

- **gas consumers facing prices in excess of the switching cost** (i.e. prices in excess of what would prevail in a workably competitive market - see Box 3 in appendix B.3.3), which would lead those that can switch to electricity or other alternatives to bring forward their decisions to exit the gas network and result in higher prices for remaining customers that face barriers to switching
- **gas distribution service providers experiencing increased stranding risks**, which could lead them to withdraw and/or cease the provision of pipeline services earlier than expected, leaving customers without access to gas and potentially requiring government intervention and support.

The Commission is proposing a package of targeted reforms to help mitigate these risks. At the core of our package are proposed changes to the capital cost recovery tools that would support efficient capital recovery that promotes the long-term interests of consumers. Our intent is to minimise the risk that gas consumers face prices in excess of what would prevail in a workably competitive market, while preserving service providers' incentives to continue to prudently and efficiently operate their networks, invest where necessary and continue to provide safe and reliable services.

We have also identified opportunities to strengthen other key areas of the economic regulatory framework that would better promote the long-term interests of consumers. We consider that there could be more transparency and accountability in how decisions made in the AA period impact on gas consumers and service providers in the longer-term. Our reform package also includes proposed changes to minimise capital and operating expenditure in the context of an increasingly uncertain, and potentially declining, demand outlook. Finally, we consider that additional guidance to the service provider and the regulator could help them design reference tariffs and tariff variation mechanisms that better promote the long-term interests of gas consumers under a broader range of demand scenarios.

We consider our proposed direction to be a balanced package that maintains the risk and reward equilibrium as the framework operates into an uncertain future. We consider that our proposed direction would strengthen the existing economic regulatory framework and provide more flexibility to accommodate future uncertainty, ensuring that the regulatory arrangements continue to promote the long-term interests of consumers through the energy transition.

50 Under section 72 of the NGL, the Commission must have regard to the NGO in performing or exercising any function or power. Under section 291 of the NGL, the Commission may only make a rule if we are satisfied that it will, or is likely to, contribute to the achievement of the NGO.

51 In addition to the NGO, under section 293 of the NGL, the Commission must take into account the RPPs in making a rule for or with respect to regulatory economic methodologies as applied to scheme pipelines.

We note the concerns raised by the proponents and a number of stakeholders that bringing forward capital cost recovery would lead to higher prices in the short term, potentially creating affordability issues for customers at a time when they are also facing cost of living pressures.

However, it is important to recognise that depreciation is the means by which service providers are repaid the efficient capital that they have invested in an asset. Contrary to what the proponents and some stakeholders suggested, the Commission does not accept the view that the acceleration of this repayment involves a transfer of costs and risks to consumers. This is because, absent any decline in demand, consumers would have paid the same capital costs in net present value terms; acceleration changes only the timing of the recovery, not the total.

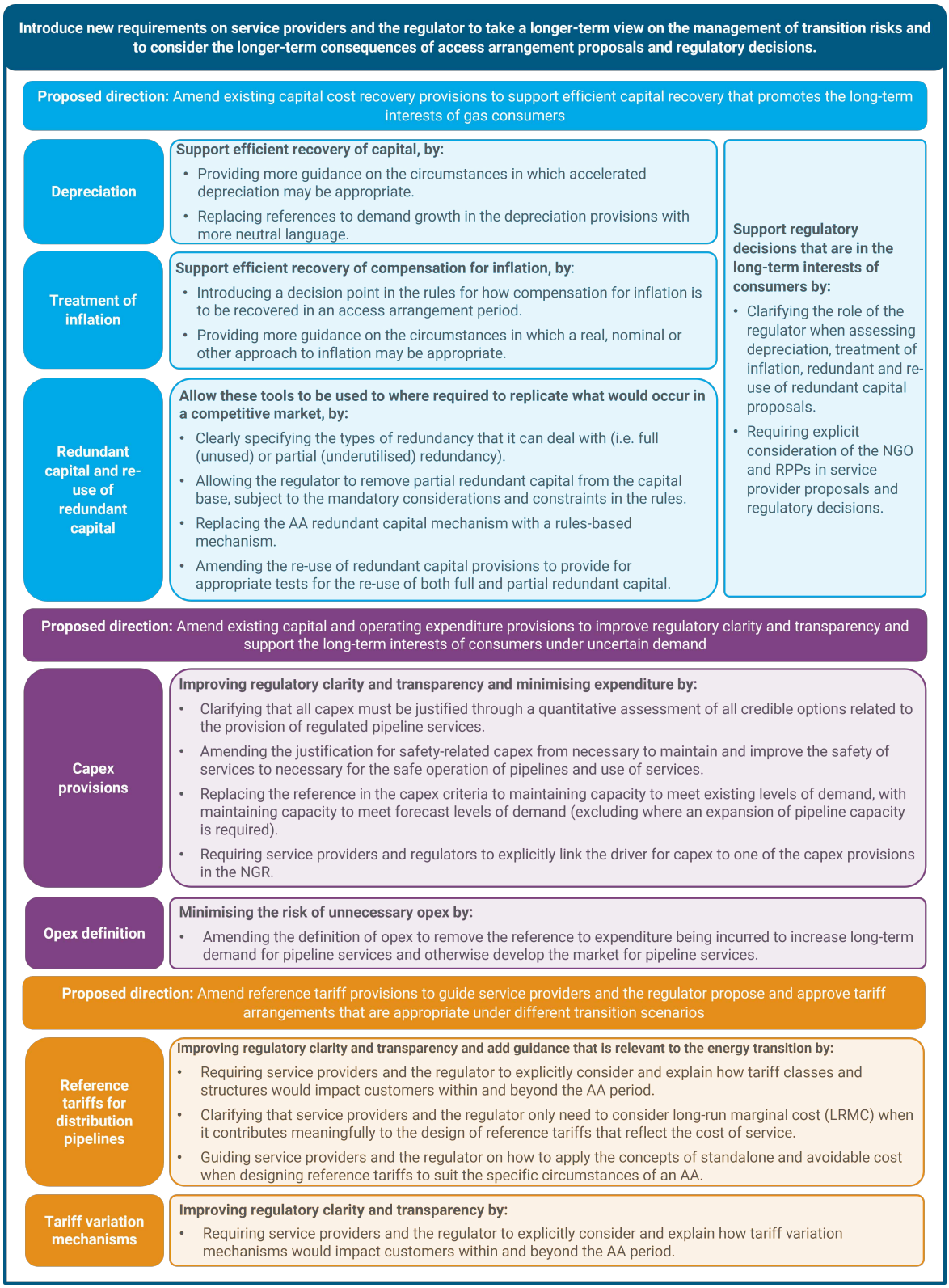
When demand is falling, continuing with a straight-line approach would defer an increasing share of cost recovery into future years when there are fewer gas consumers remaining to use the service. This creates a growing mismatch between who benefits from use of the asset, and who is required to pay for it. Allowing service providers to recover a greater portion of their capital earlier in an environment of declining demand ensures that capital cost recovery is better aligned with the expected use of the pipeline. This would result in more efficient reference tariffs for consumers, promote intergenerational equity and maintain incentives for efficient investment, without altering the total amount consumers pay in net present value terms.

That is not to say that consumers bear all the risk associated with the capital that a service provider has invested. Rather, the risk ultimately sits with the service provider, because if demand falls faster than expected or there are other technological or market developments that constrain what a service provider can charge, then they may be unable to recover all the capital they have invested. Put simply, accelerated depreciation does not immunise service providers from the risk of stranding; rather it ensures that cost recovery better aligns with the period in which demand exists.

The Commission acknowledges that our proposed changes to the capital cost recovery tools would mean that today's gas consumers face higher prices. We must, however, have regard to the long-term interests of gas consumers when considering changes to the NGR. As we outlined above, we do not consider that these interests would be promoted if there was a disorderly energy transition. We also do not consider that the long-term interests of consumers would be promoted if gas consumers remaining on the network face inefficient and sharply escalating prices. Many consumers that remain on the network into the future are likely to face barriers to switching, either financial (e.g. vulnerable customers) or technical (e.g. apartment dwellers and renters, and some industrial and large commercial customers). Timely use of regulatory tools would miminise price impacts for current customers by spreading costs across a larger number of customers.

Figure 5.1 below outlines our proposed direction for reform.

Figure 5.1: The Commission's proposed direction for reforms



5.1 Our proposed direction for reform would better promote the NGO than alternative options and is consistent with the RPPs

Our proposed direction for reform would better promote the long-term interests of gas consumers in the context of demand uncertainty, and is consistent with the RPPs.

Together, our proposed reform package would improve outcomes for consumers, maintain the safety, security and reliability of gas services, and promote principles of market efficiency and good regulatory practice.

We have adopted a targeted approach that is aligned with the current stage of the energy transition to minimise implementation cost and complexity while preserving consumer trust and confidence in the regulatory framework's ability to continue to promote the long-term interests of gas consumers.

Improving transparency and accountability in decision-making under uncertainty by employing a longer-term outlook

The Commission proposes to require:

- service providers to develop a 20-year outlook for their networks and to submit this to the regulator as part of their AA proposal and the regulator to consider a 20-year outlook when making its regulatory decisions
- service providers and the regulator to assess and report on the longer-term consequences of their AA proposals and regulatory decisions for both:
  - consumers, in terms of prices, service availability and the safety, security and reliability of service over the short, medium and longer term, and
  - service providers, in terms of capital cost recovery, as well as their incentives to continue to operate and maintain their pipelines through the transition, or to repurpose their pipelines.

We consider that this new obligation on service providers and the regulator would help surface transition risks earlier when a broader set of options remains available and support transparency and accountability in how decisions to trade off the different options to address transition risks have been made. This would allow for more effective stakeholder engagement by providing more insight and visibility over how present-day decisions are expected to impact on, for example, future prices and service outcomes.

We acknowledge that our proposed change may increase the regulatory burden on service providers and the regulator. However, we note that service providers and the regulator are already incorporating long-term analysis into their AA proposals and decisions. As such, we do not consider that our proposed change would materially increase the regulatory burden on service providers and the regulator as it simply formalises and builds on current practice.

Supporting efficient capital recovery that promotes the long-term interests of consumers

The Commission proposes to amend and provide more guidance on the use of capital cost recovery tools to improve outcomes for consumers, maintain the safety, security and reliability of gas services and promote principles of market efficiency.

Our proposed changes recognise that service providers facing declining and/or uncertain demand are best placed and incentivised to manage the associated risks appropriately but preserves and clarifies the oversight role of the regulator in ensuring outcomes that promote the long-term interests of gas consumers.

Broadly, we envisage the capital cost recovery tools working together as a complementary package by allowing for the following where service providers are facing uncertain and/or declining demand:

- Service providers, subject to regulatory oversight, would be able to recover a greater portion of depreciation earlier and cease the deferral of compensation for inflation where this is consistent with the NGO and RPPs. This would ensure that service providers facing stranding risk are provided with a reasonable opportunity to recover at least their efficient costs.
- Service providers and the regulator would be able to use the redundant capital provisions to remove full or partially redundant capital from the capital base when stranding cannot be averted. The regulator's use of this tool would be subject to specified conditions. Our intent is to replicate what would otherwise occur in a workably competitive market, where firms face the risk of stranding due to competition, technological and policy changes.
- If it subsequently becomes clear that the redundant capital can – at least to some extent – be recovered, then service providers and the regulator would be able to consider adding this capital back into the capital base so it can be recovered from users.

The Commission considers that our proposed direction is necessary to give service providers confidence that they would have a reasonable opportunity to recover at least their efficient costs, because the absence of this could have a range of adverse effects on gas consumers. It could, for instance, result in service providers deciding to cease their operations early, or otherwise affect their incentive and/or ability to maintain the network, invest where it is prudent and efficient to do so, and provide safe and reliable services to gas consumers for as long as that is required. It may also affect their incentive and/or ability to transition to renewable gases, where that is a viable option.

Minimising expenditure while supporting safety and reliability

The Commission proposes to amend the capex provisions to require clearer justification of expenditure proposals, including quantitative assessment of credible options. This would improve outcomes for gas consumers by increasing transparency and place greater accountability and discipline on service providers to identify and pursue efficient and least-cost solutions to meet an investment need. Greater transparency would also improve stakeholders' abilities to engage with and provide feedback on AA proposals.

Our proposed changes would minimise expenditure while supporting the safe and reliable provision of pipeline services. We propose to adopt a more outcomes focused approach to justifying safety related capex and refocusing the justification for capex to meet forecast demand (rather than maintaining existing levels of demand). We also propose changes to the opex definition to remove the presumption of growth to strengthen the focus on prudent and efficient opex.

The Commission considers that this element of the proposed direction is necessary to minimise capex and opex in the context of an increasingly uncertain, and potentially declining, demand outlook. Our proposed direction incorporates elements of ECA's rule change proposal and would strengthen existing incentives on service providers facing increasing uncertainty to incur expenditure efficiently to avoid stranding risks. Our proposed changes would promote principles of good regulatory practice by improving transparency in how service providers justify expenditure and how expenditure is assessed by the regulator, improving consumers and other stakeholders' confidence that the regulatory framework is promoting efficient outcomes.

Guiding the design of efficient tariff arrangements for different demand scenarios

The Commission proposes to amend the distribution reference tariff provisions to provide service providers and the regulator with guidance on how to propose and approve tariff classes, structures and variation mechanisms (tariff arrangements) that promote the long-term interests of consumers given the changing conditions facing gas distribution networks.

Our proposed direction recognises that concepts of economic efficiency should remain the primary considerations for service providers and regulators when proposing and approving tariff arrangements. However, our proposal also recognises that these concepts can be applied differently depending on the circumstances facing the service provider – for example forecast demand or the jurisdictional policy environment.

Our main proposed change is to require that the service provider and the regulator consider and explain how reference tariff arrangements may impact customers within and beyond the AA period.[52] Our intent is to ensure that service providers and the regulator focus more explicitly on the impact that reference tariff arrangements may have on customers, while also ensuring that tariff arrangements continue to be economically efficient.

We are also proposing to guide service providers and the regulator on how they should apply the concepts of long-run marginal cost, standalone costs and avoidable costs, to suit the specific circumstances of an AA.

We consider that our proposed direction would improve outcomes for consumers by focusing service providers and the regulator on the impact reference tariff arrangements may have on customers over the long term (i.e. within and beyond the AA period). Requiring service providers and the regulator to explain their proposals and decisions with reference to these potential impacts on customers would also promote good regulatory practice and principles of market efficiency by improving transparency around tariff decisions. The proposed direction would also support reference tariff arrangements to be set in a way that is internally consistent with other components of the AA.

Question 1: Our proposed package of reforms

1. What are stakeholder views on our assessment of the proposed direction and how it better promotes the NGO and is consistent with the RPP, in comparison to the status quo and the ECA and JEC rule change proposals?

Question 2: Implementation considerations

1. Do stakeholders consider that there are any barriers to implementing our proposed package of reforms considering the planned publication of the final determination in December 2026? Do you consider some form of transitional arrangements are required for any element?
2. Do stakeholders consider there are any significant implementation costs associated with our proposed package of reforms that the Commission should consider?

52 We note that gas reference tariffs are charged by gas pipeline service providers to pipeline users, typically retailers and large gas users that contract directly with service providers. Gas retailers may use reference tariffs as an input to the setting of their gas retail charges, which also includes the costs a retailer incurs in procuring gas and other services required to supply the retail customer. Retailers have some discretion as to how they recover distribution charges from their customers (e.g. they can employ a different tariff structure and/or level of charges to that used in a service provider's reference tariff).

Question 3: Application to transmission and distribution

1. What are your views on our proposed direction that reforms should apply to distribution and transmission pipelines (where relevant)?

A Our proposed approach to require service providers and the regulator to apply a longer-term outlook

A.1 Requiring service providers and the regulator to apply a longer-term outlook would promote the long-term interests of gas consumers

As the energy transition progresses, service providers and regulators are expected to face increasing challenges managing the longer-term risks and impacts associated with uncertain and/or declining demand. It is important therefore that service providers and regulators:

- consider the longer-term outlook when developing access arrangement (AA) proposals and making regulatory decisions
- assess and report on the longer-term consequences of AA proposals and regulatory decisions.

This is not currently required by the NGR. While we understand that service providers and regulators have considered a longer-term outlook when making decisions about capital cost recovery, the same approach has not been applied to other aspects of an AA, such as expenditure forecasts and reference tariff arrangements. This is a limitation in the current arrangements that could result in inefficient decisions being made that could have long-lasting consequences for both consumers and service providers (see appendix A.2).

To address this limitation in the current arrangements, our proposed direction (see appendix A.3) requires:

- Service providers and the regulator to consider the long-term outlook when developing AA proposals and making regulatory decisions. To facilitate this, the service provider would be required to develop a 20-year outlook for their distribution network or transmission pipeline and to submit it with the AA proposal. The outlook would indicatively include the service provider's:
  - forecasts for demand, revenue building blocks and reference tariffs over the outlook period
  - longer-term asset management plan, covering future investment, repurposing and/or decommissioning plans over the outlook period, and
  - assessment of the risks or uncertainties facing customers and the service provider and how it proposes to manage those risks over the outlook period.
- Service providers and the regulator to assess and report on the longer-term consequences of their AA proposals and regulatory decisions for both:
  - consumers in terms of the prices they are likely to have to pay, as well as service availability and the safety, security and reliability of services over the outlook period
  - service providers in terms of capital cost recovery (including the value of any stranded capital) and their ability and/or incentive to efficiently provide pipeline services and to efficiently operate and invest over the outlook period.

Together these elements of our proposed direction would promote the NGO (see appendix A.4) by:

- Supporting more informed and efficient decisions by service providers and the regulator about future expenditure, capital cost recovery and reference tariff arrangements, which should promote more efficient investment in, and operation and use of the network or pipeline.
- Providing for greater transparency of service providers' longer-term outlook and regulatory decision-making, which should help consumers and other stakeholders (including

jurisdictional governments and safety regulators), to engage more effectively in AA processes and make more informed and efficient decisions about the future use and operation of the network or pipeline.

We consider that this new obligation on service providers and the regulator would help surface transition risks earlier when a broader set of options remains available and support transparency and accountability in how decisions to trade-off the different options to address transition risks have been made. Our intent is for service providers and the regulator to provide more insight and visibility over how present-day decisions are expected to impact on, for example, future prices and service outcomes. It should also provide for greater consistency of decision-making across the building block elements within an AA period and over time.

This would, in turn, improve outcomes for consumers, promote principles of market efficiency, support safety, security and reliability. It is also consistent with good regulatory practice.

Our proposed direction is also consistent with the RPPs. In short, it would promote economic efficiency[53] avoid the costs and risks of over- and under-investment[54] and better support service providers having a reasonable opportunity to recover at least their efficient costs.[55]

While our proposed direction differs from the ECA proposal in its planning rule change request, it would address many of the concerns that ECA and other stakeholders identified in their feedback to the consultation paper. It would also do so at a lower cost to consumers than the proposed Gas Annual Planning Review (GAPR). We expect our proposed direction would better promote the long-term interests of consumers than ECA's proposed solution (see appendix A.5).

A.2 A longer-term focus for AA proposals is required to manage the impacts of uncertain and/or declining demand

The AA review process currently requires both the regulator and service provider to focus on forecast demand, the forecast revenue requirement and reference tariffs within the upcoming AA period. For example, the rules currently require a service provider to submit the following information when submitting its proposed AA:[56]

- forecast pipeline capacity and utilisation over the AA period
- the projected capital base over the AA period
- forecast depreciation over the AA period
- forecast capex and opex over the AA period
- the allowed rate of return and estimated cost of corporate income tax over the AA period
- the total revenue to be derived from pipeline services over the AA period.

The emphasis placed on what is expected to occur in the upcoming AA period has worked well in the context of stable or growing demand. However, maintaining this approach in an environment of uncertain and/or declining demand has the potential to result in:

- inefficient expenditure being incurred
- inefficient use of the capital cost recovery tools (i.e. depreciation, treatment of inflation, redundant and re-use of redundant capital provisions), and
- inefficient reference tariff arrangements.

53 Consistent with NGL section 24(3).
54 Consistent with NGL section 24(3) and 24(6).
55 Consistent with NGL Section 24(2).
56 NGR, rule 72.

For example, if service providers and the regulator only focus on the upcoming AA period when making capex decisions and do not account for projected reductions in demand in subsequent periods, it could result in more capex being incurred than is required to provide safe, reliable and secure services over the remaining life of the network or pipeline. This could, in turn, result in customers having to pay more for services than they should and add to the capital at risk of stranding. Similarly, if service providers and the regulator do not consider the longer-term outlook when making decisions about whether to accelerate the recovery of capital, then the opportunity to use this tool to efficiently manage the risk of higher future prices and stranded capital may be lost.

Although the NGR does not currently require service providers or regulators to consider the longer-term outlook when developing and approving AA proposals, we understand that:

- service providers have started to provide longer-term demand forecasts and other longer term analysis to support their proposals to accelerate the recovery of capital (e.g. by adopting shorter asset lives and/or using a different depreciation profile)[57]
- the AER and ERA have started to include longer-term analysis in their decisions on whether to allow accelerated depreciation.[58]

While this is a positive development, a longer-term outlook appears to only have been used to inform capital cost recovery decisions and not other aspects of an AA where a longer-term outlook would also be important to consider (e.g. expenditure and reference tariff proposals). It is possible that internal inconsistencies and inefficiencies could start to emerge across AA proposals and regulatory decisions, because the same longer-term assumptions are not being used across an AA proposal or decision. This is a limitation in the current arrangements that the Commission considers should be addressed.

Another limitation that we have identified with the current arrangements is that service providers and the regulator are not required by the NGR to assess or report on the longer-term consequences of their AA proposals or regulatory decisions. This is problematic because, as the examples above highlight, many of the decisions made in an AA can have longer-term implications for both:

- consumers, in terms of prices, service availability and the safety, security and reliability of services, and
- service providers, in terms of capital cost recovery as well as their ability and/or incentive to continue to efficiently provide pipeline services and to efficiently operate and invest, where necessary (including to potentially repurpose the network or pipeline).

A.3 The Commission proposes to amend the NGR to require service providers and the regulator to apply a longer-term outlook

Our proposed direction seeks to improve consideration and transparency of outcomes beyond the AA period for both consumers and service providers. We consider this will help promote efficient expenditure decisions, efficient use of the capital cost recovery tools and efficient reference tariff arrangements, all of which are in the long-term interests of gas consumers.

57 See for example, AGN, 2023-2028 AA proposal, Attachment 6.1 - Future of Gas – our approach to accelerated depreciation, July 2022; JGN, 2025-30 AA proposal, Attachment 7.3 - Depreciation approach, June 2024; ATCO, 2025-29 AA proposal, Attachment 03.002 – Future of Gas, September 2023; Evoenergy, 2026-31 AA proposal, Attachment 6 - Depreciation, June 2025.

58 See for example, AER, Draft decision – Evoenergy AA 2026-31, Attachment 1, November 2025; ERA, Final decision – ATCO AA 2025-29, Attachment 6, November 2024.

To this end, our proposed direction is to amend the NGR to require scheme pipeline service providers and the regulator to:

- consider the longer-term outlook for the relevant network or pipeline in an internally consistent manner when developing AA proposals and making regulatory decisions
- assess and report on the longer-term consequences of their AA proposals and regulatory decisions for both:
  - consumers in terms of the prices they are likely to have to pay, as well as service availability and the safety, security and reliability of services over the outlook period
  - service providers in terms of capital cost recovery (including the value of any stranded capital) and their ability and/or incentive to efficiently provide pipeline services and to efficiently operate and invest over the outlook period.

The Commission is still considering the precise form these obligations should take.[59] What follows is therefore an indication of how the obligations could work.

A.3.1 Our proposed direction would require service providers to develop a long-term outlook and to assess and report on the longer-term consequences of its AA proposal

Indicatively, our proposed direction would require scheme pipeline service providers to:

- Develop a 20-year outlook for their distribution network or transmission pipeline and to submit this to the regulator as part of the AA proposal, with the outlook to be published alongside other AA information.
- Explain how their AA proposal reflects the 20-year outlook and is internally consistent across the relevant building blocks (e.g. the same long-term demand forecast is used for both capital cost recovery and capex proposals).
- Assess and report on the consequences of their AA proposal for consumers and service providers over the 20-year outlook period.

We consider a 20-year outlook period is appropriate to use in this context and note that it is consistent with the outlook period used for AEMO's Gas Statement of Opportunities, which we understand is typically relied upon by service providers when developing their demand forecasts. While we understand that there would be some inherent uncertainty associated with such a long-term outlook, we consider it appropriate to use in this context given the long-lived nature of pipeline assets and the potential impact that the energy transition could have on demand over this period. It would also ensure consistency of decisions across elements over time.

Table A.1 provides an indication of the type of information that could be included in the 20-year outlook.

Table A.1: Indicative information that could be included in a service provider's 20-year outlook

Information type	Indicative reporting requirement
Revenue requirement and reference tariff related forecasts	The outlook could include the service provider's best forecast or estimate (arrived at on a reasonable basis) of the following for each year of the outlook period, as well as the underlying assumptions:

59 The information required to be contained in the longer-term outlook could be set out in the NGR or could be the subject of a guideline or other instrument.

Information type	Indicative reporting requirement
	• forecast demand, which given the uncertainty surrounding demand is likely to take the form of demand scenarios with associated probabilities of occurrence • forecast capacity and asset utilisation • the projected capital base • forecast depreciation, including the expected economic lives of assets • forecast capex and opex (broken down by the key driver, e.g. safety or integrity related, replacement capex, transition-related etc) • forecast revenue requirement • forecast reference tariffs • how the delivered price of gas in the network area is expected to compare with the forecast price of alternative energy sources over the outlook period.
Longer-term asset management plan	The outlook could include information on the service provider's long-term asset management plan, covering future investment plans, as well as any proposal to repurpose or decommission the network or pipeline (or parts thereof) and the likely timing of such changes.

Longer-term risk management plan	The outlook could include information on:
	• the demand-related risks or uncertainties the service provider and customers are likely to face over the outlook period and their source
	• how the service provider proposes to manage the risks or uncertainties over the outlook period, including through the use of:
	  • any of the capital cost recovery tools (i.e. depreciation, indexation, redundant capital and/or re-use of redundant capital)
	  • other regulatory tools (e.g. reference tariff variation mechanisms, AA re-openers, shorter AA periods)
	  • other measures (e.g. minimising expenditure, repurposing, decommissioning, divestment etc)
	• when these regulatory tools or other measures are expected to be used and how their use would be in the long-term interests

Information type	Indicative reporting requirement
	of consumers.
How the longer-term outlook and risks have been accounted for in the AA proposal	The outlook could set out how the service provider has accounted for the longer-term outlook and risks in an internally consistent manner across its: • capex and opex forecasts for the AA period • proposed use of capital cost recovery tools in the AA period • proposed reference tariffs and tariff variation mechanism for the AA period

Our intent is that the 20-year outlook and other information listed above would form part of a service provider's AA proposal and be published alongside the other AA information that service providers are required to submit to the regulator. This information should therefore help consumers and other stakeholders to engage more effectively in the AA process and to make more informed decisions about their future use of the network or pipeline. It could also help to inform jurisdictional policy and safety-related decisions. The Commission notes that the obligations and information listed above are indicative only at this stage, and we would welcome any stakeholder feedback on this aspect of our proposed direction.

A.3.2 Our proposed direction would also require the regulator to consider the longer-term outlook and to assess and report on the longer-term consequences of its decision

Indicatively, our proposed direction would also require the regulator to consider the service provider's 20-year outlook when making its decision on the AA proposal. While the regulator would not be bound by the service provider's outlook, if the regulator had a different view on the outlook, it would need to explain why that is the case, set out its alternative forecasts and employ these consistently across its decision.

Like service providers, the regulator would be required to assess and report on the consequences of their AA decision for both consumers and the service provider over the 20-year outlook period. This could involve assessing and reporting on what their decision would mean for:

- consumers in terms of the prices they are likely to have to pay over the outlook period, as well as the likely impacts on service availability and the safety, security and reliability of services over this period
- service providers in terms of:
  - capital cost recovery over the outlook period, including the estimated value of any unrecovered capital at the end of the outlook period
  - their ability to efficiently provide pipeline services and to efficiently operate and invest over the outlook period.

It is important to note that the requirement for the regulator to consider the longer-term outlook and to assess and report on the longer-term consequences of its decisions is not intended to bind future decisions by the regulator. Rather, the intent is to support more informed regulatory decision-making for the AA period and to provide consumers and other stakeholders (including jurisdictional governments) greater transparency of the potential implications of such decisions.

A.3.3 Our proposed direction would support other elements of the proposed direction

In addition to addressing the limitations set out in appendix A.2, the requirement to apply a longer-term outlook is intended to support our proposed direction on:

- Capital cost recovery by allowing service providers and the regulator to take a longer-term view on how to efficiently use the capital cost recovery tools to manage the price and stranding risks associated with uncertain or declining demand and when each of these tools may be used.
- Expenditure by allowing service providers and the regulator to make more informed and efficient decisions about the future investment needs of the network or pipeline.
- Reference tariffs by allowing service providers and the regulator to make more informed and efficient decisions about future tariff arrangements.

A.4 Our proposed direction would promote the NGO and give effect to the RPPs

Our proposed direction would better promote the NGO than the status quo by supporting more informed and efficient decision-making by service providers and the regulator and providing for greater transparency of service providers' longer-term outlook and regulatory decision-making. This should, in turn:

- **Improve outcomes for consumers** by strengthening consideration of long-term outlooks and the longer-term consequences for consumers in AA proposals and regulatory decisions. This would provide confidence to stakeholders that:
  - future possible demand scenarios are appropriately informing decisions about expenditure, capital cost recovery and reference tariffs
  - longer-term impacts on consumer prices and the availability and quality of services are being taken into account.

Greater transparency of service providers' longer-term outlooks and regulatory decisions would also enable customers and other stakeholders to engage more effectively on AA proposals. It would also enable customers to make more informed decisions about their future use of the network or pipeline.

- **Promote principles of market efficiency** by ensuring that expenditure, capital cost recovery and reference tariff decisions appropriately reflect the longer-term outlook, which should promote efficient investment in, and operation and use of pipeline services over the longer term.
- **Support safety, security and reliability of services** and **broader gas market reform** over the longer term. That is, by requiring the service provider and regulator to consider the longer-term consequences for the safety, security and reliability of services. Greater transparency of these consequences, together with information on the potential for asset stranding, could help jurisdictional governments, safety regulators and other relevant bodies make more informed decisions about the future operation of the network or pipeline.
- **Align with good regulatory practices** by promoting internal consistency across the elements of a service provider's AA proposal and regulatory decision-making within an AA period and over time. Our proposed approach would also improve transparency of how longer-term considerations have been taken into account and the consequences of regulatory decisions for consumers and service providers.

- **Consider the implementation burden** on the service provider and the regulator by aligning new obligations with current informal approaches for incorporating long-term analysis into AA proposals and decisions, and building on these approaches to provide a broad range of stakeholders with more valuable and transparent insight into critical decision-making.

Our proposed direction is also consistent with the RPPs. For instance, the requirement for service providers and the regulator to consider the longer-term outlook should:

- promote economic efficiency by providing for more efficient decisions to be made about expenditure, the use of capital cost recovery tools and reference tariffs, which should, in turn, promote efficient investment in, and operation and use of pipeline services over the longer term
- avoid the costs and risks of:
  - underinvestment that may otherwise arise if service providers believe they will not have a reasonable opportunity to recover at least their efficient costs over the longer term, or
  - overinvestment that may otherwise arise if the potential for uncertain and/or declining demand beyond the AA period is not appropriately factored into decision-making.

The requirement for regulators to consider the longer-term consequences of their decisions on service providers in terms of capital cost recovery, as well as their ability and/or incentive to continue to operate, is also intended to ensure that service providers are provided a reasonable opportunity to recover at least their efficient costs.

A.5 We also considered ECA's planning rule change request, but found our proposed direction would better promote the NGO and be consistent with the RPPs

A.5.1 ECA proposed that service providers for gas distribution networks be required to publish a GAPR

In its planning requirements rule change request, ECA expressed concerns about the limited planning related reporting by gas distribution network service providers. Elaborating on this further, ECA stated that gas distribution network service providers do not provide enough granular and regular information over an adequate time horizon to enable stakeholders to make informed decisions about the future of gas distribution networks.[60]

To address its concerns, ECA proposed that scheme and non-scheme pipeline distribution service providers be required to publish a Gas Annual Planning Report (GAPR). ECA suggested that the GAPR employ a 20-year planning horizon with scenario-based analysis, as well as information on:[61]

- forecast numbers of connections, disconnections, energy consumption and relevant laws and regulations in a jurisdiction that may impact these forecasts
- expected useful life for all assets
- potential replacement or augmentation projects, the relevant drivers of these projects and potential alternative investment projects
- a consumer engagement strategy for the review and a strategy for eliciting demand response (like electricity).

60 ECA, Rule change request – Planning requirements, pp. 15-16.

61 ECA, Rule change request – Planning requirements, p. 17.

A.5.2 Stakeholder expressed mixed views on the ECA's GAPR proposal

A number of consumer and other interest groups agreed with ECA that there was limited publicly available planning information and supported either a GAPR or some other form of reporting to help stakeholders evaluate AA proposals and better understand the future of the network or pipeline.[62]

Origin and EnergyAustralia also supported new reporting requirements.[63] Origin noted it could help support efficient regulatory decision-making and help consumers better understand how service providers are managing transition costs and risks.[64] It also suggested that any new requirement include information on demand forecasts and demand scenarios; asset utilisation, redundancy risk indicators; decommissioning and repurposing plans; and expenditure by function.

Alinta stated that while a GAPR could be "useful", its value may be limited if it is 'reporting for reporting's sake'. Alinta added that there would be costs associated with a GAPR that would invariably be passed on to consumers and so suggested a cost-benefit analysis be undertaken.[65] The AER similarly observed that further consideration needed to be given to both the costs and benefits associated with the proposed GAPR, adding that an alternative option would be to bring a long-term (potentially 20-year) planning horizon into the AA review process.[66]

A number of pipelines and industry associations agreed that there is a need to consider a longer-term outlook, but noted the proposed GAPR would be costly and duplicative of existing reporting requirements, with no clear net customer benefit.[67] Some of these stakeholders suggested alternative approaches.

- The ENA suggested that rather than imposing additional reporting obligations on service providers, the AER provide guidance on the forward looking factors to be considered in an AA process.[68]
- AusNet supported additional data sharing where there is a clear value for stakeholders, adding it is working to voluntarily publish network data to support collaboration on new approaches.[69]
- Jemena supported the use of longer range forecasts for demand and expenditure in an AA review process, noting it would mean both long and short term forecasts are prepared in the context, which could avoid potential conflicting sets of assumptions or inputs. Jemena noted that use of longer range scenarios are becoming common practice and while rules have not been required for this to emerge "*it may be that rule guidance can help target these better toward customer preferences, expectations and needs.*"[70]

A.5.3 Our proposed direction would address many of the issues raised by ECA and stakeholders

In developing our proposed direction, the Commission considered ECA's proposal and the stakeholder feedback outlined above. In short, we found that much of the information that ECA and other stakeholders suggested should be reported by service providers would either be provided through:

62 Submissions to consultation paper: JEC, p. 20; Climateworks, p. 1; Darebin Climate Action Now, p. 4; Victorian Energy Future Network, p. 10; Environment Victoria, p. 3; Gippsland Climate Change Network, p. 2; Lighter Footprints, p. 1; Rewiring Australia, p. 1; SACOSS, p. 4; IEEFA, p. 6.

63 Submissions to consultation paper: EnergyAustralia, p. 4; Origin, p. 6.

64 Origin, Submission to consultation paper, p. 6.

65 Alinta, Submission to consultation paper, p. 5.

66 AER, Submission to consultation paper, pp. 9-10.

67 Submissions to consultation paper: AGIG, p. 20; Jemena, pp. 21-22; ENA, pp. 19-20; APGA; p. 36.

68 ENA, Submission to consultation paper, p. 20.

69 AusNet, Submission to consultation paper, p. 8.

70 Jemena, Submission to consultation paper, p. 24.

- our proposed long-term outlook (see Table A.1)
- other publicly available information, including information:
  - reported by service providers as part of their AA proposals and in response to regulatory information notices, and the prescribed transparency provisions in the NGR
  - published by the regulator on service provider performance and customer numbers, new connections, reconnections, disconnections and abolishments.

When compared with the proposed direction, we also found that the more granular and frequent reporting proposed by ECA was likely to be costly for service providers to produce and was unlikely to materially benefit the regulator, consumers, jurisdictional governments or other stakeholders. In the absence of a clear benefit, it is likely that the costs of a GAPR would outweigh the benefits, which would not promote the long-term interests of consumers.

This is consistent with the feedback received from a number of stakeholders, including the AER, who observed that the costs of such reporting would ultimately be borne by consumers. It is important therefore that any new reporting obligations are targeted and proportionate to the issue they are intended to address, which in this case is the potential for inefficient decisions to be made about expenditure, capital cost recovery and reference tariffs if a longer-term view is not taken.

The other key difference between our proposed direction and the ECA's proposal is that our direction would only apply to scheme pipelines. While we considered whether similar obligations should apply to non-scheme pipelines, we found there was likely to be little benefit in doing so because they are not subject to the same level of regulatory oversight as scheme pipelines.

Overall, we found that ECA's proposal was less likely to promote the NGO than our proposed direction and so are not proposing to require service providers to publish GAPRs.

Question 4: Our proposed direction on a longer-term outlook (detailed in appendix A)

1. What are your views on our proposed direction to require service providers and the regulator to consider a longer-term outlook and longer-term consequences?
2. Do you have any views on the information or analysis that should be included in a service provider's 20-year outlook?

Table A.2: Assessment of other policy options: long-term outlook

Option	Benefits	Costs and risks	Our view
Status quo / do nothing	Maintaining the current arrangements would avoid additional regulatory costs for service providers and the regulator	There is a risk that the emphasis currently placed in the NGR on what is expected to occur in the upcoming AA period and the lack of any requirement to assess and report on the longer-term consequences of AA proposals and decisions could, in the context of uncertain and/or declining demand: • **Result in inefficient expenditure, inefficient use of the capital cost recovery tools and/or inefficient reference tariff arrangements.** The costs and risks associated with these inefficiencies would ultimately be borne by consumers and service providers. • **Impede the ability of consumers and other stakeholders** (including jurisdictional governments) to: • effectively participate in AA review processes	The Commission considers that this policy option would: • promote the NGO to a lesser extent • be less consistent with the RPPs. than our proposed direction. This is because there are a number of limitations in the current arrangements that have the potential to result in a range of inefficiencies and have long-lasting consequences for consumers and service providers.

Option	Benefits	Costs and risks	Our view
		• make informed and efficient decisions about the longer-term use and/or operation of the relevant network or pipeline.	
ECA proposal	In principle, a GAPR could help to reduce some of the information barriers that consumers and other stakeholders face and support more informed and efficient outcomes. However, as we noted in the consultation paper, 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	It would be **costly** for service providers to prepare the proposed GAPR, given both: • the scope and granularity of the information that ECA has proposed be included in a GAPR • the frequency with which this information would need to be published. We have also been **unable to identify any stakeholder that would benefit f**rom the publication of such granular information on an annual basis. More generally, there is a risk that the granularity of information proposed by ECA could cause more confusion for consumers and other stakeholders who don't know how to interpret the information.	The Commission considers this policy option would promote the NGO to a lesser extent than our proposed direction. While some of the information that the ECA has suggested be reported in the GAPR could help to drive more efficient outcomes, we consider such outcomes could be better achieved through our proposed direction.

B Our proposed approach to amend the capital cost recovery provisions

B.1 Supporting efficient capital recovery would promote the long-term interests of consumers

As the energy transition progresses, we expect the capital cost recovery tools (which include the depreciation, treatment of inflation, redundant capital and re-use of redundant capital provisions) to play an increasingly important role in helping to avoid a disorderly transition and mitigate the risks uncertain and/or declining demand pose for both gas consumers and gas distribution providers (service providers) (see appendix B.2). It is therefore important that these tools are fit for purpose and service providers and the regulator can use these tools as and when required to help support efficient capital recovery that promotes the long-term interests of gas consumers.

We have identified several limitations with the current capital cost recovery rules, based on our review of:

- the rules and the equivalent provisions in the predecessor to the NGR, the National Third Party Access Code for Natural Gas Pipeline Systems (Gas Access Code), and the original intent of these provisions (see appendix B.3)
- how the rules and the equivalent provisions in the Gas Access Code have been applied (see appendix B.4), and
- stakeholder feedback (see appendix B.5).

To address the identified limitations, our proposed direction would provide for changes to the capital cost recovery provisions in the NGR (see appendix B.6). At a high level our proposed changes would allow for the following where service providers are facing uncertain or declining demand:

- service providers to better align the recovery of capital with the expected use of the network, by reducing the extent to which depreciation and compensation for inflation is recovered in later years while:
  - there are still a relatively large number of customers to recover costs from, and
  - delivered gas prices remain below the price of competing fuels that could trigger price-driven reductions in gas consumption and connections (the 'switching point').
- service providers and/or the regulator to remove partial or fully redundant capital from the capital base when it becomes clear stranding cannot be averted (i.e. the service provider is unable to recover a full return of and on capital) and it is necessary to respond to competition, or otherwise replicates what would occur in a workably competitive market
- the regulator to add any redundant capital back into the service provider's capital base if it later becomes clear it can be recovered.

Our proposed direction to require service providers and the regulator to employ a longer-term outlook in AA proposals and decisions (appendix A) would also support service providers and regulators to make more informed and efficient longer-term capital cost recovery decisions. Figure B.1provides a summary of our proposed direction and the types of changes to the NGR that would be required to give effect to it.

Figure B.1: Summary of proposed direction to amend capital cost recovery provisions

Proposed direction: Amend existing capital cost recovery provisions to support efficient capital recovery that promotes the long-term interests of gas consumers

Depreciation

Support efficient recovery of capital, by:

- Providing more guidance on the circumstances in which accelerated depreciation may be appropriate.
- Replacing references to demand growth in the depreciation provisions with more neutral language.

Treatment of inflation

Support efficient recovery of compensation for inflation, by:

- Introducing a decision point in the rules for how compensation for inflation is to be recovered in an access arrangement period.
- Providing more guidance on the circumstances in which a real, nominal or other approach to inflation may be appropriate.

Redundant capital and re-use of redundant capital

Allow these tools to be used to where required to replicate what would occur in a competitive market, by:

- Clearly specifying the types of redundancy that it can deal with (i.e. full (unused) or partial (underutilised) redundancy).
- Allowing the regulator to remove partial redundant capital from the capital base, subject to the mandatory considerations and constraints in the rules.
- Replacing the AA redundant capital mechanism with a rules-based mechanism.
- Amending the re-use of redundant capital provisions to provide for appropriate tests for the re-use of both full and partial redundant capital.

Support regulatory decisions that are in the long-term interests of consumers by:

- Clarifying the role of the regulator when assessing depreciation, treatment of inflation, redundant and re-use of redundant capital proposals.
- Requiring explicit consideration of the NGO and RPPs in service provider proposals and regulatory decisions.

Requiring service providers and regulators to take a **longer-term outlook** is intended to address the other identified limitations, including the rules not requiring service providers or regulators to:

- take a longer longer-term view on the management of stranding risk & consumer impacts and to consider the longer-term consequences of AA proposals and regulatory decisions
- consider how these tools could be jointly used to more effectively manage these risks.

Together, these elements of our proposed direction would promote the **NGO** by:

- **Improving outcomes for consumers over the longer term** and **promoting principles of market efficiency** by providing for a more economically efficient (and smoother) time-profile of prices. This would support the efficient use of gas networks and provide for more equitable outcomes over the longer term. For those customers that face financial, technical or other barriers to switching, the proposed direction would also help to mitigate their exposure to inefficient prices and the risk service providers decide to cease operations earlier than expected. More generally, the proposed direction would help to support an orderly energy transition.
- **Supporting the safety, security and reliability of services** and **promoting principles of market efficiency** by preserving service providers' incentives to prudently and efficiently operate their networks, invest where necessary (including in compliance with applicable safety standards and regulations) and continue to provide safe and reliable services.
- **Aligning with good regulatory practice** and **being consistent with broader gas market reform** by ensuring service providers and regulators can use the capital cost recovery tools to

manage the risks and impacts associated with uncertain and declining demand, and sufficiently flexible to deal with the different positions each service provider is in.

Our proposed direction is also consistent with the **RPPs**, because it would:

- provide service providers a reasonable opportunity to recover at least their efficient costs[71]
- promote economic efficiency by ensuring service providers continue to have an incentive to efficiently provide pipeline services and efficiently invest, where necessary[72]
- avoid the costs and risks of:[73]
  - underinvestment that may otherwise arise if service providers believe they will not have a reasonable opportunity to recover at least their efficient costs, or
  - overinvestment that may otherwise arise if the redundant capital provisions could not be used where it is appropriate to do so.

Our proposed direction differs from that proposed by both ECA and JEC (see appendix B.7). This is because, in our view, constraining the recovery of capital in the manner the proponents have proposed would not be:

- in the long term interests of consumers and so would not promote the NGO
- consistent with the RPPs.

Although our proposed direction seeks to address the limitations we have identified in the NGR, CEPA modelling for the Commission indicates the regulatory framework is unlikely to fully mitigate the impacts of uncertain or declining demand on gas consumers and service providers. We therefore consider there is a role for governments in helping to address some of these impacts. There could also be value in the regulator initiating form of regulation reviews if competition from other energy sources starts to pose more of a constraint on service providers' behaviour (see appendix B.8).

B.2 The energy transition is leading to greater uncertainty about gas demand and risks, which need to be carefully managed to avoid a disorderly transition

B.2.1 The gas demand outlook is changing as the transition progress, which gives rise to risks for consumers and service providers that need to be managed

As outlined in chapter 2, the energy transition is leading to greater uncertainty about the future demand for gas, particularly in the residential and small commercial customer segment, where demand is projected to decline.[74] This is giving rise to pricing, stranding and a range of other risks for both gas consumers and service providers, which need to be carefully managed to avoid a disorderly energy transition.

The standard approach of recovering capital on a relatively constant basis over the economic life of the pipeline promoted the long-term interests of gas consumers at a time when demand was expected to remain relatively stable, or grow, over the life of the pipeline. The recovery of capital was aligned with the expected use of the pipeline, allowing the fixed costs of the network to be

71 Consistent with NGL section 24(2).

72 Consistent with NGL section 24(3).

73 Consistent with NGL section 24(3) and 24(6)

74 See for example, AEMO's March 2025 GSOO, which projects that distribution connected residential and small commercial demand will fall by around 70 per cent over the next 20 years, with a 30 per cent reduction projected in the next 10 years. 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 AA periods.

spread evenly over the long life of pipelines and shared proportionally between current and future gas customers.

The standard approach to capital recovery may not promote the long-term interests of gas consumers if the demand outlook is uncertain and/or is projected to decline. This is because the fixed capital costs of a network would be spread across a diminishing demand base, meaning gas customers remaining on the network would face disproportionately higher charges. When the demand outlook is uncertain and/or projected to decline, service providers and the regulator should be able to align capital recovery with the expected use of the network to achieve smoother revenue recovery through adjustments to economic asset lives, the depreciation profile, and inflation compensation. Where stranding risks cannot be averted, they should also be able to remove full or partially redundant capital through adjustments to the capital base.

In other jurisdictions and industries, regulators have, to varying extents, sought to try and mitigate these risks and support an orderly transition. They have largely done this by shortening economic asset lives and/or adjusting the depreciation profile to reflect the expected utilisation of the infrastructure,[75] ceasing the deferral of compensation for inflation[76] and/or removing redundant capital from the capital base where stranding cannot be averted.[77] In doing so, regulators have recognised the need to carefully balance:

- providing service providers with a reasonable opportunity to recover at least the efficient costs of providing services by aligning capital cost recovery with the expected utilisation of the assets providing the service, to reduce the capital at risk of stranding, *with*
- managing consumer price impacts, to avoid triggering a disorderly exit that could otherwise:
  - adversely affect customers that remain connected to the network, which are likely to include those that face financial, technical or other barriers to switching[78]
  - increase the capital at risk of stranding and, in so doing, adversely affect service providers' incentive and/or ability to continue to operate their network, or their ability to continue to provide a safe and reliable service to remaining consumers.[79]

B.2.2 On their own, the capital cost recovery tools may be unable to address all risk for consumers and service providers, but can help mitigate impacts

While capital cost recovery tools can help mitigate the impacts of uncertainty and/or declining demand on gas consumers and service providers, they may not be able to fully address the risks, particularly if demand falls faster than expected.

CEPA modelling for the Commission shows that even if economic asset lives are shortened and/or the depreciation profile is adjusted to allow more up-front recovery, a residual risk remains that prices could start to escalate to a point of disorderly exit leading to service providers being unable to recover all the capital they have invested (see Box 2). This highlights some of the limits

75 This approach has been used by gas pipeline regulators in Great Britain, the Netherlands, Belgium, Austria, Denmark, Germany. It has also been used by regulators in Australia for rail and telecommunications infrastructure, and in New Zealand for telecommunications infrastructure. See AEMC, Gas Networks in Transition – Consultation Paper, September 2025, Appendix A.

76 This approach has been used in the Netherlands. See DNV report for ACER, Future Regulatory Decisions on Natural Gas Networks: Repurposing, Decommissioning and Reinvestments on future regulation, 28 October 2022, p. 127.

77 This approach has been used in relation to gas pipelines in Estonia, Sweden, Slovakia, Italy, Netherlands, Croatia. It has also been used by the Australian Competition and Consumer Commission (ACCC) in relation to the telecommunications infrastructure and by IPART for the Wilton to Wollongong trunk line. See AEMC, Gas Networks in Transition – Consultation Paper, September 2025, Appendix A.

78 Such as low income households and other vulnerable customers, renters, residents in some apartment buildings and industrial customers that can't switch to another source.

79 It could, for example, result in a far more expensive transition for those users that can switch. It could also result in some industrial customers having to cease operations if they are unable to switch. It may also result in welfare losses from reduced use of appliances and equipment that these customers have invested in.

of the regulatory framework in addressing capital cost recovery risk and the potential need for governments to take additional actions outside the regulatory framework (see appendix B.8).[80]

CEPA modelling demonstrates there are limits to what the regulatory framework can do. However, it shows that the timely use of capital cost recovery tools can help reduce the impacts of declining demand on gas consumers and service providers and support a more orderly transition (see Box 2). Specifically, the modelling shows that:

- Aligning capital recovery with the expected use of the assets providing the services (by shortening economic asset lives, changing the depreciation profile and/or ceasing to defer the recovery of compensation for inflation) while there are still a relatively large number of customers and gas prices are below the switching point can help to:
  - smooth the impact on consumer prices over the longer term and avoid some of the other adverse impacts on consumers outlined above
  - support the recovery of efficient capital costs.
- If it becomes apparent that a gas distribution network (or parts of the network) will likely become stranded, then timely use of the redundant capital tool can help to:
  - mitigate the impact of escalating consumer bills for those customers that remain connected to the network
  - reduce the stranding risk of the remaining capital if the lower bills result in customers staying connected to the network for longer.
- If the reduction in consumer bills brought about by the use of redundant capital tool results in customers staying connected for longer, then it could benefit:
  - those customers by providing them a longer period of time to transition
  - service providers because it may provide an opportunity to recover additional capital through prolonged operations and potentially through the re-use of redundant capital provisions.

Timely use of these tools can therefore benefit both gas consumers and service providers and support the efficient operation, use of and investment in the network over the remainder of its economic life.

These examples of how the tools can operate reinforce the importance of ensuring the capital cost recovery tools in the NGR are fit for purpose and that service providers and the regulator can use them as and when required - to help manage the challenges posed by declining and/or uncertain demand.

Box 2: Modelling the use of the capital cost recovery tools

As indicated by Figures A.1 and A.2 and subsequent commentary in Box 1in chapter 3, relative to the standard approach, reducing the extent that recovery of capital is deferred can:

- reduce the amount of capital at risk of stranding

80 In other jurisdictions, governments have legislated measures to reduce reliance on gas and enable coordinated disconnections, supporting the regulatory framework's ability to manage transition risks. The Netherlands, for example, has adopted legislation supporting reduced reliance on natural gas and partial decommissioning of the gas grid to meet the national gas-free target by 2050, including: (1) prohibiting new buildings from connecting to the gas network since 2018, where prior to this, service providers were required to connect all buildings on request, (2) requiring all municipalities to develop local heat transition plans outlining gas-free heating strategies for each district (3) allowing municipalities to set phase-out dates for gas in areas where the alternative is sustainable and cost-effective. See: 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.

- smooth some of the impact on customer bills and limit the rate at which price increases encourage a disorderly exit.

However, CEPA modelling shows that the framework may not be able to ensure full cost recovery in all cases. Indeed, in the majority of illustrative network and demand scenarios CEPA modelled, accelerated capital recovery (by shortening economic asset lives, changing the depreciation profile, and/or ceasing to defer the recovery of compensation for inflation) still left some residual capital, which could necessitate:

- the use of the redundant capital tool
- actions outside the regulatory framework.

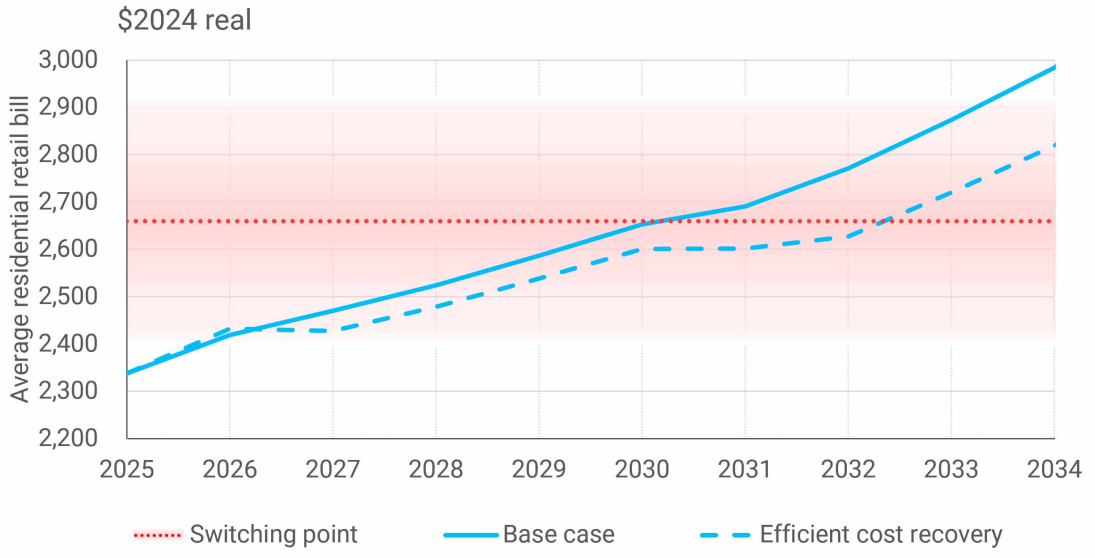
CEPA modelling indicates that the timely use of the redundant capital tool could benefit both gas consumers and service providers. It is likely to be particularly beneficial where demand is more price sensitive or where there is a rapid decline in utilisation of the pipeline. This is because smaller changes in demand lead to relatively larger price movements, limiting the ability of accelerated capital recovery to keep prices below the switching point and prevent a disorderly exit. For these service providers, the use of the redundant capital tool may moderate prices for longer, supporting greater recovery of the capital base and reducing residual stranding risk.

To demonstrate the application of the redundant capital tool, we selected the illustrative network least resilient to declining demand due to its relatively high capital asset base to consumer ratio (illustrative network 3 in the CEPA report).

Figure A.3 shows that the base case is effective in increasing the short-term return of capital (by shortening a proportion of asset lives). When the redundant capital tool is applied, however, prices remain more stable under the switching point and the network can operate for a longer period. This allows for a greater total capital recovery from consumers over time.

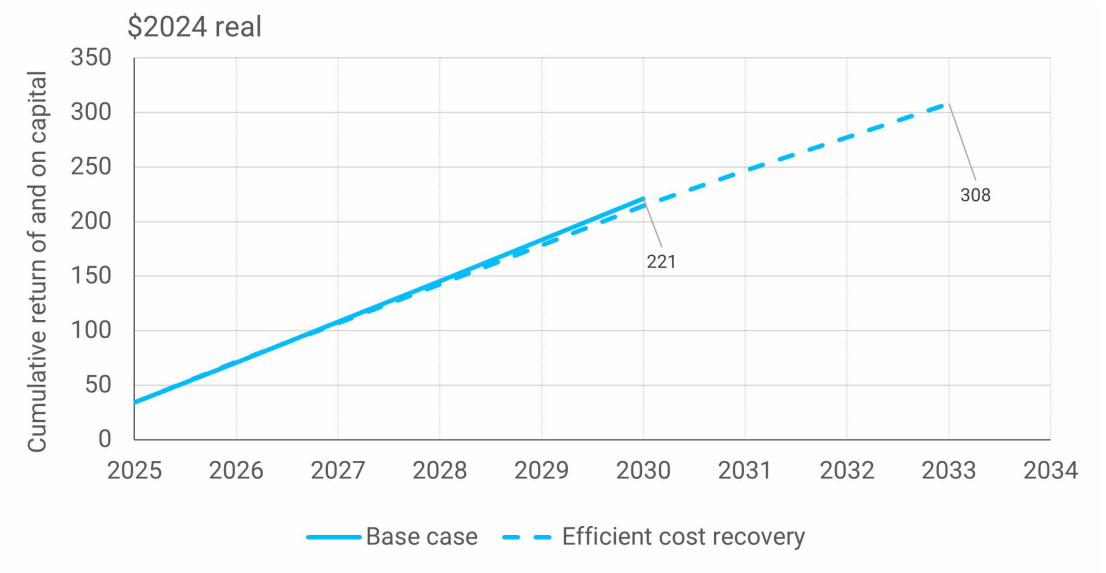
During this extended period, consumers also benefit from greater price stability and continued access to their gas appliances, supporting a more orderly transition away from the network.

Figure A.3: Modelled average residential bills for an illustrative network facing rapidly declining demand under base case and efficient cost recovery options ($/yr)



While use of the redundant capital tool would, in effect, involve a write-down of the capital base, CEPA modelling shows that a service provider's cumulative returns of and on capital could be higher than those produced by simply reducing the deferral of depreciation (by shortening economic asset lives).

Figure A.4: Modelled cumulative return of and on capital for an illustrative network facing rapidly declining demand under base case and efficient cost recovery options ($m)



This is because removing redundant capital would reduce a service provider's revenue requirement and, in turn, reference tariffs. A reduction in reference tariffs would mean that:

- consumers face the switching point later (illustrated by the dashed blue line in Figure A.3), which would benefit those customers that find it more difficult to switch by providing them more time to overcome the financial or technological barriers to switching (where such barriers are feasible to overcome)
- service providers experience a prolonged recovery period or greater recovery (e.g. if prices remain below the switching point customers may defer their decisions to exit the network), which would benefit service providers because it would mean customers make a greater contribution to returns on and of capital than would otherwise be the case.[i]

We note that reference tariffs are charged by service providers to the 'user' of gas reference services, which include retailers and larger gas users that contract directly with the service provider. Gas retailers may use reference tariffs as an input to the setting of their gas retail charges, which also includes the costs a retailer incurs in procuring gas and other services required to supply the retail customer. Retailers have some discretion as to how they recover distribution charges from their customers (e.g. they can employ a different tariff structure and/or level of charges to a service provider's reference tariffs).

Source: CEPA modelling for AEMC.

Note: [i] Note that extending the period over which recovery can occur may not be an option in those cases where a jurisdiction has fixed a date by which a gas distribution network is to cease operations, but use of the tool could help to keep more customers on up until that point.

B.3 The NGR include a number of complementary capital cost recovery tools

The NGR currently include the following complementary tools that service providers and the regulator can use to help reduce the risks associated with uncertain or declining demand:

- Depreciation provisions, which deal with how a service provider recovers capital invested in a pipeline over the life of the pipeline (appendix B.3.1).

- Treatment of inflation provisions, which deal with how a service provider recovers compensation for inflation over the life of the pipeline (appendix B.3.2).
- Redundant capital provisions, which deal with how a service provider's capital base may be reduced to remove redundant capital, and the re-use of redundant capital provisions, which deal with how redundant capital may be added back into a service provider's capital base (appendix B.3.3).

The relevant rules are summarised in Figure B.2. Further detail on these rules and some of the limitations we have identified are set out below.

Figure B.2: Current NGR capital cost recovery provisions

Depreciation provisions

Rule 88 of the NGR states that:

(1) The depreciation schedule sets out the basis on which the pipeline assets constituting the capital base are to be depreciated for the purpose of determining a reference tariff.

(2) The depreciation schedule may consist of a number of separate schedules, each relating to a particular asset or class of assets

Rule 89 of the NGR states that:

(1) The depreciation schedule should be designed:

(a) so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services; and

(b) so that each asset or group of assets is depreciated over the economic life of that asset or group of assets; and

(c) so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset, or a particular group of assets; and

(d) so that (subject to the rules about capital redundancy), an asset is depreciated only once (ie that the amount by which the asset is depreciated over its economic life does not exceed the value of the asset at the time of its inclusion in the capital base (adjusted, if the accounting method approved by the AER permits, for inflation)); and

(e) so as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.

(2) Compliance with subrule (1)(a) may involve deferral of a substantial proportion of the depreciation, particularly where:

(a) the present market for pipeline services is relatively immature; and

(b) the reference tariffs have been calculated on the assumption of significant market growth; and

(c) the pipeline has been designed and constructed so as to accommodate future growth in demand.

Treatment of inflation provisions

Rule 73 states that:

(1) Financial information must be provided on:

(a) a nominal basis; or

(b) a real basis; or

(c) some other recognised basis for dealing with the effects of inflation.

(2) The basis on which financial information is provided must be stated in the access arrangement information.

(3) All financial information must be provided, and all calculations made, on the same basis and using any applicable financial models published by the AER under these Rules.

Rule 75A states that

(1) The AER may prepare and publish a revenue model and/or a capital base roll forward model (financial models) and if it does, must do so in accordance with this rule 75A and rule 75B.

(2) If the AER publishes a financial model under this rule, a service provider must use the model in accordance with the requirements of these rules.

(3) The AER may from time to time, in accordance with this rule 75A and rule 75B, amend or replace a financial model in accordance with these rules.

The remainder of rule 75A sets out the consultation process the AER must follow when making or amending the financial models.

Rule 75B sets out the requirements for the contents of the financial models.

Redundant capital provisions

Rule 85 of the NGR states that:

(1) An access arrangement may include (and the AER may require it 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.

(2) A reduction of the capital base in accordance with such a mechanism may only take effect from the commencement of the first access arrangement period to follow the inclusion of the mechanism in the access arrangement or the commencement of a later access arrangement period.

(3) An applicable access arrangement may include a mechanism for sharing costs associated with a decline in demand for pipeline services between the service provider and users.

(4) Before requiring or approving a mechanism under this rule, the AER 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.

Re-use of redundant capital provisions

Rule 86 of the NGR states that:

(1) Subject to the new capital expenditure criteria, if, after the reduction of the capital base by the value of assets identified as redundant, the assets later contribute to the delivery of pipeline services, the assets may be treated as new capital expenditure of an amount calculated by taking their value as at the time of their removal from the capital base and increasing it annually at the rate of return implicit in the reference tariff.

(2) To the extent the new capital expenditure criteria allow, the amount arrived at under subrule (1) will be returned to the capital base in accordance with those criteria.

Source: AEMC.

B.3.1 The depreciation provisions provide for a significant degree of flexibility and regulatory discretion

Depreciation is the process by which the capital invested in assets can be recovered by a service provider, with the key determinants of depreciation being:[81]

- the economic life of the assets (i.e., the period over which the asset is expected to provide reference 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, depending on the circumstances, be constant (straight-line depreciation)[82] diminishing (front loaded depreciation), or increasing (back loaded depreciation) over time.

By design,[83] the depreciation provisions in the rules are relatively flexible, allowing for the period over which depreciation is recovered and the rate of recovery to be changed over time, depending on the conditions facing a service provider. The rules also allow for different depreciation approaches to be applied to individual assets, or groups of assets.[84] These provisions can, for example, be used to do any of the following on a whole of network basis, or for discrete parts of the network to better align capital recovery with the expected use of the network:

- recover capital on a relatively constant basis over a longer economic life when demand is expected to remain relatively stable over the life of the pipeline
- recover capital earlier over a shorter economic life and/or a higher rate of recovery when demand is projected to decline or the pipeline is facing some other form of stranding risk (e.g. if gas reserves are declining)
- recover capital later when demand is projected to increase over the life of the pipeline.

These options, which are equivalent in net present value terms, can produce different revenue and price profiles.

While relatively flexible, the depreciation provisions in the NGR currently allow the regulator a considerable degree of discretion when deciding whether or not to approve a service provider's depreciation proposal with limited guidance provided to the regulator on how to exercise that discretion.

This differs from the approach used in the economic regulation of electricity distribution and transmission services in Chapters 6 and 6A of the NER. That is, while the depreciation provisions in the NER provide for a similar degree of flexibility to those in the NGR in terms of being able to amend the economic lives and depreciation profile, the NER only allows the AER to use a different

81 The depreciation provisions are set out in rules 88-89 of the NGR and are very similar to those contained in the Gas Access Code, which preceded the NGR.

82 Note that when combined with the use of an indexed approach, the recovery of capital may not look like it is providing for a straight-line recovery of capital. This is because indexation, in effect, results in the recovery of capital being deferred.

83 In the information paper that accompanied the exposure draft of the Gas Access Code, the Gas Reform Task Force noted that: "The Reference Tariff Principles specify a number of requirements for the Depreciation Schedule, but are intended to leave substantial flexibility for the Depreciation Schedule to be designed to accommodate the particular characteristics of the market for the Services provided by the Pipeline, and to take account of the particular financing constraints of the Pipeline." Gas Reform Task Force, Information paper to accompany the exposure draft of the National Third Party Access Code for Natural Gas Pipeline Systems, 8 August 1996, p. 52.

84 NGR rule 88.

depreciation schedule if it determines that a service provider's proposal does not conform with the depreciation rules in the NER.[85]

The NGR also provide limited guidance on when it may be appropriate for the service provider recover its capital sooner (i.e., to accelerate the recovery of capital). In this regard, it is worth noting that if demand is declining, the window of opportunity to use accelerated depreciation to try and mitigate the impacts on consumers and the service provider will diminish over time. A delay in the effective use of this tool can therefore have significant consequences for both consumers and the service provider.[86]

B.3.2 The rules do not include a decision point for how compensation for inflation is to be treated in an AA period

Due to the long-lived nature of pipelines, service providers face the risk that inflation will erode their investment over time. An allowance for inflation is made to compensate for this risk.[87]

There are a number of different ways that this can be achieved, which are equivalent in net present value terms, but produce different revenue and price profiles. The main options are:[88]

- A **real (indexed) approach:** A real (indexed) approach can involve either:
  - applying a real rate of return to an inflation indexed capital base, or
  - applying a nominal rate of return to an indexed capital base and then making an offsetting reduction to depreciation to avoid double counting of inflation.

  A real (indexed) approach results in inflation being compensated via capital base indexation. All else being equal, this approach results in a more stable revenue stream and prices over time.
- A **nominal (unindexed approach)**. A nominal (unindexed) approach typically involves applying a nominal rate of return to an unindexed capital base and results in inflation being compensated via the rate of return. All else being equal, this approach results in comparatively higher revenues in early years and lower revenues in later years, which can lead to greater price volatility and consumers being exposed to more inflation risk.

The choice between these approaches will depend on the conditions facing a service provider. For example, the AER has previously observed that:[89]

- **A real (indexed) approach is generally more appropriate if demand is stable or growing.** This is because it maintains the value of the capital base in real terms over time and, when demand is stable or growing, results in current customers paying the same amount in real terms as

85 NER rule 6.5.5(a)(2) and 6A.6.3(a)(2); It is worth noting that prior to 2019, there was a regulatory discretion framework in place in the NGR, which classified rules as 'no discretion', 'limited discretion' or 'full discretion' rules. At the time, the depreciation provisions were classified as 'limited discretion' rules, which meant the regulator could not withhold its approval of the service provider's proposal if it was satisfied it complied with the depreciation rules and any relevant provision in the NGL. This is akin in many ways to what currently applies under Chapters 6 and 6A of the NER. As part of the AEMC's 2018 review into the regulation of covered pipelines, the Commission recommended that the regulatory discretion framework be removed from the NGR because it resulted in regulatory complexity and "could impede regulatory decisions that best promote the NGO". The framework was then removed as part of the 2019 rule change process, which resulted in the regulator having full discretion in relation to the depreciation rules. AEMC, Final Report - Review into the scope of economic regulation applied to covered pipelines, July 2018, p. 127 and AEMC, Rule Determination – National Gas Amendment (Regulation of Covered Pipelines) Rule 2019, March 2019, p. 70.

86 Note that consumers are protected from the risk that demand does not fall by as much as projected, by provisions in the depreciation rules. This includes the requirement that an asset can only be depreciated once (i.e. so capital cannot be over-recovered) and the ability to amend both asset lives and the depreciation profile at each AA review, if conditions change.

87 AER, Fact Sheet: Why do we index the regulatory asset base?, undated.

88 AER, Fact Sheet: Why do we index the regulatory asset base?, undated.

89 AER, Fact Sheet: Why do we index the regulatory asset base?, undated and AER, Regulating gas pipelines under uncertainty paper, November 2021, pp. 33-35.

future users. Maintaining the real value can also reduce the potential for price shocks when assets are replaced at the end of their life.[90]

- **A nominal (unindexed) approach may be more appropriate if demand is declining.** This is because it avoids deferring compensation for inflation to future periods when there may be fewer customers to recover this from and higher risks of stranding.[91] It can therefore help to avoid triggering an escalation of prices in later years and reduce the risk that service providers do not recover this compensation.

In contrast to depreciation, there is currently no rule that requires a decision to be made about how inflation is to be treated in an AA period. The rules instead provide for the regulator to determine this through any financial models (i.e. the post tax revenue and roll forward models) they decide to develop and publish, which service providers must comply with.[92] While the rules require the regulator to consult on the development and amendment of its financial models, the decision applies to all transmission and distribution pipelines. It does not therefore account for the different conditions that individual service providers may be facing at different points in time.

The approach to the treatment of inflation in the NGR differs from that used in economic regulation of electricity distribution and transmission services in Chapters 6 and 6A of the NER, which mandate the use of a real (indexed) approach.[93]

B.3.3 The redundant capital provisions are intended to replicate what would occur in a workably competitive market, but there are barriers to its use

The redundant capital provisions are set out in rule 85 of the NGR. This rule currently allows an AA 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 users.

Before requiring or approving 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".[94]

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 and meet the capital expenditure criteria.

These two rules are similar to the provisions that were set out in the Gas Access Code, which preceded the NGR. The Information Paper published during the Gas Access Code's development noted the redundant capital provisions were:[95]

90 AER, Fact Sheet: Why do we index the regulatory asset base?, undated.

91 AER, Regulating gas pipelines under uncertainty paper, November 2021, p. 34.

92 NGR, rules 73 (3) and 75A(2).

93 NER, rule 6.4.3(a)(1) and 6A.5.4(a)91); Under s. 8.5A of the Gas Access Code and the NGR as it was until 2019, gas pipeline service providers were able to propose the use of a real, nominal or other approach to the treatment of inflation. Following the AEMC's 2018 Review into the regulation of covered pipelines and subsequent rule change process, the rules were amended to allow the regulator to determine what method should be used through its published financial models. At the time this review was undertaken, the AER suggested that the rules be amended to mandate the use of a real (indexed) to ensure consistency with electricity. However, the Commission decided not to make this amendment, because it concluded some flexibility should be retained in the NGR. The Commission did, however, observe that if the AER was to publish financial models that provided for the use of a real (indexed) approach, then the new rules would require service providers to employ this approach. See AER, Review into the scope of economic regulation applied to covered pipelines – Submission to draft report, March 2018, pp. 1-2 and AEMC, Final Report - Review into the scope of economic regulation applied to covered pipelines, July 2018, p. 104.

94 NGR, rule 85(4).

95 Gas Reform Task Force, Information paper to accompany the exposure draft of the National Third Party Access Code for Natural Gas Pipeline Systems, 8 August 1996, p. 62.

> …intended to prevent unused or under used capital from being recovered through Reference Tariffs, and thereby replicating the outcomes of a competitive market.

Similar views about the intent of the provisions were expressed by the Productivity Commission[96] and regulators in contemporaneous documents.[97] The Australian Competition and Consumer Commission (ACCC), for example, who was responsible for regulating transmission pipelines under the Gas Access Code, stated that:[98]

> …in a competitive market, firms have to face and manage the risk of stranded asset cost due to competition and technological advancement and where assets are stranded as a result of poor investment decisions or adverse circumstances, a full commercial return on the investment will not be achieved. While there was no desire to increase uncertainty for the service provider, it was also not considered appropriate to shield natural monopolies totally from business risk. The risk of redundancy or stranding was also recognised as an incentive to the firm to take more care when making initial investments.

Box 3: What is a workably competitive market?

The objective of economic regulation is often framed as being to replicate the outcomes of a workably competitive market. The concept of workable competition was described by the Independent Committee of Inquiry on National Competition Policy (the Hilmer Committee) in 1993 as follows:[i]

> In markets characterised by workable competition charging prices above the level of long run average costs will not be possible over a sustained period, for higher returns will attract new market entrants or lead customers to choose a rival supplier or product…
>
> Where the conditions for workable competition are absent — such as where a firm has a legislated or natural monopoly, or the market is otherwise poorly contestable — firms may be able to charge prices above the efficient level for periods beyond those justified by past investments and risks taken or beyond a time when a competitive response might reasonably be expected. Such "monopoly pricing" is seen as detrimental to consumers and to the community as a whole.

It has also been described by the Australian Competition Tribunal as follows:[i]

> Perhaps the best shorthand description of workable competition is to envisage a market with a sufficient number of firms (at least four or more), where there is no significant concentration, where all firms are constrained by their rivals from exercising any market power, where pricing is flexible, where barriers to entry and

96 The Productivity Commission, for example, noted in its 2004 review of the Gas Access Code that: "The Commission agrees that redundant capital mechanisms increase the risk faced by service providers. However, businesses face demand risk in most industries. If regulators do not have the scope to remove redundant capital, then it seems likely that demand risk will be transferred to users (to the extent that users are unable to substitute other fuels). Nevertheless, regulators should apply redundant capital mechanisms with caution, since they could have unintended consequences. It should also be noted that redundant capital can be reincorporated into a service provider's capital base if at a later date it contributes to the delivery of services." Productivity Commission, Review of the Gas Access Regime, 11 June 2004, p. 289.

97 Similar views were expressed by the Victorian and NSW jurisdictional regulators, who at the time were the Victorian Office of Regulator General (ORG) (later the Essential Services Commission (ESC) and the NSW Independent Pricing and Regulatory Tribunal (IPART). See ORG, Final Decision Access Arrangements for Multinet, Westar and Stratus, October 1998, p. 84 and IPART, Draft Determination AGL Gas Networks Access Arrangement, 1999, p. 128.

98 ACCC, Final Determination Access Arrangement for the Amadeus Basin to Darwin Pipeline, 2002, pp. 57-58.

> expansion are low, where there is no collusion, and where profit rates reflect risk and efficiency.

Source: [i] Independent Committee of Inquiry on National Competition Policy Review, 25 August 1993, p. 269; [ii] Application by Chime Communications Pty Ltd (No. 2) [2009] ACompT 2, para 37.

In that same decision, the ACCC set out its view on the complementary nature of the depreciation and redundant capital provisions (see Box 4).

Box 4: Complementary roles of the depreciation and redundant capital provisions

In the ACCC's 2002 decision on the Amadeus Basin to Darwin Pipeline AA, the ACCC set out how it viewed the depreciation and redundant capital provisions working together:[i]

> Given that the service provider is in a good position to identify assets at risk of stranding well in advance of the threat actually materialising and can seek compensation through accelerated depreciation, the need for the immediate write-off of assets is removed….Having the flexibility to pursue such an approach removes much of the risk associated with capital becoming redundant or stranded.
>
> … Given the application of accelerated depreciation, only a minimal amount of remaining capital would be subject to the risk of removal from the capital base.

In short, the ACCC viewed the depreciation and redundant capital provisions as being complements rather than substitutes, and that there was a temporal dimension to the two tools, with service providers and the regulator expected to:

- **use accelerated depreciation once the risk of potential stranding** (physical or economic) **is identified,** to try and mitigate the risk of stranding
- **only use redundant capital provisions if the risk of stranding cannot be averted.**

Source: [i] ACCC, Final Determination Access Arrangement for the Amadeus Basin to Darwin Pipeline, 2002, pp. 57-58.

Regulatory decisions made by the ACCC and jurisdictional regulators under the Gas Access Code also confirm that the redundant capital provisions in the Gas Access Code were intended to deal with both full redundancy (i.e. when assets cease to contribute to the delivery of services) and partial redundancy (i.e. when assets are underutilised).[99]

When the Gas Access Code transitioned to the NGR, a decision was made to retain the redundant capital provisions. However, there were some changes made to the drafting that, in the Commission's view, are limiting how and when the regulator can use this tool to deal with partial redundancy compared to the previous drafting under the Gas Access Code. For example, s.8.27 of

99 For example: The AA approved by the ACCC under the Gas Access Code included redundant capital mechanisms that allowed the capital base to be adjusted to remove "wholly or partially redundant assets". See ACCC, Final Decision for the Principal Transmission System and the Western Transmission System, 1998, p. xxi; ACCC, Final Decision for the Central West Pipeline, 2000, p. xv, ACCC, Final Decision for the Amadeus Basin to Darwin Gas Pipeline, 2002, p. xvii, ACCC, Final Decision for the Moomba to Sydney Pipeline, 2003, p. 85. The AA approved by IPART, the ACT regulator, the Independent Competition and Regulatory Commission, and Queensland regulator, QCA, included redundant capital mechanisms that allowed capital to be removed where there the value of the pipeline had fallen as a result of a decline (or forecast decline) in utilisation (i.e. partial redundancy). See for example: NSW Gas Distribution Network: 2000-2004 access arrangement (p. 117) and 2005-2010 access arrangement (p. 66); ACT Gas Distribution Network: 2000-2004 access arrangement (p. 5) and 2005-2010 access arrangement (p. 20); Queensland Gas Distribution Networks: Allgas - 2001-2005 access arrangement (p. 14) and 2006-2011 access arrangement (p. 17) and AGN – 2001-2005 access arrangement (p. 7) and 2006-2011 access arrangement (p. 7). In a submission to the Victorian Essential Services Commission in 2002 on the potential effect of a redundant capital mechanism, Envestra (now AGN) also recognised its potential to be used to remove "redundant or partially redundant assets". See Envestra, Access Arrangement Information for Envestra's Victorian Distribution System, 2 April 2002, pp. 51-52.

Gas Access Code[100] allowed the regulator to require a redundant capital mechanism to be included in an AA to deal with partial redundancy (i.e. due to a decline in demand (or volume of sales)), whereas rule 85(3) of the NGR does not provide for this (see Figure B.2).

In our view, the capital redundancy provisions should continue to allow service providers to be exposed to the risks of competition from alternative fuels, changing consumer preferences, market and technological change and the risk that they do not recover all of their efficient costs as a result. However, the inability for the regulator to require partial redundant capital to be removed from the capital base may mean that this tool is not used where it would be efficient to do so. That is, while removing partially redundant capital recognises that stranding has occurred, it could also minimise the risk of stranding for the service provider's remaining capital by keeping reference tariffs below the point at which a disorderly exit may be triggered, managing price impacts for gas consumers and otherwise replicating what would occur in a workably competitive market.

B.4 Recent regulatory decisions provide some insight into the use of the capital cost recovery tools

Table B.1 provides a summary of how the capital cost recovery tools have been used by the AER and ERA in recent gas pipeline regulatory decisions.

100 This section of the Gas Access Code stated the following: A Reference Tariff Policy may include (and the Relevant Regulator may require that it include) a mechanism that will, with effect from the commencement of the next Access Arrangement Period, remove an amount from the Capital Base (Redundant Capital) for a Covered Pipeline so as to: (a) ensure that assets which cease to contribute in any way to the delivery of Services are not reflected in the Capital Base; and (b) share costs associated with a decline in the volume of sales of Services between the Service Provider and Users. Before approving a Reference Tariff which includes such a mechanism, the Relevant Regulator must take into account the uncertainty such a mechanism would cause and the effect that uncertainty would have on the Service Provider, Users and Prospective Users. If a Reference Tariff does include such a mechanism, the determination of the Rate of Return (under sections 8.30 and 8.31) and the economic life of the assets (under section 8.33) should take account of the resulting risk (and cost) to the Service Provider of a fall in the revenue received from sales of Services or part of the Covered Pipeline.

Table B.1: Use of capital cost recovery mechanisms in recent gas pipeline regulatory decisions

Service Provider & Pipeline	Regulator	Last regulatory decision	Capital Asset Base as at 2024[1]	Accelerated depreciation (amounts in addition to baseline depreciation)				Treatment of inflation	Redundant capital mechanism
				Service provider proposal	Allowed by regulator		% Difference between proposed and allowed		
					Amount	Acceleration method			
Distribution									
AusNet Vic Network[2]	AER	2023	$1.959 b	$200 m	$105 m	Reduced asset lives for mains and services plus additional acceleration capped by 1.5% p.a. price path	-48%	Real	No
Multinet Vic Network[3]	AER	2023	$1.56 b	$86 m	$53 m	Acceleration of depreciation capped by 1.5% p.a. price path	-38%	Real	No
AGN Vic Network[4]	AER	2023	$2.09 b	$175 m	$175 m	Acceleration of depreciation capped by 1.5% p.a. price path	~	Real	No

Service Provider & Pipeline	Regulator	Last regulatory decision	Capital Asset Base as at 2024[1]	Accelerated depreciation (amounts in addition to baseline depreciation)				Treatment of inflation	Redundant capital mechanism
				Service provider proposal	Allowed by regulator		% Difference between proposed and allowed		
					Amount	Acceleration method			
JGN NSW Network[5]	AER	2025	$3.80 b	$230 m	$115 m	Reduced asset lives for mains, services and trunk lines plus additional acceleration of medium pressure service depreciation capped by 0.5% p.a. price path.	-50%	Real	No
Evoenergy ACT Network[6]	AER	2025 (Draft)	$0.41 b	$105 m	$47 m	Reduced asset lives for mains and services plus additional acceleration of mains and services depreciation	-55%	Real	No

Service Provider & Pipeline	Regulator	Last regulatory decision	Capital Asset Base as at 2024[1]	Accelerated depreciation (amounts in addition to baseline depreciation)				Treatment of inflation	Redundant capital mechanism
				Service provider proposal	Allowed by regulator		% Difference between proposed and allowed		
					Amount	Acceleration method			
						capped by 4% p.a. price path			
AGN SA Network[7]	AER	2025 (Draft)	$1.97 b	$30 m	Not allowed		-100%	Real	No
ATCO WA Network[8]	ERA	2025	$1.58 b	$87 m	$38 m	Change from straight-line to tilted depreciation (tilt rate of 1%)[f]	-56%	Real	No
Transmission									
APA Amadeus Gas Pipeline[9]	AER	2021	$0.15 b	Not proposed	n.a.			Real	Yes*
APA Victorian Transmission System[10]	AER	2022	$1.48 b	Not proposed	Not specified	Reduced asset lives for pipeline assets.	n.a.	Real	Yes*
APA Roma to Brisbane Pipeline[11]	AER	2022	$0.56 b	Not proposed	Not specified	Reduced asset lives for pipeline and compressor	n.a.	Real	Yes*

Service Provider & Pipeline	Regulator	Last regulatory decision	Capital Asset Base as at 2024[1]	Accelerated depreciation (amounts in addition to baseline depreciation)				Treatment of inflation	Redundant capital mechanism
				Service provider proposal	Allowed by regulator		% Difference between proposed and allowed		
					Amount	Acceleration method			
						assets.			
GGT Goldfields Gas Pipeline[12]	ERA	2024	$0.42 b	$0.3 m	$0.3 m	Limit the maximum economic life of any pipeline and lateral assets to 2065.	n.a.	Real	No
AGIG Dampier to Bunbury Natural Gas Pipeline[13]	ERA	2025	$3.45 b	Not proposed	Not specified	Maintain the 2063 limit on the maximum economic life of any pipeline assets	n.a.	Real	No

Sources:

1. Data on AER regulated pipelines obtained from AER, Operational performance data 2025 – Gas distribution networks and AER, Operational performance data 2025 – Gas transmission pipelines.
2. AER, Final decision, AusNet Services access arrangement 2023 to 2028, Attachment 4, June 2023, pp. 4, 8 and 14.
3. AER, Final decision, Multinet Gas Networks access arrangement 2023 to 2028, Attachment 4, June 2023, pp. 4 and 8.
4. AER, Final decision, AGN (Victoria & Albury) access arrangement 2023 to 2028, Attachment 4, June 2023, pp. 4 and 8.
5. AER, Final decision, Jemena Gas Networks access arrangement 2025 to 2030, Attachment 4, May 2025, pp. 7 and 9.

6. ERA, Final Decision, Mid-West and South-West Gas Distribution Systems access arrangement 2025 to 2029, Attachment 4, November 2024, p. 20, ERA, Final Decision, Mid-West and South-West Gas Distribution Systems access arrangement 2025 to 2029, Attachment 6, November 2024, p. 30. A tilt factor reprofiles deprecation based on the selection of the tilt rate, with a higher tilt rate resulting in greater accelerated depreciation. A tilt rate of 0% is equivalent to straight-line depreciation.
7. AER, Draft decision, Evoenergy ACT access arrangement 2026 to 2031, Attachment 1, November 2025, pp. 1, 9-10, 16.
8. AER, Draft decision, AGN SA access arrangement 2026 to 2031, Attachment 1, November 2025, pp. 1, 9-10.
9. AER, Final Decision, Amadeus Gas Pipeline access arrangement 2021 to 2026, April 2021, pp. 26-28 and AER, Final Decision – Amadeus Gas Pipeline Access Arrangement 2021 to 2026, p. 25.
10. AER, Final Decision, Victorian Transmission System access arrangement 2023 to 2027, Attachment 4, December 2022, pp. 6-8 and AER, Final Decision – Victorian Transmission System 2023-27 Access Arrangement, p. 7.
11. AER, Final Decision, Roma to Brisbane Pipeline access arrangement 2022 to 2027 – Overview, May 2022, pp. 34-37 and AER, Final Decision – Roma to Brisbane Pipeline Access Arrangement, pp. 14-15.
12. ERA, Final Decision, Goldfields Gas Pipeline access arrangement 2025 to 2029, Attachment 4, December 2024, p. 23, ERA, Final Decision, Goldfields Gas Pipeline Access Arrangement 2025 to 2029, Attachment 6, December 2024, p. 1.
13. ERA, Final Decision, Dampier to Bunbury Natural Gas Pipeline Access Arrangement 2026 to 2030, Attachment 4, December 2024, p. 24, ERA, Final Decision, Dampier to Bunbury Natural Gas Pipeline Access Arrangement 2026 to 2030, Attachment 6, December 2025, p. 24.

* These mechanisms cover both assets that cease to contribute to service delivery and the costs associated with a decline in the volume of services.

B.4.1 Depreciation: Recent decisions have, in most cases, allowed for accelerated depreciation, but the amounts allowed have been lower than proposed

Until recently, depreciation for most gas distribution and transmission pipelines was recovered on a straight-line[101] basis with the economic asset lives largely assumed to be the same as the technical lives. Service providers and the regulator have traditionally employed a straight-line cost recovery approach because, when demand is stable or growing, it delivers a relatively uniform pattern of capital cost recovery and supports a stable price path. However, when demand is declining, a straight-line approach no longer provides either price stability or uniformity in capital cost recovery. In these circumstances, bringing forward a greater share of capital recovery is required to maintain a stable price trajectory and to reduce the amount of capital at risk of stranding.

A number of distribution and transmission pipeline service providers that are now facing the risk of uncertain and/or declining demand have recently proposed to accelerate depreciation by reducing the economic lives of some of their assets and/or changing the depreciation profile. In doing so, most service providers have submitted analysis showing both:

- the demand risks their networks are facing under different demand scenarios
- the potential to accelerate depreciation while prices remain below their estimates of the consumer switching point.[102]

4.1.1 In most cases regulators have recognised distributors are facing demand risks, but have allowed less accelerated depreciation than proposed

As Table B.1 shows, the AER and ERA have responded to distribution network service providers' proposals by allowing for some acceleration of depreciation in all but one of the most recent round of regulatory determinations. The exception to this was the AER's recent AGN SA draft decision, with the AER stating that it did not consider there to be "sufficient evidence that AGN's network faces significant stranding risk that currently needs to be addressed through accelerated depreciation".[103]

In all other cases, the AER and ERA accepted that the gas distribution networks were facing some degree of stranding risk and allowed for some acceleration of depreciation, although the amounts allowed for most distribution networks were around 40-55 per cent lower than what had been proposed (see Table B.1). The exception was AGN's Victorian gas distribution network, where the AER allowed 100 per cent of what had been proposed.[104]

In the ERA's case, the acceleration of depreciation was achieved by moving to more of a front loaded depreciation profile.[105] The AER, on the other hand, has maintained a straight-line depreciation profile, but used shorter economic lives and/or a 'price path approach', to enable some additional capital recovery to be brought forward (subject to the cap posed by the regulated price path).[106]

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101 Note that when used in conjunction with the indexed approach, the recovery of capital does not occur on a straight-line basis.

102 See for example, HoustonKemp, Smoothing cost recovery when gas demand is declining – a report for Jemena Gas Networks, January 2025 and ACIL Allen, Dampier to Bunbury Natural Gas Pipeline Economic Depreciation Study, December 2019.

103 AER, Draft decision, AGN (SA) access arrangement 2026 to 2031, Attachment 1, p. 15.

104 AER, Final decision, AGN (Victoria & Albury) access arrangement 2023 to 2028, Attachment 4, June 2023, pp. 4 and 8.

105 ERA, Final decision on access arrangement for the Mid-West and South-West Gas Distribution Systems (2025 to 2029), Attachment 6, p. 31.

106 The AER's price path approach involves calculating the service provider's revenue requirement based on the standard building blocks and then determining what additional accelerated depreciation could be allowed in the AA period subject to the cap imposed by the price path constraint being met.

In effect, the AER's price path approach has placed a cap on how much capital recovery can be brought forward by constraining how much reference tariffs can increase in an AA period. The AER has employed this approach because it is concerned that any material increase in prices could trigger customers to exit, even if those prices are below the switching point:[107]

> We consider that promoting relatively flat prices will prevent customers leaving gas networks prematurely and creating a so called 'death spiral'.

The Commission understands that the different price paths employed by the AER, which have ranged from 0.5 per cent to 4 per cent per annum (see Table B.1), are intended to reflect how progressed jurisdictional policies are in terms of transitioning away from gas. For example, in the recent Evoenergy draft decision, the AER noted that it had allowed a higher price path in the ACT because "the ACT's net zero emissions policy settings…is more progressed than other jurisdictions". [108]

The following extract taken from AER's recent Evoenergy draft decision provides further insight into the AER's rationale for applying the price path approach:[109]

> We recognise the potential stranded asset risk faced by Evoenergy. Allowing accelerated depreciation is necessary to ensure that Evoenergy is not deterred from making efficient investments required to maintain safe and reliable services for an ageing network in the long term interest of consumers. However, any amount of accelerated depreciation must be balanced against price impacts and affordability…
>
> We consider that our draft decision […] strikes a balance between the need for a meaningful level of accelerated depreciation to promote efficient investment, and the need to limit the price impact of accelerated depreciation on consumers, particularly for vulnerable customers and those facing challenges during the energy transition. It also shares some of the stranding risk between Evoenergy and a larger customer base while there is still an opportunity to do so.
>
> …. So long as demand continues to decline, no affordable amount of accelerated depreciation will achieve long-term price stability. We continue to encourage an open discussion between consumers, network businesses and governments regarding who should pay for the costs of stranded assets associated with past and future capital investments, and when and how these costs are shared. [110]

4.1.2 Regulators have also recognised that some transmission pipelines are facing demand risks, and have allowed some acceleration of depreciation

In the case of transmission pipelines, both the AER and ERA have allowed service providers to accelerate the recovery of depreciation in response to concerns about future demand uncertainty. In both cases this has been achieved by reducing the economic lives of pipeline and/or compression assets, with the ERA allowing the maximum economic life of these assets to be capped at 2063 or 2065 (see Table B.1).

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107 AER, Final Decision, Victorian Transmission System access arrangement 2023 to 2027, Attachment 4, December 2022, p. 8.

108 AER, Draft Decision: Evoenergy (ACT) access arrangement 2026 to 2031, November 2025, Attachment 1, pp. 27-28.

109 Similar statements were made by the AER in its 2025 decision on Jemena's AA. AER, Final Decision: Jemena Gas Networks access arrangement 2025 to 2030, May 2025, Attachment 4, p. 9.

110 AER, Draft Decision: Evoenergy (ACT) access arrangement 2026 to 2031, November 2025, Attachment 1, pp. 14-15.

B.4.2 Treatment of inflation: Regulators continue to use a real (indexed) approach to inflation

As Table B.1 shows, the AER and ERA have employed a **real (indexed) approach** in their most recent regulatory decisions for both distribution and transmission pipelines. This is consistent with the approach they have both taken in prior regulatory decisions, including in cases where service providers have proposed the use of a nominal (unindexed) approach.[111]

In the AER's case, the use of a real (indexed) approach is also consistent with the approach provided for in its financial models,[112] which service providers are required by the rules to comply with, irrespective of the conditions they are facing and the appropriateness of the approach in those conditions.[113] This rule requirement explains why the AER's recent Evoenergy draft decision did not give explicit consideration to the potential use of a nominal (unindexed) approach, even though the ACT Government has committed to phase out gas to achieve net zero by 2045. The draft decision instead referred to the AER's standard rationale for employing a real (indexed) approach as follows:[114]

> Indexation of the capital base and the offsetting adjustment made to depreciation results in a smoother revenue recovery profile over the life of an asset than if the capital base was un-indexed. The indexation of the capital base also reduces price shocks when the asset is replaced at the end of its life.

B.4.3 Capital redundancy: The redundant capital provisions have not been used for distribution networks since the NGR commenced

As the final column in Table B.1 shows, most service providers' AAs do not currently include a redundant capital mechanism. The exception is APA's three transmission pipelines in the east coast and Northern Territory, which all have such a mechanism.

The limited use of redundant capital mechanisms in AAs differs from the approach that was taken under the Gas Access Code. At that time, most AAs included a mechanism that would allow full and/or partial redundant capital to be removed from the capital base, if the conditions specified in the AA were met[115]

It is unclear why redundant capital mechanisms have not been included in most AAs since the transition to the NGR. In this regard, it is worth noting that:

- The inclusion of such a mechanism in an AA would not necessarily trigger the removal of redundant capital. Rather, the mechanism would just specify the circumstances in which redundant capital may or must be removed in a subsequent period, if the specified conditions are met (see Figure B.2).
- Without such a mechanism in place, there is no means by which to require redundant capital to be removed from the capital base, even where an asset fails, becomes obsolete or

111 For example, in 2014-15, ATCO proposed the use of a nominal (unindexed) approach, which the ERA did not allow. Similarly, in 2012-13, APA proposed the use of a nominal approach for the VTS, which the AER did not allow. See ERA, Final Decision, Mid-West and South-West Gas Distribution Systems access arrangement 2014 to 2019, June 2015, pp. 433-437. AER, Final Decision: APA GasNet Australia (Operations) Pty Ltd access arrangement 2013 to 2017, March 2013, Part 2, Attachment 6.

112 This can be seen in the AER's post tax revenue and roll forward models on its website.

113 NGR rules 73(3) and 75A(2).

114 AER, Draft Decision: Evoenergy (ACT) access arrangement 2026 to 2031, November 2025, Attachment 1, p. 44.

115 See for example: NSW Gas Distribution Network: 2000-2004 access arrangement (p. 117) and 2005-2010 access arrangement (p. 66), ACT Gas Distribution Network: 2000-2004 access arrangement (p. 5) and 2005-2010 access arrangement (p. 20), Queensland Gas Distribution Networks: Allgas - 2001-2005 access arrangement (p. 14) and 2006-2011 access arrangement (p. 17) and AGN – 2001-2005 access arrangement (p. 7) and 2006-2011 access arrangement (p. 7), Victorian Gas Distribution Networks: AGN – 1998-2002 access arrangement (p. 5), AusNet – 1998-2002 access arrangement (p. 5) and Multinet – 1998-2002 access arrangement (p. 5) and South Australia Gas Distribution Network: 2001-2005 access arrangement (p. 7). Use of redundant capital provisions under the Gas Code.

otherwise ceases to contribute to the delivery of services. The absence of such a mechanism in an AA can therefore mean that redundant capital is not removed even where it would be efficient to do so, resulting in customers having to continue to pay for the assets that are full or partially redundant.

Box 5: Use of redundant capital provisions under the Gas Access Code

From our review of regulatory decisions, it would appear the redundant capital mechanisms have only been used on one occasion to remove redundant capital from the regulated asset base. This occurred in 2005 when the Gas Access Code was in operation.

The decision was made by the IPART, who at the time was responsible for regulating the NSW gas distribution network. IPART decided to trigger the redundant capital mechanism that it had required to be included in the NSW gas distribution network's 2000-2004 AA. This mechanism allowed for redundant capital to be removed in a number of different circumstances, including where assets had decreased in value due to a decline, or projected decline in utilisation.[i]

Following the commissioning of the Eastern Gas Pipeline in 2000, the Wilton to Wollongong trunk line, which formed part of the NSW gas distribution network, experienced a material reduction in demand as customers switched to this new pipeline. IPART decided therefore to use the mechanism to remove 20 per cent of the value of this trunk line from the capital base. In doing so, IPART noted that:[i]

> An important factor leading to the Tribunal's decision was the magnitude of the decrease in sales volumes on the pipeline. It considers that such a significant decline in utilisation of the pipeline represents a clear situation of capital redundancy … and therefore necessitates some reduction in the regulatory value of the pipeline representing redundant capital.

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.[i]

Source: [i] IPART, Access Arrangement for AGL Gas Networks, July 2000, p. 23; [ii] IPART, Revised Access Arrangement for AGL Gas Networks, April 2005, p. 84; [iii] AER, Jemena Gas Networks - Access arrangement proposal for the NSW gas networks, 1 July 2010 - 30 June 2015, June 2010, p. 46.

B.5 We have identified several limitations in the capital cost recovery tools that we consider should be addressed

B.5.1 The rule change proponents and stakeholders identified a number of issues with the capital cost recovery rules

In their respective rule change requests, ECA and JEC expressed concerns about the use of accelerated depreciation in recent regulatory decisions. Both proponents assert that allowing for earlier recovery of capital inappropriately shifts the risks of stranding to consumers.[116] To address these concerns, ECA and JEC propose changes to the NGR that seek to constrain the use of accelerated depreciation and, in JEC's case, require greater use of the redundant capital provisions. Specifically:

- ECA propose changes to the depreciation rules to:[117]
  - impose stronger conditions on when accelerated depreciation can be used

116 ECA, Rule change request - Depreciation, p. 15 and JEC, Rule change request - Accelerated depreciation and redundancy, p. 4.

117 ECA, Rule change request - Depreciation, pp. 18-19.

    - ensure customers only pay what is "fair and reasonable for them to bear"
    - remove references to demand growth.
- JEC propose changes to:
    - the depreciation and redundant capital rules to prohibit the use of accelerated depreciation for the purposes of managing the stranding risk, unless used in conjunction with the redundant capital provisions
    - the redundant capital rules to broaden the definition of redundancy, include a principles-based decision-making framework and cap the amount of redundancy that can be shared with customers at 50 per cent.[118]

Stakeholders were divided in their views on the problems identified by ECA and JEC and their proposed solutions.

Most consumer and advocacy groups agree with ECA and JEC's view that accelerated depreciation transfers stranding risk to consumers,[119] and to varying extents, support changes to the depreciation and/or redundant capital provisions,[120] although not necessarily the changes proposed by ECA and JEC.[121] Alinta and Origin also supported changes to both the depreciation provisions to impose more constraints on their use[122] and the redundant capital provisions to ensure they are fit for purpose.[123]

The AER does not agree with ECA and JEC's characterisation of accelerated depreciation, but noted it is "open" to more guidance being included in the NGR on depreciation.[124] The AER also identified some limitations with the existing redundant capital provisions and stated it supports a "broader capital redundancy mechanism, properly integrated within a re-focused regulatory framework".[125]

Pipelines industry associations and the EUAA also do not agree with ECA and JEC that accelerated depreciation transfers stranding risk to consumers. They consider that the proposed rule changes would deprive service providers of a reasonable opportunity to recover at least their efficient costs, contrary to the NGO and RPPs.[126] A number of pipelines and industry associations also:

- have concerns about the AER's current approach to depreciation, with:[127]
    - Evoenergy stating it is "arbitrary", "lacks economic rigour" and ignores the long term impacts on gas consumers and service providers
    - AusNet stating that the fact there may be a residual risk of asset stranding is not a "tenable justification for the AER limiting legitimate updates to depreciation schedules"

118 JEC, Rule change request - Accelerated depreciation and redundancy, pp. 9-15.

119 Submissions to consultation paper: SACOSS, p. 5; Rewiring Australia, p. 3; IEEFA, pp. 4-5, GCCN, p. 7; Environment Victoria, p. 2.

120 Submissions to consultation paper: SACOSS, pp. 5-6; Rewiring Australia, p. 3; IEEFA, pp. 4-6; VEFN, pp. 6-7; DCAN, p. 4; Climateworks, p. 2; GCCN, pp. 6-7; Environment Victoria, p. 2.

121 For example, some stakeholders suggested that a hybrid of ECA and JEC proposals should be considered.

122 Submission to consultation paper: Alinta, pp. 4-5; Origin, pp. 4-5.

123 Submissions to consultation paper: Alinta, p. 5; Origin, p. 5.

124 AER, submission to consultation paper, p. 7.

125 AER, submission to consultation paper, pp. 7-8.

126 Submissions to consultation paper: AGIG, pp. 15-18; AusNet, pp. 5-8; ATCO, pp. 6-11; Evoenergy, pp. 3-5; Jemena, pp. 9-12; ENA, pp. 13-17; APGA, pp. 28-35; EUAA, p. 4.

127 Submissions to consultation paper: Evoenergy, p. 2; AusNet, p. 7.

- question whether the redundant capital provisions could be used to deal with stranding[128] or network-wide underutilisation[129]
- suggest the AEMC considers whether the current regulatory treatment of inflation is consistent with evolving conditions.[130]

APA also considers that we should not make a rule that relates to asset valuation or stranding, because in its view such decisions should only be made by government.[131]

B.5.2 Contrary to the concerns raised by proponents and some stakeholders, accelerated depreciation is an important regulatory tool that can help to protect consumers from the impacts of uncertain and declining demand

The Commission can only make a rule if it is satisfied that it will, or is likely to contribute to, the achievement of the NGO.[132] In addition to the NGO, the Commission must take into account the RPPs in making a rule for, or with respect to, regulatory economic methodologies as applied to scheme pipelines.[133] The Commission has considered the rule change requests and the stakeholder feedback against this background.

We acknowledge the concerns raised by the proponents and a number of stakeholders that bringing forward capital cost recovery would lead to higher prices in the short term, potentially creating affordability issues for customers at a time when they are also facing cost of living pressures.

However, it is important to recognise that depreciation is the means by which service providers are repaid the efficient capital that they have invested in an asset. Contrary to what the proponents and some stakeholders suggest, the Commission does not accept the view that the acceleration of this repayment involves a transfer of costs and risks to consumers. This is because, absent any decline in demand, consumers would have paid the same capital costs in net present value terms; acceleration changes only the timing of the recovery, not the total.

When demand is falling, continuing with a straight-line approach would defer an increasing share of cost recovery into future years when there are fewer gas consumers remaining to use the service. This creates a growing mismatch between who benefits from the use of the asset, and who is required to pay for it. Allowing service providers to recover a greater portion of their capital earlier in an environment of declining demand ensures that capital cost recovery is more in line with the expected use of the pipeline. This would result in more efficient reference tariffs for consumers, promote intergenerational equity and maintain incentives for efficient investment, without altering the total amount consumers pay in net present value terms.

That is not to say that consumers bear all the risk associated with the capital that a service provider has invested. Rather, the risk ultimately sits with the service provider, because if demand falls faster than expected or there are other technological or market developments that constrain what a service provider can charge, then they may be unable to recover all the capital they have invested. Put simply, accelerated depreciation does not immunise service providers from the risk of stranding; rather it ensures that cost recovery better aligns with the period in which demand exists.

128 Submissions to consultation paper: AGIG, Appendix 1; APGA, p. 32; ENA, p. 7.
129 Submissions to consultation paper: ATCO, p. 10; APA, pp. 3-4; AusNet, pp. 7-8; Jemena, p. 10; ENA, p. 15.
130 Submissions to consultation paper: Jemena, pp. 19-20; ENA, p. 20.
131 APA, submission to consultation paper, p. 3.
132 NGL section 291.
133 NGL section 293.

Accelerated depreciation is, nevertheless, an important regulatory tool that, in the Commission's view, a regulator should use where it is feasible to do so. This is particularly the case where there are a relatively large number of customers still connected to the network to spread the fixed costs across and gas prices remain below the customer switching point.[134]

The timely use of accelerated depreciation can reduce the risks that uncertain or declining demand can expose consumers and service providers to, and thereby help support a more orderly energy transition. That is, by:

- Providing for a more economically efficient (and smoother) time profile of prices and more equitable outcomes across all consumers, with current and future customers making equivalent contributions to the recovery of efficient capital costs.
- Mitigating the price and other adverse impacts that customers facing financial, technical or other barriers to switching could otherwise face. These customers could include renters, certain commercial and industrial users, people living in community or social housing, low income households and other vulnerable customers, residents in apartments, and industrial customers that face additional challenges to switching.
- Reducing the capital at risk of stranding and so continuing to incentivise service providers to continue to operate the network, invest where it is efficient to do so and provide a safe and reliable service to remaining customers.

In the Commission's view, constraining the recovery of capital in the manner proposed by ECA, JEC and some other stakeholders would not be in the long-term interests of gas consumers or consistent with the RPPs.

That said, the Commission does consider that there is an opportunity to strengthen the rules to ensure they are fit for purpose and capable of supporting efficient capital cost recovery that promotes the long term interests of gas consumers through the energy transition.

B.5.3 The Commission has identified a number of limitations in the current capital cost recovery rules, which may impede the efficient use of these tools

The Commission has identified a number of limitations in the current capital cost recovery rules, which in its view may be impeding the efficient use of these tools and limiting their ability to mitigate the impacts of uncertain and declining demand on both consumers and service providers.

The limitations are summarised in Figure B.3 and are based on the Commission's review of:

- stakeholder feedback
- the rules, the equivalent provisions in the Gas Access Code and extrinsic material on the original intent of the capital cost recovery rules
- how the rules and equivalent provisions in the Gas Access Code have been applied
- how regulators in other jurisdictions and industries have sought to manage similar challenges
- the results of our own modelling.

While not shown in Figure B.3, another limitation that the Commission has identified with the current rules is that there is currently no requirement for service providers to:

- take a longer longer-term view on how to manage the risk of stranding and consumer impacts, or to consider the longer term consequences of their proposals, or

134 See for example, HoustonKemp, Smoothing cost recovery when gas demand is declining – a report for Jemena Gas Networks, January 2025 and ACIL Allen, Dampier to Bunbury Natural Gas Pipeline Economic Depreciation Study, December 2019.

- consider how these tools could be jointly used to more effectively manage these risks over the remaining life of the assets.

There is also no explicit requirement in the rules for the regulator to consider these two matters when making decisions. That said, the regulator is required by section 28(1)(a) of the NGL to consider the long-term interests of consumers when making capital cost recovery related decisions.

Figure B.3: Identified limitations with the current capital cost recovery rules

Tools	Objective of these tools	When should the tool be used	Identified limitations with the current rules
Depreciation	This tool should allow capital to be recovered in an efficient manner over the economic lives of assets, having regard to conditions facing the service provider, with a: • straight line depreciation more appropriate if demand is projected to be stable over time • accelerated depreciation more appropriate if demand is projected to decline, or assets face stranding risk • back-end loaded depreciation more appropriate if demand is projected to increase over time..	If a service provider is facing uncertain or declining demand, these tools would ideally be used while there are still a relatively large number of customers to recover the costs from and gas prices remain below the switching point.	A. The decision-making model in this rule does not recognise service providers facing stranding risk: i. may be better placed to determine how to balance the risks associated with the recovery of capital and potentially triggering customers to exit early and ii. should have an incentive to do so in a manner that is aligned with the NGO and RPPs. B. The rules provide no guidance on when it may be appropriate to use accelerated depreciation. C. The rules refer to demand growth in several places and while this is not constraining the operation of the rules, more neutral language could be used
Treatment of inflation	This tool should allow for inflation compensation to be recovered in an efficient manner, having regard to the conditions facing the service provider, with: • a real (indexed) approach likely more appropriate if demand is stable or growing • a nominal (unindexed) approach likely more appropriate if demand is declining (i.e. because it avoids deferring compensation to periods when there are fewer customers to recover costs from).		D. The rules do not currently require a decision to be made about how inflation is to be treated in an AA period. The decision is instead implicitly left to the regulator to determine through any published financial models, which is problematic because this decision-making model does not: i. allow for the particular conditions facing individual service providers to be considered ii. recognise that service providers facing stranding risk may be better placed to determine how to balance the risks of cost recovery and potentially triggering customers to exit early and should have an incentive to do so in a manner that is aligned with the NGO and RPPs. E. The rules provide no guidance on when it may be appropriate to use a real, nominal or other approach.
Redundant capital	This tool should, subject to appropriate guardrails, allow the following forms of redundant capital to be removed from the capital base, consistent with what would occur in a workably competitive market: • full redundant capital, where the assets cease to contribute in any way to the delivery of services • partial redundant capital where there has been a material decline in demand & assets are underutilised.	Should be used as more of a last resort tool if full or partial stranding cannot be averted	F. The rules do not clearly identify the types of redundancy that this tool can deal with or provide any guidance on when and how this tool should be used. G. The rules do not appear to allow the regulator to require partial redundant capital to be removed from the capital base, which differs from the approach taken with full redundant capital (i.e. assets that cease to contribute in any way to service delivery) and what applied under the Gas Code. H. The rules currently require a redundant capital mechanism to be specified in an AA in the period prior to any redundant capital being removed, which could limit the timeliness with which the tool can be used.

Re-use of redundant capital	This tool should allow full or partial redundant capital to later be recovered from consumers where:
	• assets are being used to provide services and for:
	  • full redundant capital, to the extent the capital meets the new caoex criteria, or
	  • partial redundant capital, to the extent the utilisation has increased or been extended, and
	• there is an opportunity to recover some (or all) of the capital from consumers.
		May be used after redundant capital is removed	I. The current test for the re-use of redundant capital rule only allows capital to be recovered if it starts to contribute to service delivery and satisfies the new capital expenditure criteria. While this test may be appropriate for full redundancy (i.e. where assets ceased to contribute to service delivery), it doesn't adequately deal with partial redundancy arising from underutilisation of an asset still used in service delivery.
			In our view, a more appropriate test for the re-use of partially redundant assets would be linked to changes in utilisation (e.g. if demand subsequently increase, or the life of the pipeline is extended).

Source: AEMC.

B.6 We propose to amend the capital cost recovery rules to support efficient capital recovery that promotes long-term interests of consumers

Our proposed direction, which is summarised in Figure B.1, seeks to support efficient capital recovery that promotes the long-term interests of gas consumers by:

- enabling the capital cost recovery tools to be used, as and when required, to help mitigate the impacts of uncertainty and declining demand on service providers and consumers
- providing more guidance on how and when the tools should be used and the role of the regulator, and
- making some other minor amendments and consequential changes to the rules.

At a high level, the proposed direction provides for service providers, facing uncertain or declining demand to be able to do the following (subject to regulatory oversight), while there are still a relatively large number of customers to recover costs from and delivered gas prices are below the switching point:

- use the depreciation provisions to recover a greater portion of capital earlier through changes to either the economic life and/or depreciation profile, where that is consistent with the depreciation criteria, the NGO and RPPs[135]
- use the treatment of inflation provisions to cease deferring the recovery of compensation for inflation by moving to a nominal (unindexed) approach, where that is consistent with the NGO and RPPs.

While early use of these tools may help to mitigate the impacts on consumer prices, there is still a risk that higher prices could trigger increased customer exit. Service providers would therefore need to carefully consider how to balance these risks when deciding how and when to use these tools and would also need to consider the longer term consequences.

- If, notwithstanding the use of these tools, it becomes clear that stranding cannot be averted (e.g. because prices are starting to exceed the switching point), service providers and the regulator could consider using the redundant capital provisions, subject to the constraints set out in the NGR. That is, to remove full or partial redundant capital from the capital base to minimise the capital at risk of stranding, or otherwise replicate what would occur in a workably competitive market.
- If it subsequently becomes clear that the redundant capital can – at least to some extent – be recovered, then service providers and the regulator would be able to consider adding this capital back into the capital base so it can be recovered from users.

Our proposed direction recognises that service providers facing declining or uncertain demand are best placed and incentivised to manage the associated risks appropriately but preserves and clarifies the oversight role of the regulator in ensuring outcomes that promote the long term interests of gas consumers. In this way, our proposed direction reflects the intent of the propose-respond model of the gas regulatory framework. It also reflects the fact that gas, while still used by many customers today, is a fuel of choice and that competition from other fuels may pose a

135 This approach is consistent with the approach used by regulators in other jurisdictions and sectors to manage stranding risks. We set this out in the case studies included in our consultation paper. See AEMC, Consultation paper National Gas Rule Amendments 2026 (Gas networks in transition), 18 September 2025, Appendix A.

constraint on the ability of service providers to exercise market power, at least for those that can readily switch.

Together with our proposed direction to require service providers and the regulator to consider a long-term outlook (appendix A), the proposed direction to support more efficient capital cost recovery would support a more holistic and longer-term consideration of how to manage the impacts of uncertain or declining demand on gas consumers and service providers and longer term consequences of decisions. Our proposed direction also seeks to:

- **Maintain flexibility in the regulatory framework**: The Commission considers that it is appropriate to maintain flexibility in the capital cost recovery rules, given the different circumstances that service providers may be in.
- **Support regulatory decisions that are in the long term interests of consumers:** The Commission considers that changes to the existing decision-making model, together with additional guidance in the rules on how and when the capital cost recovery tools should be used, would support regulatory decisions that promote the long-term interests of consumers and give effect to the RPPs.

In the Commission's view, the proposed direction provides a balanced impact on the risk-reward package service providers currently face:

- Service providers are already facing a risk of stranding, due to jurisdictional policies, changing consumer sentiment and the increasing competitiveness of other energy sources, which is independent of the regulatory framework.
- Our proposed changes to the depreciation and treatment of inflation provisions should reduce service providers' risk exposure by reducing the capital at risk of stranding.
- A form of the redundant capital provisions has been in place since 1997 and the proposed direction provides for significant constraints on the regulator's ability to use of this tool and a lower hurdle for partially redundant capital to be later recovered from consumers.

Further detail on each element of the proposed direction is provided below.

B.6.1 We propose to amend the depreciation provisions to support the efficient recovery of capital costs

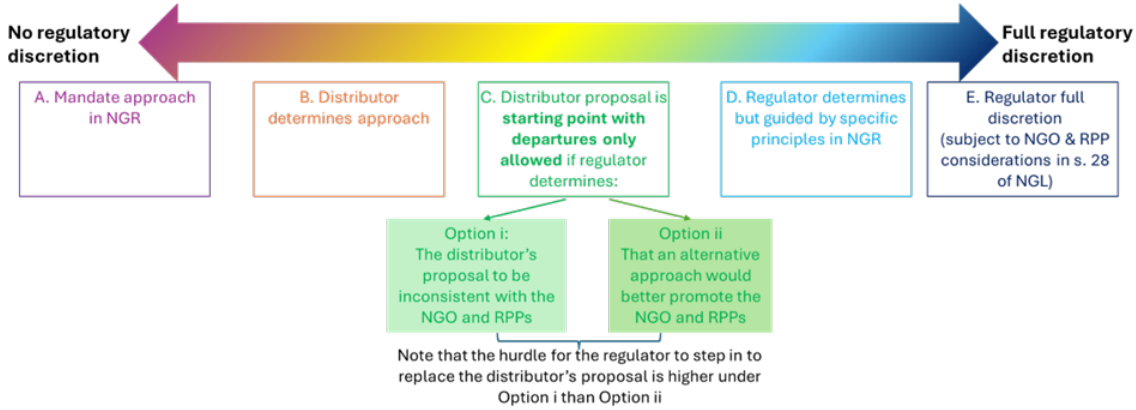
The intent of our proposed changes to the depreciation provisions is to allow capital to be recovered in an efficient manner over the economic lives of assets, having regard to conditions facing the service provider.

6.1.1 We propose to clarify the role of the regulator and require explicit consideration to be given to the NGO and RPPs in depreciation proposals

The intent of this proposed change is to allow accelerated depreciation to be used more effectively while there are still a relatively large number of customers connected to the network and delivered gas prices are still lower than the price of competing energy sources.

There are a number of options for how this could be achieved, which would involve making changes to the decision-making model. Figure B.4 sets out the potential decision-making options (note that variants are also possible).

Figure B.4: Potential decision-making models



Source: AEMC.

There are risks and benefits associated with each of these options and the choice between the options will depend on the circumstances in which they would be used. For example:

- Option A may be appropriate if there is a single solution that could be applied in all instances which meets the NGO and RPPs, and its suitability is not expected to change over time.
- Option B may be appropriate if a service provider's incentives would always be aligned with the NGO and RPPs and they are considered best placed to manage the risks of their decisions, such that there is no need for regulatory oversight.
- Option C may be appropriate if a service provider's incentives would, in most cases, be aligned with the NGO and RPPs and they are considered better placed to manage the risks of their decisions, but some form of regulatory oversight is still considered necessary. There are two sub-options for the circumstances in which the regulator could require an alternative approach, with:
- sub-option (i) requiring the regulator to determine that the service provider's proposal is inconsistent with the NGO and RPPs
- sub-option (ii) allowing the regulator to use an alternative approach to what the service provider proposed if it would better promote the NGO and RPPs.

Sub-option (i) implies a higher hurdle for the regulator to step in to replace the service provider's proposal than sub-option (ii).

- Option D may be appropriate if a service provider's incentives are not necessarily aligned with the NGO and RPPs, so regulatory oversight is required, but the NGO and RPPs are not considered sufficient to guide the regulator's discretion.
- Option E may be appropriate if a service provider's incentives are not necessarily aligned with the NGO and RPPs, so regulatory oversight is required and the NGO and RPPs are considered sufficient to guide the regulator's discretion.

In the case of **depreciation**, the Commission does not consider that Option A is appropriate to use in this context, because there is no one size fits all solution to depreciation that could be applied to all service providers in all instances. This is because while some networks are facing declining

demand and the risk of stranding, others are continuing to experience growth, or are planning to repurpose their networks.[136]

In assessing the suitability of the remaining options, the Commission has considered whether service providers' incentives would be aligned with the NGO and RPPs. In short, it would appear that:

- Where service providers are facing the risk of stranding, their incentives should be aligned with the NGO and RPPs (e.g. if they increase prices too much, this could trigger customer exit, which could lead to a greater amount of capital being stranded). They are also likely better placed than the regulator to make any commercial trade-offs that may be required.
- Where service providers are **not** facing the risk of stranding, their incentives may not be as well aligned with the NGO and RPPs, so greater regulatory oversight may be required.

Because service providers' incentives may not always be aligned with the NGO and RPPs, the Commission does not consider Option B to be appropriate to use in this context. This risk could be overcome under Option C or Option D, by providing for greater regulatory oversight.

Of the two options, **the Commission considers Option C to be preferable to Option D**. This is because in most cases where service providers are seeking to accelerate depreciation, they are likely to be well-placed and have a strong incentive to appropriately balance the risks associated with accelerating depreciation and triggering early exit.

Employing this decision-making model in the context of depreciation would mean that:

- a service provider would be required to propose how it intends to recover depreciation and to set out how it is consistent with the NGO and RPPs
- depending on whether Option C(i) or C(ii) is used, the regulator would be required to:
- approve the service provider's proposed approach, unless it determines that the proposal is inconsistent with the NGO and RPPs (Option C(i)), or
- approve the service provider's proposed approach, unless it determines that an alternative approach would be more consistent with the NGO and RPPs (Option C(ii)).

Under both options the service provider and regulator would be required to demonstrate how their proposal and/or decision is consistent with the NGO and RPPs. Service providers and the regulator would also be required to consider the longer term implications of their proposals and decisions (see appendix A).

The Commission is yet to form a view on whether sub-option C(i) or C(ii) should be employed and so are interested in obtaining stakeholder views on these options.

6.1.2 We propose to provide more guidance in the NGR on the circumstances in which the use of accelerated depreciation may be appropriate

The intent of this proposed change is to round out rule 89(2), which currently focuses on when it may be appropriate to defer the recovery of depreciation, to provide guidance on when accelerated depreciation may be appropriate.

Such guidance could involve setting out the circumstances in which bringing forward the recovery of depreciation may be appropriate, such as where:

- use of the asset is expected to decline over the remaining economic life, or

136 Note also that these rules also apply to transmission pipelines and any gas distribution networks that may be developed in the future that transport other covered gases.

- the asset is otherwise facing a risk of stranding.[137]

6.1.3 We propose to remove references to growth in rule 89

The intent of this proposed change is to remove the references to demand growth in rule 89(1)(a) so that it better reflects the conditions of an uncertain demand outlook.

B.6.2 We propose to amend the treatment of inflation provisions to support the efficient recovery of compensation for inflation

The intent of the following proposed changes is to allow for inflation compensation to be recovered in an efficient manner, having regard to the conditions facing the service provider.

6.2.1. We propose to introduce a decision point for how compensation for inflation is to be treated in an AA period

The intent of this proposed change is to allow for a proper consideration of whether a real (indexed), nominal (unindexed) or other approach to the treatment of inflation should be used, having regard to the specific circumstances facing the service provider.

This could be achieved by allowing a service provider to propose an approach and the regulator to make a determination on the approach on a case-by-case basis as part of the AA review process.

6.2.2 We propose to clarify the role of the regulator and require the service provider and regulator to give explicit consideration to the NGO and RPPs in proposals and decisions on the treatment of inflation

The intent of this proposed change is to ensure the appropriate decision-making model is used for the treatment of inflation.

In a similar manner to depreciation, the Commission considers that service providers that are facing stranding risk are likely to be well placed and have a strong incentive to appropriately balance the risks and trade-offs associated with how and when to recover compensation for inflation. Our proposed direction therefore provides for the use of the decision-making model in Option C (see Figure B.4).

Employing this decision-making model in this context would mean that:

- a service provider would be required to propose an approach to be used over the AA period and to set out how it is consistent with the NGO and RPPs
- depending on whether Option C(i) or C(ii) is used, the regulator would be required to:
  - approve the service provider's proposed approach, unless it determines that the proposal is inconsistent with the NGO and RPPs (Option C(i)), or
  - approve the service provider's proposed approach, unless it determines that an alternative approach would be more consistent with the NGO and RPPs (Option C(ii)).

Under both options the service provider and regulator would be required to demonstrate how their proposal and/or decision is consistent with the NGO and RPPs. Service providers and the regulator would also be required to consider the longer term implications of their proposals and decisions (see appendix A).

Like depreciation, the Commission is interested in hearing from stakeholders on whether Option C(i) or C(ii) should be used for decisions relating to the treatment of inflation.

137 This recognises that pipelines may face other sources of stranding risk, including for some pipelines, the depletion of gas reserves.

6.2.3. We propose to provide more NGR guidance on when it may be appropriate to use the different approaches to inflation

The intent of this proposed change is to provide service providers and the regulator with more guidance in the rules on the circumstances in which a real or nominal approach may be more appropriate.

Such guidance could involve setting out the circumstances in which a nominal (unindexed) approach may be appropriate, such as where use of the pipeline is expected to decline over the remaining economic life.

B.6.3 The Commission proposes to amend the redundant capital and re-use of redundant capital provisions so they can be used to replicate competitive market outcomes

As outlined in appendix B.2.2, it may not be possible to avert stranding from materialising through the use of accelerated depreciation and an unindexed (nominal) approach. It is important therefore that a service provider and the regulator can use the redundant capital and re-use of redundant capital provisions to minimise the capital at risk of stranding, manage price impacts that may trigger a disorderly exit, or otherwise replicate what would occur in a workably competitive market.

The intent of these proposed changes is to remove some of the barriers that we consider are limiting the application of these provisions in a way that supports efficient capital cost recovery that promotes the long-term interests of gas consumers.

6.3.1 We propose to specify the types of redundancy that can be dealt with

The intent of this proposed change is to remove barriers to the application of the redundant capital rule by clarifying that:

- This rule can be used to deal with both:
  - full redundancy, which can arise when assets cease to contribute in any way to the provision of pipeline services
  - partial redundancy, which can arise when there is a material non-transitory decline in demand and assets are underutilised.
- The removal of redundant capital does not necessarily require the removal of assets from the capital base. Rather, it may involve the removal of a value that reflects the redundancy.[138]

In the case of partial redundancy, the Commission considers that some type of materiality threshold should apply to the removal of capital from the capital base. For example, a specified percentage reduction in demand or customer numbers. We are therefore seeking stakeholder feedback on what an appropriate threshold would be.

6.3.2 We propose to clarify the role of the regulator in relation to partial redundant capital and provide more guidance on when the regulator could remove this type of capital from the capital base

The intent of this proposed change is to allow the regulator to require partial redundant capital to be removed from the capital base, but provide clear constraints on its ability to do so.

138 This is consistent with the original provisions in the Gas Access Code, which referred to the removal of an 'amount' and used the concept of capital, rather than assets.

In contrast to depreciation and the treatment of inflation, service providers are unlikely to have a strong incentive to use these provisions, even when it would be consistent with the NGO and RPPs. This is because it would result in the capital base effectively being written down.

The Commission does not therefore consider it sufficient to rely on the Option C decision-making model for this rule. Rather, the Commission considers that Option D, which provides for the regulator to make the determination guided by specific principles in the NGR, would be a more appropriate decision-making model to use in this context.

The use of this decision-making model would mean that partial redundant capital could be removed from the capital base, where:

- a service provider elects for it be removed, or
- the regulator otherwise determines it should be removed, having regard to the matters and constraints set out in the rules.

Table B.2 below sets out the types of matters and constraints that could potentially apply to the regulator's use of partial redundancy tool. Note that the matters and constraints set out in this table are indicative only at this stage and the Commission is interested in obtaining stakeholder feedback on them.

Table B.2: Indicative constraints that could apply to the regulator's use of the partial redundancy tool

Decision point	Matters to be considered or constraints	Rationale
Should the partial redundancy tool be used or are there better tools to use?	Before using the tool, the rules could require the regulator to consider: • the uncertainty that the use of this tool would cause and the effect that could have on service provider and users (which is akin to existing rule 85(4)) • whether there are any other more appropriate tools that could be used (e.g. accelerated depreciation).	These considerations are intended to point the regulator to seeing this as a last resort tool, rather than a first resort tool.
If the tool is to be used, what are the constraints on its use?	If the regulator considers the partial redundancy tool the most appropriate to use, then the rules could state that the regulator can only require partial redundant capital to be removed where the following conditions are met: 1. the service provider has already been given a reasonable opportunity to recover its capital costs (e.g. through accelerated depreciation); and 2. use of the partial redundancy tool: i. would reduce the stranding risk of remaining capital; and/or ii. it is necessary to respond to competition from alternative energy sources or another pipeline, or it otherwise replicates what would occur in a workably competitive market.	These constraints are intended to ensure the regulator uses the partial redundancy tool only where appropriate. That is, when service providers have already been given a reasonable opportunity to recovery their efficient capital costs and, when doing so would: • lead to more capital costs being recovered, which would benefit both the service provider and consumers, and/or • be consistent with what would occur in a workably competitive market, in line with the original intent of the provisions (see Appendix B.3.3).

Decision point	Matters to be considered or constraints	Rationale
What amount of partial redundant capital should be removed?	If the conditions for using the tool are met, and the regulator has decided that partial redundant capital should be removed, the rules could state that: 1. Where the service provider has elected to use this tool, the regulator must use the amount proposed by the service provider, unless it considers an alternative amount would be more consistent with the NGO and RPPs. 2. Where the regulator has determined to use this tool, the rules could require the regulator to have regard to the forecast cost of providing the services, the price of competing energy sources or pipeline services, the NGO and RPPs.	These matters are intended to provide more guidance on the amount of partial redundant capital that could be removed if the service provider elects to use the tool or the regulator otherwise determines to use it. In both cases, the decision would be guided by the NGO and RPPs.

6.3.3. We propose to replace the AA mechanism with a rules-based mechanism

The intent of this proposed change is to allow service providers and the regulator to use the redundant capital tool more efficiently when it is appropriate to use this tool. That is, by replacing:

- the current requirement for a redundant capital mechanism to be specified in an AA in the period prior to it being used (e.g. potentially 5 years before it is used), *with*
- a rules-based mechanism that could be used in the upcoming AA period.

Apart from removing the lag in the application of the current AA mechanism, this proposed change would ensure a more consistent approach to redundancy is taken across service providers.

6.3.4. We propose to amend the test for the re-use and recovery of partial redundant capital

The intent of this proposed change is to enable partially redundant capital to be added back to the capital base if utilisation has increased or been extended and there is an opportunity to recover some (or all) of the capital from consumers.

This differs from the approach currently provided for in rule 86 of the NGR, which requires the redundant capital to satisfy the new capital expenditure criteria before it can be added back into the capital base. While the Commission considers this appropriate for full redundant capital, the Commission considers a different test is required for partial redundant capital.

The Commission considers the test should be linked to demand because the asset is underutilised but still contributing to the provision of services, rather than ceasing to contribute in any way to service delivery.

B.7 Our proposed direction would promote the NGO and be consistent with the RPPs

B.7.1 Our proposed direction would better promote the NGO and is more consistent with the RPPs than the proposed rule changes

For the reasons set out below, our proposed direction would better promote the NGO than the status quo.

Our proposed direction would **improve outcomes for consumers over the longer term and promote principles of market efficiency.** That is, by enabling those service providers that are facing uncertain or declining demand to recover a greater portion of depreciation earlier and cease the deferral of compensation for inflation, while there are still a relatively large number of customers connected to the networks to spread those costs across.

Importantly, these measures would not result in service providers recovering more costs than they would have under a straight-line and real (indexed) approach. Rather, the amounts would be the same in net present value terms. They would nevertheless result in current customers paying higher prices than what they would under a straight-line depreciation and a real (indexed) approach. In this regard, it is worth noting that:

- Under a declining demand scenario, aligning the recovery of capital and compensation for inflation with the projected use of the pipeline **would produce a more economically efficient time-profile of prices and more equitable outcomes for consumers in the long term** than the straight-line and real (indexed) approach. This is because if demand is falling:

  - maintenance of a straight-line depreciation and real (indexed) approach would result in future customers bearing a disproportionate share of capital and inflation costs
  - aligning the recovery of depreciation and compensation for inflation with the expected use of the pipeline would result in current and future customers making equivalent contributions to the recovery of capital and inflation costs.
- Timely use of the two tools would mean capital and inflation costs can be spread across a larger number of customers and so minimise price impacts for current customers.

For those customers that remain connected to the network, which are likely to include customers that face switching barriers (including low income, vulnerable and other hard to abate customers), these measures would also help to reduce their exposure to:

- escalating and volatile prices
- the risk the service provider would cease operations early, which could have a range of adverse effects on these customers.[139]

These customers will also benefit from the proposed changes to the redundant capital provisions, by ensuring they do not pay more than what other consumers would pay for competing energy sources. In addition to these consumer benefits, a more efficient time profile of prices would promote the efficient use of pipeline services (including by supporting more informed and efficient decision-making by consumers about their future use of gas)[140] and help to support an orderly energy transition.

Our proposed direction would also support the safety, security and reliability of services and promote principles of market efficiency, by preserving service providers' incentives to prudently and efficiently operate their networks, and invest where necessary, including in compliance with applicable safety standards and regulations. That is, by supporting efficient cost recovery, efficient use of the pipeline (via more efficient pricing) and providing service providers with confidence that they will have a reasonable opportunity to recover at least their efficient costs.

A loss of confidence in the reasonable opportunity to recover efficient costs could adversely affect service providers' incentives to continue to efficiently operate and/or invest in the pipeline to maintain safety, security and reliability of services. This could, in turn, adversely affect those gas consumers that remain connected to the network if service providers decide to cease operations earlier than expected,[141] or if the safety or reliability of services is reduced. It could also have broader reaching implications for investment in other regulated infrastructure.

Our proposed direction is aligned with good regulatory practice and is consistent with broader gas market reform. The proposed changes to the capital cost recovery provisions seek to ensure that the tools are fit for purpose and service providers and the regulator can use the tools as and when required to help manage the challenges posed by declining and uncertain demand. They are also intended to be sufficiently flexible to deal with the different positions that service providers may be in and provide for an appropriate level of regulatory oversight.

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139 It could, for example, result in a far more expensive transition for those users that can switch. It could also result in some industrial customers having to cease operations if they are unable to switch. It may also result in welfare losses from reduced use of appliances and equipment that these customers have invested in.

140 This includes decisions by prospective customers to connect to the network and decisions by existing customers to either remain connected to the network (and potentially invest in new appliances or equipment), or to switch to alternative energy sources.

141 There are now a number of examples of this occurring, including the Esperance gas distribution system, which was shut down in 2025 and the Solstice compressed natural gas distribution system in Victoria, which is expected to shut down in 2026. ATCO has also recently announced it intends to shut down the Albany LPG reticulated gas distribution system (see here).

Our proposed direction is also consistent with the RPPs. As the proponents and a number of stakeholders (including service providers) observed[142] the RPPs do not guarantee that service providers will recover their efficient costs. They do, however, require service providers to have a reasonable opportunity to recover their efficient costs.

The Commission considers that the proposed changes to the depreciation and treatment of inflation provisions would provide service providers with such a reasonable opportunity. That is, by allowing them to bring forward the recovery of capital costs and cease the deferral of compensation for inflation to minimise the capital at risk of stranding.

There may still come a point where stranding risk cannot be mitigated and the service provider and/or regulator will need to use the redundant capital provisions when this risk materialises. This is consistent with what would occur in a competitive market, where firms also face the risk of stranding due to competition, technological and policy changes. It is also consistent with the RPPs, which do not guarantee that service providers will recover all their efficient costs.

The Commission considers that the proposed direction is necessary to provide service providers' confidence that they will have a reasonable opportunity to recover at least their efficient costs, because the absence of this could have a range of adverse effects on consumers. It could, for instance, result in service providers deciding to cease their operations early, or otherwise affect their incentive and/or ability to maintain the network, invest where it is prudent and efficient to do so, and provide safe and reliable services to consumers for as long as that is required. It may also affect their incentive and/or ability to transition to renewable gases, where that is a viable option.

The proposed direction is also necessary to:

- promote economic efficiency by ensuring service providers continue to have an incentive to efficiently provide pipeline services and, to efficiently operate and invest in the network, where necessary[143]
- avoid the costs and risks of:[144]
  - underinvestment that may otherwise arise if service providers believe they will not have a reasonable opportunity to recover at least their efficient costs
  - overinvestment that may otherwise arise if the redundant capital provisions could not be used where it is appropriate to do so.

The Commission does not consider that our proposed direction would lead to overinvestment in the network if there are projections of declining demand, as service providers still face a risk of stranding (e.g. if demand declines faster than expected). Together with our proposed direction on expenditure, this should mean that service providers have neither the incentive nor the ability to overinvest in the network.

B.7.2 The Commission has also considered and assessed alternative options against the NGO

In developing our proposed direction, we have considered other policy options, including the status quo (do nothing) option and the policy options proposed by ECA and JEC. In doing so we have had regard to the potential benefits and risks of each option and whether they are likely to promote the NGO and be consistent with the RPPs. Our assessment of these other options is summarised in Table B.3.

142 See for example, JEC, Rule Change Request, p. 4 and Stakeholder submissions to the draft determination: ECA, p. 15; ENA, p. 10; Evoenergy, p. 1; Jemena, p. 6; AGIG, p. 5; AusNet, p. 6; EnergyAustralia, p. 5; Alinta Energy, p. 1; IEEFA, p. 4 and JEC, Rule Change Request, p. 4.

143 Consistent with NGL section 24(3).

144 Consistent with NGL section 24(3) and 24(6).

The Commission does not consider any of these other options to be preferable to our proposed direction. This is because they are less likely to promote the NGO and less consistent with the RPPs. There is also a risk with the ECA and JEC proposals that service providers would be deprived of a reasonable opportunity to recover at least their efficient costs, which would be contrary to the RPPs.

Table B.3: Assessment of other policy options: Capital cost recovery

Option	Benefits	Risks	Our view
Status quo/ do nothing	Maintaining current arrangements would avoid regulatory costs and risks identified for options 2 and 3.	• **General**: There is limited guidance on the use of the capital cost recovery tools, limiting their utility as a complementary package of measures to manage stranding risk and consumer impacts. • **Depreciation**: The broad discretion and lack of guidance provided in these rules may mean this tool is not used as efficiently as it could to manage stranding risk and consumer impacts. • **Treatment of inflation**: The ability to switch to a nominal (unindexed) approach may be impeded even where it is appropriate to do so, because there is no clear decision point for the treatment of inflation in an AA . • **Redundant capital provisions**: The ambiguity in	The Commission considers that this policy option would: • promote the NGO to a lesser extent • be less consistent with the RPPs. than our proposed direction. This is because there are a number of limitations in the current rules.

Option	Benefits	Risks	Our view
		the current drafting of these provisions, and lack of guidance on when they should be used, means these provisions may not be used even where it would be efficient to do so to support efficient capital cost recovery and manage consumer impacts	
ECA proposal	• Current customers would benefit from constraints on accelerated depreciation (to the detriment of future customers). • Some of the proposed conditions could help facilitate a more consistent assessment of service provider actions to manage demand risks and adverse consumer impacts.	• Similar to status quo, but potentially more significant impacts due to constraints on ability to accelerate depreciation, some of which are not in the service providers' control. • Conditions that restrict accelerated depreciation could • adversely affect future consumers, including those that face switching barriers (e.g. through higher and potentially more volatile prices, poorer quality services, or the early termination of services)	The Commission considers this policy option would promote the NGO to a lesser extent than our proposed direction and is unlikely to be consistent with the RPPs. While some of the ECA's proposed conditions could help to drive more prudent and internally consistent behaviour by service providers, we consider that such outcomes could be better achieved through our proposed direction on improving information requirements.
JEC proposal	• Current customers would benefit from constraints on accelerated depreciation. • Current and future customers could also benefit from the proposed		The Commission considers this policy option would promote the NGO to a lesser extent than our proposed direction and is unlikely to be consistent with the RPPs. The Commission considers the intent of this proposal would be better achieved through our

Option	Benefits	Risks	Our view
	changes to the redundant capital provisions (including the 50 per cent cap consumers' share) if the provisions are used.	• mean service providers do not have a reasonable opportunity to recover at least their efficient costs, which could adversely affect their incentive and/or ability to continue to operate the network, invest where it is prudent and efficient to do so and provide a safe and reliable service to remaining customer. • Rules that require service providers to write down their capital base early (as proposed by the ECA) or place a cap on consumers' share of redundant capital (as proposed by JEC) could have the same adverse effects on consumers and service providers outlined above.	proposed direction, seeking to enable service providers and regulators to use the capital cost recovery tools in a complementary manner to manage efficient cost recovery and consumer impacts.

Source: AEMC

B.8 Looking forward, governments will need to support an orderly transition and consideration may need to be given to the form of regulation

B.8.1 There will be a role for governments given the limits to addressing consumer price impacts and stranding through the regulatory framework

Our proposed direction seeks to address the limitations in the current rules that are impeding the efficient use of the capital cost recovery tools. However, as outlined in appendix B.2.2, these tools may not be able to fully address the pricing and stranding risks associated with uncertain or declining demand. There could therefore be a role for governments in helping to support an orderly transition (see section 4.6 for more detail).

B.8.2 If conditions change, there may also be value in reviewing the form of regulation that applies to each distribution network

If stranding is expected to occur because of competition from other energy sources, then it may be relevant to consider whether a gas distribution network should:

- **continue to be a scheme pipeline** – scheme pipelines are subject to a stronger form of regulation that requires the service provider to have its proposed AA approved by the regulator on a periodic basis, or
- **become a non-scheme pipeline** – non-scheme pipelines are subject to a lighter form of regulation that focuses on facilitating commercial negotiations, supported by access obligations, disclosure requirements and a commercially-oriented dispute resolution mechanism in the NGL/NGR.

This would need to be considered by the relevant decision maker on a case-by-case basis. This is because while competition may pose more of a constraint on the service provider's behaviour when dealing with customers that can more readily switch, this is unlikely to be the case for those customers that find it more difficult to switch.

Service providers may therefore continue to exert a significant degree of market power over customers that face switching barriers, which could result in this group of customers paying significantly more for services than those that can switch more readily.

Whether scheme regulation is the best way to manage this market power is a separate question and will depend on the decision-maker's application of the form of regulation test in the NGL to the relevant pipeline (see Box 6).

In the east coast and Northern Territory, the AER is responsible for applying this test and deciding on the form of regulation a non-designated pipeline should be subject to and can do so in response to an application, or on its own initiative. In Western Australia, the relevant Minister is responsible for making this decision.

The term 'designated pipeline' is used in the NGL to refer to pipelines that jurisdictions determined should be scheme pipelines and cannot therefore be subject to a form of regulation review.[145] Of the six gas distribution networks in the east coast currently subject to scheme regulation, the AGN SA, AGN Victoria, Multinet and AusNet networks have been classified by the South Australian and Victorian governments as designated pipelines since 2008 under jurisdictional arrangements.[146]

145 The designation power was a one-off power.

The AER would not therefore be able to consider whether scheme or non-scheme regulation is more appropriate for these networks unless the designation classification was removed by the relevant jurisdictions.[147]

Noting the designation classifications have been in place since the NGR came into effect in 2008, there could be value in the South Australian and Victorian governments considering whether this classification remains appropriate, or if these distribution networks should be capable of having the form of regulation changed, like their ACT and NSW counterparts. This could be informed by an AER review into designated pipelines under s. 121 of the NGL, which Energy Ministers or service providers can ask the AER to undertake at any time.

Box 6: Form of regulation decisions

When deciding on what form of regulation should apply to a pipeline, s. 112 of the NGL requires the AER to consider the effect of regulating the pipeline as a scheme or non-scheme pipeline would have on:

- the promotion of access to pipeline services
- the costs that are likely to be incurred by an efficient service provider, efficient users and efficient prospective users, and
- the likely costs of end users.

In doing so, the AER must have regard to the NGO and form of regulation factors.

The form of regulation factors are set out in s. 16 of the NGL and are as follows:

1. the presence and extent of any barriers to entry in a market for pipeline services;
2. the presence and extent of any network externalities (that is, interdependencies) between a covered gas service provided by a service provider and any other covered gas service provided by the service provider
3. the presence and extent of any network externalities (that is, interdependencies) between a covered gas service provided by a service provider and any other service provided by the service provider in any other market;
4. the extent to which any market power possessed by a service provider is, or is likely to be, mitigated by any countervailing market power possessed by a user or prospective user;
5. the presence and extent of any substitute, and the elasticity of demand, in a market for a pipeline service in which a service provider provides that service;
6. the presence and extent of any substitute for, and the elasticity of demand in a market for, electricity or gas (as the case may be).

146 The AGN SA designation is set out in Schedule 1 of the National Gas Regulations, while the Victorian designations are set out in a Ministerial Order made under s. 9A of the National Gas (Victoria) Act 2008 (see Victorian Government Gazette, No. S 222, 30 June 2009).

147 See section 97 of the NGL; The AER could, however, conduct a form of regulation review at any time for the JGN and Evoenergy networks.

Question 5: Our proposed direction on capital cost recovery (detailed in appendix B)

1. What are your views on our proposed direction for capital cost recovery tools in the NGR?
2. Do you have any views on the decision-making model options explored for:
   a. depreciation and treatment of inflation?
   b. redundant capital provisions?
3. In relation to our proposed direction for redundant capital, do you have any views on:
   a. the materiality threshold that should apply to partial redundancy?
   b. the constraints that could apply to the regulator's use of partial redundancy?

C Our proposed approach to amend the expenditure provisions

In an environment of uncertain future gas demand, it is increasingly important that the regulatory framework requires service providers to provide sufficient justification to support the regulator's assessment of proposed gas pipeline expenditure - to minimise future costs to gas consumers and stranding risk. ECA have submitted a rule change request to update the regulatory framework in relation to the assessment of investments in long-lived assets, such as pipelines.

C.1 There is an opportunity to improve the current framework for proposing and assessing gas pipeline expenditure to better meet the challenges of uncertain demand

C.1.1 ECA consider that the current framework for proposing and assessing expenditure lacks transparency and is not promoting consumers' interests

ECA's concern is that the current regulatory framework is not protecting consumers against the risk of over investment in gas pipelines 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 service providers have recently made relatively large claims for capital expenditure (capex) (at levels similar to previous AAs while also claiming accelerated depreciation to manage the risk of stranding.[148] According to ECA, this demonstrates that service providers do not consider potential capex through the lens of declining demand and the implications for cost recovery in that context.

ECA considers that the current capex criteria are too broad and predicated on an assumption of demand growth. It also considers that:[149]

> The propose-respond model provides pipelines 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 AAs, ECA identified some key themes that it considers point to the deficiencies of the current rules for allowing capex.[150] For example, ECA submits that capex 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.

The ECA proposal raises the following key issues:

- the capex criteria do not provide sufficient prescription to ensure that only efficient capex is added to the capital base
- the regulator is limited in considering the implications of declining demand under the propose-respond model

148 ECA, Rule change request - Capital expenditure, p. 15.
149 ECA, Rule change request - Capital expenditure, p. 15.
150 ECA, Rule change request - Capital expenditure, pp. 16-18.

- stakeholders cannot adequately input into the regulator's considerations due to a lack of information
- the definition of operating expenditure (opex) is predicated on an obsolete assumption of growing demand, which may not keep opex to an efficient minimum level.

To address these issues, ECA propose to amend capex and opex provisions in the National Gas Rules (NGR) through the amendments set out in appendix C.2 and appendix C.3 below. ECA consider that more prescriptive rules would be more effective at constraining new capex compared to the current arrangements by providing for additional rigour and better information for stakeholders and regulators to assess capex proposals.[151]

ECA note that their proposed changes would by default apply to all scheme pipelines, but if they create adverse consequences for transmission pipelines, they could apply only for distribution pipelines.[152]

C.1.2 Stakeholders have diverse views on ECA's proposed changes to the NGR capex and opex provisions

Stakeholders have diverse views on ECA's proposal to amend the capex criteria in the NGR:

- **Most consumer groups and other interest groups support ECA's proposal to amend the capex criteria.** They consider that service providers have too much discretion to propose new capex and that stranding risk could be better managed if new capex were minimised to that necessary to meet the NGO. Consumer and user groups support requiring service providers to explicitly consider declining demand scenarios, carry out cost benefit analysis and consider alternatives to capex such as strategic decommissioning.[153] The AER is open to amending the capex criteria provided that they remain sufficiently flexible (principles-based and not prescriptive).[154]
- **Service providers and industry bodies do not support ECA's proposal to amend the capex criteria because they consider that:**
  - the framework is fit for purpose, supporting efficient capex through criteria that require service providers to justify capex and provide the regulator with flexibility to adapt to different demand trajectories and jurisdictional policies[155]
  - the proposed changes would add prescription to the NGR, increase administrative burden and reduce flexibility[156]
  - service providers already have a strong incentive to minimise new capex given that cost recovery is not guaranteed and there is a risk of stranding.[157]

Stakeholders have diverse views on ECA's proposal to change the definition of opex in the NGR:

- **Consumer and user groups, retailers and the AER support changing the opex definition** given the presumption of increasing long-term demand for pipeline services is no longer appropriate.[158] Origin suggests that references to increasing long-term demand should be replaced with supporting efficient and safe networks.[159] The AER supports the change in

151 ECA, Rule change request - Capital expenditure, p. 21.
152 ECA, Rule change request - Capital expenditure, p. 20.
153 Submissions on consultation paper: ECA, p. 14; Environment Victoria, p. 4;EUAA, p. 3; JEC, pp. 15-17; SACOSS, pp. 4-5; Lighter footprints p. 2.
154 AER, submission on consultation paper, pp. 4-5.
155 Submissions on consultation paper: AGIG, p. 5; APGA, p. 22; AusNet, p. 8; ENA, p. 23; EvoEnergy, p. 3.
156 Submissions on consultation paper: AGIG, p. 9; APGA, p. 22.
157 ENA, submission on consultation paper, pp. 17-18.
158 Submissions on consultation paper: AER p. 6, Alinta p. 4, BSL p. 6, ECA p. 17, EUAA p. 3, JEC p. 17, Origin p. 3, Lighter footprints p. 1, Rewiring Australia p. 3.

principle but suggests the Commission consider how it may work with the potential supply of biomethane and/or hydrogen blends.[160]

- **Service providers and industry groups do not support changing the definition of opex.**[161] Jemena considered that removing increasing demand from the opex definition, while regulating gas networks using a price cap or hybrid price-revenue cap, would mean that gas networks are unable to effectively manage demand risk (i.e. by trying to increase customer numbers).[162] The Australian Pipelines and Gas Association (APGA) and ATCO consider that the opex definition aligns with recent reforms that recognise the potential transportation of renewable gases, supporting efficient integration of renewable gases.[163]

C.1.3 We consider that the current framework for assessing gas pipeline expenditure lacks the clarity and transparency required to minimise expenditure in the context of uncertain demand

The current provisions on capex and opex apply to both transmission and distribution service providers. Given that future demand is uncertain and not all transmission and distribution service providers are facing a declining demand outlook, any changes to the rules need to be flexible and fit for purpose to cater for all service providers and scenarios. The Commission also notes that, even in scenarios where a service provider is facing declining demand, there is a need for ongoing capex and opex to ensure the continued provision of safe and reliable services.

The current regulatory framework does provide service providers with incentives to invest efficiently in their networks to minimise the risk of stranding. This is because if assets become stranded, there is no guarantee of cost recovery under the regulatory framework. For example, to date the AER has not permitted the full amount of accelerated depreciation sought by service providers, leaving them exposed to stranding risk. Incentives for service providers to invest efficiently would be further strengthened if the Commission's proposed direction for the redundant capital provisions is implemented. This proposed change would impose further discipline on service providers to invest only in capex necessary to reduce the potential need to apply the redundant asset provisions and so bear the cost of stranding.[164]

In addition, the Commission expects the quantum of capex proposed by distribution network service providers to decrease in future following our recent rule change to require newly connecting retail gas customers to pay cost-reflective connection charges upfront from 1 October 2026.[165] The Victorian Essential Services Commission implemented a similar requirement on 1 January 2025, which applies to retail customers using Victorian distribution networks.[166] Together these changes will eliminate connections capex for scheme pipelines in Victoria, New South Wales, South Australia and the ACT.[167] Net connections capex accounted for 34 per cent of total capex, based on the aggregate of all capex for scheme pipelines in their current AA period.[168] CEPA's modelling shows that, if expenditure decreased further in future, it would meaningfully

159 Origin, submission on consultation paper, p. 3.

160 AER, submission on consultation paper, p. 5.

161 Submissions on consultation paper: AGIG, p. 11; APGA, pp. 25-26; AusNet, p. 10; Jemena, p. 19.

162 Jemena, submission on consultation paper, p. 19.

163 Submissions on consultation paper: APGA, p. 11; and ATCO, p. 5 of 18.

164 This is consistent with a view expressed by the AER that "The more exposed a network business is to stranding risks, the more incentives it may have to minimise capex". See AER, Regulating gas pipelines under uncertainty, Information paper, November 2021, p. 53.

165 AEMC, Updating the regulatory framework for gas connections, Rule determination, 11 December 2025.

166 Essential Services Commission, *Gas Distribution System Code of Practice review*, Final decision, 9 May 2024.

167 The new rule in respect of gas connections applies to operators of scheme or nominated non-scheme pipelines in the National Energy Customer Framework (NECF) jurisdictions subject to Part 12A of the NGR.

168 ECA, Rule change request, *Updating the regulatory framework for gas connections*, 14 February 2025, p. 16.

reduce retail residential bills compared to the base case scenario where expenditure did not decrease in future (see appendix C.1.4).

Nonetheless, the Commission identifies several issues and gaps in the current regulatory framework for capex and opex that we consider should be addressed to support prudent and efficient investment in the context of uncertain demand:

1. **There are several areas where the NGR capex and opex criteria could be tightened to minimise expenditure while continuing to supporting safety and reliability**. For example, some elements of the NGR that may be interpreted as having an implicit presumption that residential and small commercial gas demand will stay the same or increase.
2. **There is a lack of transparency in some aspects of service providers' AA proposals.** For example, service providers' expenditure proposals in an AA do not always reference the part of NGR rule 79(2) that capex is justified under. This can make it difficult for stakeholders to consider and provide feedback on proposed expenditure, and can reduce confidence that proposed expenditure is prudent and efficient.
3. **There is no explicit requirement to consider long-term demand trends beyond the five year AA period and the potential implications of changing long-term demand trends on expenditure proposals within the five-year AA period under review.** Greater explicit consideration of longer-term demand trends or scenarios may influence expenditure decisions and help minimise stranding risks. For more information on our proposed approach to require service providers and the regulator to consider a long-term outlook, refer to appendix A.

The Commission acknowledges that the these gaps are filled to some extent by the AER's *Better Resets Handbook* and its *Information Paper on regulating gas pipelines under uncertainty*. The *Better Resets Handbook* clarifies the AER's expectations about how service providers' justification for forecast capex, including the consideration of alternative options.[169] The AER's *Information paper on regulating gas pipelines under uncertainty* sets out the AER's expectation that service providers should forecast a range of different possible demand scenarios and look well beyond the next regulatory period in preparing their AA proposals.[170] However, neither the AER's *Better Reset Handbook* nor its *Information paper on regulating gas pipelines under uncertainty* are binding and, as discussed in more detail in appendix C.2, we consider there are benefits in addressing the identified issues and gaps in the NGR.

C.1.4 CEPA's modelling of the indicative impact of lower expenditure on residential retail bills

The Commission engaged CEPA to carry out long-term modelling related to gas service providers, as explained in CEPA's report.

CEPA's modelling, shown in Figure C.1 below, shows that if expenditure decreased in future it would meaningfully reduce retail residential bills. This would improve long-term outcomes for consumers (provided that pipeline services are provided safely and all relevant regulatory requirements are met) compared to a base case scenario where expenditure did not decrease in future.[171] The base case scenario takes into account the Commission's:

- final determination and rule for all newly connecting retail gas customers to pay upfront cost-reflective charges for their gas connection, meaning that no new connections capex enters the

169 AER, Better Resets Handbook – Towards consumer centric network proposals, July 2024, p. 20.

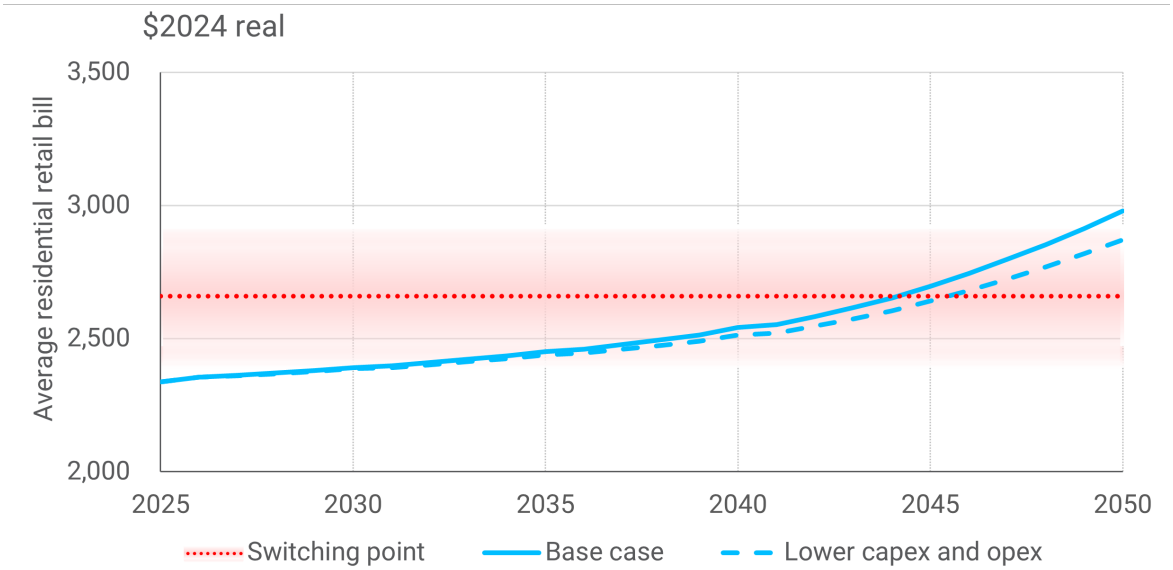
170 AER, Regulating gas pipelines under uncertainty, Information paper, November 2021, p. 53.

171 Retail residential bills in Figure A.1 are based on illustrative network 2 and assume that capex decreases by 1 per cent per annum and opex decreases by 1 per cent per annum, for the entire period from 2025 to 2050. For more information on the modelling approach, refer to CEPA's report.

capital base.[172] Net connections capex accounted for 34 per cent of total capex, based on the aggregate of all capex for scheme pipelines in their current AA period.

- draft determination and draft rule for retail gas customers to pay cost-reflective charges if they choose[173] to abolish their gas connection.[174]

Figure C.1: Modelled outcomes of average retail residential bills over 2025-2050 for an illustrative network facing gradual demand decline ($)



Source: CEPA modelling for AEMC.

Given that lower expenditure can improve long-term consumer outcomes, the Commission considers it would be useful to amend the capex and opex provisions in the NGR to minimise expenditure while supporting safety and reliability, as we propose in appendix C.2 below. We note that our proposed changes to the capex and opex provisions in the NGR would not guarantee lower expenditure in future.

C.2 We propose to amend the NGR capex and opex provisions to improve regulatory clarity and transparency and support the long-term interests of consumers under uncertain demand

In appendix C.1 above the Commission identifies issues and gaps in the current regulatory framework for justifying and assessing capex and opex. We have identified broader issues relating to the lack of transparency over service providers' and regulators' long-term approach to managing the impacts of uncertain demand and information needed to improve the efficiency of decision-making. These are addressed through our proposed approach to require service providers and the regulator to consider a long-term outlook, which is explained in appendix A.

172 The changes will take effect from 1 October 2026 under the new gas rule for *Updating the regulatory framework for gas connections*. However for simplicity our modelling assumes that no new connections capex enters the capital base over the modelling period starting from 2025. AEMC, *Updating the regulatory framework for gas connections*, Final determination, 11 December 2025, p.i.

173 If a connection has to be abolished for safety reasons the costs will be recovered from all customers.

174 These changes would take effect from the start of the next AA period for each gas distribution business under the draft gas rule: AEMC, *Establishing a regulatory framework for customer initiated gas abolishment,* Draft determination, 30 October 2025, p. viii. However for simplicity our modelling assumes that no abolishment costs apply over the modelling period starting from 2025.

To address these issues, we propose to amend the capex and opex provisions in the NGR to ensure the regulatory framework continues to support the long-term interests of gas consumers. Our proposed solution includes some, but not all, elements of ECA's rule change proposal and additional changes based on stakeholder feedback and the Commission's analysis.

We propose the following changes to the capex and opex provisions to reflect specific amendments proposed by ECA in their rule change request:

- **clarifying that service providers must justify all capex through a quantitative assessment of all credible options** related to the provision of regulated pipeline services[23] (appendix C.2.1)
- **amending the justification for safety-related capex to be necessary for the safe operation of pipelines and use of services** (appendix C.2.2)
- **replacing the reference in the capex criteria to maintaining capacity to meet existing levels of demand with maintaining capacity to meet forecast levels of demand** (excluding where an expansion of pipeline capacity is required)[26] (appendix C.2.3)
- **amending the definition of opex to remove the reference to expenditure being incurred to increase long-term demand for pipeline services** and otherwise develop the market for pipeline services[27] (appendix C.2.4).

In addition, we propose the following change to the capex provisions based on the Commission's further analysis:

- **requiring service providers and regulators to explicitly link the driver for capex to one of the capex provisions in the NGR** (appendix C.2.5).

We are also considering whether the Net Present Value (NPV) test should be retained as a reason for capex being justifiable and are seeking further stakeholder feedback on this (appendix C.2.6).

Figure C.2 below summarises our proposed changes to the capex and opex provisions. This is complemented by our proposed approach to require service providers and the regulator to consider a long-term outlook, which is explained in appendix A.

C.2.1 We propose to clarify that service providers must justify all capex through a quantitative assessment of all credible options that relate to the provision of regulated pipeline services

There is currently no requirement in the NGR for service providers to consider a range of credible options, apply a quantitative assessment of different options for all forms of capex, or explicitly consider future demand risk when justifying new or replacement capex. We propose a new approach to assessing proposed expenditure which would require service providers to:

- consider all credible options to address an identified need that relates to the provision of regulated pipeline services (but excluding options to transition the customer to an alternative fuel such as electricity or LPG tanks)
- conduct a quantitative assessment of the costs and benefits associated with all credible options.

The existing criteria for new capex in the Rules set out what is 'conforming capex'[175]and what is 'justifiable capex'[176]:

175 NGR rule 79(1).
176 NGR rule 79(2).

- **Conforming capex**: Capex that 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 in a manner consistent with the NGO.[30] We consider there is value in clarifying in the NGR how a service provider can demonstrate that they are acting prudently, efficiently and in accordance with good industry practice. Conforming capex must also be justifiable and properly allocated.
- **Justifiable capex**: For capex to be justifiable, different tests apply depending on the limb under which the capex is being justified. Specifically, capex is justifiable if:
  1. The overall economic value of the expenditure is positive,[177] or
  2. The present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capex (NPV test),[178] or
  3. The capex is necessary:[179]
     a. To maintain and improve the safety of services; or
     b. To maintain the integrity of services; or
     c. To comply with a regulatory obligation or requirement; or
     d. To maintain the service provider's capacity to meet levels of demand for services existing at the time the capex is incurred (as distinct from projected demand that is dependent on an expansion of pipeline capacity); or
     e. To contribute to meeting emissions reduction targets through the supply of services.

Currently a quantitative test is:

- required to demonstrate that capex is justifiable under the first two limbs in NGR rules 79(2)(a) and (b)
- not required to demonstrate that capex is justifiable under the third limb in NGR rule 79(2)(c), where it is necessary for one of the reasons defined above.

In addition, there is no explicit requirement:

- to identify alternative credible options to the preferred capex solution under any of the three limbs in NGR rules 79(2)(a),(b) and (c),
- to consider the long-term trajectory of demand beyond the five-year AA regulatory period.

The AER provide additional guidance to service providers in respect of how capex should be justified and how it will be assessed in its *Better Resets Handbook*[180] and Information Paper on regulating gas pipelines under uncertainty.[181] Together, these documents set out the AER's expectations for how service providers should support their AA expenditure proposals, including the matters set out below.

- How service providers' capex proposals should demonstrate prudency and efficiency of proposed investments, particularly in the context of uncertainty about future utilisation. This includes an expectation that service providers conduct a quantitative cost benefit analysis of all feasible options.[182]

177 NGR 79(2)(a); This rule is subject to subrule (3), which sets out how the test should be applied.
178 NGR 79(2)(b).
179 NGR 79(2)(c).
180 AER, *Better Resets Handbook – Towards consumer centric network proposals*, July 2024.
181 AER, *Regulating gas pipelines under uncertainty, Information paper*, November 2021.
182 AER, Better Resets Handbook, p. 20 and AER, *Regulating gas pipelines under uncertainty,* Information paper, pp. 49-53.

- Factors that service providers should consider in developing demand forecasts to support their expenditure forecasts, including:[183]
  - relevant climate change policies and cross-elasticities of demand for natural gas substitutes in their demand forecasts
  - a range of different possible demand scenarios, with associated probabilities
  - demand and supply conditions well beyond the next regulatory period, and potentially several regulatory periods into the future.

The AER also expects service providers to provide possible future energy scenarios to demonstrate stranding risk in the context of proposing accelerated depreciation.[184]

The AER's *Better Resets Handbook* and *Information paper on regulating gas pipelines under uncertainty* together provide greater guidance to service providers about the AER's expectations of how capex should be justified. However these expectations do not necessarily reflect rule requirements and service providers are not required to meet these for any proposed expenditure to be approved.

Our review of a selection of business cases across all service providers, submitted to the AER in support of regulatory proposals, suggests that most service providers are considering multiple options and are undertaking some form of quantitative analysis. Similar to the AER requirements, our understanding is that the ERA generally requires business cases to be supported by quantitative analysis. In WA, for its most recent AA period (2025-29), ATCO claimed confidentiality for most of its business cases.[185]

We consider that service providers operating prudently and in accordance with the regulator's expectations would already be conducting quantitative assessments for all proposed capex, considering alternative options and looking beyond the five year AA period. For this reason, service providers are unlikely to incur significant additional costs complying with the proposed new obligations. Nonetheless, we consider there would be benefits to consumers and other stakeholders through improved transparency and greater confidence that only necessary and efficient capex is proposed and approved.

Against this background, the Commission considers that there is benefit in clarifying in the NGR that in demonstrating that a new investment is prudent and efficient, service providers are required to:

- consider all credible options to address an identified need
- undertake a quantitative assessment of all credible options, where this is practicable
- consider all credible options that relate to the provision of regulated pipeline services.

Elevating these requirements into the NGR would help support greater transparency for stakeholders. It would also provide greater discipline on both service providers and regulators to explain clearly why expenditure is considered to be prudent and efficient. Our proposed changes to the NGR would be supported by regulatory guidance around expenditure assessment, such as the AER's *Better Resets Handbook* and ERA's *Gas Access Arrangement Guideline*.[186]

183 AER, *Regulating gas pipelines under uncertainty, Information paper*, November 2021, p. 53.
184 AER, *Regulating gas pipelines under uncertainty, Information paper*, November 2021, p. 45.
185 ATCO, *Attachment 01.005 Document Index & Confidentiality Claims, ATCO Plan 2025-29*, 1 September 2023.
186 ERA, *Gas Access Arrangement Guideline*, 25 July 2022.

Require service providers to consider all credible options to address an identified need

The Commission proposes to amend the NGR to explicitly require service providers to justify capex by considering all credible options to address an investment need to justify all types of capex, including where it is driven by maintaining safety or integrity or to comply with a regulatory obligation.

These requirements would apply to all proposed capex, irrespective of the limb under which a service provider justifies new capex.[187]

ECA proposed that service providers be required to consider alternative options to capex, including the provision of energy services (e.g. LPG tanks or electrification) by the service provider or another party.[188] ECA also proposed a range of other amendments to require consideration of the impact of declining demand for gas and improve analysis of capex, particularly replacement capex (repex), to minimise costs and customer exposure to stranding risks (see appendix C.3).

Most user groups and interest groups consider service providers have too much discretion to propose new capex and that stranding risk could be better managed if new capex were minimised to that necessary to meet the NGO. Stakeholders support amending the NGR changes to require service providers to explicitly consider declining demand scenarios, carry out cost benefit analysis and consider alternatives to capex.[189] The AER is open to amending the capex criteria provided that they remain sufficiently flexible.[190] Most consumer groups, other interest groups and retailers[191] support requiring service providers to consider alternatives to capex such as opex, or other options not relating to the provision of pipeline services (i.e. electrification and decommissioning).

Service providers and industry groups consider the framework is fit for purpose,[192] and that they have a strong incentive already to minimise new capex given that cost recovery is not guaranteed and there is a risk of stranding.[193] Service providers note that while the NGR do not require consideration of alternatives to capex, service providers already do this in practice.[194] This stakeholder group raises concerns that changes would add prescription to the NGR, increase administrative burden and reduce flexibility.[195] The AER noted that gas networks do not have substitutes for gas network services and the Australian Gas Infrastructure Group (AGIG) noted that service providers should not be expected to consider alternative options based on the provision of energy services.[196]

Require service providers to carry out a quantitative assessment of costs and benefits for all credible options, to justify all types of capex, where this is practicable

The Commission proposes that service providers be required to conduct a quantitative assessment of the expected costs and benefits of all credible options, to justify all types of capex, where this is practicable. This means that service providers would need to use quantitative cost benefit analysis to justify capex under all three limbs in NGR rule 79(2)(a), (b) and (c), including

187 See NGR 79(2).

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

189 Submissions on consultation paper: Climateworks Centre, p. 2; ECA, pp. 14-15; EUAA, p. 3; JEC, p. 16; SACOSS, p. 4; Lighter Footprints, p. 2.

190 AER, submission on consultation paper, pp. 4-5.

191 Submissions on consultation paper: BSL, pp. 4-5; Climateworks Centre, p. 2; DCAN, p. 3; ECA, p. 14; GCCN, p. 3; IEEFA, p. 3; JEC, p. 16; Lighter Footprints, p. 2; Origin, p. 2; SACOSS, pp. 4-5.

192 Submissions on consultation paper: AGIG, p. 5; APGA, p. 24; ATCO, p. 2 of 18; AusNet, p. 8; EvoEnergy, p. 3.

193 Submissions on consultation paper: AGIG, p. 5; ENA, p. 18; EvoEnergy, p. 3.

194 Submissions on consultation paper: AGIG, p. 7; AusNet, p. 8; ATCO, p. 3.

195 Submissions on consultation paper: ATCO, p. 2 of 18; AGIG, p. 7.

196 Submissions on consultation paper: AER, p. 5 and AGIG, p. 7.

where capex is necessary for reasons under NGR rule 79(2)(c). While capex justified under the first two limbs in current rules 79(2)(a) and (b) already requires a quantitative assessment, current rules 79(2)(a) and (b) do not require all credible options to be considered (although in practice service providers typically consider a range of options to address the identified need).

If it is not practicable to justify a particular type of capex using quantitative cost-benefit analysis, the service provider would need to explain why this is the case and the regulator would consider whether an alternative approach is reasonable. This would improve transparency around capex proposals and assessments in AAs.

Require service providers to consider all credible options that relate to the provision of regulated pipeline services

The Commission proposes to require service providers to consider all credible options that can be provided via pipeline services. We do not propose to require service providers to consider alternative options that cannot be provided via pipeline services (e.g. electrification or LPG tanks), however we provide some more commentary on this below. We note that service providers are already incentivised to consider opex options, where they are practicable alternatives to capex options, as this reduces new capex entering the capital base and therefore reduces stranding risk.

The Commission identifies barriers for service providers to consider alternative options such as electrification or LPG tanks, including those outlined below.

- AAs set out the terms and conditions of access to pipeline services, which are defined under the NGL as services provided by means of a pipeline.[197] Service providers are required to propose and the regulator determines which pipeline services should be specified as reference services, which allows the service provider to charge a reference tariff.[198] The provision of energy using LPG tanks or electricity are not pipeline services and could not be provided by a gas pipeline. Similarly, the costs of contracting a third party to provide these services could not be recovered via reference tariffs, since they would not form part of providing a pipeline service.
- Service providers would not have access to the necessary information to assess the relative costs and benefits of electrification or LPG tanks compared to a capex solution. Establishing the cost of switching fuel source would require estimating, among other things, the cost of all affected households and businesses changing over appliances and potentially rewiring their premises. There may be other costs that would be difficult for a service provider to ascertain, such as the need to upgrade the electricity network to support electrification.
- Scheme pipeline service providers have an obligation to connect customers and provide reference services. Scheme pipeline service providers are also not able to disconnect a customer, except upon request from the customer or under specific circumstances such as the customer failing to pay charges under a customer contract, the customer not providing safe access or the customer providing false information.[199] There is currently no mechanism that would allow customers to be disconnected on the basis that continuing to provide a gas service is not the lowest cost option. If such a rule were to be introduced, there would need to be appropriate consumer protections in place to support them to shift to an alternative fuel source, including allowing the consumer to decide whether to electrify or connect an LPG tank.

197 See section 2 NGL definition of "pipeline service".
198 NGR rule 47A.
199 NERR Rule 119(1).

Table C.1 below summarises the types of credible options that should be considered by a service provider in providing regulated pipeline services, and other options that service providers are unable to provide through regulated pipeline services.

Table C.1: Non-exhaustive examples of options that relate/do not relate to the provision of regulated pipeline services

	Credible options related to the provision of regulated pipeline services	Options that do not relate to regulated pipeline services
Examples of options	Capex solutions	Electrification
	Opex solutions	LPG tanks

Source: AEMC.

Given the barriers identified above, we consider changes to the NGL would be necessary to allow service providers to charge a reference tariff for services not provided by means of a pipeline (e.g. LPG tanks) or consider electrification options. We note that any consideration of changes to the NGL would be a matter for the Energy and Climate Change Ministerial Council (ECMC) and would occur outside of the AEMC rule change process.

We note that if the ECMC were to consider changes to the NGL to allow service providers to charge a reference tariff for services not provided by means of a pipeline, this may have a range of implications, including the matters set out below.

- It may support potential future approaches for decommissioning gas networks, if governments decide to go down that path. Decommissioning is not being considered in this rule change.
- Need to further consider a number of matters, such as:
  - the inability of a service provider to disconnect a customer from reference services (except upon request from the customer or under limited grounds in NERR rule 119)
  - how the service provider would access information to assess the costs and benefits of alternative options not related to the provision of pipeline services (e.g. LPG and electrification) relative to the costs and benefits of options related to the provision of pipeline services (i.e. capex or opex solutions).

C.2.2 We propose to amend the justification for safety-related capex

The Commission proposes to amend the justification for safety-related capex in the NGR from "necessary to maintain and improve the safety of services"[200] to "necessary for the safe operation of pipelines and use of services". Our proposal is an outcomes-based approach that would support the achievement of relevant safety standards or regulations, and any changes in relevant safety standards and regulations over time.

ECA proposed removing the justification for capex as necessary to improve the safety of services while retaining the justification for capex as necessary to maintain the safety of services.[201] Most user groups and interest groups did not explicitly comment on this proposal. However, some service providers and industry bodies were concerned that the ECA's proposed amendment would

200 NGR rule 79(2)(c)(i).

201 ECA propose to amend NGR rule 79(2)(c)(i). ECA, Rule change request - Capital expenditure, p. 20.

conflict with their ability to meet evolving safety standards and consumer expectations of continuously improving safety.[202]

Our proposal aligns with the sentiment of ECA's proposal to minimise expenditure while supporting safety and reliability. However, our proposal applies more of an outcomes-based approach. This would provide consumers with greater confidence that capex would not go beyond what is necessary to provide a safe and secure network.

C.2.3 We propose to amend the justification for capex to maintain capacity to meet forecast, instead of existing, demand for services

We propose to replace the reference in the capex criteria to maintaining capacity to meet existing levels of demand, with maintaining capacity to meet forecast levels of demand (excluding where an expansion of pipeline capacity is required).[203] This change would remove any presumption that existing levels of demand will continue, to recognise that some service providers may experience declining demand in parts of their network.

ECA proposed that the NGR rule allowing the justification for capex as necessary to maintain capacity[204] be amended to remove the reference to "existing levels of demand" and instead refer to "forecast levels of demand". There were no stakeholder submissions on this matter.

Our proposed changes would be consistent with ECA's proposal and would mean that a service provider:

- Can justify capex to maintain capacity to meet forecast demand for services such as the like-for-like replacement of meters and pipelines[205]
- Cannot justify capex to maintain capacity to meet demand that is dependent on an expansion of pipeline capacity, as per part of existing rule 79(2)(c)(iv).[206]

Our proposed solution contributes to the NGO by minimising expenditure to maintain capacity to meet existing levels of demand, if demand is projected to fall. In an environment of uncertain demand, it may not be appropriate to allow capex to be justified on the basis that demand will remain steady. This approach risks locking in investment that ultimately may not be required.

C.2.4 We propose to amend the definition of opex to remove expenditure to increase long-term demand for pipeline services and otherwise develop the market for pipeline services

The Commission proposes to remove growth references from the definition of opex in NGR rule 69. We propose to remove the reference to "expenditure incurred in increasing long-term demand for pipeline service and otherwise developing the market for pipeline services". Our proposed solution contributes to the NGO by minimising opex, which would improve outcomes for consumers and is consistent with principles of market efficiency.

Given that gas demand is uncertain, we consider that the definition of opex should be neutral in relation to demand and so should not expressly refer to expenditure being incurred to increase long-term demand.

202 Submissions on consultation paper: APGA, p. 22; ENA, p. 19; Jemena, pp. 15-16.
203 NGR Rule 79(2)(c)(iv).
204 NGR rule 79(2)(c)(iv).
205 NGR rule 79(2)(c)(iv) has been used to justify like-for-like replacement expenditure, for example to replace meters and pipelines.
206 This would be the consistent with current rule 79(2)(c)(iv) which explicitly excludes maintaining capacity to meet projected demand that is dependent on an expansion of pipeline capacity.

Importantly, the removal of this reference from the opex definition in rule 69 does not mean that service providers could not propose expenditure that would support increasing demand for pipeline services, where that is prudent, efficient and otherwise consistent with the opex criteria.[207] The change is instead intended to remove the presumption that service providers should be seeking to increase demand for pipeline services.

Our proposed approach would therefore allow service providers to propose opex to engage in marketing or other activities to try and increase demand for pipeline services, and for the regulator to assess whether such opex meets the opex criteria, on a case-by-case basis. For example:

- if a gas distribution network is being repurposed to supply biomethane, then it may be prudent and efficient to incur some opex to try and increase demand for pipeline services[208]
- a gas transmission business can be used to supply more gas to gas-fired electricity generators, that could help support the energy transition, then it may be prudent and efficient to attract this additional demand.

Opex 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".[209]

ECA consider that this limb of the definition is obsolete and should be deleted, given it is predicated on an assumption of growing demand. Several stakeholders, including consumer groups, interest groups and some retailers, support changing the definition of opex to exclude expenditure to grow the market for gas, noting that the presumption of increasing demand is no longer appropriate.[210]

Other stakeholders, predominantly service providers, oppose changes to the definition of opex on the basis that the current definition is fit for purpose.[211] Stakeholders' concerns, and our responses to them, are outlined below.

- Removing increasing demand from the opex definition, while regulating gas networks using a price cap or hybrid price-revenue cap, would mean that gas networks are required to manage demand risk without the ability to manage that risk by increasing customers.[212] We note that service providers have the ability to manage demand risk by proposing reference tariffs based on a revenue cap or hybrid tariff (blending revenue and price cap). The AER's recent decisions were to allow JGN (final decision), AGN SA and Evoenergy (draft decisions) to apply hybrid tariffs for their current and upcoming AA periods, as this supports stable prices and aligns with the transition by reducing incentives for volume growth.[213]

207 We note that under the current base-step-trend approach for proposing and assessing opex, the trend component may include forecast growth in customer numbers.

208 A service provider may propose, and the regulator may assess, that such opex related to current limb (b) of the opex definition, which is expenditure, in providing pipeline services, that contributes to meeting *emissions reduction targets*.

209 NGR rule 69. The definition also includes expenditure, in providing pipeline services, that contributes to meeting emissions reduction targets.

210 Submissions on consultation paper: AER p. 6, Alinta, p. 4; BSL, p. 6; ECA, pp. 17-18; EUAA, p. 3; IEEFA, p. 4; JEC, p. 17; Origin, p. 3; Lighter footprints, pp. 1 and 2; Rewiring Australia, p. 3.

211 Submissions on consultation paper: AGIG, p. 11; APGA, pp. 25-26; AusNet, p. 10; Jemena, p. 19.

212 Jemena, submission on consultation paper, p. 19.

213 AER, *Final decision, Jemena Gas Networks (NSW) access arrangement 2025 to 2030, Overview*, May 2025; AER, *Draft decision, Australian Gas Networks (SA) access arrangement 2026 to 2031, Overview*, November 2025; AER, *Draft decision, Evoenergy (ACT) access arrangement 2026 to 2031, Overview*, November 2025.

- The opex definition aligns with recent reforms to allow for network transport of renewable gases, supporting efficient integration of renewable gases.[214] The AER, while supporting the change in principle, also raised this issue.[215] We note that if a jurisdictional policy were to increase demand for pipeline services, e.g. due to increased use of renewable fuels, the current regulatory framework would support service providers and regulators in retaining the ability to propose and assess opex to facilitate this jurisdictional policy. However, given that the focus of the capex and opex provisions in the NGR is on the provision of pipeline services rather than the type of gas underpinning pipeline services, we do not propose to distinguish between renewable or other fuels in the definition of opex. We seek stakeholder feedback on our proposed position.

Similar to capex provisions discussed above, there is a risk that in a transitioning market, rules that presume growth in demand may not minimise expenditure . This is consistent with concerns raised by the AER that:[216]

> *given the uncertainty associated with the energy transition in Australia, it may no longer be in gas consumers' interests to allow further growth in the gas networks at this point, which contributes to greater risk of stranded assets, until the economics of using hydrogen or biomethane as reticulated gas can be proven.*

C.2.5 We propose to require service providers and regulators to explicitly link the driver for capex to one of the capex provisions in the NGR

The Commission proposes to amend the NGR to require both service providers and regulators to explicitly identify the basis on which proposed capex is being justified. Currently, there is no specific requirement for service providers to link the driver for capex to one of the provisions under which capex may be justified under the NGR. This can make it difficult for customers and stakeholders to understand the basis on which service providers propose capex.

Our proposed solution would contribute to the NGO by improving good regulatory practice by promoting transparency in how service providers justify expenditure. This would benefit consumers and stakeholders by allowing them to more readily understand why a service provider proposes an investment. It could also reduce ambiguity where a service provider provides multiple justifications without clarity on the primary driver. Greater transparency could allow for more meaningful engagement and challenge during AA reviews.

ECA did not raise this issue in its rule change request. Accordingly, we did not seek stakeholder views on this issue to date.

C.2.6 We seek stakeholder feedback on whether to retain the NPV test as a means to justify capex

The Commission are considering whether it is necessary to retain the NPV test as a justification for capex.[217] This test allows a service provider to justify capex where the present value of the expected incremental revenue to be generated as a result of the expenditure exceeds the present value of the capex (NPV test).

Our understanding is that the NPV test is used to support capex for:

- new connections that are to be added to the service provider's capital base

214 Submissions on consultation paper: APGA, p. 11; ATCO, p. 5 of 18.
215 AER, submission on consultation paper, p. 6.
216 AER, Regulating gas pipelines under uncertainty, Information paper, November 2021, pp. 59.
217 NGR rule 79(2)(b).

- other investments, such as augmentation expenditure and increasing pipeline capacity, that are not necessary to:
  - maintain the safety of services
  - maintain the integrity of services
  - comply with a regulatory obligation or requirement
  - maintain the service provider's capacity to meet the demand for services.[218]

The Commission recently determined that all newly connecting retail gas customers in NSW, ACT and South Australia should pay upfront cost-reflective charges for their gas connection. To give effect to this, the Commission removed the equivalent NPV test in Part 12A of the NGR.[219] Together with the decision by the Victorian Essential Services Commission to employ a similar approach in Victoria, this means that no new retail customer connections capex should need to enter the capital base for the current set of scheme distribution networks in all jurisdictions except Western Australia.[220]

Given these changes, we are considering whether NGR rule 79(2)(b) is still required, or if it could be removed. We are therefore seeking stakeholder feedback on whether the removal of this test could have any unintended consequences, including for:

- the retail customer connection charge arrangements in Western Australia[221]
- scheme transmission pipelines
- the assessment of capex to augment or increase the capacity of pipelines, which would have to be justified under rule 79(2)(a) if the NPV test is removed.

This matter was not identified in ECA's rule change request, our consultation paper or in stakeholder submissions.

C.3 Analysis of other policy options considered on expenditure assessment

Inappendix C.2 above we explain why we support some of ECA's proposed changes to the NGR capex and opex provisions. In this section we:

- outline how our proposed direction would promote the NGO and give effect to the RPPs (appendix C.3.1)
- note other changes proposed by ECA to the regulatory framework for expenditure assessment, that the Commission does not propose to make (appendix C.3.2), and
- provide a comparison of all policy options considered (appendix C.3.3).

C.3.1 Our proposed direction would promote the NGO and give effect to the RPPs

Our proposed amendments to the NGR would contribute to the achievement of the NGO by:

- **Improving outcomes for consumers** by increasing the discipline on service providers to identify the most suitable option to meet an investment need, to minimise expenditure while continuing to support safety and reliability.

218 These are the justifications for capex that are necessary under existing NGR rule 79(2)(c).

219 NGR rule 119M.

220 See AEMC, *Updating the regulatory framework for gas connections*, Rule determination, 11 December 2025.

221 Part 12A of the NGR only applies in jurisdictions that have adopted the National Energy Customer Framework. However, we note that in Victoria the Essential Services Commission made changes to the connection charge arrangements that align with the changes we made in rule change on *Updating the regulatory framework for gas connections*.

- **Support the safety, security and reliability of gas services** by requiring service providers to continue to invest efficiently so that the operation and use of their networks is safe and in compliance with applicable safety standards and regulations.
- **Emissions reduction** by minimising capex in new long-lived gas assets, supporting the energy transition towards net zero.
- **Promoting principles of market efficiency** by requiring service providers to explicitly consider future potential demand scenarios and identify the probability of each scenario occurring as part of justifying capex forecasts. This would help minimisecapital investment and the risk of stranding.
- **Promoting good regulatory practice** by improving transparency in how service providers justify expenditure and how expenditure is assessed by the regulator, improving consumers' and other stakeholders' confidence that the regulatory framework is promoting efficient outcomes. Greater transparency would also improve stakeholders' abilities to engage with and provide feedback on AA proposals.

Our proposed changes are consistent with the revenue and pricing principles (RPPs) as service providers would retain incentives to efficiently invest in pipelines and efficiently provide pipeline services.

C.3.2 We do not support other changes proposed by ECA to the regulatory framework for expenditure assessment

The Commission does not support the following other changes to the regulatory framework for expenditure assessment that were proposed by ECA in its rule change request:

- requiring service providers to explicitly consider the impact of declining demand in capex programs[222]
- requiring a regulator to review whether the service provider acted prudently in its past decisions before allowing new repex to be approved[223]
- requiring service providers to consider the value that gas consumers place on reliability when proposing capex to maintain network integrity[224]
- requiring service providers to account for future abolishment costs in their cost-benefit analysis[225]
- excluding from reference tariffs capex relating to renewable gases[226]
- removing advance determinations for future capex or require public consultation on all applications for advance determinations.[227]

Our initial view is that these other changes would not contribute to the long-term interests of consumers. They would either be impractical, increase investment risk or the additional regulatory burden would outweigh the benefits.

222 ECA, Rule change request - Capital expenditure, p. 19.
223 ECA, Rule change request - Capital expenditure, p. 19.
224 ECA, Rule change request - Capital expenditure, p. 19.
225 ECA, Rule change request - Capital expenditure, p. 19.
226 ECA, Rule change request - Capital expenditure, p. 20.
227 ECA, Rule change request - Capital expenditure, pp. 20-21.

C.3.3 We explored alternative policy options to address the identified issues around expenditure assessment but concluded that they would not be as effective in promoting the NGO

This section provides an overview and Commission's assessment of alternative policy options under the expenditure assessment workstream. We note that the below is not an exhaustive list of policy options and hybrid policy options are possible based on a combination of the policy options presented in this directions paper.

The characteristics of the considered alternative policy options are outlined below.

1. **Status quo**: retaining the current capex and opex provisions.
2. **Our proposed changes to the capex and opex provisions in the NGR**:
   a. clarifying that all capex must be justified through a quantitative assessment of all credible options that relate to the provision of regulated pipeline services
   b. amending the justification for safety-related capex in NGR rule 79(2)(c)(i) to be necessary for the safe operation of pipelines and use of services
   c. replacing the reference in the capex criteria to maintaining capacity to meet existing levels of demand, with maintaining capacity to meet forecast levels of demand (excluding where an expansion of pipeline capacity is required)
   d. requiring service providers and regulators to specifically link and reference the driver for capex to part of NGR rule 79
   e. amending the definition of opex to remove expenditure to increase long-term demand for pipeline services and otherwise develop the market for pipeline services, while proposing a neutral approach where service providers may propose opex for increasing long-term demand for assessment by the regulator.
3. **Replace capex criteria with a net economic benefit test:** changes to the capex and opex provisions in Option 2 plus the following additional changes:
   a. Introducing a net economic benefits test similar to the Regulatory Investment Test (RIT) in electricity.
   b. Requiring the regulator to develop guidelines on how the service providers would apply the new net economic benefit test.
4. **ECA's rule change proposal:**
   a. Elements of ECA's proposal that the Commission supports:
      i. clarifying that service providers must justify all capex through a quantitative assessment of all credible options related to the provision of regulated pipeline services
      ii. amending the justification for safety-related capex to be necessary for the safe operation of pipelines and use of services
      iii. replacing the reference in the capex criteria to maintaining capacity to meet existing levels of demand with maintaining capacity to meet forecast levels of demand (excluding where an expansion of pipeline capacity is required)
      iv. amending the definition of opex to remove the reference to expenditure being incurred to increase long-term demand for pipeline services and otherwise develop the market for pipeline services
   b. Elements of ECA's proposal that the Commission does not support, as set out above in appendix C.3.2.

Table C.2 below sets out our initial assessment of the benefits and costs of each of the policy options considered in relation to the justification and assessment of gas pipeline expenditure. Our initial view is to propose Option 2, as explained in appendix C.2 above, and not propose any of the alternative options.

Table C.2: Assessment of other policy options: Expenditure assessment

Option	Benefit	Risk	Our initial view
1) Status quo (do nothing)	Maintaining current arrangements would: • provide a stable regulatory and investment environment • avoid the implementation costs and risks associated with Options 2 to 4.	• No requirement to consider all credible options to address an identified need and demonstrate that the preferred option is the most economically efficient option. • Limited guidance in the NGR how to apply the test for whether capex is conforming. • Several areas where the capex and opex criteria could be tightened to minimise expenditure while supporting safety and reliability. • Lack of transparency in some aspects of AA proposals.	**We do not support this option.** As explained in Appendix C.1.3, we consider there are sufficient gaps in the status quo such that changes to the rules are warranted. While in practice some of these issues may be addressed by service providers or the regulator, there is benefit in clarifying the rules to ensure a stable and predictable framework.
2) Amend NGR capex and opex provisions	**We propose this option** for the reasons set out in Appendix C.2.		
3) Replace capex criteria with a net benefits test	**All of the benefits from option 2 and in addition:**	• **Would materially increase regulatory costs for service**	**We do not support this option.** While there are clear benefits of Option 3, it is a significant change from the status quo that is likely to materially increase regulatory

Option	Benefit	Risk	Our initial view
	• **Additional rigour** as all proposed capex above a threshold would be subject to a net economic benefit test rather than just a subset under the current test. • **Improved consumer outcomes** as additional rigour would help minimise expenditure while maintaining safety.	**provider and regulator** related to the net economic benefit test for capex, under a range of scenarios, compared to the status quo. The extent of the increase in administrative burden would depend on the type of consultation, noting that consultation requirements are material for the RIT in electricity. • **Implementation costs** for the regulator to develop new guidelines.	costs for service providers and regulators. It is also possible that the risk of stranding will incentivise service providers to constrain new capex, in which case significant new costs to test the prudency of new capex would likely outweigh the benefits.
4) ECA's proposed changes to NGR capex and opex provisions	**We do not support this option.** While our proposed solution (Option 2) aligns with some elements of ECA's proposed solution (Option 4) we consider that other elements are either impractical, increase investment risk or the additional regulatory burden would outweigh the benefits.		

Source: AEMC.

Question 6: Our proposed direction on expenditure (detailed in appendix C)

1. What are your views on our proposed direction to amend the NGR capex provisions? For example:
   a. Clarifying that service providers must justify all capex through a quantitative assessment of all credible options that support the provision of regulated pipeline services.
   b. Amending the justification for safety-related capex to be necessary for the safe operation of pipelines and use of services in NGR rule 79(2)(c)(i).
   c. Amending the justification for capex to maintain capacity to meet forecast (instead of existing) demand for services under NGR 79(2)(c)(iv).
2. What are your views on the need for the NPV test in rule 79(2)(b)?
3. What are your views on our proposed direction to amend the NGR opex definition?

D Our proposed approach to amend the reference tariff provisions

Gas reference tariffs are the regulated prices that a gas distribution service provider (service provider) charges users for reference services. A 'user' of gas reference services is usually a gas shipper or retailer and reference tariffs are designed to signal the efficient cost of providing each reference service. Gas retailers may use reference tariffs to inform the prices they then charge to end-use gas customers, but reference tariffs are not charged directly to end-use customers.

Reference tariffs are the mechanism through which the service provider recovers its allowed revenue requirement. Reference tariffs are proposed by the service provider and approved by the regulator as part of an access arrangement (AA) and may vary within the AA period consistent with an approved tariff variation mechanism.[228] This mechanism determines how demand forecasting risks are allocated between the service provider and customers during the AA period and has an impact on a service providers' ability to recover its efficient costs.

As the energy transition progresses, gas reference tariffs and tariff variation mechanisms can play a role in supporting efficient customer decisions and managing the risks associated with uncertain and/or declining gas demand. It is therefore important that the reference tariff provisions within the NGR can support service providers and customers in managing these challenges.

Rule change proponents ECA and JEC did not explicitly raise any concerns or propose amendments to reference tariff provisions. While some retailers and customer groups considered that the reference tariff provisions should be updated to better reflect the changing external landscape, most service providers thought that the current rules provide sufficient flexibility going forward without need for change (see appendix D.3.2 for more detail).[229]

While the Commission considers the current reference tariff provisions are broadly appropriate in terms of the overarching approach and options they provide to service providers and regulators, we have identified potential issues based on our review of the rules, and how the rules have been applied (see appendix D.1). These issues relate to the provisions that govern reference tariffs for distribution pipelines and reference tariff variation mechanisms.[230]

To address these issues, our proposed direction is to add guidance to the NGR reference tariff provisions to support service providers and regulators in proposing and approving reference tariff classes, structures and variation mechanisms to suit the broad range of circumstances that may emerge during the energy transition (see appendix D.2).

D.1 Reference tariff provisions lack guidance on how to apply efficiency concepts when designing reference tariff arrangements for a wider range of demand scenarios

The main purpose of the reference tariff provisions is to guide service providers and the regulator on how to allocate costs across different customer groups and to decide how tariffs may vary within the AA period. The provisions help service providers propose, and regulators approve tariff classes, structures and variation mechanisms that are underpinned by concepts of economic

228 NGR Rule 96.
229 AEMC, *Gas networks in transition consultation paper*, September 2025.
230 NGR Rules 94 and 97.

efficiency. While these concepts are well-understood and remain sound, there is variation in how they are applied across service providers and AAs. Changes to the NGR may be needed to clarify how reference tariff provisions should apply so that they align with other components of the AA and promote efficient outcomes under the broader range of future scenarios that may occur during the energy transition.

D.1.1 The purpose of the current reference tariff provisions is to allocate costs and manage risk within an AA period

The main purpose of the reference tariff provisions is to guide service providers and regulators on how to allocate costs across different customer groups and decide, by determining the tariff variation mechanism, how demand forecasting risk is managed and shared between service providers and customers within the AA period.

The current NGR provisions for setting and varying reference tariffs focus primarily on designing tariffs to signal the efficient marginal costs of a service and promote efficient decisions by customers about their consumption of gas. Broadly speaking, the reference tariff provisions guide service providers to propose, and the regulator to approve arrangements that divide customers into tariff classes on an economically efficient basis, while avoiding unnecessary transaction costs.[231] Tariffs are set for each tariff class based on several cost efficiency concepts. For each tariff class the rules currently state that:

- the revenue expected to be recovered by the service provider should lie on or between an upper bound that represents the standalone costs and a lower bound that represents the avoidable costs or serving that tariff class.[233]
- the tariff and each charging parameter within the tariff must be set taking into account the long-run marginal cost (LRMC), transaction costs and a customers' ability to respond to price signals.[234]

Tariffs can be adjusted away from efficient costs in order to achieve expected revenue recovery, but must be done so with minimum distortion to efficient patterns of consumption.[235] In certain cases, service providers can also propose prudent discounts and a regulator can approve these, if it is satisfied that:[236]

- the discount is necessary to respond to competition from other providers or maintain efficient use of the pipeline
- provision of the discount is likely to lead to reference or equivalent tariffs lower than they would otherwise have been.

An AA must include a reference tariff variation mechanism, which specifies how reference tariffs can vary over the AA period.[237] Reference tariffs may vary within the AA period if actual demand is different from forecast demand, or as a result of a pass through of costs for a defined event.[238]

Overall, the reference tariff provisions seek to promote reference tariffs that reflect the underlying risks and cost of service for a particular customer or customer group, without transferring those risks or costs to other customers or customer groups.

231 NGR rule 94(2)
233 NGR rule 94(3).
234 NGR rule 94(4)
235 NGR rule 94(5).
236 NGR rule 96. This rule applies to both distribution and transmission service providers.
237 NGR rule 92(1).
238 NGR rule 97 sets out the mechanics of the tariff variation mechanisms. This rules also applies to transmission pipelines.

D.1.2 We consider that changes to NGR reference tariff provisions would support tariff arrangements that are appropriate to a broad range of demand scenarios

The concepts of economic efficiency included in the reference tariff provisions are, and should remain the primary considerations for service providers and regulators when designing tariff classes, structures and variation mechanisms.

In particular, the concepts of LRMC, standalone costs and avoidable costs guide service providers and regulators in proposing and approving reference tariff structures that are efficient and thus promote the long-term interests of consumers while providing service providers with a reasonable opportunity to recover at least their efficient costs.[239] While these efficiency concepts are well-understood and commonly used in electricity and gas regulatory frameworks, there is variation in how they are currently applied across service providers and AAs.

We consider the concepts themselves will remain sound under a broad range of future scenarios. However, there are different ways a service provider could apply each efficiency concept, depending on the circumstances facing the service provider. For example, factors such as forecast demand, size and characteristics of the customer base and the jurisdictional policy environment in which a service provider operates may influence how a service provider calculates and how a regulator considers the concepts of LRMC, standalone costs and avoidable costs for the purpose of reference tariffs arrangements.

Against this background, we consider the rules could be amended to support service providers and the regulator apply these efficiency concepts in context-specific ways, acknowledging the broader range of demand and jurisdictional policy scenarios that may emerge during the energy transition. If these concepts are not applied in a context-specific way, we may see tariffs and tariff variation mechanisms that:

- are not internally consistent with the intent of decisions made in other components of an AA[240]
- fall short of delivering the long-term interests of consumers[241]
- do not give service providers a reasonable opportunity to recover at least their efficient costs.[242]

While the rule change proponents ECA and JEC did not explicitly raise concerns or propose amendments in relation to the reference tariff provisions, we consider they need to change to support the intent of our other proposed changes in this paper and to ensure that the tariff provisions promote outcomes that are in the long-term interests of customers as demand scenarios and jurisdictional policy environments change.

The changes we propose in appendix D.2 aim to future-proof the reference tariff provisions so that service providers and regulators are better-supported in designing, proposing and approving tariff classes, structures and variation mechanisms to suit the wider range of scenarios we anticipate in the future.

239 NGR rule 94(3) and 94(4)(a).

240 Appendix A sets out our proposal to improve consideration of the long-term outlook and promote internally consistent AA decisions.

241 Consistent with the NGO.

242 Consistent with section 24(2) of the NGL.

D.2 We propose amendments to the reference tariff provisions to better guide service providers and regulators on how to design, propose and approve tariff classes, structures and variation mechanisms

We propose amendments to the reference tariff provisions that guide service providers and regulators on how to design, propose and approve tariff classes, structures and variation mechanisms, to account for different demand scenarios. Our proposed direction is to:

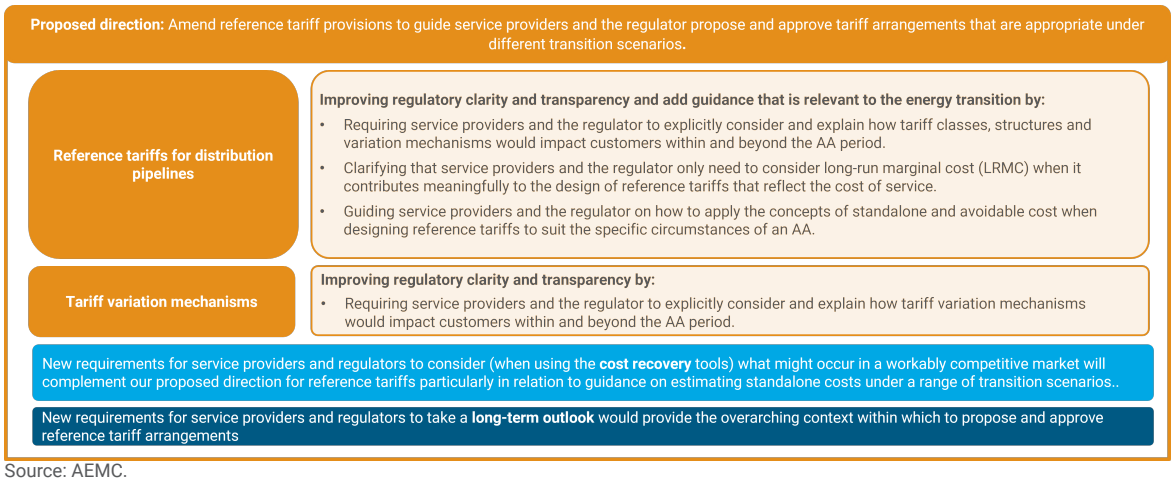
- require service providers (when proposing) and regulators (when approving) to explicitly consider and explain how tariff classes, structures and variation mechanisms would impact customers within and beyond the AA period (see appendix D.2.1)
- clarify that service providers and regulators only need to consider LRMC when it contributes meaningfully to the design of reference tariffs that reflect the cost of service (see appendix D.2.2)
- provide guidance on how to apply the concept of avoidable cost when designing reference tariffs to suit the specific circumstances of an AA (see appendix D.2.3)
- provide guidance on how to apply the concept of standalone cost when designing reference tariff, to suit the specific circumstances of an AA (see appendix D.2.4).

We do not propose to change the options available to service providers and regulators when proposing and approving tariff variation mechanisms, or to change the timing of the tariff variation mechanism decision (see appendix D.3.2).

Our proposed changes seek to supplement existing considerations in the rules so that service providers and regulators are encouraged to propose and approve tariff classes, structures and variation mechanisms that are suited to the specific circumstances of a service provider and are internally consistent with other components of the AA. It is not our intent to replace efficiency and revenue recovery as the primary considerations when designing tariff classes, structures and variation mechanisms.

Each of our proposed amendments is summarised in Figure D.1 and discussed in more detail below.

Figure D.1: Proposed direction for amendments to NGR reference tariff provisions



Source: AEMC.

D.2.1 We propose that service providers and regulators be required to consider and explain how tariffs and tariff variation mechanisms would impact customers within and beyond the AA period

The first of our proposed amendments would require service providers and regulators to explicitly consider and explain the impacts of tariff classes, structures and variation mechanisms on customers within and beyond the AA period.[243] This could include consideration of the following:[244]

- **Customer exit:** how the design of tariff classes, structures and variation mechanisms is expected to influence a customers' decision to remain on, or exit the network, including whether and how price stability and predictability play a role in this decision
- **Competition:** how competition and the outlook for competition from alternative fuel sources is expected to influence customer behaviour and how a service provider should take this into account through the design of tariff classes, structures and variation mechanisms
- **Long-term consumer impacts**: the implications for customers remaining on the network and how reference tariffs are expected to change for customers remaining on the network within and beyond the AA period in question
- **Opportunity to recover efficient costs:** how the proposed tariff arrangements would maintain the service providers' reasonable opportunity to recover at least their efficient costs and promote the long-term interests of all consumers
- **Internal consistency within an AA:** how the design of tariff classes, structures and variation mechanisms are expected to give effect to the other decisions made for other components of the AA including the cost recovery and risk allocation decisions.[245]

Service providers would be required to explain how a proposed tariff class, structure and/or variation mechanism promotes the long-term interests of consumers given the expected impacts on them. Regulators would also need to consider the expected impacts of reference tariff arrangements on customers when making their decisions. Tariff proposals would only be approved if the regulator accepted that there was a clear benefit to customers over the long term for example from improved efficiency, alleviating cost recovery, or better risk management.

Service providers and regulators are already implicitly required to consider the long-term interests of consumers when designing reference tariff arrangements that promote the NGO. Our proposed direction to require service providers and regulators to more explicitly consider and explain the expected impacts of tariff arrangements on customers is intended to supplement, rather than replace the existing efficiency-based considerations that service providers and regulators currently use when proposing and approving tariffs arrangements. We recognise that there are increasing challenges with applying efficiency-only concepts to tariff setting in a declining demand scenario and the additional guidance is intended to assist service providers and the regulator to manage these challenges.

243 A clause with similar intent exists in the electricity distribution pricing rules at NER clause 6.18.5(h). It focuses on the customer impact of a change to an electricity network tariff from the previous year, and allows variations away from the economic principles if necessary, having regard to certain criteria including (1) the desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one regulatory control period); (2) the extent to which retail customers can choose the tariff to which they are assigned; and (3) the extent to which retail customers are able to mitigate the impact of changes in tariffs through their decisions about usage of services.

244 Our proposed amendments would be reflected in rule 94 and 97 of the NGR.

245 Appendix B sets out the Commission's proposed direction to support efficient capital recovery, with the objective of providing service providers with the reasonable opportunity to recover at least their efficient costs, while at the same time protecting remaining customers from monopolistic pricing. If the design of tariff classes, structures and variation mechanisms does not consistently carry though the intent of supporting efficient capital recovery. this creates a clear risk of conflict between stages of the regulatory framework. Such an outcome would be detrimental to both consumers and service providers undermining efficiency, coherence, and credibility across the overall regulatory package.

We acknowledge requirements based on broad concepts like 'customer impact' can be interpreted in different ways. For example, one response when considering the impact of reference tariffs on customers may be to limit tariff increases to protect short-term consumer interests. This in turn may adversely impact future consumers as well as challenge a service providers' reasonable opportunity to recover at least their efficient costs. Another response may be to increase the fixed portion of a tariff to increase stability and predictability of prices benefiting some customers through the resulting change in how revenue is allocated across tariff classes. However, this may bring forward exit decisions from other customers.

Considering consumer impacts of tariff arrangements would support tariffs and tariff variation mechanisms that are suited to specific circumstances of an AA

By adding a new requirement for service providers and regulators to consider and explain how reference tariff arrangements are expected to impact customers, the Commission seeks to achieve the following outcomes:

- better recognition of the context in which tariffs are being designed and the role that tariffs can play in realising the intent of decisions made in other components of the AA
- improved guidance to help service providers propose and regulators approve tariffs classes, structures and variation mechanisms that are suited to the specific circumstances of the service provider
- improved transparency around tariff decisions, supporting stakeholder engagement in the regulatory process and customer decision-making around their gas consumption and/or decision to exit (acknowledging that reference tariffs may inform, but are not the same as the price a retailer charges its retail customers)[246]
- greater consideration from the regulator of the long-term impacts that reference tariff arrangements may have on customer decisions around consumption and exit when assessing tariff proposals[247]
- a reasonable opportunity for service providers to recover at least their efficient costs while promoting the long-term interests of consumers.[248]

Our proposed amendments would also bring ideas from the NGO and RPPs directly into the process of setting tariff classes, structures and variation mechanisms. While the focus remains on ensuring tariff arrangements are 'economically efficient', our proposed direction would require service providers and the regulator to consider economic efficiency within the specific context of the AA period and beyond. We consider that our proposed direction would therefore better promote the NGO and consideration of the RPPs compared to the status quo, by supporting a more comprehensive and transparent consideration of how customer interests are best served while designing reference tariff arrangements to support efficient use of the network and give the service providers a reasonable opportunity to recover at least their efficient costs.

Considering the impact of reference tariff arrangements on customers would build on the existing work service providers do to understand their customers' needs and behaviours

Service providers already employ a range of tools and processes to understand the needs, views and responses of their customer base. This includes active engagement with large and small

246 Gas reference tariffs are the regulated prices that a gas pipeline service provider charges users for reference services. A 'user' of gas reference services is usually a gas shipper or retailer and reference tariffs are designed to signal the efficient cost of providing each reference service. Gas retailers may use reference tariffs to inform the prices they then charge to end-use gas customers, but reference tariffs are not charged directly to end-use customers.

247 Consistent with the NGO.

248 Consistent with section 24(2) of the NGL.

customers, retailers and other stakeholders, including holding consumer forums, interactive workshops and conducting surveys. Service providers have engaged extensively with their stakeholders to help them develop future plans and AA proposals that better reflect customer and stakeholder views.[249] We acknowledge service providers' increased engagement on the future of gas and the role of the network in recent AA proposals given the changing demand environment. In relation to tariffs, we note that there has been strong engagement by service providers to ensure that any proposed changes align with stakeholder and customer views.

Regulators also employ various tools and processes to build and refine their understanding of customer views, needs and behaviours. For example the AER *Better Resets Handbook* sets out expectations of how network businesses should engage with consumers and how the outcomes of that engagement should be reflected in their proposals.[250] Also, the AER may establish a Consumer Challenge Panel to inform their decision-making through an AA process.[251]

Service providers and regulators are continually updating and refining their understanding of customers and have a particular focus on this when developing their AA proposals. Our proposal is to leverage these existing practices where possible, but formalise it and set a clear expectation on what service providers and regulators should consider and document for the purposes of a reference tariff proposal. We expect this would encourage service providers to undertake more sophisticated analysis of their tariff class designations and the impacts on risk and pricing outcomes for customers given changing consumer characteristics and preferences. This would also encourage regulators to engage more explicitly with this analysis when assessing proposals.

We acknowledge that a formal requirement to consider and explain reference tariff proposals and decisions with reference to how they are expected to impact customers, will increase the regulatory obligation on both service providers and regulators.

Greater consideration of the impact of reference tariff arrangements on customers aligns with proposals made in other workstreams

Our proposal to require service providers and regulators to consider, and explain their proposals and decisions with reference to the impact tariff arrangements may have on customers, complements our proposed direction to require the service provider and regulator to:

- consider a long-term outlook, including the service provider's expenditure forecast, intended use of capital cost recovery tools, and consumer price impacts over a 20-year time horizon. We consider this long-term outlook would provide the overarching context within which service providers and regulators would consider and explain how specific reference tariff arrangements are expected to impact customers. Together, these proposals would improve transparency of decision-making and support internal consistency within the AA (see appendix A for more information on our proposed direction to require service providers and the regulator to apply a longer-term outlook).
- consider (when using the cost recovery tools) what might occur in a workably competitive market ensure that capital cost recovery and the resultant revenue requirement does not inadvertently trigger a disorderly exit by exceeding the customer switching point. Supporting service providers to propose and regulators to approve reference tariff classes, structures and

249 All service providers engage with consumers in different ways. For some examples, see AGIG and Ausnet *Final Engagement Plan for Engaging Victorians on the Future of our Networks* – July 2021 here, Jemena *Customer Forums Participant Feedback* – Research Report June 2024 here and *Evoenergy Engagement strategy for our gas network 2026-2031 access arrangement regulatory process* - March 2024 here.

250 AER, *Better resets handbook,* July 2024 available here.

251 The Consumer Challenge Panel (CCP) assists the AER to make better regulatory determinations by providing input on issues of importance to consumers. More information here.

variation mechanisms that also reflect this intent and, in particular, recognise competition from alternative energy sources when determining the standalone costs, would complement these proposed changes (see appendix B for more information on our proposed direction to amend the capital cost recovery provisions).

The Commission is seeking stakeholder feedback on this proposed direction.

D.2.2 Service providers and the regulator should only take LRMC into account if it helps design reference tariffs that reflect the cost of service

Service providers are currently required to take into account the LRMC of providing the relevant reference service when they are designing reference tariffs to achieve expected revenue recovery.[252] LRMC measures the future costs that would be caused by an incremental change in demand, including any need to expand the capacity of the network to serve the incremental change in demand.

Requiring service providers to take LRMC into account when setting tariffs and tariff parameters is based on the economic principle that prices should reflect the underlying costs of providing the service. By signalling the incremental change in costs caused by a small change in volume, reference tariffs based on LRMC can theoretically inform consumers to use the network when the value to them exceeds the additional costs caused by the change in consumption.

The economic principle that tariffs should be designed to reflect the underlying cost of service remains sound for all future demand scenarios. However, in a scenario where a service provider is facing declining demand and the LRMC of service is trending towards zero (or potentially negative), it may not be a meaningful factor when designing efficient reference tariffs.

See Box 7 for an example of how the LRMC approach may become less meaningful in different contexts.

Box 7: Evoenergy considers LRMC is not relevant in a declining demand scenario

The challenges of estimating LRMC in a declining demand scenario were recognised in Evoenergy's revenue proposal 2026-2031 where it argued that the concept of LRMC is no longer relevant to its situation given the increasing spare capacity in the network as utilisation falls.

Given the expected level of under-utilisation in Evoenergy's network, they note that any modelled increase in demand is likely not to require any additional expenditure to serve that change in demand. Similarly, a modelled decrease in demand is unlikely to cause a change in future expenditure in network capacity given that the investment has already been made. In this situation, future expenditure will be mostly caused by approved replacement and safety expenditure where customer utilisation is less of a driver to the change in costs.[i]

In a declining demand scenario, the relationship between changes in costs and changes in customers' consumption decisions becomes significantly weaker, thereby limiting any efficiency value through setting prices based on LRMC. On this basis, Evoenergy:

- argued that there is no clear causation between a marginal increase in demand and an increase in long-run costs for their network
- decided not to include LRMC estimates in its proposal.

252 NGR rule 94(4)(a).

Source: AEMC summary of Evoenergy Access arrangement information ACT and Queanbeyan-Palerang gas network access arrangement 2026–31, Submission to the AER, attachment 7-Transportation (including metering) reference service and tariffs, June 2025, link here.

Note: [i] For example, in a declining demand scenario, regulatory obligations may require meters to be replaced if they do not meet accuracy requirements or replaced on a like-for-like basis.

Service providers use a variety of modelling approaches to estimate LRMC for the purposes of designing reference tariffs. Typically, service providers use an average incremental cost approach, which estimates the LRMC as the average change in forecast operating and capital expenditure attributable to a future increase in demand.[253] This calculation attempts to measure the extra costs of meeting additional demand. An average incremental cost approach is effective in a stable or growing demand scenario as the calculation requires positive incremental demand to be the cause of the forecast increase in costs.

An alternative, but more complex methodology is the perturbation approach, which requires the network to develop different capital programs for different demand scenarios. The perturbation approach is based on estimating LRMC as change in costs caused by a permanent change in demand.[254]

The Commission notes that the modelling exercise to estimate LRMC can add time and cost to the process of designing and proposing reference tariffs. In addition, LRMC estimation methodologies are sensitive to the assumptions, timeframes and methodologies used. Increased uncertainty about future demand levels will create challenges for current LRMC calculation approaches which, as explained in Box 7 above, assume a reasonably steady stream of future investments and stable demand trends. This could lead to increase variability in LRMC estimates as they are updated at the start of each AA period to reflect new information.

In a context of declining demand where a service provider does not anticipate a need for capacity growth, LRMC may not be a well-defined or meaningful measure to signal to consumers the efficient use of the network and therefore will likely not provide an accurate or effective basis to set network tariffs.

Where LRMC estimates are meaningful in determining the underlying cost of service, service providers should be required to continue to appropriately calculate and apply them. However, where LRMC does not meaningfully contribute to the goal of designing reference tariffs that reflect the underlying cost of service, the benefits of estimating it may not outweigh the costs.

We propose clarifying that service providers and regulators need only consider LRMC when it meaningfully contributes to the process of designing reference tariffs that reflect the underlying cost of service

In the context of the transition, we consider the rules should be clear that service providers and regulators need only consider LRMC when it meaningfully contributes to the process of designing reference tariffs that reflect the underlying cost of service.[255] This would avoid the need for complicated modelling to estimate LRMC where there is no clear benefit in informing the design of tariffs for the next AA period.

253 For example AGN SA has used the average incremental cost approach to estimating LRMC as part of its 2026-2031 AA. See AGN SA's *Attachment 14.1 Network Pricing,* July 2025, p. 5, available here.

254 For example ATCO used the perturbation approach to estimate LRMC as part of its 2025-29 AA. See ATCO's *Attachment 16.002 Tariff setting method,* September 2-23, p.10 available here.

255 To achieve this outcome we are considering amendments to NGR rule 94(4)(a) and 94(5).

The NGR already recognises the potential limitations of LRMC, requiring only that service providers must "take into account" LRMC and allows for tariffs to be adjusted away from LRMC to ensure the recovery of expected revenue.[256]

The Commission is seeking stakeholder feedback on this proposed direction.

D.2.3 We propose changes to help service providers and regulators apply the concept of avoidable costs appropriately under different scenarios

The third part of our proposed direction is to amend reference tariff provisions to help service providers and regulators apply the existing concept of avoidable costs in a way that reflects the circumstances of the service provider.

The existing rules note that the revenue a service provider expects to recover for each tariff class through reference tariffs should not be lower than the avoidable cost. That is, the cost the service provider would avoid, were it not to supply those customers.[257]

If service providers set reference tariffs for a given tariff class at a level that would generate less revenue than the avoidable costs for that class, it would mean they would need to recover the difference from other customers (i.e. cross subsidise) or earn a lower return. The purpose of this provision is therefore to prevent service providers from imposing the costs of supplying one tariff class on other tariff classes by pricing below this lower bound.

256 NGR rule 94(4)(a) requires service providers to take LRMC into account, NGR rule 94(5) allows service providers to adjust tariffs away from those that meet the criteria set out in NGR rule 94(4) to ensure the recovery of expected revenue.

257 NGR rule 94(3)(b).

The way avoidable costs are currently calculated may not be appropriate in a scenario of uncertain or declining demand

The concept of avoidable costs is well-understood in economic regulation, and the idea of using it as a price floor remains sound under the broad range of scenarios that could arise through the energy transition.[258] However, it is currently applied in a variety of ways for the purposes of calculating the lower revenue bound a service provider expects to recover for each tariff class.

Estimates of avoidable costs tend to be based on the costs associated with the assets dedicated to supplying a tariff class (i.e. assets that serve only one particular group of customers). Calculation methodologies differ across service providers and these differences result in a wide variation in avoidable costs boundaries used to set tariffs. The differences relate to:

- How the network distinguishes between dedicated and shared costs associated with each tariff class, with some networks including only meters and connection assets, and others assume that a proportion of pressure mains and services can be dedicated to different tariff classes.[259]
- Whether the capital costs for dedicated assets are based on replacement values or the current regulatory asset base. In theory, avoidable costs should be based on a forward-looking assessment of future costs. However, for reasons of convenience, some networks tend to use existing asset values.[260] One service provider (Ausnet) conducts an even simpler approach of calculating avoidable costs by using the short run marginal costs of supply multiplied by the estimated average usage for each tariff class.[261]

In a scenario of uncertain or declining demand a range of factors can influence the calculation of avoidable costs. There may be:

- fewer customers within a class contributing to the same total avoidable cost
- a shift in allocation of costs between shared to dedicated assets
- greater segmentation of customers through more tariff classes.

Given the range of scenarios we anticipate during the transition, it is important that the methodologies used to calculate avoidable costs for the purposes of designing reference tariffs, reflect the circumstances of an AA. See a hypothetical example in Box 8 below.

Box 8: How the approach to calculating avoidable cost may change during the transition

One common application of the avoidable cost test assumes that assets dedicated to a particular customer or tariff class will continue to be replaced over time. In that case, a convenient proxy for avoidable cost is to annualise the future replacement and service provision cost of those dedicated assets, using the regulatory building blocks as a shorthand. That approach implicitly presumes a continuation of the network in steady state. However, in a declining demand environment - or where the network is moving toward decommissioning - replacement is no longer certain.

A more economically coherent approach would weight future replacement costs by the probability

258 Avoidable costs are also used in NER clause 6.18.5(e) for similar reasons to NGR 94(3).

259 For example, MultiNet and other AGN networks only includes meters and connection assets in its avoidable cost calculation, We understand that in Evoenergy's methodology a proportion of pressure mains and services are considered to be dedicated to a particular tariff class (see Table 4 p. 6 of ActewAGL *Distribution AAI Appendix 12.02 HoustenKemp COSM Final Report,* July 2015 available here.

260 For example Jemena methodology uses replacement value (see appendix 1 of Jemena Gas Networks *Attachment 1 10.1 Pricing,* June 2024, available here), while Evoenergy methodology uses current regulatory asset base. AGN also uses depreciated optimised replacement costs (DORC) in its calculations of avoidable costs (see AGN's *Attachment 14.2 Cost Allocation Model,* July 2025, available here.

261 Ausnet *Access Arrangement Information, Gas Access Arrangement Review 2024-2028,* avoidable cost methodology on p. 201 here.

of their replacement, rather than assume replacement with certainty. If the probability of replacement falls to zero, the capital component drops out of the avoidable cost calculation, materially lowering the avoidable cost floor that constrains tariff setting.

Source: AEMC.

We propose amendments to the reference tariff provisions to assist service providers and regulators apply the concept of avoidable costs appropriately under different circumstances that may arise during the transition

We are proposing to amend the rules to assist service providers and regulators in applying the concept of avoidable cost appropriately under different scenarios.

During the transition there will be a range of factors that influence a service providers' circumstances when designing tariff classes and tariff structures. It will be important that the methodologies used to calculate avoidable costs are suited to the circumstances of an AA so that it can act as a meaningful lower bound for setting reference tariffs that promote the long-term interests of consumers and give service providers a reasonable opportunity to recover at least their efficient costs.

There will be scenarios during the transition where one of the methodologies described above is more suited than another. There may also be scenarios during the transition where a fundamentally different approach to calculating avoidable costs is warranted.[262]

There is already flexibility within the current rules for service providers to propose and regulators to approve avoidable cost methodologies that account for a range of circumstances. However, we consider the rules could be amended to help service providers and regulators identify the appropriate methodology to apply at different phases of the transition and are also internally consistent with other components of the AA.

The Commission is seeking stakeholder feedback on this proposed direction.

D.2.4 We propose guidance on how service providers and regulators should apply the concept of standalone costs under different scenarios

The fourth part of our proposed direction is to amend reference tariff provisions to help service providers and regulators apply the existing concept of standalone costs in a way that reflects the circumstances faced by service provider.

The rules note that the revenue a service provider expects to recover for each tariff class through reference tariffs should not be higher than standalone costs, that is the costs the service provider would incur, were the network only to supply those customers.[263] If a service provider set reference tariffs above the standalone costs this could create:

- incentives for some customers to seek alternative supply options (increasing the risk of revenue underrecovery)
- unfair impacts on customers that are unable to access alternatives.

262 For example, if redundant capital provisions are exercised, the avoidable cost would be based on the network's ability to service those customers (both capex and opex) compared to the reference tariff which would be determined based on what the price of the competitor energy source (e.g. electricity). In this scenario there may be other, more appropriate ways to estimate avoidable costs.

263 NGR rule 94(3)(a).

The way standalone costs are currently calculated may not be appropriate in a scenario of uncertain or declining demand

Like the concept of avoidable costs, the concept of standalone costs is well-understood in economic regulation and the idea of using it as a price ceiling as a measure of the price beyond which bypass could occur remains sound under the broad range of scenarios that could arise through the energy transition.[264] However, it is currently applied in a variety of ways resulting in a wide range of potential outcomes.[265]

Standalone cost calculations used in AAs today tend to focus on the costs of building a hypothetical gas network that only supplies customers within that tariff class to the required standard, availability and quantity. As with avoidable costs, calculation methodologies differ slightly across service providers. These differences relate to:

- how to identify the assets required per tariff class;[266]
- whether the alternative supply to be costed is through another gas network or an alternative fuel source. We note that in one circumstance the network models the cost of supplying bottled gas instead of network supply.[267]

Uncertain and declining demand will have implications for the standalone cost methodologies and how this boundary is used in tariff setting. For example, instead of the calculation being based on an alternative hypothetical network, it could be more relevant to base standalone cost estimates on the cost at which members of a tariff class would reasonably switch to another energy source.[268] This would effectively set the upper bound for reference tariffs at a lower point compared to what it is under current methodologies for standalone cost. This may be appropriate in some demand scenarios (for example a declining demand scenario) ensuring that customers in relevant tariff classes are not facing prices that encourage early exit from the network.

Theoretically, there could be merit in removing reference to an upper bound as competition from alternative energy sources may provide a natural upper bound. However, we consider the upper bound serves as an important safeguard for those customers who face financial, technical or other barriers to switching and will ensure consistency with the proposed direction on capital cost recovery.[269]

Calculating standalone costs with reference to competing energy sources can ensure that reference tariffs reflect what would occur in a workably competitive market

Consumers who remain on the gas network should not face prices consistently above those that would prevail in a workably competitive market.[270] The Commission recognises that some households and businesses have made long-run investment decisions in reliance on the continued

264 Standalone costs are used in NER clause 6.18.5(e) for similar reasons to NGR 94(3).

265 For common residential tariffs, the expected revenue boundary for standalone costs range between 6 to 15 times the avoidable cost estimation. For example, for its 2025-2030 Access Arrangement Proposal, Jemena presented a range of between $132m to $1,721m (see table 6.1.1, p.23 of its Pricing Attachment - JGN - Att 10.1 - Pricing - June 2024, available here). The range of permitted outcomes between these boundaries can be significantly higher for other non-domestic tariff classes, with ranges over 10,000 times the avoidable costs calculation.

266 For example AGN determines the stand alone cost for all tariff classes as the cost associated with major transmission and high-pressure distribution mains forming the core of the network plus the regulator stations. (See AGN (Victoria and Albury) *Attachment 14.1, Network Pricing Formulae and Efficiency, July 2022*, available here). Jemena calculates stand alone costs as the sum of the annualised shared costs and dedicated asset costs per tariff class plus the annual operating and maintenance costs associated with the assets and an allowance for non-system asset costs (See JGN *Appendix 1 - Pricing,* June 2024, available here.

267 For example ATCO gas bases the calculations on the AA approved costs uses actual values (see ATCO, *Attachment 16.002,Tariff setting method,* September 2023, available here), Ausnet uses replacement values (See Ausnet gas network, *Access information 2024-28*, p. 201, link here).

268 See appendix B on capital cost recovery where our intention is to ensure service providers have the reasonable opportunity to recover at least their efficient costs while protecting consumers from monopolistic pricing. Giving effect to this policy intent may require service providers to set tariffs on the basis of consumers who do not face barriers in accessing alternative energy sources (for example electrification or LPG).

269 For example AGN currently sets some of its residential tariffs at the standalone cost boundary, see *Attachment 14.1 Network Pricing, Formulae and Efficiency Final Plan 2023/24 – 2027/28,* table 2.1, p. 4, available here.

270 Australian Government, *National Competition Policy Review Report (the Hilmer Report),* August 1993, available here.

provision of regulated gas services at prices that emulate workably competitive market conditions. Prices cannot be described as workably competitive if they remain elevated longer than the period within which a competitive response might reasonably be expected.[271] Where material financial or technical barriers to switching exist – such as for large apartment blocks or business users facing high switching costs or other technical barriers – competitive discipline may be weak or delayed.

Calibrating the standalone cost to a level at which a consumer that faced no impediment to switching would reasonably switch to an alternative energy source would protect those consumers who remain connected to the network from paying prices in excess of what would prevail in a workably competitive market. That ceiling reflects the credible exit option of consumers who can leave and, in doing so, constrains prices for others within the same tariff class that may find it more difficult to do so. The broad application of tariff classes, primarily grouping customers by use and consumption level rather than by their capacity to switch, should protect those consumers with lessened ability to access alternative energy sources.

However, it is possible that as more consumers switch away from gas, the standalone cost for those remaining customers that face barriers to switching could increase significantly. Such an outcome would undermine the competitive constraint that our proposed approach to standalone cost is intended to provide.

We propose amendments to reference tariff provisions to assist service providers and regulators apply the concept of standalone costs appropriately under different circumstances that may arise during the transition

We are proposing to amend the rules to assist service providers and regulators in applying the concept of standalone cost appropriately under different scenarios.

During the transition there will be a range of factors that influence a service providers' circumstances when designing tariff classes and tariff structures. It will be important that the methodologies used to calculate standalone costs are suited to the circumstances of a service provider so that they can act as a meaningful upper bound to protect customers from paying prices in excess of what would prevail in a workably competitive market and give service providers a reasonable opportunity to recover at least their efficient costs.

There is already flexibility within the current rules for service providers to propose and regulators to approve standalone cost methodologies that account for a range of circumstances. However, we consider the rules could be amended to help service providers and regulators identify the appropriate methodology to apply at different phases of the transition and are also internally consistent with other components of the AA.[272]

The Commission is seeking stakeholder feedback on this proposed direction.

D.3 We considered a range of options and we consider our proposed direction for reference tariff arrangements will support the overall direction of the rule change

The Commission broadly considers the current reference tariff arrangements to be fit-for-purpose. However, for the reasons outlined above we consider that there are opportunities to improve the current framework. Our intent is to ensure that reference tariffs and tariff variation mechanisms

271 Australian Government, *National Competition Policy Review Report (the Hilmer Report),* August 1993, available here, p. xxxiii.

272 The way standalone costs are calculated is particularly relevant to our proposed direction set out in appendix B on capital cost recovery.

continue to be designed in a way that promotes the long-term interests of gas consumers, particularly in the context of uncertainty and projected declining demand.

We considered a range of options (see appendix D.3.4) and consider that our proposed direction (see appendix D.2) would better promote the NGO compared to alternatives (see appendix D.3.3) and support service providers and regulators in designing, proposing and approving tariff classes, structures and variation mechanisms that:

- reflects the broad range of scenarios that could arise through the energy transition
- give effect to decisions made in other parts of the access arrangement

This section provides additional context that is useful in understanding the proposed direction set out in appendix D.2. In this section we have summarised:

- how reference tariff provisions have applied to date (appendix D.3.1)
- stakeholder feedback we have received in relation to reference tariff arrangements (appendix D.3.2)
- assessment against the NGO and RPPs (appendix D.3.3)
- alternative options we considered for change (appendix D.3.4)

D.3.1 Reference tariff classes, structures and variation mechanisms have not varied much during recent periods of stable or growing demand, but this is starting to change

The way reference tariffs are set and varied has an impact on both customer decision-making and stakeholder confidence in the regulatory arrangements. Therefore, tariffs arrangements play a role in supporting and orderly transition. In the context of stable or growing demand, the way tariff classes, structures and variation mechanisms have been designed has been fairly consistent across AAs and over time. This is starting to change as service providers and regulators adapt to the context of uncertain demand.

Reference tariff classes

Historically, distribution service providers have divided customers into a small number of tariff classes (residential, commercial, industrial). However, the current arrangements allow for any number of tariff classes as long as customers are grouped on an economically efficient basis and avoid unnecessary transaction costs.[273] Tariff structures are then designed to suit each class (see next section).[274]

For example, a service provider may use more tariff classes to reflect different characteristics, locations and potential customer behaviours or responses between residential customers. More divergence in pricing could promote revenue recovery while meeting differing preferences (such as stability) for various consumer types.

There is sufficient flexibility under current arrangements for the regulator to allow cost shifting between tariff classes where it can be justified to be economically efficient. For example, historically, residential customers have tended to contribute a greater proportion towards network revenue recovery relative to their usage compared to industrial and commercial customers. This is because they were seen as 'stickier' (less likely to alter their demand in response to prices) and encouraging industrial demand resulted in greater utilisation of the network. We note that some

273 NGR rule 94(2).

274 NGR rule 94 (3)-(5) govern how reference tariffs are set for distribution pipelines.

service providers have started to rebalance this by shifting more costs onto industrial customers in recent AAs.[275]

Service providers have the ability to offer prudent discounts to specific customers or customer classes.[276] This is based on the idea that some cross subsidisation may be efficient where the benefit of additional demand allows for network costs to be spread over a larger volume, resulting in lowering tariffs for all customers over time. Prudent discounts are governed by clear rules that allow the regulator to approve a discount if it is satisfied that:

- the discount is necessary to respond to competition from other providers or maintain efficient use of the pipeline
- provision of the discount is likely to lead to reference or equivalent tariffs lower than they would otherwise have been.

Reference tariff structures

Service providers have traditionally structured reference tariffs around the two common charging parameters - fixed (supply) and variable (consumption) charges. For example, for its South Australian network, AGN currently recovers 75 per cent of its revenue through variable tariffs, with 25% through the fixed daily charge for residential and commercial customers.[277] Historically, service providers have tended to recover a higher proportion of their revenue from residential customers than commercial customers relative to the costs of serving those customers.

Variable charges for both large and small customers have been commonly structured as declining block charges, where the price per gigajoule decreases as consumption increases. However, reference tariffs structures approved in recent AAs have been flattening out to reflect the regulators' view that declining blocks promote increased consumption and are therefore in conflict with the emissions reduction objective in the NGO.

Different tariff structures may provide different price signals to retailers and their 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). This is because their overall network tariff component and effective dollars per GJ both increase.

Tariff setting for other services

Service providers can offer services other than reference services, which are referred to as non-reference services.[278] The price and other terms and conditions of access to non-reference are negotiated directly between service providers and customers. The rules allow the regulator to classify non-reference services as rebateable services where there is substantial uncertainty around the demand for, or the revenue to be generated from the service and the market for the service is substantially different from the market for any reference service. If these conditions are met, the regulator can allow the costs of providing rebateable services to be included in the cost

275 For example Jemena 2025-2029 AA rebalances tariffs to shift a portion of revenue recovery from residential volume market customers towards its demand (large and industrial) customers. Decision here.

276 NGR rule 96.

277 Australian Gas Networks, *Five year plan for SA network,* July 2025 available here, see section 14.5.1.

278 NGR rule 93(4). Rebateable services are considered as minor services (such as backhaul and interruptible) where demand and/or revenue generated from these services are uncertain. Therefore, any revenue generated from these services can be rebated back to users of the reference service by a reduction in the reference tariff. Such a service is known as a rebateable service. If a service is classified as such, the costs associated with the service can, in whole or in part, be included in the calculation of the reference tariff, if an appropriate portion of the revenue derived from sales of this service is returned to reference service users through a rebate or refund.

of providing reference services, if it is satisfied the service provider will apply an appropriate portion of the revenue generated from the sale of those services to provide price rebates to users of reference services.

We have considered the possibility that in a declining demand scenario, service providers might elect to either:

- price below the reference tariff to remain competitive with alternative energy sources (e.g. electricity), and/or
- seek to classify more services as non-reference services so that they fall outside the scope of the regulatory framework.[279]

The potential for a service provider to charge some customers less than the reference tariff is also relevant to the decision on whether to apply a revenue cap or hybrid tariff variation mechanism. In the Commission's view, if a service provider decides to offer some customers lower prices than the reference tariff, then this should be treated as foregone revenue by the service provider rather than being compensated through the revenue or hybrid tariff variation mechanism. Put simply, the revenue or hybrid tariff variation mechanism should only compensate the service provider for deviations in demand, not for price discounting. Otherwise the mechanism would result in some customers cross-subsidising the discounts offered to other customers.[280] While the NGR is silent on this, it is something that we think the AER should continue to consider when approving the specification of any revenue cap or hybrid tariff variation mechanism in the AA.[281]

Tariff variation mechanisms

AAs must include a reference tariff variation mechanism, which may provide for variation of customer reference tariffs within the AA period having regard to criteria covering efficiency, consistency and risk management.[282] Examples of tariff variation mechanisms include:[283]

- revenue caps
- price caps
- combinations of these (hybrid).

The choice between these options will determine how demand risk is allocated between service providers and customers and the stability of revenue and prices within the access arrangement period (see Table D.1). Long-term demand risk is ultimately shared between service providers and customers. Under a revenue cap or hybrid tariff variation mechanism this occurs within the AA period. Under a price cap, forecast demand risk is recalibrated when demand forecasts are refreshed as part of the AA reset, so the risk a service provider bears is limited to deviations between forecast and actual volumes within the regulatory period.

279 We note there are arrangements under NGR rule 47A for the regulator to require additional reference services to be included in an AA

280 Under a revenue cap tariff variation mechanism, the revenue is capped. Where a service provider recovers more or less than the approved revenue amount in one year due to demand being higher or lower than forecast, this is "trued up" by increasing or decreasing tariffs in future years of the AA in line with the approved revenue cap tariff variation mechanism. In practice, the service provider is not able to "true-up" or recover voluntarily foregone revenues in a future year. Commercially-agreed tariffs that are more or less than the reference tariff are not relevant to how a price cap tariff variation mechanism operates.

281 An example can be found in Jemena Gas Networks' Access Arrangement for its NSW gas distribution network,1 July 2025 – 30 June 2030, May 2025, p.66, available here. In the AA, the true-up formula is tied to reference services only and any allowed and actual revenue for other services are automatically removed from the revenue cap calculations. Further the calculation for allowed revenue is based on the actual tariff charged in relation to the reference tariffs.

282 NGR rule 97(2) and (3).

283 NGR rule 97.

Table D.1: Risk allocation under different tariff variation mechanisms: price cap, revenue cap and hybrid

	Forecasting demand risk within the AA period	Long-term demand risk	Services priced below the reference tariff (e.g. in response to competition)
Price cap	Forecasting demand risk sits with the service provider.	This is not determined by tariff variation mechanism.	Risk sits with service provider.[1]
Revenue cap	Forecasting demand risk sits with the customer.		
Hybrid	Forecasting demand risk is shared between service provider and customer.		

Source: AEMC
Note: [1] The service provider should not able to recover foregone revenues in a future year that result from a decision to charge less than the reference tariff.

Under a **price cap**, the regulated price is fixed for the period, but revenue varies with actual volumes. So when demand grows faster than forecast, the service provider earns more revenue than assumed in the access arrangement. When demand grows slower than forecast, the service provider earns less revenue than assumed in the access arrangement. In this way, the service provider bears the symmetrical (upside and downside) demand risk in an AA period. Until recently, price caps have been the most common form of tariff variation mechanism because the prevailing view has been that service providers had some influence over connections and usage (given gas is a fuel of choice) and were therefore the most appropriate entity to manage demand risk in an environment of growing demand.[284]

Under a **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.[285] When demand grows faster than forecast, customers pay less than what was projected and when demand grows slower than forecast, customers pay more than. Because of this, customers bear the upside and downside demand risk within the AA period. To date, a pure revenue cap has not been approved for gas distribution networks under the NGR. [286] This may reflect the view that gas customers (particularly residential customers) do not have the information or tools to appropriately manage the demand forecasting risk associated with a revenue cap.[287]

284 AEMC, *Gas networks in transition consultation paper*, 18 September 2026, available here, see Appendix B, p.80-81.

285 Revenue cap arrangements are commonly used in electricity regulatory frameworks given the electricity network service provider as less ability to affect demand given electricity is an essential service. Revenue caps can also be appropriate where they can deliver stable revenues that better match efficient costs.

286 In its 2026-2031 access arrangement proposal (available here), Evoenergy proposed a shift from a price cap to a revenue cap for a range of reasons including to reduce dependency on demand forecasts, better support efficient cost recovery, align with electricity network arrangements and because it considers a revenue cap is more likely to support emission reductions removing incentive on networks to increase volumes. The AER did not approve this proposal and instead required Evoenergy to submit a hybrid tariff variation mechanism incorporating both price cap and revenue cap regulation. The AER's draft decision (available here)noted its view that a hybrid mechanism weakens the network operator's incentive to grow demand for gas, compared to price cap regulation, but moderates potential year-on-year tariff volatility that can be a feature of revenue cap regulation. Evoenergy has proposed a hybrid tariff variation mechanism in its revised proposal (available here).

287 Hybrid tariff variation mechanisms do include revenue cap arrangements if actual demand breaches a threshold specified in the AA.

A **hybrid tariff variation mechanism** incorporates elements of both price cap and revenue cap and allows for different levels of demand risk within an AA period to be shared between a service provider and consumers. For a year in which actual demand is within a band (+/-) compared to forecasts, price cap regulation applies. If actual volumes fall outside the band, the service provider shares the resulting revenue over- (or under-) recovery with customers via lower (or higher) prices. In this way a hybrid mechanism weakens the network operator's incentive to grow demand for gas, compared to price cap regulation, but moderates potential year-on-year tariff volatility that can be a feature of revenue cap regulation. Recently the AER has stated their preference for a hybrid arrangement as a way of sharing demand uncertainty between service providers and customers within an AA period. This acknowledges the fact that demand risk will be driven, at least in part, by external factors such as emissions reduction objectives and competition from alternative energy sources.

Box 9 provides current examples of a price cap, and hybrid tariff variation mechanism.

Box 9: Current examples of price cap and hybrid tariff variation mechanisms

ATCO Gas Average Price form of control

A current example of a price cap tariff variation mechanism under Part 9 of the NGR is the weighted average price cap applied by the Economic Regulation Authority (ERA) for ATCO's WA gas distribution systems. This mechanism allows average prices to increase by the annual change in CPI (weighted average across eight capital cities), plus or minus an X-factor that is varied for debt risk premium updates and cost pass-through items. This form of price control ensures that ATCO is exposed to demand risk within an AA period rather than guaranteeing it a fixed level of revenue and passing on the costs (or returning revenue) to users, thereby providing incentives for more efficient tariffs and new connections.[i]

Jemena Gas Networks NSW hybrid tariff variation mechanism

For the NSW Jemena Ga Networks 2025-30 AA, the AER approved a proposal to move away from price cap to a hybrid approach. Under this arrangement, for a year in which actual gas volumes supplied by its network are within 5 per cent (+ or -) of the volume targets used to determine its tariffs, weighted average price cap regulation will apply as in previous access arrangements. However, if actual volumes are more than 5 per cent higher (or lower) than target, Jemena Gas Networks and customers will share in the resulting revenue over (or under) recovery. That is, Jemena Gas Networks will retain 50 per cent of any volume-driven revenue over-recovery while 50 per cent will be returned to customers via lower future network tariffs. Equally, 50 per cent of any volume-driven revenue under-recovery will be carried by the network operator and 50 per cent carried by customers via higher future network tariffs.[ii]

Source: Box Source

Note: [i] WA Economic Regulation Authority – Draft decision on revisions to the access arrangement for Mid-West and South-West Gas Distribution System, Attachment 3: Revenue and Tariffs, 24 April 2024. See page 14 - available here.

Note: [ii] AER - Final decision - JGN access arrangement 2025–30 - Attachment 10 - Reference tariff variation mechanism - May 2025 available here.

The Commission acknowledges that a tariff variation mechanisms is one of the key tools a service provider uses to manage forecast demand risk. In a declining demand scenario, a price cap (or hybrid) tariff variation mechanism can increase the risk that the service providers will not recover efficient revenue. This risk can be further exacerbated where there is uncertainty or disagreement around the forecasts that underpin the mechanism.

Decisions on tariff variation mechanisms should be applied with the broader context of the access arrangement explicitly taken into account. This is because in periods of rapid or uncertain demand, the form of regulation chosen can either reinforce or undermine other aspects of the

access arrangement. For example, where capital redundancy is being used to manage prices so they remain below the switching point range, the use of a revenue cap can inadvertently lead to prices above that range if actual demand is lower than forecast demand.

D.3.2 Stakeholders have not identified any specific issues with reference tariff arrangements but consider they can be amended to ensure appropriate tariffs and tariff variation mechansims under a range of future scenarios

The rule change proponents ECA and JEC did not explicitly raise any concerns or propose amendments in relation to the reference tariff arrangements.

In our consultation paper, we sought stakeholder feedback on the following issues:

1. Price signals, and whether consumers may need more efficient price signals to manage the potential impacts of projected declining demand on the prices customers pay.
2. Tariff variation mechanisms, and whether current arrangements allocate demand risk to the party best able to manage that risk in a context of uncertain demand.
3. Whether there was any benefit in requiring the regulator to make decision on tariff variation mechanisms sooner in the AA process - i.e. at the reference service proposal decision stage, prior to the AA proposal submission

Price signals could play a more meaningful role in managing the impacts of the transition if amendments were made to NGR reference tariff provisions

In our consultation paper, we noted that different tariff structures may provide different price signals to customers, depending on how they are passed through to customers by retailers. We asked whether stakeholders considered 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.

Stakeholder feedback was mixed with:

- The majority of pipelines and industry groups considering the current rules provide sufficient discretion. Evoenergy on the other hand, stated that the LRMC principle doesn't make sense in a declining demand environment and also stated that the concept of efficient pattern of consumption in rule 94(5) should no longer be applied.[288]
- Consumer groups and retailers considering that the current tariff principles could be updated to better reflect the declining demand situation but did not raise any particular examples or suggest new wording.[289]

This feedback, along with our own analysis contributed to our proposal outlined in appendix D.2.

Provisions that govern tariff variation mechanisms are sufficiently flexible to support a range of future scenarios

In our consultation paper we noted that the tariff variation mechanism applied to a service provider determines who bears the demand risk within the AA period.[290] We asked whether stakeholders consider there should be more guidance on when different reference tariff variation

288 Submissions on consultation paper: EvoEnergy p.8, AGIG p.23, APGA p.40, ATCO p.15, JGN p.23.

289 Submissions on consultation paper: ECA p.32, Origin p.7, Alinta p.6.

290 Price caps only protect customers against the volume risk within the AA period (forecasting risk), as prices are re-calibrated to actual volumes at the end of the AA period. Customers still hold some demand risk under a price cap variation mechanism including short term demand risk where an access arrangement reopener is needed to recalibrate for a material change in demand and medium to long-term demand risk as prices are adjusted at the end of the five years AA period.

mechanisms should be used and/or whether the decision on the applicable reference tariff variation mechanism should be brought forward.

We received the following feedback from stakeholders:

- Institute for Energy Economics and Financial Analysis (IEEFA) considers that the ability to switch to revenue cap should be constrained because, in their view distribution gas networks have received upside benefit of price caps but are now seeking to share downside risk with consumers.[291]
- Pipelines and industry groups stated that no additional guidance is needed and that current rules are working fine with sufficient flexibility and direction to regulators.[292]

The Commission considers that different forms of control could be required during different phases of the transition and restricting the options could lead to inefficient outcomes for both consumers and service providers.

We consider that it is important to retain the flexibility within current arrangements to propose and approve different types of variation mechanism, but consider that additional NGR guidance is needed to ensure that service providers and the regulator give appropriate consideration to the expected impacts of proposed tariff variation mechanisms on consumers (see appendix D.2.1).[293]

Bringing forward the regulator's decision on tariff variation mechanisms would deliver minimal benefit

In our consultation paper we sought feedback on whether bringing forward the regulator's decision on the variation mechanism could provide benefits to stakeholders by enabling earlier consultation on the service provider's proposed approach and benefits to the service provider by providing it with more certainty. We received the following feedback from stakeholders:

- Pipelines and industry groups did not support the idea of bringing forward a decision on the tariff variation mechanisms noting that for this to work, regulators' decisions must be binding.[294]
- Evoenergy raised concerns that bringing forward a decision on the variation mechanism would:[295]
  - limit meaningful engagement with stakeholders on any changes, and
  - create challenges given the inter-dependencies between tariff variation mechanisms and other components to the AA.

We consider that changes to the NGR are not warranted. While the regulator may use its discretion to provide some early guidance on tariff structures and tariff variation mechanisms as part of its decisions on the reference service proposal, we consider it appropriate that the decision on tariff variation mechanisms occurs as part of the AA. In line with our proposed direction to require a longer term outlook from service providers and regulators (see appendix A), we consider it is important that inter-dependencies across all components of an AA are recognised and properly considered, especially from the perspective of how stranding risks and overall impacts of the AA on customers are collectively managed.

291 Submissions on consultation paper: IEEFA p.7-8.

292 Submissions on consultation paper: AGIG p.22, APGA p.38-39, ATCO p.13-14, JGN p.23

293 Our proposed direction is to require service providers and regulators to consider the impacts of reference tariff classes, structures and variation mechanisms on customers within and beyond the AA period. Our proposed changes would be reflected in NGR rule 94 and 97.

294 Submissions on consultation paper: AGIG p.22, APGA p.38-39, ATCO p.13-14, Evo Energy p.6-7, JGN p.23.

295 Submissions on consultation paper: Evoenergy p. 6.

D.3.3 Our proposed direction would promote the NGO and give effect to the RPPs

We consider our proposed amendments to reference tariff provisions would better promote the NGO compared to alternatives (see appendix D.3.4). They will also complement the other proposed changes set out in this directions paper.

Our proposed direction would promote the NGO in the following ways:

- **Improve outcomes for consumers** by requiring tariff decisions to be informed by the consideration of how reference tariff arrangements impact customers and how to manage changing demand contexts – both during the AA period and beyond – which should lead to tariffs that promote more efficient outcomes for service providers and customers over the long term. The amendments would also improve consumer understanding and support better decision-making around whether and when to disconnect by requiring better information in tariff proposals and regulatory decisions about how tariffs will impact customers and the potential/expected responses from different types of customers.
- **Promote principles of market efficiency** by providing the service provider and the regulator with regulatory guidance on designing efficient tariff arrangements that suit the broader range of circumstances that could arise over the course of the energy transition. Requiring service providers and regulators to consider and explain how reference tariff arrangements are expected to impact customers would provide discipline and lead to more transparent decision-making.
- **Promote good regulatory practice** by ensuring service providers and regulators can use reference tariffs to manage the risks and impacts associated with uncertain and declining demand, and are sufficiently flexible to deal with different pipeline circumstances. Our proposed direction would also improve transparency and predictability in how businesses justify tariff proposals and how these are assessed by the regulator with minimal increase in regulatory burden. This, in turn would improve stakeholder confidence in the regulatory framework's ability to promote the long-term interests of gas consumers in an environment of increasing uncertainty. Greater transparency would also improve stakeholders' understanding and ability to engage with and provide feedback on AA proposals.

We note that our proposed changes would not directly impact **safety, security and reliability** given tariffs are unlikely to have any material impact on investment decisions in the near future and would be neutral in terms of **emissions reductions**.

Our proposed direction would also be consistent with the **RPPs.** The requirement for service providers and regulators to consider and explain the impact of their proposed reference tariff arrangements on consumers both within and beyond the AA period when proposing and determining reference tariff arrangements will result in reference tariff arrangements that are not only 'economically efficient' but also specific to the context of the service provider, including their forecast demand, the characteristics of their customer base and the jurisdictional policy environment in which they are operating. This would promote efficient decisions about the reference tariff arrangements that will best-suit the circumstances of the service provider at each phase of the energy transition and over the long term. This, in turn, will:

- help avoid the costs and risks associated with under- or over-investment that may arise if the impact of reference tariff arrangement on customers beyond the AA period are not appropriately factored into decision-making,[296]

296 NGL part 24 (6) and (7).

- support efficient investment in, and operation and use of the pipeline services over the long term,[297]
- provide service providers with a reasonable opportunity to recover at least their efficient costs.[298]

D.3.4 We considered a range of options and we consider the changes we are proposing are balanced

We explored a range of options to amend reference tariff provisions so they remain fit for purpose during the energy transition (see TTable D.2). We consider our proposed amendments to reference tariff provisions will better promote the NGO compared to alternatives (see appendix D.3.3).

297 NGL part 24(3).
298 NGL part 24(2).

Table D.2: Assessment of other policy options: Reference tariffs

Option	Benefits	Risks	Our view
Status quo	• Relatively flexible and allows service providers to propose a variety of tariff arrangements. • Minimise disruption / change • Avoid implementation costs • Promotes price stability during transition	Current arrangements do not reflect changing circumstances facing gas networks and consumers.	We do not consider the status quo is fit for purpose through the energy transition. We consider more meaningful guidance is needed to promote tariff arrangements that are suitable under a range of future scenarios including one of declining demand.
Provide full flexibility to the service provider to propose, and the regulator to decide on, tariff design	• Allows service providers to propose a broader range of tariff options in an attempt to manage risks and costs. • Leverages the concept of providing a reasonable opportunity to recover at least their efficient costs under the RPP	• May produce negative consumer outcomes (price shocks, winners and losers), undermining confidence in how the transition is being managed • May increase regulatory burden because there is less guidance in how tariff design should be approached • Reduced market efficiency if networks are allowed to price according to commercial and risk considerations rather than efficiency principles and it would not be considered good regulatory practice to give networks (either actually or by perception) more control over	This option creates uncertainty and increases risks for consumers who are less able to bear it than service providers. Also, given consumer concern around the energy transition and the social and economic impacts of gas network tariffs, it does not seem appropriate to devolve further decision-making to networks.

Option	Benefits	Risks	Our view
		tariff arrangements	
Limit flexibility through more prescription and removing discretion in tariff design, e.g. by limiting or banning use of declining block tariffs, mandating the use of specific forms of control (price/revenue caps) under certain conditions	• Removes possibility of tariff arrangements that would inappropriately transfer risks to customers in a scenario of declining demand potentially improving consumer outcomes. • Banning declining block tariffs supports emissions reduction	• Constraining options does not allow for different jurisdictional pathways/demand scenarios. • Extra constraints may hinder a service provider's reasonable opportunity to recover at least its efficient costs. • Constraining options limits the regulator's ability to consider the collective effects and interdependencies across all components of the AA.	This option does not accommodate the range of jurisdictional circumstances and possible futures. Declining demand will affect networks differently and will occur at different speeds. It is essential to have some level of regulatory discretion to assess the individual circumstances at the time of the AA.

Source: AEMC

Question 7: Our proposed direction on tariff arrangements (detailed in appendix D)

1. What are your views on our proposed direction for amending the reference tariff arrangements?
2. What are your views on our proposal to provide guidance on applying the concepts of long run marginal cost, standalone and avoidable costs?
3. What are your views on our proposal to require service provider and the regulator to give greater consideration to customer impacts in setting tariffs and tariff variation mechanisms?

E Our proposal to not amend the length of access arrangement periods or re-opener provisions

E.1 In our consultation paper, the Commission considered whether providing the regulator with additional tools would better support the regulator in managing uncertainty

We acknowledge that uncertain future demand may give rise to unforeseen events and changes that could affect service providers' operations, including the recovery of their expenditure. It is prudent to explore whether the existing AA framework provides sufficient flexibility for the regulator to manage this uncertainty.[299] Existing arrangements provide service providers flexibility to propose the length of an AA periods and variations.[300] In our consultation paper, we sought stakeholder feedback on the regulator's existing ability to:

1. determine the length of an AA period
2. propose a variation of the AA within an AA period.

E.1.1 We considered whether providing the regulator greater flexibility to determine arrangement period lengths would help manage uncertainty

The service provider proposes, and the regulator approves, the date when the AA revision proposal is due.[301] Service providers propose a 'review submission date' effectively marks the conclusion of an AA period. This date is typically is five years after the commencement date of the current AA, but service providers can propose longer or shorter periods. Where the regulator is satisfied the proposed date is consistent with the National Gas Objective (NGO) and Revenue and Pricing Principles (RPPs) and the revision commencement date is not less than 12 months after the proposed review submission date, the regulator must approve it.[302]

We sought stakeholder feedback on whether the regulator should have greater discretion to set AA periods different to those proposed by service providers. We considered that shorter AA periods may reduce the risk that material changes would occur within the AA period while longer AA periods could support decision-making in line with long-term considerations beyond the period. We also considered that providing greater discretion to set AA lengths may allow the regulator to align their gas and electricity distribution decisions, and that this alignment could improve decision-making by facilitating a better understanding of gas and electricity sector interactions.

E.1.2 We considered whether amending the re-opener provisions, including providing the regulator with the ability to propose a variation of an AA, would help manage uncertainty

Currently, a service provider may propose a variation to an AA before the end of the AA period.[303] The regulator may approve the proposed variation without consultation where it deems the variation immaterial.[304] Where a variation is deemed material, the regulator must consult on the variation as it would on an AA proposal.[305]

299 AEMC, Gas Networks in Transition, Consultation paper, 18 September 2025, pp. 35-37.
300 Rules 52(2) and 65 of the NGR.
301 Rule 52(2) of the NGR. The regulator must consider the NGO and the revenue and pricing principles when approving the due date for the access arrangement revision proposal.
302 Rules 50(1), (2) of the NGR.
303 Rule 65 of the NGR.
304 Rule 66(2) of the NGR.
305 Rule 66(3) of the NGR.

The regulator can only propose a variation to a service provider's AA to correct a material error or deficiency, such as a clerical mistake, miscalculation or deficiency resulting from false or materially misleading information. The current regulatory framework may not provide the regulator sufficient flexibility to respond to unforeseen changes during the regulatory period that may impact service providers or consumer. We sought stakeholder feedback on whether there would be benefit in:[306]

1. enabling the regulator to propose a variation to an AA
2. enabling the regulator to conduct narrowly scoped reviews (rather than a review of the entire AA) in response to variation proposals for service providers
3. constraining service providers' ability to propose variations to their AA.

E.2 We consider that existing arrangements are fit for purpose

Enabling the regulator to propose alternative AA period lengths would not provide for material benefits noting that the regulator can already take longer term considerations into account

In response to our consultation paper, some consumer and other interest groups suggest that longer AA periods may be beneficial, as they would enable alignment of AA with jurisdictional net-zero targets or network decommissioning plans and allow stakeholders to better evaluate investment decisions.[307]

Pipelines and industry groups generally oppose more discretion for the regulator given:

- the regulator can already require service providers to disclose information with an outlook beyond the AA period to consider when evaluating AA proposals[308]
- the requirement that an AA period is approved if it is consistent with the NGO and RPPs provides the regulator appropriate discretion[309]
- the benefits of aligning the timing of electricity and gas distribution decisions are unclear as the regulator already has information on what is happening in both sectors, but alignment would create regulatory costs and practical challenges.[310]

We consider that longer AA periods are not required to support long-term decision-making. The regulator can currently assess AA proposals with an outlook beyond the AA period. This is further supported by our initial proposal to require service providers to publish and the regulator to consider information with a 20-year outlook when proposing and deciding on an AA. Against this background, we conclude that there would be limited benefit in enabling the regulator to determine alternative timeframes for AAs.

Updating the re-opener provisions, which could include enabling the regulator to propose variations to AAs or limiting service providers' ability to propose variations, would increase uncertainty

Some consumer groups and retailers suggest that enabling the regulator to vary AAs could improve flexibility and responsiveness in managing uncertainty during the energy transition.[311] The AER considers that AAs should only be varied as a last resort, but the regulator's flexibility to reopen AAs, where appropriate, should be further considered.[312]

306 AEMC, Gas Networks in Transition, Consultation paper, 18 September 2025, pp. 37.
307 Submissions to the consultation paper: ECA, p. 14; GCCN, p. 3; Rewiring Australia, p. 8.
308 Submissions to the consultation paper: ATCO, p. 13; ENA, pp. 26-27; APGA, p. 38.
309 Jemena, Submission to the consultation paper, p. 23.
310 Submissions to the consultation paper: APGA, p. 41; ATCO, p. 16; ENA, pp. 27-28; EnergyAustralia, p. 7; Evoenergy, p. 11; Jemena, p. 24.
311 Submissions to the consultation paper: Origin, p. 6; ECA, pp. 34-35; SACOSS, p. 10; EnergyAustralia, p. 7.

Pipelines and industry groups generally oppose changes to the re-opener provisions, including service providers' scope to propose variations, suggesting that existing AA mechanisms provide sufficient tools to manage uncertain future demand.[313] These stakeholders also consider that increased flexibility for the regulator could undermine investor confidence and the ex-ante incentive-based regulatory framework.[314] Conversely, JEC consider that the current NGR arrangements, allowing service providers to propose a variation to their AAs in response to unforeseen circumstances may reduce the incentives for service providers to incorporate likely risks and plan for decline in the network in their AA proposals.[315]

We consider that existing re-opener provisions are fit for purpose, as existing regulatory mechanisms are sufficient for the regulator and service providers to manage uncertain future demand. We consider that changes to the re-opener provisions to either increase the regulator's ability to propose a variation of an AA or limit a service provider's ability to propose a variation to an AA could undermine investor confidence and create greater uncertainty instead of addressing uncertainty around future gas demand.

312 AER, Submission to the consultation paper, p. 9.

313 Submissions to the consultation paper: AGIG, p. 23; Evoenergy, p. 11; APGA, pp. 41-44; ENA, p. 27.

314 Submissions to the consultation paper: Evoenergy, p. 11; Jemena, p. 24; APGA, pp. 43-44; ENA, p. 28.

315 JEC, Submission to the consultation paper, p. 23.

F Incentives in the gas regulatory framework

F.1 We will consider the need for additional or modified incentives after reviewing stakeholder submissions on our package of proposed changes to the gas regulatory framework

As the energy transition progresses, explicit and implicit incentives in the gas economic regulatory framework will continue to play an important role for service providers and consumers in supporting the efficient and safe provision of pipeline services in the context of uncertain and/or declining demand. It is therefore important that these tools are fit for purpose and can be used as and when required to promote the long-term interests of gas consumers.

We have not yet considered whether any new or modified incentives are required. Instead, this directions paper focuses on proposing a coherent package of reforms to the gas regulatory framework relating to expenditure assessment, capital cost recovery, reference tariffs and long-term outlooks.

We will consider stakeholder submissions on our proposed package of changes to the gas regulatory framework, as set out in this directions paper. For the draft determination, we will assess whether there is a need to also amend incentives in the regulatory framework to best encourage efficient outcomes in the long-term interests of consumers. This ensures that any proposed changes of explicit and implicit incentives complement the package of other proposed changes to the regulatory framework.

Neither ECA nor JEC proposed any changes to NGR provisions for incentive mechanisms in their rule change requests.

F.2 The current gas regulatory framework includes explicit and implicit incentives for service providers

We have identified two broad categories of incentives in the current gas regulatory framework – explicit and implicit incentives. These are explained below.

The gas regulatory framework includes explicit incentives

Currently an AA 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.[316] However, we note that the NGR does not:

- define the types of incentive mechanisms that the AER may apply to service providers
- require the AER to develop and implement any incentive mechanisms for service providers.

This is different from electricity where the NER requires the AER to develop and implement incentive mechanisms.

Currently, service providers propose, and the regulator decides, whether or not to include any incentive mechanism in their AA. The current incentive schemes the AER applies to gas service providers in their AA relate to expenditure and are set out below.

- **Capital sharing incentive scheme (CESS):** Designed to incentivise efficient spending on capex by rewarding service providers for lowering their capex below the amount approved for the AA period. The rewards are shared between the service provider and consumers. The CESS is currently applied to all distribution service providers and not transmission service providers.

316 Rule 98 of the NGR.

- **Operating expenditure incentive mechanisms:** The AER currently applies either the Efficiency carryover mechanism (ECM) or Operating expenditure incentive mechanism (OEIM) to service providers.[317] These incentive mechanisms are intended to provide a continuous incentive for service providers to pursue efficiency improvements in opex, and provide for a fair sharing of these between service providers and consumers.

ERA did not apply any incentive mechanisms to ATCO in their current AA.[318] ERA accepted ATCO's proposal to not include any new incentive mechanisms in their current AA on the basis of ATCO's top quartile performance.[319]

Currently no incentive mechanisms relating to service standards apply to gas service providers. This is different from electricity where network service providers apply the Service Target Performance Incentive Scheme (STPIS).

The regulatory framework includes implicit incentives

The current regulatory framework includes implicit incentives for service providers, including incentives to manage:

- **Demand risk:** The reference tariff variation mechanism proposed and approved as part of the AA determines who bears the risk that demand within the access arrangement period will be more or less than what was forecast by the service provider. This provides a financial incentive for service providers to increase demand under a price cap or hybrid reference tariff mechanism (based on a combination of price and revenue caps). It may also provide an implicit incentive for service providers to present forecasts with lower levels of demand.
- **Stranding risk:** In the context of uncertain demand, service providers may have an incentive to minimise new capex entering the capital base to minimise potential stranding risk. This means that service providers may seek to limit new expenditure, while continuing to support the safe operation of the network.

F.3 Stakeholders had diverse views on whether to modify or apply additional incentives for service providers to support the energy transition

Stakeholder views on explicit incentives in the regulatory framework

In our consultation paper, we asked stakeholders whether modified or additional incentive mechanisms should apply to service providers in the energy transition. Stakeholders had diverse views on whether changes are needed to incentive mechanisms:

- **Support changes:** ECA and EUAA supported reviewing incentive schemes to ensure they are fit for purpose, depending on the outcome of the rule change.[320] Some retailers and consumer groups supported incentives so that expenditure only occurs where it is economic, justified or is efficiently balanced against service levels.[321] Alinta and GCCN suggested that we explore the Spanish approach of incentivising the ongoing operation of fully depreciated assets, provided that these assets are operated safely.[322]

317 The AER currently applies the ECM to all distribution service providers and some transmission service providers. The AER currently applies the OEIM to APA Victorian Transmission System (VTS).

318 ERA, *Final decision on access arrangement for the Mid-West and South-West Gas Distribution Systems (2025 to 2029) - Attachment 7: Return on capital, taxation, incentives*, 8 November 2024, p. 1 https://www.erawa.com.au/sites/default/files/24363/Final-Decision-Attachment-7-Return-on-capital-taxation-incentives.PDF.

319 ATCO, *Gas 2025-29 Draft plan – ATCO Mid-West and South-West Gas Distribution Systems*, April 2023, p. 102. https://gas.atco.com/content/dam/web/atco-australia/for-home/aa6/2025-29%20Draft%20Plan%2020230418.pdf.

320 Submissions on consultation paper: ECA, p. 35 and EUAA, p. 7.

321 Submissions on consultation paper: Brotherhood of St Laurence, p. 8; EnergyAustralia, p. 4-5; Origin, p. 8; Alinta, p. 6.

- **Neutral on changes:** The AER was open to considering incentives to support efficient and safe outcomes.[323]
- **Oppose changes:** Most pipelines and industry groups considered that existing incentive mechanisms are sufficient to invest efficiently and maintain service standards, and are flexible enough to accommodate changes in demand.[324] APGA considered additional or modified schemes would add complexity.[325] JEC does not support introducing new economic incentive mechanisms as they do not consider such schemes have been effective in electricity.[326] IEEFA noted that in 2023 the AER reviewed incentive schemes for electricity and gas network service providers (focusing primarily on electricity), making improvements to the CESS and no changes to the EBSS, and does not consider that there would be benefit in another review of incentive schemes.[327]

Stakeholder views on explicit incentives in the regulatory framework

The ENA noted that in relation to stranding risk, cost recovery is not guaranteed and as such service providers already have a strong incentive to minimise new capex entering the capital base.[328] For more information refer to appendix C.

In our consultation paper we noted that the tariff variation mechanism applied to a service provider determines who bears the demand risk within the AA period.[329] We asked whether stakeholders consider there should be more guidance on when different reference tariff variation mechanisms should be used and/or whether the decision on the applicable should be brought forward. For more information refer to appendix D.

F.4 We seek stakeholder views on whether changes should be made to explicit or implicit incentives to support our proposed changes to the gas regulatory framework

In this directions paper we have set out a package of proposed changes to the gas regulatory framework covering expenditure assessment, capital cost recovery mechanisms, reference tariffs and long-term outlooks. Given this package of reforms, we seek stakeholder feedback on whether changes are needed to explicit or implicit incentives in the regulatory framework.

Question 8: Incentive mechanisms (detailed in appendix F)

1. Having regard to our proposed direction, do you consider there is a need for additional or modified incentive mechanisms for service providers?

322 Submissions on consultation paper: Alinta, p. 6 and GCCN, p. 12.

323 AER, submission on consultation paper, p. 6.

324 Submissions on consultation paper: AusNet, p. 12; Jemena, p. 24; EvoEnergy, p. 5; ATCO, p. 17.

325 APGA, submission on consultation paper, p. 43.

326 JEC also noted that it would support considering incentives to lower demand, efficiently reduce emissions and decommission assets. if there is a wider review as part of a fit for purpose framework.

327 IEEFA, submission on consultation paper, p. 9.

328 ENA, submission on consultation paper, pp. 17-18.

329 Price caps only protect customers against the volume risk within the AA period (forecasting risk), as prices are re-calibrated to actual volumes at the end of the AA period. Customers still hold some demand risk under a price cap variation mechanism including short term demand risk where an access arrangement reopener is needed to recalibrate for a material change in demand and medium-long term demand risk as prices are adjusted at the end of the five years AA period.

Abbreviations and defined terms

AA	Access arrangement
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGIG	Australian Gas Infrastructure Group
APGA	Australian Pipelines and Gas Association
CESS	Capital Expenditure Sharing Scheme
Commission	See AEMC
ECA	Energy Consumers Australia
ECMC	Energy and Climate Change Ministerial Council
ERA	Economic Regulation Authority Western Australia
EUAA	Energy Users Association of Australia
GAPR	Gas Annual Planning Report
Gas Access Code	National Third Party Access Code for Natural Gas Pipelines Systems
GSOO	Gas Statement of Opportunities
IEEFA	Institute for Energy Economics and Financial Analysis
JEC	The Justice and Equity Centre
JGN	Jemena Gas Networks
LRMC	Long run marginal cost
NERR	National Energy Retail Rules
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NPV	Net present value
OEIM	Operating Expenditure Incentive Scheme
Proponent	The individual / organisation who submitted the rule change request to the Commission
RIT	Regulatory investment test
RPPs	Revenue and pricing principles
STPIS	Service Target Performance Incentive Scheme