Australian Gas Infrastructure Group

30 April 2026

Australian Energy Market Commission (AEMC)
via online submission

Dear Commissioners,

"Gas Networks in Transition" Directions Paper (GRC0082)

Australian Gas Infrastructure Group (AGIG) welcomes the opportunity to provide this submission to the Australian Energy Market Commission (AEMC) in response to its "Gas Networks in Transition" Directions Paper. Through our ownership of Australian Gas Networks (AGN), Multinet Gas Networks (MGN) and the Dampier to Bunbury Pipeline (DBP), AGIG delivers energy to more than two million customers, operates extensive gas distribution, transmission and storage infrastructure and actively pursues renewable and carbon-neutral gas production, infrastructure and storage projects across Australia.

Overall, we consider the Directions Paper reflects a sound economic framework and is consistent with the intent of the National Gas Rules (NGR). While the existing framework can support the transition, the AEMC's proposed refinements have potential to improve how it will be applied in a way that promotes efficient outcomes over time. Our submission focuses on three key principles which underpin this view.

Networks face symmetric market incentives under the NGR

The Directions Paper recognises that networks have limited incentive to depart from efficient outcomes under the NGR, particularly given the risk of asset stranding where depreciation is brought forward unnecessarily. This is an important starting point, as it establishes the basis for understanding how incentives operate under the framework. Just as networks are not incentivised to propose excessive depreciation, they are also disincentivised from deferring efficient partial asset redundancy.

In practice, redundancy outcomes are constrained by prices that customers are willing to pay, meaning networks have no incentive to maintain assets or prices above efficient levels. This symmetry is important and has direct implications for how discretion is allocated between networks and the regulator. Extending the AEMC's reasoning on depreciation to partial asset redundancy supports an approach where networks propose outcomes and the regulator tests them against a clear evidentiary standard.

Depreciation decisions have potential to create asymmetric risks in the longer term

Depreciation and partial asset redundancy are inherently linked, and decisions made today on depreciation settings shape future redundancy outcomes. There is an important asymmetry in how risks arise. Where depreciation is brought forward too quickly, the consequences are observable through customer behaviour and can be corrected through subsequent regulatory processes, with networks strongly incentivised to respond.

By contrast, where depreciation is deferred, the consequences emerge over longer timeframes through inefficient asset retention and potential for eventual stranding. These effects are more difficult to correct, particularly as the opportunity to adjust depreciation narrows over time. This asymmetry supports an approach where any material reduction in depreciation should only be accepted where supported by a strong evidentiary basis, reflecting the greater risk of irreversible inefficiency.

Clear Rules and willingness to pay must anchor the framework

How these issues are framed in the NGR will be critical to the long-term effectiveness of the framework. Clear and durable drafting is required to ensure that the Rules continue to be interpreted and applied as intended, including in circumstances where supporting guidance may no longer be readily accessible. Embedding key principles in the Rules themselves will strengthen transparency and support accountability over time.

Where key principles are not clearly reflected in the Rules themselves, there is a risk that interpretation may diverge from the original intent. In this context, willingness to pay provides the most appropriate economic basis for decision-making, particularly in relation to pricing and asset utilisation. Alternative constructs, such as switching costs, are less well suited to capturing efficient outcomes.

We have structured this submission as follows:

- **Appendix A:** Overarching Questions
- **Appendix B:** Longer-Term Outlook
- **Appendix C:** Capital Cost Recovery
- **Appendix D:** Expenditure
- **Appendix E:** Tariffs
- **Appendix F:** Incentive Mechanisms

Thank you for considering this submission. For further discussion, please contact Owen Sharpe, Strategy and Policy Manager, at owen.sharpe@agig.com.au.

Kind Regards,

Cathryn McArthur
Executive General Manager
Customer and Strategy

Australian Gas Infrastructure Group

Appendix A: Overarching Questions

In this section, we provide brief answers to the series of overarching questions from Chapter 5 of the AEMC's Directions Paper.

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?*

We consider the Directions Paper reflects a sound economic framework and is consistent with the intent of the National Gas Rules (NGR). While the existing framework is capable of supporting the transition, the AEMC's proposed refinements have potential to improve the likelihood that it will be applied in a way that promotes efficient outcomes over time.

We believe the Directions Paper represents a significant step forward compared to the rule changes proposed by the ECA and JEC, noting that providing clarity and guidance outlined in our subsequent responses would strengthen the framework's ability to achieve its objective and promote efficient outcomes.

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?*

We do not consider that there are significant transitional requirements associated with AEMC's proposed changes, nor any barriers to implementation. We consider the AEMC's final rule changes, if published in December 2026, should be applied to the Australian Gas Networks (AGN) Victoria, Multinet Gas Networks (MGN) and AusNet decisions, as appears to be the AEMC's intention (Directions Paper p18).

Implementation of some parts of the proposed rules, such as the 20-year forecasts, may present some practical challenges, particularly in the first instance. We note that the Victorian Access Arrangement (AA) proposals are due to the AER in mid-2027. During the rest of 2026 we will be working through our demand forecasts, depreciation modelling and building block modelling. We will aim to follow the Directions Paper (and draft rules, when they are published) in forming our evidence base, and would welcome the opportunity to engage with the AEMC and other stakeholders the issues we face in doing so, with a view to informing the final rules.

2. *Do stakeholders consider there are any significant implementation costs associated with our proposed package of reforms that the Commission should consider?*

At this stage, we do not consider any significant implementation costs. While the 20-year forecasts requirement is a new element of the framework, we have already provided longer-term forecasts in our past AA proposals. We will be in a better position to provide further comment on implementation costs once the draft rules are published, which will provide greater clarity of the proposed requirements.

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)?*

We consider that, in terms of broad principles, the proposed rule changes could be applied equally to both distribution and transmission systems.

However, the rules will need to be written with sufficient flexibility to accommodate the differing demand profiles of gas transmission versus distribution and their respective sources of uncertainty. For example, this might include considerations of changes to electricity generation that may impact transmission pipelines.

Appendix B: Longer-Term Outlook

In this section, we provide responses to the questions that the AEMC poses in Appendix A of its Directions Paper, focusing on the requirement to produce long-term demand forecasts to underpin depreciation and other aspects of the building block model in regulatory proposals.

Our key concern is that the Rules may risk leading networks, regulators and other stakeholders into a false sense of assurance about the future of the gas network. This could occur if assumptions to build scenarios of the future are relied upon without adequately exploring the consequences of those assumptions being incorrect, and if decisions are taken based upon false confidence in the assumptions. In simple terms, we consider that the AEMC should ensure that the structure of the Rules around the requirement to provide forecasts does not create an incentive for networks or regulators to derive forecasts based wholly upon unexplored or inadequately explored assumptions. The nature of uncertainty in the energy sector is such that a "best forecast" complemented by sensitivity analysis around key assumptions would be highly unlikely to lead to robust decision-making.

As background to this concern, and to our answers to the AEMC's questions, this section discusses three key elements associated with the demand for gas transportation services:

- Volume is very different from connections;
- The nature of evolving demand in the energy sector is profoundly uncertain (see below), and decision-making needs to be built around this uncertainty; and
- Demand and depreciation are linked, meaning there is no progression from a demand forecast to a depreciation schedule, because changes in depreciation change demand.

In respect of volume, our submission to the Discussion Paper distinguishes between declining demand and declining connections. While consumption per connection may moderate, the number of connections does not necessarily decline at the same rate, and in many networks, it continues to grow. Additionally, in most networks, commercial and industrial demand has remained relatively stable. As network utilisation and cost recovery are driven primarily by connections rather than throughput, a decline in aggregate demand does not, in itself, indicate underutilisation or asset stranding.

At present, across many networks, connections are steadily growing while demand per connection is falling, suggesting the market remains in the process of adjusting to an evolving equilibrium between usage and connection decisions. This is important not only for forecasting, but also when comparing forecasts: declines in volume from one forecast may have little in common with changes in connections in another.[1]

The second and third points are inter-related, and more fundamental. Gas networks, and the energy sector more generally, are facing uncertainty about the future that is "profound" in nature. That is, whilst one can determine feasible scenarios of future demand, there is no information which would allow one to assign a probability, or even a likelihood, to any given demand scenario. Similar considerations arise in other parts of the energy system, such as the pace of electrification or the uptake of distributed energy resources, where both the scale and nature of future demand are uncertain. This matters because the best way to plan in the face of this type of uncertainty is very different from simply choosing a "best" forecast, and dealing with uncertainty via sensitivity analysis.[2]

The problem is compounded by the interaction between demand and depreciation. Put simply, demand is dependent on price, and changes in depreciation flow through to prices. It is impossible to define a demand forecast and subsequently set a depreciation profile based on that forecast, as the choice of the depreciation profile itself influences demand. Rather, demand and depreciation should be iteratively considered to provide a joint outcome where both are optimal (or at least mutually consistent).

The risk is that ignoring uncertainty provides a view of the future, which provides clarity, and may therefore be attractive to stakeholders. However, this obscures how unpacking all of the uncertainties embedded in the underlying assumptions might fundamentally alter the appropriateness of decisions based on overly simplistic "best" forecasts. Unless there is clear guidance on

---

[1] We note that the Australian Energy Market Operator (AEMO) does forecast connections (see, for example, p27 of the 2026 GSOO, available here). However, AEMO makes it very clear (see ibid, p26) that its measure of "effective connections" assumes that consumption per connection will be the same as it has been historically, which AEMO recognises is unlikely to be the case, suggesting that consumption per connection is likely to fall. We support the AEMC's clarification (see the summary of the public forum, p1, available here) that it will not require networks or regulators to use AEMO forecasts, noting they are not designed for this specific regulatory purpose.

[2] Where uncertainty relates to outcomes within known probability distributions, decision-making can be based on expected outcomes. Where probabilities cannot be meaningfully assigned to alternative futures, different approaches are required, including frameworks that focus on robustness across scenarios, such as "minimax regret" (see here, for a textbook treatment of decision-making under uncertainty).

the reliance that can be placed on any 20-year forecasts and how they are to be made, the framework could give rise to even greater risks whereby:

- General agreement is formed on what can be estimated, what must be assumed, and what the boundaries will be on all of the assumptions, with each boundary being agreed to be very tight so that forecasts are "consistent" with each other;
- A certain number of scenarios is created based on these input assumptions;
- Either each scenario is assumed a probability, or a "most likely" scenario is either chosen by consensus or must be justified by each network individually; and
- Each network is required to develop a depreciation profile which matches this "most likely" scenario; or in some way link to the assumed likelihood of scenarios.

In the United Kingdom (UK), the National Energy System Operator (NESO) is required to produce a series of scenarios aligned with emissions targets to 2050 across the energy system. The Office of Gas and Electricity Market (OfGEM) has, in the current RIIO-3 process, asked gas networks align aspects of their regulatory proposals with these scenarios.[3] The risk is that, where decisions are designed around a central NESO forecast, networks may be constrained in exploring the consequences of key assumptions being incorrect, particularly those underpinning why certain scenarios are considered more likely.[4]

The Directions Paper's approach to 20-year forecasts raises a similar risk. It may lead to decision-making that places undue weight on a single forecast, whether developed by a network, regulator, or AEMO. For example, the AEMC proposes requiring networks to include their "best forecast or estimate" (Directions Paper p32) of factors such as demand, Regulatory Asset Base (RAB) utilisation, capex and opex over the 20-year time horizon, supported by an asset and risk management plan. The regulator would then be expected to respond with their own "best estimate" (Directions Paper p34).

A "best estimate" could, in principle, encompass a range of scenarios without assigning explicit probabilities, while appropriately reflecting the underlying uncertainties. However, our reading of the Directions Paper appears to indicate that the AEMC may be seeking a single forecast to represent that "best estimate". We would welcome further clarification from the AEMC on this point as the process progresses.

If the intent is for a "best estimate" to be expressed as a single forecast, this risks introducing an approach similar to that emerging in the UK. Requiring a network or regulator to provide a single "best estimate", or even a limited set of scenarios, does not in itself resolve the underlying uncertainty in the energy sector. Different parties may reasonably adopt different assumptions, leading to materially different forecasts, with no clear or objective basis for determining which set of assumptions is preferable.[5]

This creates a risk that the framework may become less robust to uncertainty. In our view, it is preferable to place uncertainty at the centre of the process and adopt decision-making approaches that are resilient across a range of plausible outcomes, even where this results in forecasts that are less simple or less definitive.

Addressing this challenge may require two actions from the AEMC. First, to clearly explain in its guidance notes and explanatory statements the importance of not obscuring uncertainty under assumptions, how decisions can be made effectively under uncertainty, and why stakeholders should place undue weight on apparent forecast precision. Second, by reflecting in the NGR the need for both explaining assumptions and their consequences clearly and ensuring that any decision-making process relying on forecasts is robust to that uncertainty.

We appreciate that the net result will not be a simple "line on a graph" forecast; even without the uncertainty, the interaction between depreciation and demand would make this impossible. This is appropriate, because the real world is not reducible to a single forecast path.

Question 4: Our proposed direction on a longer-term outlook

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?*

[3] *Office of Gas and Electricity Market (2024), RIIO-3 Business Plan Guidance, 18 July 2024. Available at: RIIO-3 Business Plan Guidance (accessed 30 April 2026).*

[4] *Wales & West Utilities (2024), Business Plan 2026–2031. Available at: https://www.wwutilities.co.uk/about-us/business-plan/ (accessed 30 April 2026).*

[5] *This is before we get to the problem that depreciation and demand are linked, so any "best estimate" will depend not only on assumptions, but also on which choice is made for depreciation.*

We consider it is appropriate for both networks and the regulator to explicitly consider the longer-term outlook and consequences. However, as outlined in the introduction, the manner in which this outlook is reflected in forecasts and how decisions rely upon forecasts is critical, particularly to avoid a false sense of assurance in the decision-making process.

One key aspect of the Directions Paper that we consider positive is the AEMC's intention to introduce a greater degree of symmetry in the requirements applying to networks and regulators in relation to forecasts. For example (Directions Paper, p17):

> *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*

And further (Directions Paper p30):

> *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 is a positive development, and we agree with the AEMC that this direction is consistent with the Revenue and Pricing Principles (Directions paper p30). In fact, we would suggest the AEMC go further and require the regulator to provide evidence of their considerations, including why its forecasts represent an improvement on those proposed by any networks. We agree with the AEMC (Directions Paper p31) that a current lack of such a requirement (on both parties) in the NGR is a limitation.

We note that this requirement should not be viewed as a consequence of stakeholder views about the adequacy of justification regulators have provided in recent decisions about depreciation; rather, it reflects a more fundamental consideration. The basis of incentive-based regulation (see for example, the canonical textbook treatment of Laffont and Tirole)[6] is that regulation provides incentives for monopoly firms to reveal otherwise private information about costs so that pricing becomes increasingly efficient over time. The "propose-respond" model of regulation is well suited to eliciting this type of information.

However, the "information" associated with the energy transition is fundamentally different. It is not the case that networks hold private information about how the energy sector will evolve that can be elicited through regulatory incentives. Rather, it reflects genuine uncertainty on the future direction of the energy sector. Increased incentives to reveal private information via a "propose-respond" model of regulation can, therefore, do nothing to deal with this type of uncertainty that the energy sector faces. Instead, regulators and networks need to work together to understand what this uncertainty means for decision-making, which requires both parties to provide the evidence relied upon in an open, transparent and balanced manner.

We view the AEMC's approach in respect of greater symmetry in providing evidence between networks and regulators as a recognition of an important difference in the nature of the "information" associated with the evolution of the energy sector.

We do not consider that a requirement for more symmetry in the provision of evidence means that a regulator should be required to form a 20-year forecast in the same way as a network is required to do. Instead, it means that regulators should provide the same level of evidence when they make decisions in a given AA process as they require of networks when forming 20-year forecasts. This is something which could be encoded into the NGR more formally, as the relative provision of evidence is something which objective and independent stakeholders can assess relatively easily. Encoding this in the NGR ensures that both regulators and networks are held to account on this important point.

2. Do you have any views on the information or analysis that should be included in a service provider's 20-year outlook?

Our views as to what a 20-year forecast should contain are influenced by our principled position outlined at the start of this chapter, particularly the need for forecasts to not provide undue confidence in a specific forecast path. This means that, whilst it is important for forecasts to include demand, depreciation, evolving RAB profiles, opex and capex and similar items (covered by the AEMC on p29 of the Directions Paper), it is equally critical to include elements to reduce the risk of creating a false sense of assurance amongst stakeholders. Some examples of these include:

---

[6] *Laffont, JJ and Tirole, J, 1993, A Theory of Incentives in Procurement and Regulation, MIT Press, Cambridge: Mass.*

- Descriptions of the major forces which are driving outcomes;
- A description of key assumptions underpinning demand;
- A clear outline of the limitations of the forecast to prevent it from becoming viewed as more accurate than it is; and
- An outline of how the forecasts are used to make decisions; the formal decision-making process[7]

At this stage, we do not consider that the AEMC should simply prescribe a list of tools for critiquing forecasts, as this would give rise to a risk that the process becomes a compliance exercise that does not improve decision-making. Instead, we consider that the AEMC should embed this principle in the NGR and rely on stakeholders to enforce it (guided by the AEMC's explanatory or guidance notes published with the final rule) by holding networks and regulators accountable to the principle.

[7] *See footnote 2 for a reference to decision-making processes which are robust to the kinds of uncertainty prevalent in the energy sector.*

Appendix C: Capital Cost Recovery

In this chapter, we provide answers to the AEMC's questions posed in Appendix B of the Directions Paper, relating to capital recovery. As with previous chapters, we provide an overview of some key principles and use this to answer the AEMC's subsequent questions. As outlined in our introduction to this response, we consider that the AEMC's proposed direction is broadly sound.

We do not discuss inflation or the RAB indexation explicitly in this section.[8] Moving to a nominal RAB is effectively another way of changing depreciation. The same is true for other approaches such as sum-of-the-digits.[9] The points we make here apply to most changes in depreciation. The only exception is where we discuss how depreciation interacts with demand, which approaches such as removing indexation do not address. For this reason, we do not comment further on RAB indexation. However, if depreciation is to be governed under AEMC Option C(i), this should also apply to decisions to remove indexation.

We introduced many of the key issues associated with capital recovery in our introductory chapter. Here, we expand upon two key issues:

- The incentive structure for networks in the context of depreciation compared with asset redundancy; and
- The key linkage between depreciation and asset stranding and the possibility that regulatory action can cause more asset stranding than is efficient.

In respect of depreciation, we agree with the expert report from Incenta (see pp 8-9) submitted by Energy Networks Australia (ENA) that the AEMC has largely captured the incentives networks face. For example where it suggests (Directions Paper p73):

> *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.*

Given all networks face some degree of asset stranding risk, we agree with the first point. In relation to the second point, however, if it is taken to suggest that the extent of stranding risk should influence the degree of alignment with the NGR, we do not consider that conclusion follows, as illustrated in the case study set out below.

A related question arises when comparing this approach with the treatment of electricity networks. Electricity networks, which are generally not considered to face material stranding risk, are currently afforded greater discretion over depreciation than gas networks (see Directions Paper pp.50–51). The AEMC has not proposed to move the electricity framework toward governance options such as Option C(ii) or D. This is not to suggest that such a change should be made in electricity, but rather to highlight a potential inconsistency in applying a more discretionary governance approach in gas in these circumstances.

The Directions Paper places significant emphasis on the potential impacts on vulnerable customers, particularly those who may find it difficult to switch away from gas and could face higher costs if other customers exit the network more quickly.

In this context, it is also relevant to recognise the role of network incentives. Networks have a strong commercial interest in maintaining a broad and sustainable customer base over time. A customer base comprised predominantly of those least able to respond to price increases would not be viable, and networks therefore have an incentive to retain customers with greater flexibility to switch. In practice, this creates a discipline on pricing outcomes, including a tendency toward more conservative approaches to depreciation. This aspect of network incentives should be considered in the development of the Rules.

[8] *The expert report from Incenta, submitted with the ENA submission to the Directions Paper ((pp21-23) provides more detail on the treatment of inflation.*

[9] *Removing RAB indexation is also a one-time change, whereas changing depreciation schedules is something that c an be fine-tuned at each AA as more information becomes available. This difference, however, is not significant in the context of the issues discussed in this chapter.*

The AEMC appears to consider that network incentives are aligned with the NGR in respect of depreciation. However, it appears to take a different view in respect of asset stranding, noting (Directions Paper, p. 76):

> *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.*

This then leads the AEMC to favour Option D over Option C amongst its governance options. We concur with the view of Incenta in its expert report for the ENA (pp26-27) that this characterisation does not fully capture the incentives networks face when asset stranding actually occurs.

As a general proposition, any business (regulated or not) will seek to recover its invested capital where it is able to do so. If market forces move against the business such that it must price below the level implied by a mechanical accounting model (like the Post Tax Revenue Model (PTRM)) to retain customers, the business will do so and recover some of its fixed costs rather than none. A regulated firm behaves no differently in this regard. Provided (see our answer to the question below) asset redundancy is used as a "last resort" once the scope for depreciation is exhausted, it will simply bring down the building block price to a level that can be supported in the market. As the network would, in any event, be charging that price under those market conditions (regardless of what the PTRM indicates), there would be no difference for the network or its customers when partial asset redundancy is recognised, and hence limited incentive for the network not to use it.

In the forum on 9 April 2026, the AEMC addressed this question and noted that, while it agreed with the sentiments outlined above, the benefit of the partial asset redundancy framework is that, rather than charging a lower price and permanently losing the relevant portion of the RAB, the redundant capital could be put into a separate fund and recovered at a later point if conditions improve.[10] Whilst we can see the AEMC's point in this regard, we do not consider it necessary to have a different governance model for depreciation vs partial asset stranding. In our view, it is sufficient to rely on the existing ability to use Rule 86 to remove assets from, and reintroduce them back into the RAB as appropriate (see discussion in answer to question below).

The second key issue is the linkage between depreciation and asset stranding and, more particularly, the degree to which choices about depreciation today can cause, rather than reflect, the future.[11] Simply put, the amount of asset stranding which actually occurs can be driven by choices made now in respect of depreciation.

In particular, inadequate depreciation may increase the risk of more asset stranding than would be the case if depreciation were set efficiently. One way in which this might occur is if depreciation is limited based upon estimates of the "switching point", this is estimated via switching costs (rather than willingness to pay, which is the economically correct measure to use; see the discussion in our response to Appendix D below) and estimates of switching cost are set artificially low; perhaps due to outsized concern about short term price pressures.[12]

The situation is, if anything, worse than simply a case of choices in respect of depreciation influencing future outcomes. If the depreciation is set too low, asset stranding will only likely emerge decades later, by which time it may be challenging to separate out cause and effect. The choice of one depreciation schedule also precludes observation of the counterfactual of what would have occurred under an alternative depreciation schedule. Hence, it may be challenging to identify errors arising from selecting insufficient depreciation. In this instance, stakeholders may conclude that asset stranding happened exactly as the forecast suggested it would decades previously, missing the point that it occurs due to the choices made in respect of depreciation at that point in time, rather than being a necessary consequence of market forces.

Moreover, there is an asymmetry between the impacts of depreciation being set lower than or higher than what is the true efficient level. If depreciation is set too high, the consequences in terms of inefficiently high prices will be seen immediately through demand reductions significantly in excess of those predicted when the change in depreciation was proposed. Not only is the error easy to see, but it is easy to fix. If high prices are causing exit, prices can be lowered. Moreover, networks have a motivation and an ability to change prices rapidly. Networks face the consequences of asset stranding if they do nothing in the face of faster than expected demand decline. Since they operate in a price cap environment, they are under no obligation to charge the building block price.

---

[10] See the AEMC's summary of the session, p3, available here.

[11] The AEMC clearly recognises the interlinked nature of depreciation and asset redundancy and is trying to create a framework whereby they are used together (see Directions Paper p26), but it does not appear to have captured the potential for action (or inaction) on depreciation today to cause a given future, and the need to consider this aspect of the interaction between depreciation and asset redundancy as a matter of key importance. The ACCC (see the AEMC's Directions Paper p54) likewise notes how flexibility on depreciation makes less of a risk of asset stranding, but does not capture the possibility of choices on depreciation causing stranding.

[12] Note that this is not an issue of using switching points per se; a network will itself try to keep prices below the point at which customers will switch because this is how it (like any other business) remains viable. It is rather an issue of simplistic approaches towards estimating switching points which have the tendency towards downward bias. In particular, we think it would be difficult, if not impossible, to produce a single "switching point" estimate that would work for all customers with their diverse needs (either for depreciation and asset stranding or for tariffs).

By contrast, if depreciation is set too low, as noted above, it may be decades before this error is uncovered, if indeed it can be. By the time the error is uncovered, it may be too late to act because price pressures from substitutes to network-delivered gas may have risen too high to correct the error by changing capital recovery. This is essentially the point made by Crew and Kleindorfer, which we refer to in our previous submission.[13]

This has an important bearing on how both depreciation and partial asset redundancy are governed. Given that networks have limited incentive to deliberately overstate depreciation as they face the asset stranding consequences which come with this, they should, in governance terms, be afforded the benefit of the doubt, and assessment of depreciation proposals should be based upon the technical veracity of the forecasts being made, rather than the motivations of networks who make them.

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?*

We have covered our views in a general sense in the introduction to this chapter about some of the key issues in considering capital recovery. By and large, we think the AEMC is headed in the right direction, and there are only a handful of small changes needed.

In particular, we think the AEMC has moved in the right direction because it has injected a great deal of common sense into the debate. In particular (Directions Paper p23, with further detail on pp66-67) it has:

- Not accepted the contention that changing depreciation shifts risks to consumers, because consumers still only pay the same capital recovery costs, with only a timing difference;[14]
- Networks are not in any way "immunised" from asset stranding risk as depreciation changes because demand can (and likely will) continue to change; and
- There is a mismatch between those who benefit from the use of an asset and those who pay for it if demand declines but depreciation schedules do not change with it. Changing depreciation is essential to maintain efficient tariffs, inter-generational equity and incentives for investment, and can be done without changing the NPV of the total amount consumers pay.

Overall, we believe the AEMC has expressed the issue well when it frames the issue around a "disorderly energy transition", noting the shared impact of asset stranding on customers and networks (Directions Paper p(i) and 22) with customers facing raised prices which bring forward decisions to electrify, adversely affecting other customers and networks who face an increased risk of asset stranding. We agree with the AEMC's overall goal (with some caveats about switching costs, outlined below), which it describes as follows (Direction paper p22):

> *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.*

The AEMC defines a "workably" competitive market on p53 of the Directions Paper We consider it useful that this definition is given a prominence in the debate, as it helps stakeholders to focus on the role of competition in improving incentives in the gas sector. It also reinforces the fundamental principle that regulation is intended to reflect the pressures of a competitive market which are absent for a monopoly. This perspective can get lost in the debate around minutiae of regulatory practice, to the detriment of sound regulatory design.

We also agree with the AEMC's rationale for taking any action on depreciation would be inconsistent with the long-term interests of consumers (Directions Paper p23):

> *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*

[13] *See Section 2.1 of Attachment 1 of our submission to the AEMC's September 2025 Consultation Paper or, alternatively, Crew, M and Kleindorfer, P, 1992, "Economic Depreciation and the Regulated Firm under Competition and Technological Change", Journal of Regulatory Economics, 4(1), 1992, pp51-61, available here*

[14] *The AEMC again clarified this point in its public forum (see the summary of questions, p2, available here).*

renters, and some industrial and large commercial customers). Timely use of regulatory tools would minimise price impacts for current customers by spreading costs across a larger number of customers.

In closing, we agree with the AEMC's proposal to "round out" NGR 89(2), with the caveat that it is not yet clear what "round out" means in practice, and its proposal to remove references to growth in NGR 89 (Directions Paper pp73-4). We also agree with the proposal to provide a "decision point" for a switch from an indexed to a non-indexed RAB, and that this should be part of an AA proposal (See Directions Paper p74). For the same reasons that we think Option C(i) is the most appropriate governance mechanism for changes to depreciation in general, we also believe it is the most appropriate option for deciding whether the RAB should be indexed or not. We note finally that it should not be an "either/or" proposition; creating the best response to future asset stranding risk may involve the use of both changes in inflation and other changes in the depreciation schedule, so the NGR should not preclude this, but should rather focus on making sure that the total response is appropriate.

2. *Do you have any views on the decision-making model options explored for:*
    a. *depreciation and treatment of inflation?*
    b. *redundant capital provisions?*

Based on our discussion of key principles at the start of this chapter (and in the introduction to this response), we consider that Option C(i) is appropriate for both depreciation and partial asset stranding. However, we agree with the view from Incenta in its expert report for the ENA (p19 and 32 for depreciation and asset redundancy respectively) that a case could be made for Option B as well, particularly in respect of asset stranding, once it is considered properly.

The use of Option C(i) for depreciation would appear to be in line with depreciation in the electricity sector at present and the limited discretion which previously applied in the NGR (see Directions Paper p50-51). Indeed, as we discuss in the introduction, if the AEMC believes that exposure to asset stranding risk is conducive to networks incentives being more aligned to the NGO and it believes that electricity networks face lower stranding risks than gas networks, it could be illogical for regulators to have more discretion when it comes to depreciation for gas networks than is the case for electricity networks. If electricity networks effectively have Option C(i), this may lead the AEMC to propose Option B for gas networks, but it could not, logically, lead it to propose Option C(ii) or Option D.

We make three further points in respect of depreciation. Firstly, the AEMC appears to believe that there is a difference between the incentives of a network which does and does not face asset stranding risk, or more particularly, the congruence of those incentives with the NGR. We are not clear exactly what the AEMC means by this as we do not consider that there are any networks with no asset stranding risk. However, we guess that the AEMC means that, were any network likely to have an incentive to claim more than the efficient amount of depreciation, it would be one where asset stranding risk is lower. This is worthwhile testing

The most recent round of regulatory proposals provides a useful contrast. In South Australia, where there is no explicit policy to phase out gas networks and the policy framework remains comparatively neutral, AGN SA faces less asset stranding risk than Evoenergy in the ACT, where government policy is explicitly directed toward phasing out the gas network over time.[15] Clearly there is a significant difference in asset stranding risk between the two. The question is whether the lower stranding risk of AGN SA caused it to claim an inefficiently high amount of additional depreciation.

In our proposal for AGN SA, the amount we put forward for additional depreciation based on the results of the model ($70 million) is the smallest amount which creates any difference to the asset stranding risk present in our model.[16] The only way we could have asked for any less is if we assumed zero asset stranding risk and therefore zero risk to be reduced in the first place. This was clearly untenable given the model results suggested, across simulation runs, a 34 percent chance that the network would not be viable in 2050.

As part of our ongoing engagements during the AA, AGN SA's South Australian Reference Group challenged whether it is asking for too little additional depreciation.[17] We do not consider that asking for the smallest amount of additional depreciation consistent with any change in the risk of asset stranding could be construed as somehow asking for an inefficiently high amount of additional depreciation. We do not consider that we face incentives, in respect to proposing depreciation which are congruent with the NGO, that are any different than those facing Evoenergy (or any other network for that matter) and we consider that evidence of this is available in the actions we took. From this perspective, there may well be scope for the AEMC choosing Option B, as it appears that

[15] *As the AEMC points out (Directions Paper p62), it appears that the AER's decisions on how much of a price change to allow has been driven entirely by consideration of relative policy forces.*
[16] *See p 9of Attachment 6.5 to our Revised Final Plan (available here) and, for more detail, pp23-29 of Attachment 6.1 of our Final Plan (available here).*
[17] *See p8 (in particular, footnote 13) of Attachment 6.5 of our Revised Final Plan (available here) for a summary of the SARG views on this topic with relevant page numbers. The SARG submission itself is available here.*

the reason against choosing it in the Directions Paper (see p73) is a concern that not all networks would have incentives aligned with the NGO on depreciation.

Secondly, where depreciation is limited by the estimation of a "switching point", we consider that this must be based on willingness to pay, and not an estimate of switching cost.[18] We discuss the principled reasons for this in our response to Appendix D below, as the AEMC itself deals with switching cost estimates in Appendix D which deals with tariff setting, but note that the principles we discuss around the use of willingness to pay and the dangers of lowballing estimates apply equally to assessment of depreciation.

Further, we consider that assessment of depreciation by regulators should be based on the *maximum* and not some average (and certainly not a minimum) willingness to pay. This does not mean that networks will actually charge a price equal to the maximum willingness to pay as to do so would immediately cause almost all (technically, all save those who have this maximum willingness to pay) customers to leave the network. The intent is rather to prevent the asymmetric effects of errors when too little depreciation is allowed (see discussion in the introduction to this section). A regulator who allows any depreciation proposal that produces prices below the maximum willingness to pay at a point in time cannot, by definition, err on the side of allowing too little depreciation and thereby cause more asset stranding than is efficient.

Thirdly, the revenue allowed to be recovered from sub-groups of customers are currently set based on the basis of network costs (standalone vs avoidable cost), but the AEMC is suggesting that there may be scope for basing such recoverable revenue on customer characteristics, specifically an estimate of switching costs. We address this issue in our response to Appendix D below, but there is also a governance issue.

Since tariffs to different groups of customers reflect an apportionment of efficient fixed costs only (the regulatory building block model does not allow more than efficient costs to be recovered, in aggregate). If one group of customers has its tariffs limited below their willingness to pay, this means other customers with a lower willingness to pay will be required to pay more. Where this increase pulls them above their willingness to pay, they will leave. To avoid this, the network would need to reduce its depreciation below the efficient level which has been determined in aggregate to avoid the consequences of limits set for particular sub-groups of customers. Tariff setting, in other words, could subvert depreciation, and this would be a particular issue if regulators were given far more discretion over the setting of tariffs for sub-groups than they were for depreciation as a whole, and the inconsistent governance arrangements could provide an incentive for regulators to limit depreciation by more than NGR 89 gives them scope to do.

The issue only arises because of the proposal by the AEMC to replace stand-alone cost estimates with customer-based characteristics. The simple (and correct; see our response to Appendix D below) solution is not to move away from stand-alone costs in tariff setting, and thereby not create the inconsistency in the first instance. However, if the AEMC does determine that it should remove the stand-alone cost test and replace it with a test based on customer characteristics, then it would need to base maximum tariffs on the same maximum willingness to pay metric as for depreciation, and would need to afford the regulator the same degree of discretion in setting allowed revenues for sub-groups for customers as it allows in setting depreciation.

Turning to asset redundancy as we outline in our introduction, we consider that the same incentives for asset redundancy lead to the same conclusion in respect of the appropriate model; it should be Option C(i). In fact, once asset redundancy is properly considered (see the discussion in our answer to the question below), though regulators could set asset redundancy, they would be doing so only in reaction to clearly observed market events, which has the effect of moving the application of imposing asset redundancy closer to Option B. There is certainly no scope for Option D; as Incenta point out in their expert paper for the ENA (pp27-30). In fact, a combination of Option D and an ability for regulators to act on a prediction of potential future redundancy would give rise to the issues we raise in our previous submission in respect of the JEC proposal around asset redundancy, which the AEMC has rejected.[19]

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?*

To begin, a small point of clarification on nomenclature. The AEMC (Directions Paper p8) suggests that:

[18] *As we note in the introduction, networks have an incentive to price below the price level where it believes customers will switch away from gas. However, this point is not uniform across customers, and it is not based on analyses of "switching costs"; particularly single estimates made by analysts who do not consider the diversity of customer situations. The parties with the motivation to produce the best estimate of switching points are the networks themselves, as they have the most skin in the game.*
[19] *See pp15-19 of our submission to the AEMC September 2025 Consultation Paper (available here), as well as Sections 3.1 and 3.2 of Attachment 1 of the submission for further detail.*

> *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.*

It is the last part of this definition that is important. Asset or entire network could be fully utilised, but at a price which is lower than its building block price. This asset is partly stranded because its value cannot be recovered. By contrast, an asset or network could be utilised at only, for example, 20 percent capacity, but prices still reflect building block prices because the asset has been sufficiently depreciated although it is not economically stranded. In its expert report for the ENA, Incenta (p26) provide further details on this point.

The AEMC's definition above does not appear to be materially hampering its treatment of partial asset stranding, but it is important, particularly given the confusion on this issue in the ECA and JEC rule change proposals, which we discuss in our earlier submission,[20] that definitions are clear.

Underpinning our view on the constraints and thresholds which ought to apply in respect of partial asset stranding is a view on *when* it should be applied. As Incenta outlines in its expert report to the ENA (p30), it should only be applied as a last resort when there is no more scope for other measures, such as changing depreciation schedules, to produce building block prices that the market can support. That is, it should apply when the price a network can charge is restricted by market forces and not by a building block model. It should then only apply to the extent that the building block price is brought back into line with the price the market will bear.

This is in line with how a workably competitive market works. Where it is feasible to do so, a firm will seek to recover its fixed costs. The underlying reason is fairly simple, pricing below cost by choice, except in limited circumstances where the firm is trying to expand market share, sends a signal to investors that the firm in question has little interest in recovering the funds they have invested in it.[21] Such a firm will find new investment hard to come by. It is only when market forces leave the firm with no other option than to price at below full cost and recover at least some invested capital, that it will do so.

The AEMC appears to have recognised the importance of asset redundancy operating only as a "last resort" when other tools are no longer effective where it suggests, summarising a position put by the ACCC (Directions Paper p54) that:

> *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.*

Which appears to have influenced its own view that (Directions Paper 70):

> *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.*

The AEMC further notes (Directions Paper p77) that considerations about uncertainty about the effects of use of the tool and whether there may be better tools to use lead the AEMC to conclude that it ought to point the regulator towards seeing the tool as

[20] *See Chapter 2 of Attachment 1 of our submission to the AEMC's September 2025 Consultation Paper, available here.*

[21] *Investors get exactly the same signal if a regulatory regime predicts possible future asset stranding decades hence and then forces losses on investors today, as per the JEC proposal. Essentially, they do not care if it is poor governance by the firm or poor governance by the regulatory regime which forces losses when losses are not necessary.*

“a last resort tool, rather than a first resort tool”, and that the tool should only be used when service providers have “already been given a reasonable opportunity to recover their efficient capital cost”.

While this provides a greater clarity, the notion of what a “last resort” means should be made very clear for all stakeholders, and the guidance as to the amount of partial asset stranding will also need to be made very clear.

As Incenta point out in their expert report for the ENA (p30), when they introduce the concept of “revealed redundancy”, there is a very simple rule that the AEMC could direct networks and regulators to follow. The “last resort” in which the tool is applied should be the situation whereby the prices being charged by networks have already fallen below building block prices (see discussion on thresholds below) and the amount of reduction should be enough only to bring building block prices in line with prices the market (which by then will be workably competitive by virtue of the fact that market prices have begun to constrain networks) will bear. As noted in our answer to the previous question, the effect of this rule, even where the regulator has discretion to allow or disallow redundancy would be to create a governance arrangement similar to the AEMC’s Option B. This is appropriate as all parties (regulators and networks) are acting based solely on clear and objective market evidence rather than using their discretion to declare assets partially redundant and delineate the scope of this redundancy. Regulators, therefore, effectively have no less discretion than networks.

This is the key constraint on regulatory action which the NGR itself should contain, rather than it being relegated to the guidelines. Anything less than absolute clarity on this point is likely to make investors very concerned that regulatory forecasts about what might happen in the future could force them to take losses, causing sovereign risk concerns.

The question also asks about thresholds. This is a matter of costs and benefits. Clearly, if the market price fell one dollar below the building block price for one week, it would not be worth the effort of creating partial redundancy.

Incenta (p32) suggest only making a change to the RAB in the AA following the one where networks have priced below the building block price. This is one approach to use. Another may be to adapt an approach used in US antitrust, mergers are assessed using the Small but Significant and Non-transitory Increase in Price (SSNIP Test).[22] Further assessment of a proposed merger is undertaken if it can be shown that the proposed merger would likely cause prices to rise by a small but substantial level for a sustained period of time. Partial asset redundancy could have its own form of SSNIP test, whereby it is applied when market prices have fallen (not are predicted to fall, importantly) below building block prices by a small but substantial degree and either have or are reasonably expected to remain at this lower level for a substantial period of time. It is probably unnecessary for the AEMC to provide the two definitions of “substantial”, and it is certainly too early now, well before any asset stranding is on the immediate horizon to do so. However, the concept could be explored further by the AEMC.

The final aspect of the AEMC’s partial redundancy proposal is its proposed amendments to Rule 86, which (see Directions Paper p79):

- Removes the requirement that a redundant capital mechanism be specified in a given AA before it is used and replace this with a rule-based mechanism which allows its use in any upcoming AA period; and
- Allow re-use and recovery of formerly redundant capital via the RAB when it can be shown that utilisation has been increased and there is an opportunity to recover some or all of the formerly redundant capital from customers.

In respect of the first of these changes, provided the rule-based mechanism reflects the “last resort” factors noted above (that is, when market prices have fallen below building block prices), there is no impact in respect of removing the requirement that the rule be pre-specified in an AA, for networks or customers, and hence there is no problem in making the change. This is not true if, by design or by effect, regulators are able to include forecasts of potential future asset stranding, as noted above.

In respect of the second, we can appreciate the intent of the AEMC in developing a “redundant asset fund” to capture the partially redundant assets and then bring them back into the RAB is feasible. When there is partial asset stranding (whether it is reflected formally in the NGR or not), market prices are effectively driving regulatory prices. If this is not reflected in changes in the RAB, then the regulatory process goes on “in the background” so to speak; generating regulatory prices which are not used. As part of this “background operation”, the PTRM would include depreciation and, since actual prices and revenues are not reflecting the full building block price, this regulatory depreciation would never be part of the capital actually returned to investors.

If the partially redundant assets are taken out of the RAB, and placed in a “partial asset redundancy fund”, where they are no longer depreciated as they would be in the RAB, and where they are indexed by the Weighted Average Cost of Capital (WACC) to reflect the opportunity cost of capital which is deployed but for which no return on capital is earned, then the losses alluded to above do not occur and investors are made whole if and when the assets return to the RAB.

[22] *For a textbook treatment see Harrigton, JE, Sappington DE and Viscusi, WK, 2018, Economics of Regulation and Antitrust: 5th edition, MIT Press, Cambridge Mass.*

For this reason, the proposed rule change provides a degree of insurance for investors. This is likely to be of only marginal benefit given that, if the prices of substitutes fall by enough to render some assets partially redundant, and they continue to fall, it seems unlikely that much redundant capital will return to the RAB. However, the fact that the possibility exists is better than it not existing.

In respect of adding the 'fund' back into the RAB, there is no reason why this should require any special test of acceptability such as evidence of changes in use or an ability to now recover some or all of the capital back from customers,[23] provided the same limit which placed assets in the redundant assets fund is applied when a network seeks to put funds back into the RAB; which it would, by default.

By way of an example, consider a scenario whereby the building block price is $2 per GJ, and market forces dictate a price of $1.50, requiring the removal of $100 million from the RAB to the partial asset stranding fund to create a building block price of $1.50. Then assume that demand recovers a little, so that the building block price is now $1.40. Assume in this context that the price dictated by market forces remains at $1.50. Under these circumstances, if a network tries to put the whole $100 million back into the RAB, given the higher demand levels, the building block price might be $1.90. However, this price would immediately make some of the returned capital stranded again, and the network would have to take some of the $100 million back into the redundant capital fund. The maximum which can be put back into the RAB will always be the *minimum of* the amount taken out in the first place or the amount which equates the building block price with the market price. This is a natural restriction which requires no regulatory involvement to determine whether assets should be returned to the RAB, as the competitive market is providing the limiting factor. Even in cases where competitive market pressures vanish entirely in the future (which we consider highly unlikely) no network is ever able to earn back more than its efficient level of costs due to the pre-existing regulatory framework and its protections.

[23] *We note that, as per the definition of stranded assets, utilisation is somewhat irrelevant when deciding whether an asset goes back into the RAB; an asset may not change its utilisation levels at all, but customers might be willing to pay more, and hence the asset should be returned to the RAB. Alternatively, utilisation could increase substantially, but only at prices which would allow no extra RAB recovery, in which case it would be pointless seeking to add the funds back into the RAB.*

Appendix D: Expenditure

We consider it important that any modifications to the expenditure rules are fit for purpose and limited in nature. Gas infrastructure owners historically, currently and into the future, have had no incentive to spend more than the minimum required in order to provide our reference services to customers. As noted by the AEMC on page 91 of the Directions Paper:

> *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.*

Given the AEMC's recognition of this lack of incentive on network service providers to incur inefficient capex historically, and therefore by extension into the future, any proposed rule change should be very limited. Further, not all network service capital expenditure is long lived, such as Information Communication and Technology (ICT) capex.

We also agree with the AEMC's conclusion in respect of "Credible Options" (page 94) that gas network service providers should not have to consider the cost to customers and other non-gas service providers of electrification or shifting to LPG.

The below answers the questions specifically.

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.*

All capital expenditure that we propose as part of an AA, or that is incurred as part of actual capital expenditure, is justified on a quantitative basis. That is to say, as part of the business cases we submit with our AA proposals, we include quantitative options analysis which forms a part of the justification for the ultimate option that is proposed. We have augmented our options analysis over time after feedback from the AER and ensure that our business cases reflect best practice.

It should be noted that, for instance, the value derived from ICT expenditure is largely qualitative. For example, cybersecurity expenditure is capital investment with the objective of preventing malicious attacks on our systems from external actors. The benefit of cybersecurity investment is the successful prevention of system compromise and operational interruption. Therefore, the mechanistic application of Net Present Value analysis for this type of investment could provide limited insight into decision-making as each option is simply a discounted cost profile over the life of the project and the benefits of the investment are the absence of a negative outcome. Also, much IT investment is compliance driven, so the best option is the option that delivers compliance with regulatory obligations, whilst balancing cost and avoided risk of non-compliance.

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).*

The vast majority of our non-IT capex is invested to deliver safe and reliable haulage reference services to our customer base whilst complying with regulations and safety standards. This is always the objective of this type of investment and therefore we do not consider amendment of the NGR to be required in this case.

c. *Amending the justification for capex to maintain capacity to meet forecast (instead of existing) demand for services under NGR 79(2)(c)(iv).*

Our capital expenditure proposed and incurred already factors in expected future demand. It is important however to note that we still have various obligations to meet the safety and reliability requirements of our current demand. We would expect this rule is not amended such that the business would be limited in its expenditure which would result in safety and/or reliability issues for the networks. In practice, we already consider the need to augment our network against the backdrop of declining demand, and augmentation of the network has always been justified on the basis of rising demand on the network, particularly when the network is analysed on a segmented basis, and particularly at the margins of the network where growth is generally the most pronounced, augmentation was justified. Where demand is expected to fall, augmentation of this type would not be considered or proposed.

2. What are your views on the need for the NPV test in rule 79(2)(b)?

The NPV test should remain as it may be required to assess connections to the network which would inject covered gas, whether renewable gas or other, into the network. The NPV test should therefore remain, noting that reliance on NPV analysis alone is unnecessary where the outcome of the expenditure is compliance with regulatory obligations or the avoidance of a negative event, as described above in relation to cybersecurity expenditure for instance. The NPV (in this case simply the discounting of future costs) should not be the central metric with which approvals are given for programs of this nature.

*3. Wha*t are your views on our proposed direction to amend the NGR opex definition?

The proposed direction to remove the growth references from the definition of opex (from rule 69) to make it neutral in relation to demand shouldn't preclude opex which supports increasing demand for pipeline services, where it is prudent, efficient and otherwise consistent with the opex criteria. Under the base-step-trend approach to opex forecasting, the trend component already caters for positive or negative growth. Further, we agree with the AEMC that there are possibilities in the energy transition where opex would be practical to support increased demand for gas such as if a gas distribution network is being repurposed to supply biomethane.

We support the opex definition continuing to focus on expenditure in providing pipeline services, rather than the type of gas, in contributing to meeting emission reduction targets to ensure investments in emission reduction projects, including transitional projects, are not hindered.

Appendix E: Tariffs

In this section, we discuss the AEMC's views in respect of tariffs. A key point of principle we discuss in the introduction to this section relates to the notions of "switching costs" and estimation of the "switching point" at which customers disconnect from the gas network due to a perception of a better value service being offered via electrification. We note that the principled points we discuss here also have relevance in respect of the estimation of appropriate changes in depreciation (see our response to Appendix C above). However, since the AEMC discusses the estimation of switching costs in Appendix D, we address the issues of principle here. Our key concern relates to how the AEMC proposes to estimate switching costs (see p123 of the Directions Paper),[24] which gives rise to two key concerns:

- Switching costs (particularly one switching cost estimate applied to a diverse customer base) are not an appropriate metric to use, and the AEMC should rather require the use of the economically correct willingness to pay measure; and
- The particular switching cost estimates the AEMC proposes on p123 of the Directions Paper presents significant risks to vulnerable customers.

We note that neither switching costs nor willingness to pay should be used as a replacement for standalone costs, and we discuss our reasons for this conclusion in response to the AEMC's questions below. In this introduction, we focus on principled arguments (which have application for depreciation as well) and the two dot points above.

Turning to the issue of willingness to pay vs switching costs, we note first of all that the AEMC appears open to the possibility of willingness to pay being used. In the forum on 9 April 2026, the AEMC recognised it as a possibility, but suggested that the AEMC was itself neutral on whether willingness to pay or switching cost is used.[25] We do not consider this to be the best response; willingness to pay is the economically correct measure to be used, and so it should be used. In fact, we consider that this should be set in the NGR.

In the Directions Paper p111, the AEMC notes, that tariffs should be designed to "achieve expected revenue recovery, but must be done so with minimum distortion to efficient patterns of consumption". It is well established in economics that the way to do this is to apportion fixed costs based upon demand elasticity or willingness to pay, with the customers with the lowest demand elasticity (highest willingness to pay) paying the highest price and those with the highest elasticity (lowest willingness to pay) paying the lowest price.[26] By comparison, if all customers face the same price via fixed costs being allocated equally to all customers, then some will leave because their willingness to pay is lower than the average cost, which means a smaller customer base over which to allocate costs and the remaining customers paying more.

In an ideal world, with perfect information, a firm with fixed costs would charge every customer based upon their willingness to pay, and this would maximise the number of customers that can be served, maximising consumer welfare. In reality, such perfection is impossible, and firms in workably competitive markets tend to group customers together based upon what they can gather about willingness to pay, charging differentially to these different groups.

In principle, there is a relationship between willingness to pay and switching costs. One way to frame this is to recognise that any good or service can be understood as a bundle of attributes. A customer will switch from one service to another when the perceived value of the bundle of attributes in the alternative good or service exceeds that of the current good or service, taking into account price, switching costs, and the attributes of the service itself.

In the context of energy services, customers are not only comparing prices and upfront switching costs, but also factors such as performance, reliability, familiarity, and suitability for their specific needs. Similar considerations arise across a range of industries and decisions, including telecommunications, transport, and industrial processes, where customers assess alternatives based on a combination of price, switching costs, and the value they place on different service attributes.

As these attributes are valued differently across customers and are not directly observable, switching costs cannot be understood solely as transactional costs, but must also reflect the value customers place on the attributes they would forego when switching. As these preferences vary across the customer base, a single estimate of switching costs is unlikely to capture the relevant trade-offs faced by customers in practice.

[24] *The AEMC does not specify how (or even if) it proposes to estimate the switching point for depreciation, though an estimate of the switching point has been used in its illustrative modelling. To the extent that p123 represents the AEMC's thinking of how switching points more generally (rather than just in respect of tariff setting) should be estimated, our concerns are magnified.*

[25] *See the AEMC's summary of this issue from the stakeholder forum, available here pp 3-4.*

[26] *The seminal paper in this regard is See Baumol, W and Bradford, D, 1970, "Optimal Departures from Marginal Cost Pricing" American Economic Review, 60(3), 265-83, available here.*

Since willingness to pay and switching costs for the exact substitute lead to the same result, in principle, one could use either. However, willingness to pay is a much more direct measure (and, moreover, one which is directly observable in the decisions customers make, whereas the bundle of characteristics in each good or service and their value to each customer is not observable) than establishing what all of the attributes of any given good or service is, identifying what other goods or services have similar attributes and then establishing what the value of each of these are.[27] Hence, economics focuses on willingness to pay as the relevant metric. The NGR should therefore direct decision makers to consider willingness to pay where this issue arises.

If switching costs are not an appropriate basis for determining pricing outcomes, reliance on a single, relatively low switching cost estimate risks compounding this issue, particularly where that estimate is used as a binding constraint on prices. In the Directions Paper (p. 123), the AEMC states:

> *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.*

We do not consider that this approach will achieve the intended outcome of protecting customers who remain connected to the network. Setting a price ceiling on an overly conservative estimate of switching costs, or willingness to pay, risks producing the opposite outcome.

With overall fixed costs being restricted to an efficient level by the regulatory process more generally, the role of willingness to pay is to allocate those efficient fixed costs across customers in the most efficient way possible.[28] Where the ceiling is set below the willingness to pay of some customers, this necessarily reallocates fixed network costs those customers would have been willing to pay to other customers. For example, a customer willing to pay $100 may be charged $50, with the remaining costs recovered from other customers. If that results in a customer with a willingness to pay of $40 being then required to pay $45, that customer is likely to exit the network.

This dynamic reduces the number of customers over which fixed costs are recovered, placing upward pressure on prices for those who remain. In this way, an unduly conservative price ceiling risks accelerating customer exit and increasing costs for the remaining customer base, including those least able to respond to price changes.

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?*

We make specific points in respect of the use of long run marginal cost, standalone costs and avoidable costs in our answer to Question 2 below, and we reflect our views in respect of impacts on customers in our answer to Question 3. In the context of reflecting changes made in other components of the Directions Paper in tariffs where necessary for maintaining internal consistency, we agree with the principle, but would suggest the AEMC look carefully to understand exactly what changes are actually required.

It may be sufficient, for example, for the AEMC to include in its guidance note points like those which it makes on p114 of the Directions Paper, rather than making a formal change in the Rules themselves. That is, make it clear that both networks and regulators take into account how the design of tariffs might affect exit, or be affected by competition (for example), but not codify what networks or regulators must do to achieve this in the Rule, as each network will be subtly different and all networks are already strongly incentivised to respond to competitive pressures to keep tariffs and tariff structures efficient.

The alignment of network incentives with the NGR, as recognised by the AEMC in respect of depreciation (see our response to Appendix B above) also applies even more strongly to tariff design in our view. This is because competition is likely to impact sub-sectors of customers before they impact customers as a whole and, as we note elsewhere in this response (see also the Incenta report for the ENA p30) networks have a strong incentive to keep as many sub-groups of customers connected to the network for as long as possible to maintain the viability of the network for all customers. Although the AEMC does not consider governance options for tariff setting, we consider that something like its Option B, or at most its Option C(i) should guide regulatory discretion when it comes to tariff setting.

We make further, more specific points in answer to the following two questions.

---

[27] *We note the linkage between willingness to pay and the "switching cost" of the bundle of attributes represented by a given good or service largely because the debate about switching from gas to electricity in policymaking is often far too simplistic, ignoring completely the possibility that gas appliances may have attributes that customers value, but which are poorly replicated in the electric alternative chosen by a given analyst.*

[28] *If switching costs are used as a proxy for willingness to pay, the same would be true; provided they were a good proxy. If switching costs have no linkage to willingness to pay, then using them as a basis for pricing has no economic relevance whatsoever.*

2. What are your views on our proposal to provide guidance on applying the concepts of long run marginal cost, standalone and avoidable costs?

In respect of stand-alone cost, we agree with the expert report from Incenta provided with the ENA submission to this Directions Paper (pp36-39) in that there is no case to replace the stand-alone cost as the upper limit for the revenue allowed to be recovered from a particular group of customers. As Incenta points out:

- The AEMC proposed approach does not appear to fully reflect the economic principles that underpin the use of the stand-alone cost metric, both in gas networks in Australia and in regulated industries internationally;
- The AEMC's approach of basing the upper limit of revenues which can be recovered from a group of customers would be inconsistent with regulatory practice in comparable contexts; and
- There are significant practical challenges in establishing the limit, which is based on a customer characteristic which is assumed to be constant across customers but is in fact highly variable.

For these reasons, covered in more detail by Incenta, we consider that replacing the stand-alone cost test with a customer-centric measure would not be consistent with established principles.[29] If a change is nevertheless pursued, a measure based on maximum willingness to pay would be more consistent with the existing framework. As we note in our response to Question 2 from Appendix C above, this is also the only metric that maintains consistency between revenue recovery across customer groups and overall efficient depreciation. By contrast, the "unimpeded switching cost" measure risks introducing inconsistencies between these elements.

The lower bound is a simpler proposition. In a workably competitive market, a firm will not supply customers whose willingness to pay is below the short run marginal cost of serving them. Doing so would require other customers to bear a greater share of fixed costs, increasing prices and potentially leading to further customer exit.[30] This means that the short run marginal cost is a good lower bound for prices. According to the AEMC, Ausnet already does this (Directions Paper p120), meaning that there is no need to change the NGR in order to make use of short run marginal cost as a proxy for the avoidable cost; and it would be considerably simpler than the mechanisms (see, for example, Box 8 on pp120-121 of the Directions paper) being contemplated.

In respect of long run marginal cost, we agree that its use to determine additional capex based on additional demand are probably limited if networks are declining, but that does not mean it is not useful at all. Monopoly power exists because a business has declining average costs over a large range of outputs, which is driven by declining marginal costs as output increases. The converse of this is that a smaller network will have higher long run marginal costs.

There may be cases where a legacy network is serving a smaller customer base, and the regulator wishes to see if that network is efficient via some sort of benchmarking. In that case, the relevant benchmark would be a network designed to serve a smaller customer base.[31] If this is higher than the costs of the legacy network, then there are no inefficiencies in the prices being charged by the legacy business. In these circumstances, there may be a role for LRMC as a checking mechanism. However, we agree with the AEMC that its use is likely to be limited.

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?

In respect of customer impacts, we reiterate the point about discretion made in response to Question 1, and provide a specific example. In recent decisions, regulators have, in some cases, sought to flatten tariff structures compared to what networks propose, and supported by customer feedback.[32] These changes are often motivated with reference to the new emissions reduction component of the NGO.

In the first instance, there is some ambiguity in respect of jurisdictional targets; not all states have the same target and it is important to ensure that state policies are reflected, when changes in tariff structure can have a significant impact on customer retention. This can occur where a given customer has a lower willingness to pay for higher use bands of gas (some appliances are more discretionary than others), so if the price of these higher bands increases, the gas demand drops, meaning more of the fixed

[29] *We note also, as the AEMC point out in the Directions Paper (see p110), that no stakeholders seem to be seeking these changes.*

[30] *In a world of theoretical perfection where every infra-marginal customer is paying their exact willingness to pay, and the new customer causing the need for cross subsidy comes along adding to the prices all customer face, all of them would leave as all face prices higher than their willingness to pay. We note also that, if all customers are paying at least their short run marginal cost of service, then none are cross subsidising any others and all are contributing something (even if it is very small) to the recovery of fixed costs.*

[31] *It is not the case that the LRMC is zero or even negative (Directions Paper p117) because there is no need to replace assets for an existing network where demand is expected to vanish before assets would otherwise be replaced. Rather it is that the basis of comparison is not the growth or otherwise of the network on the ground, but the efficient cost (LRMC) of the same service being provided by a new network, created for that purpose.*

[32] *As we reflected in our Attachment 14.4 of our response to the AER's Draft Decision regarding the tariff structure for our AGN SA network from 2026/27 to 2030/31 (available here pp. 2-8).*

costs are allocated to lower use bands for the customer in question, and across all customers; this reflects the same underlying cost allocation issue discussed in the introduction.

Secondly, there is the question of the evidentiary standard required.[33] We consider the evidentiary requirement when assessing whether tariff structures will meet a particular climate goal should be subject to the same principles as we discuss for long run demand in our response to Appendix B of the Directions Paper above. This differs from contexts in which regulation is designed to elicit private information from networks (networks do not have a particular information advantage when it comes to understanding emissions goals) for which the propose-respond framework of incentive regulation was designed.

In this context, information on how emissions goals may be met is more widely available across stakeholders. For this reason, like the AEMC has itself proposed for long-term forecasts, where regulators or networks motivate tariff structures based upon their ability to meet climate goals, they should be subject to the same evidentiary requirements. At the same time, the evidence should also outline how one particular goal, like emissions control, interacts with others. For example, where changes to tariff structures may reduce emissions but increase the share of fixed costs borne by more vulnerable customers, it is important that the evidentiary basis for these trade-offs is clearly articulated.

[33] *The need for evidence was a view shared in the SARG Review Panel submission to the AER Draft Decision regarding the tariff structure for our AGN SA network (available here p. 5).*

Appendix F: Incentive Mechanisms

In this section, we answer the single question from Appendix F, which deals with incentive 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?*

We do not consider that there is a need for additional incentive mechanisms beyond those that already exist. In practice, one of the strongest incentives for efficient outcomes is the discipline created by emerging or potential competition. This is more likely to produce efficient results than changes to regulatory schemes, which can be more susceptible to unintended outcomes. We note (see Directions Paper p18) that the AEMC has not yet started considering changes to incentive mechanisms, and we suggest that, with a number of other complex issues to tackle, there appears to be limited benefit in expanding the scope at this stage.

We have only two points to make in respect of incentives. The first is that, just as they have been in the past, they should be applied in a symmetrical fashion. We note in the recent draft decision for Evoenergy that the AER appears to propose a framework where cost overruns are penalised, but underspends are not retained.[34] This is not a symmetric outcome, and it is unclear how this would provide an effective incentive to reduce costs. It might assist if the AEMC made it clear in the NGR for any incentive mechanism to be symmetric to avoid issues such as this arising in future.

The second is that regulators and energy policymakers need to look more broadly at incentives. This is out of scope for the current review, but it should be borne in mind by the AEMC as it sets out proposed Rules during the remainder of the process.

The Directions Paper, along with recent rule change proposals and broader stakeholder discussions, focus on three parties that can address asset stranding risk: consumers currently accessing network services, network investors, and government

. However, there is a fourth pathway for new business opportunities. In our submission to the AEMC's review, we outlined a three-part framework for sharing risk, including new business opportunities.[35] We have applied this framework ourselves in regulatory proposals.

In our AGN SA regulatory proposal, for example, we did not seek to claim all of our RAB back from current regulated services, but deliberately looked out to new (unregulated) services and the value these might bring, then sought to recover only part of our RAB during the period when we thought regulation would be the driving force of our prices.[36] This had the effect of meaning less risk exposure for network investors, customers and government.

This approach is not without precedent. Historically, gas networks adapted to structural change by developing new markets as existing uses declined. As demand for gas lighting fell, networks expanded into applications such as cooking and space heating, creating new sources of value.[37] As the AEMC progresses its work, it is important that nothing in the proposed Rules unnecessarily constrains the ability of networks to pursue new business opportunities that may reduce risk and create value for stakeholders.

---

[34] *See Attachment 6 of the AER's Draft Decision (p2, available here).*
[35] *See our submission to the AEMC's Consultation Paper, p38, available here.*
[36] *See Attachment 6.1 of our Final Plan for our AGN SA network (p17, available here)*
[37] *A precursor to AGN SA established a showroom on King William St in Adelaide to teach housewives how to cook with a gas stove, so they were actively seeking to create a new market that had not existed previously. We discuss this, and other cases of gas networks shifting from light to other uses, in Attachment 6.1 of our Final Plan for our SA network (see p10, available here)*