Attachment 6.5

Response to Draft Decision on Depreciation

Revised Final Plan 2026/27 – 2030/31

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PUBLIC

Australian Gas Networks

1. Response to Draft Decision on Depreciation

The AER's Draft Decision did not accept our proposal in our Final Plan to include an amount of $30 million of additional depreciation. In our Revised Final Plan, we have re-proposed an amount of additional depreciation of $70 million. Our position is driven by our view of the appropriate approach to assessing depreciation under the Rules and the long-term interests of consumers, no matter the course of the energy transition. It is also supported by our recent customer engagement which showed support for additional depreciation now as the fairest option to customers.

1.1 Overview

This attachment responds to the AER's decision on additional depreciation, contained within Attachment 1 of the Draft Decision. The detail in this attachment responds to Section 1.2.3 and 1.2.4.1 of the AER's Attachment 1 of the Draft Decision, which reflect its reasoning in respect of the additional depreciation of $30 million we proposed in our Final Plan.[1] Our response to other components of Attachment 1 of the Draft Decision is summarised in Table 1.3 with the detail provided in other attachments in the Revised Final Plan as necessary.

Part of our response focusses on issues contained in the AGN SA Draft Decision. However, as we outline below, we consider that there are several issues with the AER's approach in both the AGN SA Draft Decision and the Draft Decision for Evoenergy which raise concerns as to the approach to depreciation in future decisions as the energy transition progresses. For this reason, part of our response also focuses on these broader issues from both decisions.

Section 1.2 provides a brief overview of stakeholder views, Section 1.31.3 provides an overview of the AER's Draft Decision, and Section 1.4 provides the detail of our response in respect of additional depreciation. We structure the detail of our response in Section 1.4 as follows:

- In Section 1.4.11.4.1 we explain why we believe that our modelling results, showing a minimum amount of additional depreciation of $70 million, remain sound. We also outline why we have proposed this amount, rather than the $30 million included in our Final Plan. In this section, we cover:
    - How providing options for flexibility across different outcomes can benefit and is in the long-term interests of consumers.
    - How the three-part framework in our Final Plan lowers consumer costs.
    - The importance and value provided by clear signaling on the regulatory approach to depreciation.
- In Section 1.4.2, we cover the issues specific to the AGN SA Draft Decision, being:
    - The ramifications of not considering risk and the nature of economic lives.

[1] *We note the AER's view that any tilt function represents "accelerated depreciation". We maintain our view in respect of terminology expressed in our Final Plan but note that differences in nomenclature make no practical difference to the AER's Draft Decision or this response.*

  - How policy similarities between NSW and SA mean the decisions for AGN SA and Jemena are inconsistent with each other.
  - Our concerns regarding the AER's views on what constitutes a "significant" asset stranding risk
  - The basis for our proposal seeking $70 million in additional depreciation.
  - Where we consider the AER's implementation of a simplified form of our model leads to an incorrect conclusion that reducing capex is an adequate substitute for more depreciation.
  - Why short-term network growth and longer-term additional depreciation are not inconsistent.

- In Section 1.4.3 we cover the broader trends emerging in the AER's approach to depreciation, from the AGN SA and Evoenergy Draft Decisions, and why we consider these to be detrimental to the long-term interests of consumers. Specifically, we cover:
  - Issues with the AER's "real price path" approach, particularly the lack of evidence underpinning decisions of what the appropriate path should be.
  - Issues around how much of a role depreciation can play; how long and how much the AER will allow the "window" of action to be open.
  - Issues around the wider consequences of what appears, in the Evoenergy decision, to be a change in the AER's views of the regulatory compact entails.

While we remain of the view that our gas distribution network will likely have some future, which will include transition to renewable gas, we are less certain about what the future network will look like. For example:

- Will renewable gas be supplied to all customers or only some customers or segments? Will renewable gas be transported at 100% or some blend of gases and by when?
- To what extent will natural gas still play a role?
- To what extent will there be other uses for the network?
- Will our network remain viable in the event that electrification speeds up?

These uncertainties and challenges remain and while we continue to pursue our low carbon vision, the course of the energy transition remains very difficult to predict. No matter how the energy transition evolves, it is in the long-term interests of consumers to take small steps now to reduce risk, deliver more stable prices through time and support the competitiveness of networks into the future, which ultimately provides our customers with choice as the energy sector transitions. That is:

- If we are successful in transitioning our network to renewable gas, we will need to be able to charge prices that are competitive into the future and provide options for other uses of the network in a more competitive future environment. Modest amounts of additional depreciation now will support competitiveness in the future, providing flexibility and customer choice while reducing asset stranding and price risks to remaining customers as demand for natural gas declines. This is the basis of our modelling provided with our Revised Final Plan.
- If the transition to renewable gas is not successful and gas distribution networks do face material decline between now and 2050, a modest amount of additional depreciation in

the next period will also support a reduced risk of asset stranding and price increases for customers who remain on the network as demand declines.

In either scenario, or any scenario in between, the very modest amount of additional depreciation we propose is in the long-term interests of consumers. It has an immaterial impact on price now but has the benefit of providing flexibility in future Access Arrangement periods. It is also supported by our recent customer engagement, as representing a fairer intergenerational balance and a more reasonable balance between all stakeholders. This is the context which we consider supports our proposed approach to additional depreciation.

1.2 Stakeholder and customer feedback

In preparing the revised Final Plan we have continued to engage with customers and stakeholders, including our South Australian Reference Group and through consideration of submissions to the AER on our Final Plan. We have also undertaken dedicated engagement with members of our SA Reference Group sub-panel, the SARG Review Panel, to respond to feedback on our Final Plan and the AER's Draft Decision. A summary of the feedback provided on depreciation is provided in Table 1.1 below, with detail of the engagement methodology and outcomes provided in Appendix A of this Attachment.

Table 1.1: Summary of customer and stakeholder feedback

Customer and Stakeholder Feedback	Our Response
Across all four phases of engagement, customers consistently identified affordability and price stability as key priorities.	In developing this Revised Final Plan, AGN has had regard for the impact individual aspects will have on the affordability of natural gas. Overall, our proposal is centralised around affordability and price stability.
Stakeholders expressed differing views on additional depreciation, with some emphasising intergenerational equity and price stability, and others questioning whether customers should pay for assets to be depreciated more rapidly. The SARG Review Panel indicated that additional depreciation could support greater flexibility should future policy settings change, with potential benefits for customers.	We are optimistic for the future of gas in South Australia, but must be realistic in expecting shifts in policy, like we have seen in Victoria, as Governments change. We have undertaken modelling to ensure our proposal: • ensures we can remain agile in an uncertain future, • achieves price stability and affordability for our customers, and • continues to deliver a safe and reliable service to our 490,000 South Australian customers
Customers trust AGN's depreciation modelling and recognised its role in supporting price stability over the Access Arrangement period. Customers considered that paying slightly more now may represent a fairer outcome when impacts on current and future customers, future network leavers and AGN are taken into account.	Our proposal is consistent with feedback from customers that some additional depreciation now is fair to current customers, future customers and stakeholders. Our proposal is also in-line with their understanding that paying more now will reflect greater intergenerational equity and will support AGN acting in the best long-term interest of customers.
Revised Final Plan Outcome	
Our Revised Final Plan proposes $70 million Additional Depreciation.	
Customers understand the impact of no additional depreciation vs some additional depreciation to different groups and consider AGN's proposal is fair to the majority of customer and stakeholder cohorts. Customers are satisfied with our proposal, which ensures price stability across the five-year period.	
Stakeholders will meet in early February 2026 to form a view on the proposal in our Revised Final Plan. The SARG will prepare a submission during the AER's consultation process.	

1.3 AER Draft Decision

The AER considers the capital base, regulatory depreciation and corporate income tax in Attachment 1 of its Draft Decision. The AER's decision is summarised in Table 1.2.

Table 1.2: Summary of the AER's Draft Decision on our capital base and depreciation.

	AER Draft Decision	AER Comment
Opening capital base	Modify	A slight increase (0.6 percent) in the dollar amount due to the AER using an updated inflation figure for 2025-26.[2] Conforming capex during the period 2021-26 is assessed in Attachment 2.[3]
Year by year tracking	Modify	The AER accepts our approach to use year-by-year tracking, but it removes the inputs to the "inlets" and "future of gas depreciation" asset classes in the final year adjustment to reflect its decision on additional depreciation.
Straight line depreciation	Accept	The AER accept our use of straight-line depreciation in the PTRM.[4]
Asset classes and standard asset lives	Modify	The AER accepts our asset classes and standard asset lives, with the exception of our "future of gas" asset class, which contains our additional depreciation adjustment.[5]
Additional depreciation	Reject	The AER does not accept our claim for additional depreciation, concluding that our AGN SA network does not face sufficient risk of asset stranding.[6]
Closing capital base	Modify	The closing capital base is a function of the AER's decisions in respect of inflation, the opening capital base, capex during the 2026-31 AA period, and depreciation during the period.[7] The AER accepts our approach to base the opening asset base on 1 July 2031 on the approved depreciation schedules and forecast capex during the 2026-31 AA.[8]
Corporate income tax	Accept	With the exception of our additional tax depreciation, to match our additional regulatory depreciation, the AER has accepted our tax approach. It has proposed a different opening tax asset base, due to errors it has uncovered in the approved roll-forward model approved in 2021, and it notes that approved tax depreciation will be based on approved capex, but it has agreed with the amount of zero for income tax in our proposal, due to carried forward tax losses.[9]

Note: In this 'traffic light' table, green shading represents the AER's acceptance of our Final Plan, orange represents the AER's modification of our Final Plan and red shading represents the AER's rejection of our Final Plan.

[2] *AER Draft Decision, Attachment 1, p1 & p5.*
[3] *AER Draft Decision Attachment 1, p6.*
[4] *AER Draft Decision Attachment 1, p10.*
[5] *AER Draft Decision Attachment 1, p9 & p20.*
[6] *AER Draft Decision Attachment 1, pp11-19.*
[7] *AER Draft Decision Attachment 1, p6-7.*
[8] *AER Draft Decision Attachment 1, p8.*
[9] *AER Draft Decision Attachment 1 pp21-26.*

1.4 Our Response to the Draft Decision

With the exception of the AER's Draft Decision on additional depreciation, we accept most parts of the AER's Draft Decision outlined in Attachment 1. For clarity:

- We accept the AER's decision on year-by-year tracking (Section 1.2.4.2 of Attachment 1 of the Draft Decision). See Attachment 10.1A for further details.
- We do not have any issue with the AER's use of standard asset lives (Section 1.2.4.3 of Attachment 1 of the Draft Decision); though we note that, should the AER choose to give effect to additional depreciation by shortening asset lives as part of the AER's 2-step approach, then this would be acceptable.
- Any issues we have with the 2031 closing capital base (Section 1.1 of Attachment 1 of the Draft Decision) in 2031 are a function of different views on capital spending during the forthcoming AA period. See Attachment 10.1A for further details on the closing capital base and Attachment 9.13 for details on capex.
- Any issues associated with amounts of corporate income tax (Section 1.3 of Attachment 1 of the Draft Decision) relate to differences in other aspects of the Revised Final Plan compared to the Draft Decision. See Attachment 11.2 for further details

A summary of our response to Attachment 1 of the AER's Draft's Decision is provided in Table 1.3 below. Note that, owing to a difference between where we deal with issues in our Final Plan and where the AER deals with issues in its Draft Decision, much of the detail summarised in Table 1.3 is outside this attachment. We provide the relevant references for completeness, so that stakeholders can see where we address all the issues raised by the AER in Attachment 1 of its Draft Decision. Our major focus in this attachment to our Revised Final Plan is on the topic of additional depreciation.

Table 1.3: Summary of our response to the AER's Draft Decision on depreciation

	AER Draft Decision	Our response	Our Comment
Opening capital base	Modify	Accept	See Attachment 10.1A
Year by year tracking	Modify	Modify	We have added back in the inputs to the "inlets" and "future of gas depreciation" asset classes in the final year adjustment to reflect our position on additional depreciation. See Attachment 10.1A
Straight line depreciation	Accept	Accept	See Attachment 10.1A
Asset classes and standard asset lives	Modify	Modify	We have added back in the future of gas depreciation class. See Attachment 10.1A for further details
Additional depreciation	Reject	Reject	See detailed discussion in Sections 1.4.1 1.4.1to 1.4.3 1.4.3 below.
Closing capital base	Modify	Modify	We and the AER are aligned on approach; what differences arise do so due to differences in inputs. See Attachment 9.13 for capex, Attachment 10.1A for the capital base and this attachment for additional depreciation.
Corporate income tax	Accept	Accept	See Attachment 11.2 for details. What differences arise do so due to differences in inputs and not approach.

The following sections detail our response to the AER's Draft Decision in this revised Final Plan.

1.4.1 Maintenance of support for our current approach

In our Final Plan, our modelling showed that the smallest amount of change we could make to depreciation to make a difference to the risks AGN and its customers face is roughly $70 million. In our Final Plan, mindful of recent AER decisions which focussed on short run price stability, we proposed only an amount which would keep prices stable (at that time $30 million). We have reconsidered this position in this Revised Final Plan for two key reasons set out below.

Firstly, at the time of our Final Plan, the renewable gas certificate scheme and our HyP Adelaide project appeared likely to be implemented in the early years of our AA, which gave us greater confidence in the progress of renewable gas in South Australia. It now appears more likely that the delivery of the project and the certificate scheme, if implemented at all, would likely occur several years later, possibly in the next Access Arrangement period. This highlights the risks and uncertainty of the energy transition and we consider it more prudent to take at least the smallest step towards managing risk than we did at the time of our Final Plan.

Secondly, the AER's evolving approach to depreciation, as seen across the AGN SA and Evoenergy Decisions, gives rise to significant concerns in respect of networks ability to recover efficiently incurred capital expenditure and an increased risk of economic asset stranding. This is an issue we discuss in detail in Section 0. Here, we note that, if market and policy forces in South Australia became detrimental to AGN, the AER's position in respect of Evoenergy suggests that the willingness of the AER to act, and the evidentiary basis of action, will put AGN at far greater risk of economic asset stranding than anticipated at the time of the Final Plan. For this reason, we consider it more important and in the long-term interests of consumers to act now, when conditions are less challenged, than risk the consequences of waiting.

As explained in detail below, there are three factors which lie behind our view that our $70 million modelling result remains the minimum amount of appropriate additional depreciation:

- The degree to which it balances risks of future success or failure of renewable gas.
- The way our framework of sharing risk operates, and the way in which it limits the need for large amounts of additional depreciation. This is also covered in our Final Plan.
- The importance of signalling to markets how regulation might support or otherwise, networks under transition.

Balancing risks of future states of the world

One way to consider the future of gas networks is to consider different future states of the world, and to try and take actions to create options which would assist in meeting different states of the world. This is a standard approach found in business planning and is known as a "real options" approach.

The example often given is a mine, which would profitable if minerals prices are above a certain level, but make a loss if they were below that level. Mines cannot be brought online instantaneously, so mining companies will often take actions which give them the ability to move more quickly if minerals prices move favourably; actions which create real options.

Usually, they will start with actions which are low cost but time consuming, such as getting environmental approvals. They then move to more costly actions as the mineral price improves. It may turn out that the money spent on some of these actions is effectively lost, because the state of the world where the mine is profitable never eventuates. However, it is still beneficial to undertake the investment, because the value of being able to move quickly if a favourable state of the world eventuates outweigh the costs incurred to develop the option in the event that the future turns out unfavourable for the mine and the mine does not produce.

Renewable gas expenditure has a direct link to the mining example above; our spending is primarily on weld testing and updating safe work practice documentation, which is low cost but time consuming. Additional depreciation also provides options but has two subtle differences:

- Since it reduces the future RAB, it provides options and flexibility to meet both a favourable and unfavourable futures.
- Since it only happens once, it does not represent a cost to consumers as a whole when more depreciation is added in a given AA because it means that less depreciation is needed in future. Instead, it is a transfer between consumers at different points in time.

Depreciation can also be used to create options. When using changes in depreciation to create options; primarily for customers. Unlike the mining example above, we earn no additional profits when we change depreciation schedules. We do lower the likelihood of future asset stranding, but this is a benefit that we share with customers as customers have access to a network which provides services for longer, and we have the opportunity to continue to provide services. We endeavoured to formally quantify these benefits to consumers by considering changes in consumer surplus in our Victorian AA proposal in 2022.[10] In our AGN SA Final Plan, we examined longer-term benefits for customers subtly differently, by considering the long-run value of the network in a competitive market.

We have put forward a real options framework in previous AA proposals,[11] but acknowledge it was not supported by some stakeholders who essentially told us that we should choose a more likely future and aim for that, rather than trying to provide flexibility.[12] Whilst we disagree with this approach to planning for the future, we are aware of the need to respond to stakeholder feedback and have not included the framework formally in our AGN SA Final Plan.

However, a real options framework, and the options depreciation can create for customers, is useful for comparing and contrasting our views on depreciation with those of our South Australian Reference Group; particularly in the context of their view in respect of the role of renewable gas. They consider it much less likely to be successful, noting:[13]

> *Given the above economic factors, the recent closure or suspension of almost all hydrogen development projects across Australia, reflecting similar experience overseas, is not surprising. A sustainable distribution network future built on hydrogen has a very low probability in the absence of a massive additional*

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[10] See Attachment 6.7 of our Revised Final Plan for our AGN network, pp 12-17, available here. We followed the same approach for Multinet. The approach was based on an expert report contained in Attachment 6.8 of our Revised Final Plan, available here.

[11] See pp16-19 of Attachment 6.1 of our AGN Victoria and Albury Final Plan, submitted to the AER in July 2022, available here.

[12] See, for example, submissions from the Brotherhood of St Lawrence (available here, p17) and Energy Australia (available here, p2) to our 2022 Victorian proposals and the ECA (available here, p7) and SACOSS (available here, p7) to our AGN SA process.

[13] See the SARG's submission to our Final Plan (available here), pp 3 to 4. The SARG also provides considerably more detail on the evidence it considered on pp13-19 of the same submission. On pages 5 and 6, and again on p20, the SARG outlines its views about a higher amount of additional depreciation being appropriate. The SARG do not propose a number, but note (see p5 of their submission) that, if new connections capex was removed and could be captured as additional depreciation instead (giving a total of $187 million), then this would lead to less pressure on the AER's real price cap

> *Government subsidy to ensure an 'economic' outcome ie one where network customers continue to see gas as a real alternative to electricity assuming Government policy allows choice to continue.*
>
> *The Panel considers this 'economic' outcome is very unlikely to occur. Nor is it considered a likely future by other expert forecasting reports, such as the ISP9 or the Net Zero Australia mobilisation report.*
>
> *While the cost of biomethane may end up being competitive with renewable electricity, we do not have enough information to be confident that there will be the volume of competitive biomethane available to ensure a viable distribution network.*

In our Final Plan, we put forward $70 million as the minimum amount of additional depreciation supported by our modelling because our focus on creating options for our consumers was centred around our more positive view of the future of renewable gas. This led us to believe our network would be worth $1 billion in a future competitive market and, along with other cost-minimising aspects of our Final Plan, we concluded that $70 million of additional depreciation would be needed to meet this $1 billion goal. We noted that it was the bare minimum needed but, given a desire to be conservative in the face of uncertainty, we concluded this was appropriate, based on the modelling. In the Final Plan itself, however, we followed the AER approach of flat real prices, which gave $30 million in additional depreciation; less than the minimum required to start to manage risk according to our modelling. We were comfortable doing this on the basis that the proposed HypAdelaide project would be going ahead.

By contrast, the South Australian Reference Group believed that we should be creating options for our customers that better protected future customers (particularly vulnerable customers) from the price consequences of customers leaving the network. Their conclusion that much more additional depreciation would be needed to produce this option was entirely logically consistent with their views about renewable gas. If a more pessimistic view of the future of renewable gas in our networks is taken, then we would agree that much more depreciation than we have currently proposed would be required.[14]

By contrast, the AER's position appears to be that we should not act now to provide options for our customers; either to support a renewable future or to help protect against future downside risk. It appears instead that the AER believes that networks should only take action when it becomes sufficiently clear that a particular future state of the world will emerge and to do nothing until that point in time. We consider this approach will mean that any action taken will be too little, too late (see Section 1.4.3), and that the uncertainty it creates for stakeholders until a decision to act is taken is detrimental to their interests.

Our three-part framework and additional depreciation

In our Final Plan, we outlined a three-part conceptual framework for risk-sharing whereby:[15]

- A network operator, seeing a decline in demand, looks to new sources of demand which are sustainable in any future competitive marketplace, to fill the now available capacity. Regulators, recognising the benefits of competition to consumers, support this.
- Customers of currently regulated services (whether the customers are existing or new), seeing that not all of the costs previously incurred to provide their services could be

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[14] *We have yet to model this pessimistic framework but consider higher amounts than suggested by the SARG may be required.*
[15] *See Section 3.1 of Attachment 6.1 of our Final Plan.*

recovered though new markets or into a competitive future, where reasonably practicable, seek to cover the balance before competitive forces have a greater impact.

- Customers, realising that growth in regulated services cannot always be assumed, no longer impose costs on each other as they enter or leave the energy network; instead paying all costs attributable to their own use themselves.

This has important consequences for depreciation; particularly when comparing our framework above with what appears to be the AER's view that additional depreciation should only be applied when a network is on a pathway to closure. Differences arise both in terms of the cost consequences (short and long-term) and the incentive consequences. We discuss both below.

We consider that our framework, outlined above, could form part of a toolkit to consider depreciation within the current NGR framework, and avoid many of the problems the AER seems to have with an uncertain environment and the possibility of network decline.

Cost consequences

As we outline in our Final Plan, the first two points are part of the "bargain" between networks and customers and represent a constructive way to consider that bargain than apportioning losses from unrecovered assets,[16] whilst the third represents part of the bargain between different groups of customers. As noted above, we have tested this framework with customers in consultation post the Draft Decision and find understanding and support in respect of fairness (see our Revised Plan Overview).

This has important consequences for additional depreciation which the AER may not have considered in its Draft Decision. In fact, this framework represents an additional tool for meeting future risk, meaning depreciation in building block model needs to play less of a role.

Our risk, and the risk which customers who stay on the network face, is essentially based on the size of the RAB through time. Since the regulatory building block model mechanically produces prices based on a return on and of the RAB, the larger is the RAB for longer, the higher is the risk in an environment where the future may be very different from today.

Conversely, the smaller is the RAB, the lower is the risk for investors and future customers. There are three basic ways to make the future RAB smaller:

- Start reducing it now via relatively higher amounts of depreciation.
- Stop adding to it as much by adding less capex.
- Find other sources for recovery of the RAB.

Our Final Plan does all three things together, and doing so means we can rely on any one of these options less, most particularly, we can rely on less additional depreciation.

Our Final Plan already minimises our capex, and we assume in our depreciation modelling that connections capex is not added to the RAB post 2031; something which will now happen earlier because of the recent AEMC Rule change.[17] However, there are limits to reducing capex, because the network still needs to operate safely and reliably for the benefit of customers. In

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[16] *That is not to say that losses will never occur, but rather there are different ways to consider the issue than the simplistic zero-sum game between networks and consumers over inevitable losses.*

[17] *AEMC rule change "Updating the Regulatory Framework for Gas Connections, detailed here. We note that, under the new rule, connecting customers would pay the full costs of their connection from 1 October 2026.*

many cases, the alternative to capex is a short-term or 'Band-Aid' opex solution to a given problem, and this can lead to higher prices for customers.

However, if we can find other sources of revenue which sit outside our current set of regulated customers, then there is less need to add depreciation to the building block model. This is where the $1 billion of sustainable business post-2050 comes from. We agree with the AER (Attachment 1 p16) that any forecast post 2050 is subject to a high degree of uncertainty, with each of the drivers being highly variable.

However, the AER may not have appreciated our point; by making a prediction (however difficult that might be) about future business value and removing this predicted value from the consideration of how much to change depreciation in a regulatory building block model, the net result is to require far less of the current set of consumers of regulated services.

The AER's reasoning in its Draft Decision seems to dismiss our post 2050 network valuation. If it does so, it misses the opportunity to reduce the amount of additional depreciation by focussing only on a world where the RAB goes to zero under regulation. Any scenario where the RAB goes to zero by a given date will involve more depreciation than one where there is a positive RAB at the end of the same time period.

Incentive consequences

As outlined above, our three-part framework, accepts the possibility of different uses for a network in the future and integrates that into consideration of depreciation. By contrast, the AER appears to take a different view. It appears to believe that the only role for depreciation is when a network is on a pathway to eventual closure. In the AGN SA Draft Decision (Attachment 1 p12), it says:

> *Our draft decision is to not accept AGN's proposed $30 million ($2025–26) accelerated depreciation for the 2026–31 period. We do not consider there to be sufficient evidence at this time to suggest that AGN's network faces significant asset stranding risk that needs to be addressed through accelerated depreciation to provide AGN reasonable opportunity to recover its efficient costs. Both the policy environment in South Australia and AGN's overall proposal suggest that AGN's gas network is expected to play a continued role in the transition to net zero.*

Additionally (Attachment 1 p14) the AER notes:

> *There is currently no strong evidence that demand for the usage of AGN's gas network in South Australia will materially decline in either the short or long term. Forecasts indicate that gas demand in South Australia is expected to decline gradually over time. However, the rate of decline is expected to be slower than that projected for other jurisdictions.*

We understand the AER's position to be that the role of additional depreciation should be limited to cases where networks are moving towards no customers (see further discussion on economic asset stranding in Section 1.4.2). This approach is, in our view, a problematic view; particularly from the perspective of the long run interests of consumers. To see this, consider a case where a network that currently has a RAB of $2 billion and has two potential future pathways.

In the first, it can pivot to future business opportunities in circa 2050 that it thinks will provide an ongoing network value of $1 billion. To do so requires investment both from the network and from others attached to the network (from renewable gas producers, for example) starting now, and this investment is unlikely to be forthcoming if the network is unable to reduce its

RAB down so that it has an exposure of no more than $1 billion by 2050 because this is how much asset exposure can be supported in the post-2050 market. This will require some increase in depreciation today.

In the second, it makes no pivot to different markets and is able to continue serving natural gas customers until 2060, when either market or policy forces will require closure as natural gas is no longer a viable fuel. This would also require an increase in depreciation, as some assets today have a remaining asset life of more than 25 years. Moreover, it would require future maintenance capitalised into longer-term assets (like pipe) to have their lives capped at 2060.

If the AER gives a clear signal that it will only accept a change in depreciation where it is dealing with risks associated with eventual network closure, and a network has some degree of choice in respect of how it plans for its future, then the AER risks creating some strong incentives which are not in the long run interests of consumers.

We consider that this is to the detriment both of current and future customers. For future customers, the option of a network providing a service different from today is foreclosed. For current consumers, it is a detriment because the depreciation required to get to zero in 2060 is greater than the amount required to get to $1 billion in 2050 (roughly $55.6 million per annum in depreciation in the first case, assuming no new capex, versus $38.5 million in the second).

For this reason, we consider that our three-part framework should be used to guide regulators, and regulators should look for options whereby gas networks have flexibility and can have other uses, where feasible, and depreciation can be used to facilitate this, rather than simply focussing on its use to protect against network failure in future. This sends a much better signal to networks and other stakeholders about the future outcomes which the AER is willing to support via its regulatory approach.

Signalling

We outline an aspect of signalling when we discuss the example of the two potential future pathways above, but the issue is much broader than this. Although it does not form one of the reasons for additional depreciation in our Final Plan, signalling is an important consideration. The whole point of the WoOPS model (see Section 1.4.3) is that a regulator will often need to act before it is clear that some future challenge to networks will arrive with certainty, because, by the time that such information is clear, it may well be too late to act.

There is a very large difference, in respect to the signals it provides investors, between a regulator who effectively says, "the future is unclear, so I will do nothing", compared to a regulator who says, "the future is unclear, but a case can be made for change, so I will allow a small change". All stakeholders, seeing the former approach, are left to try and deduce for themselves how (and when) a regulator might act in future. Since many customers incur their own sunk costs connecting to the gas network, this uncertainty is costly for them.[18]

By contrast, by taking action when the future is uncertain,[19] the regulator sends a signal to stakeholders (investors, ratings agencies, customers and producers of renewable gas) about its intention to act, and the kinds of actions it will take as the future becomes more clear. That is

[18] *See Biggar, D, 2009, "Is Protecting Sunk Investments by Consumers a Key Rationale for Natural Monopoly Regulation?", Review of Network Economics, 8(2), 128-52, available here.*

[19] *And even making it clear that the action is being taken under conditions of uncertainty, and explaining how this uncertainty has influenced the regulatory decision. For an example of this, see [1510] to [1527] of the ERA's 2021 Final Decision for our DBNGP network, available here.*

not to say that simply taking action creates positive signals; we outline our concerns with the AER's real price path approach in Section 1.4.3, for example. However, the value of good signalling by regulators should not be under-estimated, nor its importance in ensuring regulatory certainty to encourage efficient investment in the long term interests of consumers.

1.4.2 AGN SA Draft Decision

In this section we cover issues specific to the AGN SA decision and respond to the AER's reasoning for not allowing any additional depreciation.

The AER has formed the view that there is not sufficient evidence at this time to suggest that the AGN SA network faces significant asset stranding risk that needs to be addressed through accelerated depreciation to provide a reasonable opportunity to recover efficient costs. The position is based on the AER's view of the policy environment in South Australia compared to other jurisdictions, its view of demand forecasts and probability of asset stranding shown in our future of gas modelling. It is also based on its view of the consistency of the overall proposal submitted by AGN SA. We cover each of these issues in more detail below, focussing on why some amount of additional depreciation is necessary. We deal with what we consider that amount should be (and why) in the preceding section, and also in our Final Plan.

The issues which we consider here are:

- We consider that the AER overstates differences between the policy environment in South Australia and New South Wales, and this has led it to make a decision for our AGN SA network which is different to the decision it made for Jemena in NSW.
- In respect of economic lives, it appears that the AER focuses solely on expected lives and not on risk, which is equally important. Additionally, it appears to place much more focus on the length of economic lives, missing the opportunities to be gained from considering their nature.
- The AER's view of "significant" in respect of asset stranding risk is not consistent with the evidence before it.
- The AER does not make a clear distinction between economic and physical asset stranding and appears to contemplate changes to depreciation only where a network is definitively on a pathway to closure, rather than as a tool for sustaining a network. This has significant implications for the choices available to our customers in future.
- The AER does not appear to appreciate the motivation for our asking for only $70 million in additional depreciation. It also does not seem to appreciate the degree to which capex has already been minimised.
- The AER notes other means of meeting the $1 billion 2050 target we have used for 2050, most notably capex changes, but there appear to be issues with the AER's calculations which, when adjusted, lead to the opposite conclusion.
- The AER motivates its decision to disallow any additional depreciation with reference to consistency between additional depreciation and network growth but does not consider the important timing difference between short run appliance decisions made by customers and the longer-term risks of our asset exposure. The AER also appears to act inconsistently between AGN SA and Jemena in terms of linkages between growth and depreciation.

Overstating policy differences

The AER has suggested that, because SA policy settings are more supportive of gas networks than those in jurisdictions such as the ACT or Victoria there is no need to undertake any changes in depreciation. There are three issues with this:

- We do not consider the policy comparison the AER makes is complete or accurate, particularly in respect of South Australia and New South Wales, leading to inconsistent treatment of depreciation between Jemena in NSW and AGN in SA.
- The Draft Decision policy comparison does not consider Federal government policy, particularly the National Construction Code, which has substantial impacts on the competitiveness of gas in every state.
- The analysis in the Draft Decision does not consider market forces, which have effects equal to or greater than policy.

South Australia and New South Wales policy environments

The AER appears to have based its decision to allow no additional depreciation in the AGN SA network on policy support for renewable gas in South Australia compared to other jurisdictions such as Victoria or the Australian Capital Territory, where government policy settings are actively negative towards natural gas. In so doing, it downplays the significance of a comparison between SA and NSW.[20] In its Draft Decision, the AER (see Attachment 1, Table 1.4) suggests two key differences between SA and NSW in respect of policy:

- It suggests four local governments in NSW have either proposed or implemented natural gas bans in NSW but none have done so in SA.
- It suggests that AGN SA is already delivering renewable gas to its customers, but Jemena only has pilot projects in place.

This summary of policy in the two jurisdictions is incomplete. We provide a more complete overview in Table 1.4 overleaf.

[20] *We note that West Australian policy settings are, if anything, more supportive of gas than South Australian settings, and that Perth has a similar climate and market for gas as Adelaide. This did not prevent the Economic Regulation Authority from recently allowing $38 million (See Attachment 6, Table 6.8 of the ERA's Final Decision for ATCO, available here) in additional depreciation for the ATCO network (or 24 percent of its RAB, compared to the 34 percent that $70 million represents for the opening RAB for AGN SA in the AER's Draft Decision). The ERA has also allowed additional depreciation for our DBNGP asset in Western Australia in 2021 and again in 2026 (see here for the ERA's most recent decision which also contains references to the 2021 decision and subsequent work).*

Table 1.4: Summary of NSW and SA policy positions

Category	Topic	New South Wales (NSW)	South Australia (SA)	Summary
Climate and net zero framework	Net zero targets	Legislated targets for 50% emissions reduction by 2030, 70% by 2035, net zero by 2050[21]	Legislated targets for 60% emissions reduction by 2030, net zero by 2050[22]	Comparable – similar ambition and timeframes
	Electricity targets	82% renewable electricity target by 2030[23]	100% net renewable electricity by 2027[24]	SA more advanced – earlier electricity milestone for net zero. This is a risk to gas
	Gas targets	No gas emissions reductions targets	No gas emissions reductions targets	Comparable – no gas specific pathways
Natural gas	Natural gas role	Explicitly recognised as essential for reliability, firming and affordability[25]	Explicitly recognised as essential for reliability, firming and affordability[26]	Comparable – same functional role
	Supply policy	Market based supply[27]	Active support via grants and exploration programs[28]	SA more advanced – direct supply support through exploration grants
	Demand policy	Technology neutral, no gas connection bans or electrification mandates[29]	Technology neutral, no gas connection bans or electrification mandates[30]	Comparable – similar settings
Renewable gas	Role	Renewable fuel strategies covering hydrogen, biomethane, and other fuels[31,32]	Hydrogen focused strategy deferred, renewable gas policies evolving[33]	NSW more advanced – broader focus on renewable fuels with policy measures in place
	Supply policy	$170m committed to renewable fuels and biomethane[34]	No comparable funding mechanism	NSW more advanced – dedicated funding allocated
	Demand policy	Market based Renewable Fuel Scheme, creating demand for up to 8 PJ by 2038[35]	No comparable schemes	NSW more advanced – certificate demand scheme for retailers and large gas users in place
	Other enablers	90% electricity network charge concessions for hydrogen electrolysers[36]	No equivalent concessions	NSW more advanced – electricity network tariff relief provided
	Project maturity	Hydrogen: 7-8 projects in development[37]. Biomethane: 8 projects aimed for connection to distribution network by 2030 (per Jemena AA[38])	Hydrogen: 6-7 projects in development[37]. Biomethane: 1 project in construction, limited additional projects in development by 2030[39].	NSW more advanced – hydrogen comparable, biomethane project pipeline larger in NSW

[21] *NSW Government Climate and Energy Action. Net Zero Plan, available here, accessed 6 January 2026.*
[22] *Government of South Australia, 2024. South Australia's Net Zero Strategy 2024–2030, available here, accessed 5 January 2026.*
[23] *NSW Government Climate and Energy Action, Net Zero Plan, available here, accessed 6 January 2026.*
[24] *Government of South Australia Department for Energy and Mining. Leading the green economy, available here, accessed 12 January 2026.*
[25] *NSW Government, 2020. Future of Gas Statement, available here, accessed 6 January 2026.*
[26] *SA Department for Energy and Mining, 2023. South Australia's Green Paper on the Energy Transition, available here accessed 6 January 2026.*
[27] *NSW Government, 2020. Future of Gas Statement, available here, accessed 6 January 2026.*
[28] *Government of South Australia. Industry activity, available here, accessed 9 January 2026.*
[29] *The Guardian, 2023. NSW won't ban gas in new homes as Premier declares 'I don't need another complication', available here, published 31 July 2023.*
[30] *Government of South Australia, 2025. Exploration opportunities open to firm South Australia's energy future, available here, accessed 9 January 2026.*
[31] *NSW Government, 2021. NSW Hydrogen Strategy, available here, accessed 6 January 2026.*
[32] *NSW Government, 2025. NSW Renewable Fuel Strategy, available here, accessed 6 January 2026.*
[33] *InDaily, 2025, Turbines for hydrogen plant to be on-sold after industry plans shelved, available here, published 21 February 2025*
[34] *NSW Government, 2025. NSW Renewable Fuel Strategy, available here, accessed 6 January 2026.*
[35] *NSW Government, 2025. Renewable Fuel Scheme, available here, accessed 6 January 2026.*
[36] *NSW Government, 2021. NSW Hydrogen Strategy, available here, accessed 6 January 2026.*
[37] *CSIRO HyResource, 2026. Hydrogen projects and facilities database, available here, based on HyResource data filted by state as at 5 January 2026.*
[38] *AER, 2025. Jemena Gas Networks (NSW) - Access arrangement 2025–30, available here, accessed 13 January 2026.*
[39] *ARENA, 2025. Delorean – SA1 Biomethane Upgrading Project, available here, accessed 13 January 2026.*

From Table 1.4, we conclude that:

- Climate policy in NSW and SA is largely comparable, with a net zero target by 2050 and no specific plan to reduce emissions on natural gas; certainly not one which involves specifying a future for gas networks.
- In respect of natural gas and its role, the SA government has set out a more recent and clearly articulated policy position in its 2023 Energy Transition Green Paper[40], while the NSW government adopts a similar position in its 2021 Future of Gas Statement.[41]
- Although SA provides more funding for gas exploration through initiatives such as the Gas Initiative Grant and the legacy Plan for Accelerating Exploration grants[42], the NSW Government has reaffirmed its commitment to supporting sufficient, reliable and affordable gas supply via limited gas exploration beyond the Narrabri Gas Project, interstate gas imports, and where required overseas LNG imports.[43]
- In respect of households and gas appliances, neither state has imposed a ban on gas appliances or new gas connections.[44,45] Whilst some local governments in NSW favour such policies, and the City of Adelaide has also been strongly supportive of electrification, the NSW Government has questioned the power of local governments to effect such bans. Moreover, although SA previously operated the Retailer Energy Productivity Scheme and NSW currently offers a battery subsidy, neither government has a scheme that incentivises the replacement of gas appliances, unlike the Victorian Energy Upgrades scheme.

In respect of renewable gases, both states have renewable gas strategies. However, NSW offers more funding support ($170 million via the NSW Renewable Energy Strategy), stronger targets and transmission and distribution use of system relief for hydrogen producers,[46] none of which are currently available in South Australia following the deferral of the Hydrogen Jobs Plan in Whyalla. Overall, we consider that both jurisdictions maintain broadly aligned, technology-neutral approaches to the energy transition. A key distinction is that NSW is the only state in Australia that has implemented tangible policy mechanisms to support renewable gas, including hydrogen and biomethane through the NSW Hydrogen Strategy (2021), Renewable Fuel Strategy (2021) and Renewable Fuel Scheme (2025). While SA has been a longstanding leader in hydrogen, there are no directly comparable funding programs, network charge concessions, or demand-based mechanisms in place or announced as under development.

We note that Jemena proposed 8 biomethane projects totalling 6.7 PJ of supply in its recent AA proposal (2025-30). Notwithstanding the AER's subsequent decision, and development of those projects is understood to have commenced. By contrast, in SA there is currently only one biomethane facility, proposed to be connected in April 2026, with capacity of approximately 210 TJ per annum.[47]

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[40] *SA Department for Energy and Mining, 2023. South Australia's Green Paper on the Energy Transition, available here, accessed 6 January 2026.*
[41] *NSW Government, 2020. Future of Gas Statement, available here, accessed 6 January 2026.*
[42] *Government of South Australia. Industry activity, available here, accessed 9 January 2026.*
[43] *NSW Government, 2020. Future of Gas Statement, available here, accessed 6 January 2026.*
[44] *The Guardian, 2023. NSW won't ban gas in new homes as premier declares 'I don't need another complication', available here, accessed 6 January 2026.*
[45] *Government of South Australia, 2025. Exploration opportunities open to firm South Australia's energy future, available here, accessed 9 January 2026.*
[46] *NSW Government, 2021. NSW Hydrogen Strategy, available here, accessed 6 January 2026.*
[47] *See p66-69 of the JGN plan, submitted to the AER in June 2024, available here for details on its biomethane projects. Details on the SA biomethane project is available here and here.*

In respect of hydrogen, HypSA, delivers a 10 percent hydrogen blend to 3,700 households in suburbs around the plant.[48] By comparison Jemena's Malabar Biomethane plant produces enough biomethane to meet the full gas demand of approximately 6,300 customers.[49] The practical scale of these two projects is not obviously divergent. HypSA supplies a partial hydrogen blend to a larger number of customers, but the Malabar facility provides sufficient renewable gas to meet the full consumption of a smaller cohort. We note finally that HypSA is a pilot project, as with the projects the AER mentions in respect of Jemena; we do not recover any costs specific to hydrogen from customers of HypSA.

In its recent Jemena decision, the AER allowed $115 million of additional depreciation, or 3 percent of its RAB.[50] Were it to apply its assessment of policy consistently between AGN SA and Jemena, 3 percent of the AGN SA opening RAB from the AER's Draft Decision would be $62 million in additional depreciation. The value of zero for additional depreciation in the AGN SA Draft Decision is inconsistent with the Jemena decision, under broadly similar policy support.

Federal Government policy

The AER has considered only state government policy settings when considering amounts of additional depreciation and has ignored Federal Government policy settings. In the past, it has considered Federal Government climate goals,[51] but a more material driver for gas networks is the National Construction Code.[52] It requires all new homes, including rebuilds of existing homes, to meet a 7-star energy efficiency standard.

Customers are not precluded from using natural gas by the 7-star energy efficiency standards, but they do materially increase the cost of installing gas appliances. In particular, to meet the "energy budgets" required under the 7-star standard, a homeowner who wished to install gas appliances would, in practice, need to install rooftop solar to come in under the "energy budget" requirements. Based on AGIG analysis, this requirement adds approximately $3000-$4000 to the cost of constructing or rebuilding a home.[53]

This makes it much more challenging for networks to connect new residential customers and raises the likelihood of losing customers as existing houses are renovated or rebuilt. Moreover, since it is Federal Government policy, it applies equally across all jurisdictions and represents a common operating environment for all networks.[54] This needs to be considered by the AER if it is going to base its assessment of additional depreciation on pro electrification policy settings.

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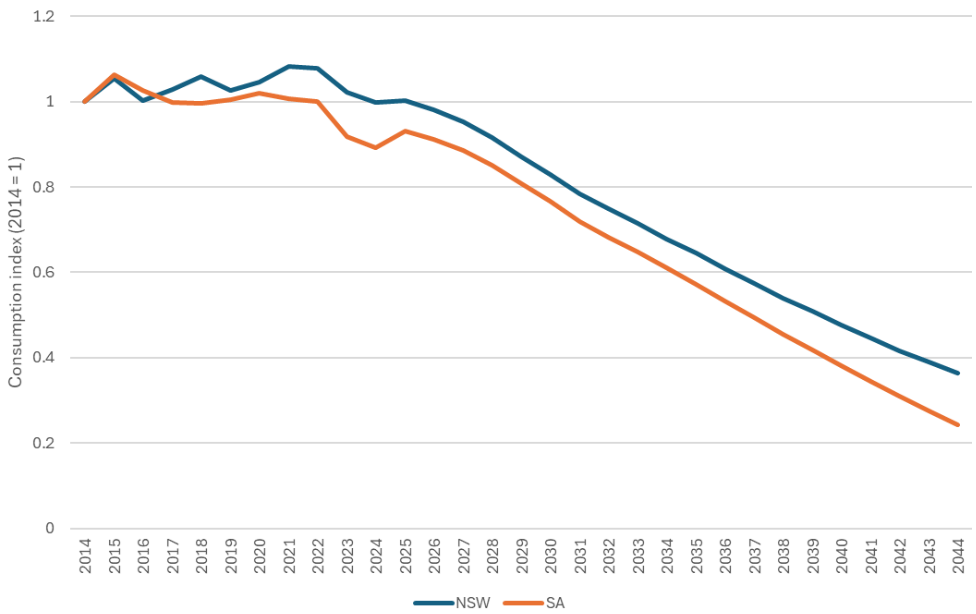
[48] *HypSA details available here.*
[49] *Malabar Biomethane plant information available here. Note that we have not included hydrogen production from Jemena's Western Sydney Hydrogen Hub (see here) as Jemena do not provide data on how many customers are supplied with gas, but we note it is about 40 percent of the size of HypSA.*
[50] *See Table 4.5 in Attachment 4 of the AER's Final Decision, available here.*
[51] *See, for example, the 2021 Information Paper Regulating Gas Pipelines Under Uncertainty, pp3-4, available here. Decisions, on particular networks tend to focus most on the relevant jurisdiction, but the AER does consider Federal targets as well, see for example, pp11-12 of Attachment 4 of its Draft Decision for the NSW networks of Jemena in November 2024 (available here)*
[52] *An overview of the relevant changes is available here, with further detail, and links to the codes themselves available here. We note that the AER did consider the NSW building code (BASIX – see p12 of Attachment 4 of the Jemena Draft Decision of November 2024, available here), but it is not clear how this has directly influenced that decision.*
[53] *Based upon a 213 sqm average-sized SA home, and using the whole of home calculator provided as guidance (available here), noting that the results are illustrative and depend upon many factors in the home.*
[54] *NSW, Tasmania and the Northern Territory have their own requirements. However, specifically in the case of NSW We note that the NSW BASIX framework is consistent with the 7 star NCC framework, meaning NSW and SA face essentially the same building code requirements (see the NSW Government summary of BASIX, available here). This is relevant for any comparison of the AGN SA and Jemena NSW decisions.*

Market forces and forecast gas demand

We consider that the AER relies too much on policy settings when considering appropriate additional depreciation, and too little on market forces. Apart from some discussion about how uncertain inputs are (pp15-16), the only substantive discussion of gas markets is the assessment of forecast gas demand in South Australia and New South Wales shown on p14 of Attachment 1. This, however, presents gas volumes for residential, commercial and industrial customers and ignores the far more important issue of revenue.

Even in respect of volumes, we do not consider the analysis to be complete. Figure 1.1 provides an overview of residential and commercial demand in the Jemena NSW and AGN SA networks out to 2044 from the same source as used by the AER; (removing industrial volumes and presented in index form to allow for easier comparison of networks of different scales). From 2026, the average annual decline in NSW is 5.2 percent, whilst in SA it is 6.8 percent.

Figure 1.1: 2025 GSOO demand forecast – SA and NSW residential and commercial



Source: AEMO GSOO 2025: Step Change Scenario, available here, accessed 29 December 2025

The AER's conclusion in respect of demand is driven not by residential and commercial customer demand, but by slight differences in industrial gas use between the jurisdictions.[55]

However, whilst industrial gas volumes make up roughly half of total (residential, commercial and industrial; not gas for power generation) gas volumes in the NSW AEMO data today and nearly three quarters for SA, in each jurisdiction, industrial volumes make up less than ten percent of revenues.[56] If volumes for residential and commercial customers (who make up around 90 percent of revenues for both AGN SA and Jemena) are considered, it is clear that,

[55] *In the same dataset, industrial gas demand falls by 0.47% per annum on average for Jemena and increases by 0.25 percent per annum for AGN SA over the period from 2026 to 2044. It appears to be this small difference in industrial demand growth which drives the percentage figures the AER uses on p14 of Attachment 1 of its Draft Decision.*

[56] *In our Final Plan (see p 75, available here) we report 78.7 percent of revenues from domestic reference services and 14.1 percent from commercial reference services. Jemena do not produce a similar figure, but, from the F3 worksheet of their RIN data for 2023/24 (available here, and noting that some data are confidential and not shown), volume customers comprise 93 percent of reported revenue.*

there is a stronger case for additional depreciation in AGN SA than was the case for Jemena as the demand reduction for these key customers is greater.

Moreover, the AGN decision is being made in the context of a changed environment whereby connecting customers must pay the full costs of their connection in SA (they must do so too in NSW, but this was not certain at the time of the decision, when the AER was considering demand). This means that AEMO's volume forecasts may be overstated. We capture the impact of connection charges on demand in Attachment 13.4.

Other information not considered

There are a number of additional matters and forces we think should also be taken into account when considering the approach to depreciation.

What is also required to understand depreciation properly is the market forces driving decisions about customer connections. In respect of residential consumers, there are several studies which highlight how electric appliances can save consumers money already.[57] We do not necessarily agree with all of these studies, and we consider that customers have reasons other than price in mind when they choose appliances. However, we do consider that the cost differences must form a key part of any understanding of how customers might choose gas or electric appliances, and from this what their future gas demand will be; particularly from the key residential sector.

Over the longer term, as we outlined in our Final Plan and as we discussed extensively with our customers,[58] we see competition emerging from new sources, most particularly from customers themselves as they gain more sovereignty over their own energy supply. This, as we point out in our Final Plan has the possibility of changing the energy sector in very profound ways.[59]

The Draft Decision does not consider these longer-term market forces. Indeed, the AER appears to believe (Attachment 1 pp15-16) that the amount of uncertainty about the future is a reason for no action. We maintain our view (see Section 1.4.3) that the AER should develop (or at least use; we have provided two examples to date) a transparent consumer choice model to formally study consumer reactions to the changes in price caused by changes in depreciation. Price elasticity considerations are always used in demand forecasts, but do not appear to have been considered by the AER.

Economic lives – risk length and nature

The interpretation of what the National Gas Rules say about changes to economic lives has clearly driven the way the AER has assessed proposals for changes in depreciation.

It is clear that it is Rule 89(1)(c) which requires depreciation schedules be changed to reflect "*as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset, or a particular group of assets"* that is most important.

We understand the AER's interpretation of it Rule 89(1)(c) is different to ours and, in particular that it considers that:

[57] *See, for example, this paper from Energy Consumers Australia. The ECA summarises other, similar studies in its submission to the AEMC Rule Change process (see here, pp 8-11)*

[58] *See Attachment 5.3 of our Final Plan.*

[59] *See Attachment 6.1 of our Final Plan pp 4-14, which captures much of the information we provided to customers in workshops, along with the evidence behind it.*

- Since the Rule states "expected economic lives", when it is considering possibilities over a variety of different scenarios, it must consider only the most likely or, mathematically, the average representation of the future.
- The primary focus should be on the length of economic lives.

The first point is apparent from the AER's views on whether or not a stranding risk of 34 percent prior to 2050 in the case of AGN SA is "significant" or not; a topic we return to below.

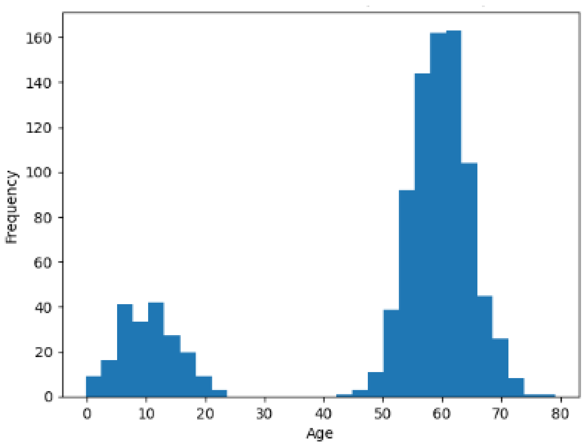
The second is apparent from the AER's two-step approach, first implemented in its Jemena decision (see discussion on the AER's "real price path" approach in Section 1.4.3). The first step in that approach is to shorten lives. Only when this does not provide an answer the AER considers reasonable does it provide some additional depreciation in its second step. It is not clear what informs the AER's second step in this context as it appears to be based solely on regulatory judgement, but we consider that the length of economic lives should not be the major focus.

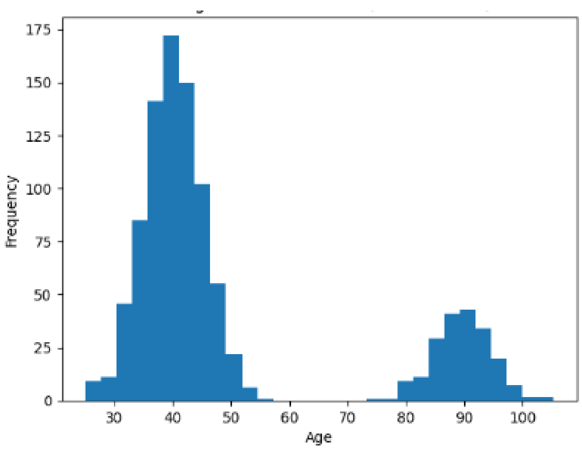
We address each of these issues below.

Expected economic lives and risk

To motivate the distinction between expected outcomes and risk, note the two scenarios illustrated in Figure 1.2. The numbers have been created purely for illustrative purposes and represent 1000 draws (each) "lives". They could be interpreted, for the purposes of this illustration as being the asset lives that a given network would have in 1000 future states of the world. In each state of the world, the asset might (for simplicity) have a different life because, in that state of the world, the last customer leaves in that year, meaning that the left-skewed diagram represents an outlook where most customers in most states of the world leave relatively early, whereas the right-skewed diagram represents an outlook where more customers stay longer under most states of the world. Each histogram could be taken to represent a different network. Or they could be taken to be a given network at different points in time where the range of possible future worlds it encounters changes because of some shock.

Figure 1.2: Expectations and risk





In both cases, by construction, the expected life, or the life that the network would have in the average over all future states of the world (mathematically speaking) is identical; it is 50 years. Additionally, the variation in lives, via the standard deviation around each average is also (almost) identical. The key difference is in the risk profile (mathematically, the skew; where each is almost a mirror of the other), which is very different. The network on the left has a large number of potential future states of the world which are longer than 50 years, and the average or expected value is dragged down to 50 years by a handful of cases with very short lives. On the right-hand side, most of the states of the world give short lives, but a handful of longer lives drag the average up to 50 years.

The key question here is what should a regulator, required under the Revenue and Pricing Principles to provide a "reasonable opportunity" to recover efficiently incurred capex allow in respect of asset lives for the purposes of depreciation? The AER's approach, so far as we can understand it, would be to give both networks (or the same network at different points in time) the same regulatory asset life of 50 years.

We do not consider that this does, or can, meet the Revenue and Pricing Principles, because time matters. In the left-hand panel, there are many states of the world where the asset life is longer than 50 years so, (assuming the distribution of future states of the world do not change through time) then at the average asset life of 50 years, there are still many states of the world where the asset has a longer life. By contrast, in the right-hand panel at the same point in time, there are much fewer future states where this is true.

If the AER is allowing a 50-year asset life for depreciation in each case, then it cannot be defining "reasonable" in the same way for each network; or for the same network at different points in time. In respect of our AGN SA network, our basic premise is that, in prior AA periods, the set of "states of the world" which we could have conceivably faced looked a lot more like the left-hand panel. They have now changed to look a lot more like the right-hand panel. If the AER, therefore, makes no changes to depreciation on the grounds that expected asset lives has not changed, it has just transferred risk from customers to the network. This is the basis of our concern, and why we consider that, despite the use of the word "expected" in NGR 89(1)(c), to meet the Revenue and Pricing Principles, the AER must consider changes in risk.

Changes in economic lives – length and nature

In respect of the length and characteristics or nature of economic lives, we consider that both can change, and both are important. This is an issue which Incenta pick up in their expert report (see Attachment 6.6 pp 6-7), noting how both length and characteristics are important.

If a network was in a situation where its market situation was basically the same all throughout its life until some exogenous shock came along and drove its value to zero (say a policy change which required network closure by a certain point in time; in a world where few or no customers leave before that date), then all the AER would need to consider is the length of economic lives and, in the event that a shock became likely, shorten the lives to the length determined by the shock.

However, that is not the reality faced by any network at this point. In reality, the nature and characteristics of the economic life changes because the world changes. This could be, as in the WoOPS model (see Section 1.4.3) because of cost-reducing technological change in substitutes, or it could be because customers are leaving the network pushing building block prices up so that fewer customers are willing to pay the building block price, causing a death spiral. This was something recognised by the AER in its 2021 Information Paper.[60]

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[60] *See AER 2021, Regulating Pipelines Under Uncertainty: Information Paper, November 2021, pp24-5, available here.*

There is also an additional, more subtle point. One perspective a regulator could take is that it reacts solely to exogenous forces; the market drives prices of a substitute down so the AER changes the depreciation profile to keep prices below the substitute for example, or it changes the length of economic lives to meet a decarbonisation goal. However, this is not the only perspective. By changing depreciation profiles, specifically, by allowing more depreciation closer to the present so that prices in the future fall, the AER can extend economic lives. Put differently, by bringing depreciation forward and influencing future prices, it can allow each asset in a network to serve its full technical life with no redundancy in the future. This was the basic insight behind our use of the tilt function both in 2022 with our Victorian networks and our current proposal with AGN SA and is in fact the reason why we have not shortened the economic lives with the tilt.[61]

It is not clear what position the AER is taking on changes to the characteristics of economic lives. It accepted the tilt function we used in our 2022 proposal for our Victorian networks and has not opined on the suitability of the function itself in the AGN SA case. It has rejected Evoenergy's use of a "sum of the digits" depreciation approach, but it does not appear that it has done so purely because it does change the characteristics of Evoenergy's asset lives.[62] In its own real price path approach, it adds additional depreciation to a change in asset lives, but it is not clear whether it considers the issues noted above when it does so. We would urge the AER to consider how changing the characteristics of the economic life in its decisions can effectively change the economic lives of the assets it regulates and allow them to provide benefits to customers for longer.

"Significant" risk reductions

In the section above, we outline why the AER should consider risk, as well as expected economic lives in order to determine whether a claim to recover efficiently incurred capex is reasonable or not. The issues are given concrete form in our Draft Decision where the AER suggests (Attachment 1 p15) that:

> *While AGN's modelling shows some level of stranding risk at 2050, we do not consider that its modelling provides sufficient evidence to suggest that AGN's network faces a significant stranding risk in the long term that needs to be addressed through accelerated depreciation in the 2026–31 period to ensure they have reasonable opportunity to recover efficient costs.*

We understand the AER's perspective to be that, because a majority of cases in our modelling do not strand prior to 2050, this indicates that the risk of stranding is not "significant". We consider that a risk of stranding of 34 percent is "significant" and Incenta, (Attachment 6.6 – p 8) report that it certainly meets a threshold for action.

We therefore consider that the AER should:

- Consider risk as well as just expected economic lives when it makes its decisions.

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[61] Note that the two are not inconsistent in the sense that with a tilt there should be no shortening of lives, as one may do both. But they are an alternative. Note also that a regulator may use a tilt deliberately to extend lives, or this may just be a consequence of using the tilt function.

[62] See Attachment 1 p21 f the Evoenergy Draft Decision. It is perhaps more accurate to say that the AER does not accept the particular change in characteristics of that particular function, rather than a principled rejection of all changes away from straight line.

- Explain, if 34 percent is not significant, what threshold of asset stranding risk it does consider significant and also:
  - How this threshold meets the threshold of a reasonable opportunity to recover efficiently incurred capex as required in the Revenue and Pricing Principles; and
  - How it represents a continuity of the risk profile which networks have faced in the past and which has therefore been factored into the decisions under which investment was made, to ensure that this is not a new risk level that will impact future investment.
- How other aspects of its decision-making are consistent with this decision. For example, it is difficult to see how, in its RoRI process, the AER could continue to assume that gas networks have a BBB+ credit rating if the approach to depreciation suggests that a one-third probability of, essentially, default, is not significant.[63]

In this context, we note the conclusions of Incenta (Attachment 6.6 p 8) who point out, given the asymmetric risks involved, that a high threshold for change, which acts to prevent early action, is unlikely to enable the regulator to meet the long run interests of consumers; particularly in the context of depreciation which does not impose additional costs to consumers as a whole, but merely redistributes costs.

All of this is to say that the AER needs to establish an appropriate trigger for action on depreciation and does not answer the question as to how large that action should be. In our Final Plan, we put forward the change in depreciation that is consistent with the smallest reduction in the risks of stranding, for the reasons we discuss in Section 1.4.11.4.1; where we also note that the South Australia Reference Group advocate for a larger reduction in risk. Once it has answered the question on the threshold for action, we would expect the AER to make its own considerations in respect of what that action should be.

Economic and physical asset stranding and the role of additional depreciation

In its 2021 paper on Regulating Gas Pipelines Under Uncertainty, the AER is very clear that the stranding risk it is seeking to address is economic asset stranding. The AER notes (pp 24-5):

> *Stranded assets are investments that are no longer able to earn an economic return prior to the end of their economic life as assumed at the investment decision point. Their economic life may be curtailed due to either changes in technology, regulation, market changes, or some combinations of these.*
>
> *Economic stranding of assets is caused by a change in relative costs or prices. It refers to unused or underutilised assets to such a degree that the owner cannot recover a full return of and on capital. It is distinct from physical stranding, which refers to an asset that ceases to be used because of reasons such as obsolescence, failure, damage etc. The regulatory framework allows for assets to stay in the RAB even if they have become physically stranded, although there are*

[63] *For context, we note that the average annual default rate for sub investment grade debt is roughly 3 percent for US firms over the last 30 years, according to Moodys (available here, see p26) is about 3 percent whilst, for European firms, it is less than 2 percent (ibid, p27). This risk increases with the time horizon. The highest rated investment grade debt has a cumulative risk of default of around 20 percent over 10 years, which is almost 5 times as high as the cumulative rate for the lowest investment grade debt (see calculations here).*

provisions in the NGR to allow the exclusion of a redundant asset that is no longer used from the RAB.

Provided that customers can switch from gas with little or no transaction cost, end-user gas prices (which includes gas access prices amongst other things) would be constrained by customers' willingness to pay for gas and/or the prices offered by competitive gas substitutes such as electricity. If the constraints on gas prices become sufficiently strong such that gas becomes relatively uncompetitive, then with falling demand, regulated revenues for regulated businesses may not support full cost recovery of the RAB. In this scenario, the network business will under recover the amounts it has invested over the life of its assets, including a normal rate of return on those capital investments.

The focus on economic asset stranding is made clear when the AER talks about the recovery of "a full return of and on capital" and about network prices being constrained by "customers' willingness to pay for gas and/or the prices offered by competitive gas substitutes such as electricity". Additionally, the AER, when it refers to assets which are "underutilised or unused" (rather than just referring to unused assets) is clearly aware that economic asset stranding runs all the way from zero to a completely stranded asset, and is therefore aware of the basic notion of partial asset recovery in the WoOPS model (see Section 1.4.11.4.3).[64] As we discuss below, it is no longer clear whether this is the case.

The AER's position in 2021 is consistent with the economic literature as it pertains to changes in depreciation that deal with market forces which remove or reduce the competitive advantage of a hitherto monopoly service. Crew and Kleindorfer note that:[65]

Section 2 provides an optimization model which illustrates the rather general applicability of the concepts of economic depreciation and relates these to competitive firms, to the RoR firm facing technological progress, and to the price-level regulated firm. It is shown that, under conditions of competition and technological progress, front-loading of capital recovery is essential if the regulated firm is to remain viable. In addition, if the introduction of accelerated capital recovery is delayed by regulators, they may effectively vitiate any opportunity of the firm to recover its invested capital. The breathing space, or period of time, that the regulators can delay introducing the application of efficient capital recovery without ultimately compromising the firm's ability to recover its invested capital is called the "Window of Opportunity" (WOO). This same window of opportunity requires that the level of depreciation initially be set optimally. There are limited opportunities in the future, under technological change and competition, to rectify mistakes made now. Thus, in the case of price-cap regulation, if depreciation is set solely based upon the status quo, the initial price cap may be set at too low a level to allow full capital recovery. It is critical to make this distinction if economic regulation is to function effectively.

Finally, as Incenta point out in their Expert Report (Attachment 6.6 – p 6), it is possible to have physical asset stranding without economic asset stranding (that is, an asset is no longer used, but all of its incurred costs have been recovered); just as it is possible to have a degree of

[64] *This must be the case, the AER cites the paper on p40 of its Information Paper.*
[65] *See Crew, MA and Kleindorfer, PR, 1992, "Economic Depreciation and the Regulated Firm under Competition and Technological Change", Journal of Regulatory Economics, **4**, 51–61, p52 available here.*

economic asset stranding without physical asset stranding. A focus on physical asset stranding would miss this point and hence point the change in depreciation towards the wrong thing.

We discuss this at length in our submission to the AEMC.[66] Briefly, a focus on physical stranding misses the damage which can eventuate from economic asset stranding by assuming that assets that continue to be used do so at prices which support their construction cost. It is a failure to understand the difference between the two concepts, which is a key reason why we consider the ECA and JEC proposed rule changes to be flawed.

However, it is not clear in the AGN SA Draft Decision, whether the AER's view on the distinction between economic and physical asset stranding has changed. On p12 of Attachment 1, the AER suggests that:

> *We do not consider there to be sufficient evidence at this time to suggest that AGN's network faces significant asset stranding risk that needs to be addressed through accelerated depreciation to provide AGN reasonable opportunity to recover its efficient costs. Both the policy environment in South Australia and AGN's overall proposal suggest that AGN's gas network is expected to play a continued role in the transition to net zero.*

This suggests a view from the AER that a network which continues to play a role cannot become stranded, and it suggests that the AER does not take into account the prices that can be charged in a market where competitive forces prevail.

It goes further on p13, noting that:

> *Under its current policy settings and energy generation, South Australia has already met 100% of its operational demand from renewable resources on 180 days (49%) of the year in 2021 and is aiming to achieve 100% net renewable energy generation by 2027. This indicates that South Australia can maintain the operation of its gas distribution network while still meeting its net renewables and zero emissions targets.*

And finally on p17, that:

> *AGN's proposed capital expenditure program adds around $100 million to the asset base each year. It also includes capex related to renewable gas and hydrogen adaption. AGN submitted that its proposed additional depreciation and renewable gas capex must go together, as its network is unlikely to be competitive without continued expenditure to grow its network and provide renewable gas options.*
>
> *We consider that AGN's proposal for accelerated depreciation is inconsistent with a forecast capex program that is aimed at growing its network and preparing for a renewable gas future.*

It appears to us that the AER holds the view that economic asset stranding occurs when an asset is available to be used (that is, it was technically able to be used), but there are no customers left. This, to our understanding, represent physical asset stranding. It also ignores all cases where customers do exist but are unwilling or unable to pay a price which covers the cost of building the asset.

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[66] *Available here, see in particular, the discussion on pp33-36 of the collated pdf document (Sections 2.1 and 2.2 of Attachment 1 of our submission)*

It appears that the AER now believes that changes in depreciation should only be made when a network is on a pathway to closure (whether it be due to market or policy forces) and that it should not play any role as part of a way to keep a network sustainable into the future by allowing change in the future price of services. In the context of Section 1.4.11.4.1, the AER appears to believe that additional depreciation should only be used when networks are likely to close, and not to make them more viable (see discussion in Section 1.4.1 on our three-part framework).

This is an issue we discuss in more detail in Section 1.4.1 where we discuss our three-part framework, and the poor incentives and negative customer outcomes a focus on changing depreciation only in cases where a network is headed for closure can bring. We treated the issue more formally in our 2021 proposal to the ERA for our DBNGP asset where we highlighted the consequences of a situation where the regulator does not take into account how regulatory action interacts with economic lives and may falsely conclude that they have lengthened when they can only lengthen with regulatory action supporting more depreciation earlier in their lives.[67]

A focus on economic depreciation, and more particularly on working out how to make a network sustainable into the long run with changes to depreciation today also lessens the burden on customers of regulated services; now and into the future. If a network can support 50 percent of its value in a post-regulation, competitive marketplace, then the regulator needs only to consider 50 percent of the RAB, not the whole RAB. By focussing on depreciation only in cases of network failure, the AER risks allowing too much additional depreciation, as well as causing customers to lose options given by a sustainable network. This is a key part of the 3-part framework we present in our Final Plan and in Section 1.4.1

Finally, partly because the problem is very much bigger when the AER focuses on cases of network failure, the requirement for certainty is higher. Moreover, the needs of future customers automatically weigh less because there will not be any of them. This may make the AER more likely to fail to act until levels of certainty are very high, and effectively miss its window to act, or to focus only on short term prices (See Section 1.4.30). For this reason, we consider that the AER should focus on how depreciation can help sustain a network by dealing with economic asset stranding, rather than just applying it when a network is likely to be subject to physical asset stranding in future.

The risk mitigation motivation for $70 million in additional depreciation

One reason the AER gives for doing nothing in respect of depreciation is that it appears to consider depreciation will not change results substantially, noting (DD Attachment 1, p15):

> *As shown in Figure 1.4, without any accelerated depreciation in the 2026–31 period, AGN's modelling suggests there is around 34% likelihood of a stranding occurring before 2050. Even if $270 million accelerated depreciation (which accounts for about 13% of its opening capital base) is applied in the 2026–31 period, the likelihood of stranding by 2050 across the scenarios tested will only be moderately reduced to 27%*

[67] *See Attachment 9.7 to our revised Final Plan to the ERA in 2021 (available here, pp9-16), which is based upon an expert report (Attachment 9.9, available here). Our subsequent use of a tilted depreciation profile is submissions to the AER (for AGN and Multinet in Victoria, and the current AGN SA proposal) represents a step forward from the kinked schedule we suggested in the ERA process.*

We discuss in Section 1.4.1 our views in respect of risk balancing across different potential future states of the world, and the creation of options and flexibility for customers. As we explain there (and in our Final Plan, see pp 69-70), our decision to ask for the minimum amount of depreciation that would start to change risk levels is consistent with our more optimistic views about renewable gas. If we did not hold these views, we would, like our SARG did, focus more on options to protect downside risks associated with eventual network closure, and request much more additional depreciation (see Section 1.4.1 and the discussion on differing views on real options).

The AER's statement that our proposed depreciation amount makes little difference suggests it shares the SARG's view about the likely future success of renewable gas. However, this is not logically consistent with then allowing zero additional depreciation. Rather, the logical approach would have been that which the SARG suggests, insisting upon more (see Section 1.4.1 and the discussion on real options).

Finally, we do not consider it logical to assert that a one third risk of total RAB loss prior to 2050 is not significant on the one hand and then argue against a small amount of additional depreciation on the grounds that it would make little difference on the other. These two decisions do not appear to be consistent with each other.

Evidence and other means of addressing future risk

The AER suggests that changes to depreciation are not the only means of addressing risk about the future. We agree. As we discuss in Section 1.4.1, there are several options, including changes to capex, changes to depreciation and seeking other non-regulated markets which can help address the basic problem of the size of the RAB exposed to future risk. There we outline how our consideration of these approaches has led directly to a smaller depreciation ask than would have been the case had we not sought these other measures.

In the Draft Decision, the AER is less specific referring to "other measures", but the only measure we can see Attachment 1 of the Draft Decision referring to are changes in capex (see in particular pp16-18). The AER states that its modelling suggests that capex reductions of 25 to 30 percent would be sufficient to meet the 2050 target of $1 billion, and that the capex reductions in its Draft Decision would likewise be sufficient (see p15 of Attachment 1) and the AER notes the possibility that "different expenditure approaches that might reach this ($1 billion by 2050) capital base level without requiring accelerated depreciation" (ibid p16).

We understand that the AER applied an arbitrary reduction in capex (that is, it did not seek to understand whether or not it would be feasible to make the capex reduction, given the need to maintain the network) of 25 to 50 percent in each of the three "central" cases of gas and electricity prices for Price Bundle 1, 2 and 3, and then tested what the model said the RAB would be in 2050 to form its views about the adequacy of capex alone to meet the RAB value which can be supported in future.[68]

The AER may not have interpreted its modelling results consistently. There are three key outputs to the model (see p34 of Attachment 6.1 of our Final Plan); the RAB at 2050 (which the AER has used), the "compromised asset date" (which is the date at which cash flows go negative) and the network charge. The first two are key here; the fact that there is a dollar

[68] *We used the @Risk software to run 1000 simulations for each of these price bundles. The AER did not have access to this software and so we prepared a version of the model with the @Risk functions switched off. This took away a lot of the nuances of our assessments of model outcomes.*

value of the RAB for 2050 does not mean that the network is a going concern in 2050. In a given simulation, if the RAB at 2050 showed $2 billion and the "compromised asset date" showed 2045, this would mean that the network would have gone out of business in 2045, with $2 billion of RAB value still remaining unrecovered in 2050. This is a situation of unrecovered assets being stranded.

When we replicate what the AER did, using the version of the model it used, we get the results shown in Table 1.5.

Table 1.5: Capex and asset stranding

	Unrecovered RAB in 2050 ($ mil)	Compromised asset date
No capex reduction		
Price bundle 1	$1,504	2075
Price bundle 2	$1,151	2041
Price bundle 3	$1,132	2029
25 percent capex reduction		
Price bundle 1	$1,300	2075
Price bundle 2	$1,038	2042
Price bundle 3	$1,018	2029
35 percent capex reduction		
Price bundle 1	$1,218	2075
Price bundle 2	$989	2042
Price bundle 3	$973	2029
50 percent capex reduction		
Price bundle 1	$1,096	2075
Price bundle 2	$921	2043
Price bundle 3	$886	2030

What this means, in the case of a 25 percent capex reduction, under Price Bundle 2 (which is where the price settings favour electricity), the unrecovered RAB at 2050 is $1.04 billion (as the AER has found), but the network has effectively gone out of business in 2042 with negative cashflows and that $1.04 billion is a stranded asset and not an indication that the network has an ongoing value of $1 billion post 2050. For Price bundle 3 (which has the same electricity prices but assumes customers choose cheaper appliances (see Attachment 6.1 of the Final Plan, p23), the network is stranded even sooner.

Since we simulate price combinations around the three central price "bundles", we end up with fewer than two-thirds of cases where the network strands before 2050 (34 percent with no additional depreciation, as the AER points out); this is in fact why we used a simulation approach. However, far from showing that the network is sustainable with no additional depreciation provided capex is reduced, what the AER's analysis actually shows is that, even with significant capex reductions (up to 50 percent), in most cases, the network will suffer economic asset stranding absent of action on depreciation.

Consistency between additional depreciation and network growth

The AER suggests (Attachment 1 pp16-17) that its decision to disallow any additional depreciation is "consistent" with its decision to allow augmentation capex ($6.4 million) and renewable gas expenditure ($8 million), and further that additional depreciation would be "inconsistent" with a growing network. It appears from the discussion that network growth is the more important reason, and that the AER's basic point is that growing networks add to asset stranding risk, so that a network forecasting growth must therefore not require any additional depreciation.

In respect of renewable gas expenditure, this is an issue we discussed at length in our Final Plan where we explained that it is a "gateway" to future network sustainability in the sense that, without an ability to move renewable gas, we would lose our social licence to operate but that, even with renewable gas, we need to consider the price of delivered gas (See Attachment 6.1 pp8-9). We further discuss how the very modest spending on renewable gas creates real options for further investment if it is warranted and how additional depreciation today widens the span of renewable gas manufacturing prices that translate to competitive delivered prices in the future when the energy market is competitive in Section 1.4.1.

Our main focus here is on augmentation capex and network growth. We consider the approach in the Draft Decision to involve a mismatch in timing, benefits that have not been taken into account and inconsistency with other decisions.

The fact that customers are still requesting connections does not mean that there is no need to consider additional depreciation. A residential customer typically has gas appliances which last for roughly 15 years. This means that a customer who fully intends to be all electric by 2045 may well be currently considering gas appliances and a gas connection; to use for 15 years before, say, waiting for the next generation of electric appliances (or solar and batteries to power them) so they can electrify. By contrast, it is precisely to manage the risks in the post 2045 world, when our much longer-lived assets are exposed to higher levels of risk than they are at present because the new customer who connects to the network today is gone by 2040, that we are considering changes to depreciation now.[69] If we were to wait until there was no network growth at all, then we would essentially have a maximum of 15 years (for our residential customers, at least) left before the last customer who has joined the network makes a choice to replace the gas appliances they purchased when joining the network or to electrify. This is far too little to have any meaningful chance of recovering our invested capital. If the AER's criteria is to do nothing until network growth ceases, then it will almost certainly cause the window for action to close.

Incenta, in their expert report (Attachment 6.6 – p 9) also note the timing difference between customers and networks in terms of risk, and the benefits which can come from network expansion in some instances where additional depreciation is required. They also note that, if the AER has concerns with the efficiency of capex, it should address that issue in its own right, rather than modifying depreciation.

Secondly, the AER is also potentially missing a benefit for existing customers, and an additional way to lower the cost of the energy transition for customers by linking additional depreciation to network growth in the way that it has. In this Revised Proposal, we forecast roughly 30,500 new residential customers will join the network over the forthcoming AA period.[70] This compares

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[69] The AER appears to pick up on precisely this issue in its 2021 Information Paper (see p viii and 51).
[70] This is the gross number of new connections, but it is this gross number which would be missing if growth was zero.

to roughly 431,700 customers who would be connected to the network at the end of the AA absent of these new arrivals.

The new arrivals will pay the full cost of their connection to the network, so this will not impact the RAB at all.[71] We are forecasting $6.4 million in augmentation capex to cover two areas of potential low pressure at the edges of the network (Angle Vale, roughly $4 million in spending and Seaforth Aldinga, roughly $2 million in spending) where most of these new connections will be occurring. If we allocate 100 percent of that new capex to the new customers, then absent of the arrival of the new customers, the 431,700 customers who would be connected to the network at the end of the AA would share the $1.983 billion closing RAB (excluding the $6.4 million in new augmentation capex) amongst themselves, making a share of $4,594 per customer. By contrast, if the 30,500 new customers arrive, by the end of the AA, the RAB is $1.989 billion (including the augmentation capex), customer numbers are 462,200, and the RAB per customer is $4,301. That is, existing customers (because all customers share the RAB equally) save $290 per existing customer, or roughly $125 million overall.

This is a considerable saving in RAB per customer for existing customers; $6.4 million is added to the RAB to deliver a saving associated with RAB per customer for existing customers of roughly $125 million. It shows that new customers *can*, as they do here, represent a benefit to existing customers, lowering their bills through time.

We note that it is lower bills through time which leads to less need for additional depreciation today, because lower bills mean less risk of economic asset stranding in the future. So, far from being mutually exclusive to additional depreciation, network growth today (provided it is not imposing additional costs on current consumers) is simply another tool which can be used to lower future prices.

By setting up the dichotomy, the AER implies a choice as to either accept new connections or reduce risk by increasing depreciation. We consider this to be to the detriment of both current and future consumers, because, if risk is lowered via additional depreciation (for the reasons around timing differences outlined above), current consumers will end up paying more, and if there is network growth more long-term risk, future customers will pay more. Both tools working together help lower prices for all customers.

Network growth and additional depreciation are complementary actions to support a sustainable business now and into the future. This future is further supported where we take prudent actions to facilitate the delivery of renewable gas.

Finally, we note that the AER's apparent position of zero or near zero new customer growth (noting that the actual impact on the RAB will be only roughly $6.4 million in augex over the forthcoming AA) is not consistent with other decisions made by the AER. In its most recent Jemena decision, the AER allowed additional depreciation, despite net new customer growth over the AA period of around 20,000 residential customers or roughly 1.4 percent of the number of customers at the start of the AA period;[72] and this in a context where those new customers would not, under the rules as they existed at the time, pay their connection costs. Our projected net customer growth in this Revised Final Plan (see Attachment 13.2A) represents a decline of

[71] *Given the timing of the rule changes, and the fact that some customers who actually connect during the new AA period have arranged their new connection under the existing rules, there will be some new connections in the forthcoming AA period which will enter the RAB. We estimate this one-off transition effect as being roughly $9.5 million in RAB growth.*
[72] *See Attachment 12, p2 (available here). Note that Table 21.1 shows a percentage increase of 0.17% over the period. This appears to be a typographical error; the final number of residential customers is 1,523,482, which is 20,581 more than the starting number of 1,520,901, or 1.37%. Commercial customers, in the same table, fall by 953, or 2.8 percent.*

3.3 percent of our customer base at the start of the next AA by the end of the AA.[73] These two decisions do not appear to be consistent with one another.

1.4.3 Observations across the AGN SA and Evoenergy decisions

Ordinarily we would focus our response only on the AER's decision in respect of our own network, and not on other decisions which might have been made at the same time. However, in this instance, we consider it important to look across both the AGN SA and Evoenergy Draft Decisions, as they give an indication of how the AER will approach depreciation in different environments.

The two networks can be considered as "bookends"; policy forces for Evoenergy will see it forced to close by 2045, whereas we consider the AGN SA network (absent of adverse future policy changes) has the potential to remain sustainable. However, if our views in respect of AGN SA turn out to be incorrect, Evoenergy provides an indication of how the AER may reason in future. Additionally, our next decisions are for our Victorian networks, which face a policy framework more similar to the ACT than to SA. We therefore consider it important to deal with some of the issues we see across both decisions.

Our concerns are:

- The AER's "real price path approach", which began in the last Victorian Gas Access Arrangement reviews, appears to have become the AER's preferred approach, despite almost all stakeholders noting issues with it. Key amongst our concerns are the focus on current price changes at the expense of the long run, and the limited evidence basis of the AER's conclusions.
- Considering AGN SA and Evoenergy together gives rise to concerns about a lack of clarity from the AER around the "window" within which it is prepared to use depreciation as a risk mitigation tool. Our concern is that the AER may delay action so long that, by the time it is willing to act, it will be unable to make much difference in respect of risk, and opportunities for customers will be closed off as a result.
- The AER's apparent willingness to alter the nature of the regulatory compact without a strong and transparent evidence base for doing so gives rise to have significant concerns for investment and the financeability of the Australian energy sector.

The real price path approach

The AER's "real price path" approach was first applied in our Victorian Access Arrangement decisions in 2023, where the AER first suggested a zero percent price change in our Draft Decision, which was then raised to 1.5 percent in the Final Decision. It was not clear at the time whether this approach was a temporary measure for the Victorian networks, or whether the AER intended it to form a more permanent part of its toolkit. The AER noted:[74]

> *For the reasons discussed in section 4.4.2.2.1, our final decision is to apply a higher base real price path constraint than the draft decision constraint of 0% per*

[73] *479,000 customers at the start of 2026/27, down to 462,200 at the end of the AA. Table 1.4 in Attachment 13.4 shows average customer numbers in each year. If these are compared, it is a decline of 2.6 percent in customer numbers; it is not clear whether the Jemena data are from the opening at the start of the AA to the end of the AA, or are average customer numbers each year.*

[74] *See p10 of Attachment 4 of the AGN Victoria Final Decision, available here.*

> *annum. Further, as discussed in section 4.4.2.1, we acknowledge that AGN's long term future of gas modelling supports the case for accelerated depreciation in the 2023–28 period. We also note that in applying a 1.5% per annum constraint for this final decision, we are not making a decision on the approach for subsequent access arrangement periods.*

The Jemena decision added a two-step component to the real price path approach whereby the AER first looks at shortening asset lives and then, if this is not sufficient, adding extra depreciation until it is.[75] The total amount of additional depreciation allowed is to remain within a "guard-rail" established via regulatory judgement and taking into consideration the various factors the AER deems relevant to the particular decision which, in practical terms, seems to be focussed mostly on the AER's views of different gas policy settings amongst jurisdictions.[76]

The AER's view of its approach is outlined in its submission to the AEMC's current rule change process considering depreciation, where the AER says that:[77]

> *We consider our approach to approving some accelerated depreciation strikes the right balance. Our approach is consistent with approaches taken by economic regulators in other parts of the world in respect of their gas networks where there is, or is expected to be, declining network use. As a regulatory tool, accelerated depreciation provides flexibility for the future if demand doesn't decline as expected. We have been considering these issues for some time, as set out in our information paper Regulating gas pipelines under uncertainty. As we and others have noted, economic regulators have limited levers with which to manage asset stranding risk, due to bill impacts for customers and impacts on the incentives for distributors to continue to provide services.*
>
> *In undertaking our regulatory responsibility to assess depreciation proposals we have explicitly considered the bill impact on customers of accelerated depreciation being passed through to gas retail offers. In determining the amount of accelerated depreciation, we have applied a limit on the real network tariff increase as a guardrail to ensure price stability and affordability during the energy transition. Our approach also manages risk of triggering a rush of customers leaving gas networks that could in turn leave remaining gas customers (including vulnerable customers) with the burden of high per unit network costs, and place increasing pressure on the existing electricity network and supply.*

We have concerns with a number of aspects of the AER's approach, not least its congruence with regulatory practice on depreciation elsewhere and the degree to which it "manages the risk of triggering a rush of gas customers leaving gas networks".

We understand other stakeholders to also hold concerns with the approach. In the AGN SA process, the SARG said:[78]

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[75] *See p10 of Attachment 4 of the Jemena Final Decision, available here. The "baseline" which comes from shortening assets lives amounts to $77 million, with an additional $38 million applied (ibid p7).*

[76] *We find the AER's reasoning in its decisions hard to follow when it describes how it reached a given guardrail and even, sometimes, what the guard-rail actually is. For example, the "guardrail" of 0.5 percent applied to Jemena appears intended to include both the shortening of asset lives and the additional depreciation (see p15 of Attachment 4 of the Jemena Final Decision available here), but then in Table 4.5 the AER show $115 million as leading to a 1 percent real price increase, but with this including incentives (see ibid, p17-18). It is also unclear why 0.5 percent is correct save that 0 percent (from the Draft Decision) was too low, and that a better policy environment in NSW compared to Victoria meant that 1.5 percent was too high.*

[77] *Available here, p7.*

[78] *See pp19-20 of the SARG submission to our Final Plan, available here. Note that "this approach" in the quotation refers to the approach the AER took in its Jemena decision.*

> *The Panel would suggest that this approach has its limitations eg:*
>
> - *Changes in other variables outside of the network's or the AER's control eg WACC can leave little or no ability to have accelerated depreciation which the AER agrees is required. This was the case for the Jemena decision. Subsequent to selecting a 0% cap in its Draft Decision, the AER found that a higher WACC and lower expected inflation increased the total revenue by 2.7%. Maintaining the 0% cap would only allow the baseline $77m accelerated depreciation that the AER saw as too low. Having the 0.5% cap meant accelerated depreciation increased to $115m, still less than the $157m in their Draft Decision. What if these uncontrollable factors change over the course of AGN's AA? Will the cap be adjusted?*
> - *Finetuning small changes in network costs may have little impact on the total bill when the commodity component of the bill is increasing strongly; this has been the case in the last five years and is expected to continue being the case for 2026-31 with the network component has fallen in real terms in the current period and is flat in real terms in 2026-31*
>
> *For example, a $70m accelerated depreciation would result in a one off 2.5% increase in the total bill for an average residential customer - $28 on $1,120. We invite the AER to consider whether a cap higher than 0.5% still results in a reasonable trade-off between intergenerational equity and current consumer affordability.*

Additionally, the ECA, as part of its motivation for its rule change proposal, noted its own concerns about the shortcomings of the AER's approach, suggesting:[79]

> *The AER appears to have adopted a heuristic that limits the amount of accelerated depreciation to an amount that does not result in material real price increases for customers. The AER describes this as a "price path approach" and considers it appropriate "because it allows the AER to balance accelerated depreciation price impacts on consumers and uncertainty around demand forecasts and policy developments." The price path approach is not hard and fast - while at the draft decision stage of the Victorian gas distribution network 2023-28 Access Arrangements, the AER set a limit of 0 per cent real price increase, at the final decision it allowed a 1.5 per cent real increase.*
>
> *Regardless of the arguable merits of this approach, it has the following implications:*
>
> - *A price path approach cannot entirely reduce the asset stranding risk (see below for further discussion of the very limited effectiveness of accelerated depreciation in achieving this outcome).*
> - *Because the constraint is based on price impacts in the short run, it avoids any consideration on what the split of stranded asset risk should be between gas distribution networks and their customers (let alone governments - noting that the AER cannot compel governments to contribute).*
> - *Further, the constraint is influenced by the other components of the building blocks that go to make up the final decision. A gas distribution network with higher opex and capex (relative to its existing RAB) than its peers will thus be*

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[79] See the ECA's proposed rule change to the AEMC on depreciation, pp 16-17, available [here](). It is difficult to reconcile consumer representatives citing dissatisfaction with the AER's approach in their motivation for a rule change on the one hand with the AER's own confidence in its approach on the other.

allowed less accelerated depreciation. This can be seen in the Victorian decision, where Multinet's accelerated depreciation allowance was considerably less as a proportion of its RAB than the other two gas distribution networks. This is because Multinet had a higher capex allowance, largely due to its more extensive repex program. In this instance, accelerated depreciation is being applied in a way that illustrates that it is not – on its own – able to avoid asset stranding, given that if Multinet has higher ongoing capex requirements, then it is at greater risk of asset stranding.

- *This characteristic of the price path approach could in principle serve as a useful incentive for gas distribution networks to take further steps to reduce their ongoing and future expenditure requirements. This would create greater "headroom" for higher levels of accelerated depreciation and thus lower their asset stranding risk. Further, it's unclear how effective this incentive is, given that it is not a hard and fast rule. While any reduction in capex has the potential to reduce stranding asset risk, for consumers any potential savings would be offset by higher levels of accelerated depreciation. In other words, the only outcome is for consumers to lose.*

We share the concerns that other stakeholders have (if not always their solutions) with the AER's real price path approach. In respect of the ECA's views above we highlight in particular our agreement with their concerns about how the AER's approach artificially limits it when considering depreciation, due to movements in other building blocks (like WACC) which are irrelevant to the long run asset stranding risks to be dealt with by changing depreciation. We note that our SARG shared the same view. The AER, by contrast, appear to consider this aspect of its approach as a feature which supports price stability, which is difficult to reconcile with the views of other stakeholders.[80]

Overall, however, our major concern is with the lack of a robust evidence base for the AER's approach by which it arrives at the "guard-rail" for the real price change for any given decision; certainly it is hard to see how the AER's approach could meet its expectations for arguments for additional depreciation put forward by networks, outlined in its 2021 information paper.[81]

To outline our concern, we discuss in more detail the approach the AER takes in its Evoenergy Draft Decision, where it has allowed some additional depreciation (as distinct from the AGN SA decision) and hence has a "guard-rail".

Guard-rails in the Evoenergy decision

To begin, we note that, in the Evoenergy Draft Decision, the AER motivates its approach by presenting a straw-man alternative, noting that (p20):

> *There is a real risk that adopting a policy of accelerating depreciation, without clearly defined limits, would be likely to result in large and repeated increases in future gas prices. This would not align with the long-term interests of customers, as it risks the use of the network (including the number of customers) declining faster than anticipated, which further increases the risk of asset stranding and of costs being borne by an even smaller number of customers in the future.*

[80] *See p21 of Attachment 1 of the Evoenergy Draft Decision.*
[81] *See AER, 2021, Regulating Pipelines Under Uncertainty: Information paper, November 2021, available here, p45.*

We agree that a price rise or a series of price rises without limits would be inappropriate.[82] However the key issue is what limit should be applied? Whichever limit is chosen, it must be backed by robust and transparent evidence and reasoning to promote stakeholder confidence.

In the case of Evoenergy, the headline rate reported by the AER is 4 percent, but we understand that only 1.5 percent is due to additional depreciation.[83] This is a very tight limit for a network with an asset life dictated by policy at only 20 years and is below that which would be sufficient to give Evoenergy a "reasonable opportunity" (see discussion below) to recover its efficiently incurred capex.

Of particular concern is the way in which, despite the requirement in the National Gas Objective to look to the long run interests of consumers, the "real price path" approach focuses only on the short-term price changes associated with any additional depreciation. Moreover, there is no demonstration of testing of either the short or the long-term price effects of the AER's real price path approach in respect of how consumers might react to price changes caused by action or inaction.

While the AER assesses the price path that would eventuate under the Evoenergy proposal (see Attachment 1 p24), it only does so in the sense that it puts the prices into a long run building block model; demand scenarios in the AER's analysis are exogenously imposed rather than being derived as a consequence of consumers responding to prices. The AER motivates its assessment of different exogenous demand pathways in its long run PTRM model by challenging the long run demand forecast provided by Evoenergy (see Attachment 1 p22), and the stability of prices which would result. However, the key to robust assessment is not replacing one exogenous demand schedule with 6 but rather testing how consumers might react to price changes caused by changes to depreciation; demand is endogenous and driven by price. The AER has not undertaken this assessment.

Having dismissed Evoenergy's proposal, the AER then appears to move straight to its own proposed real price path without testing any alternatives in respect of how consumers might react to the price paths involved. Instead, it reasons (Attachment 1 p14) that:

> *Allowing accelerated depreciation is necessary to ensure that Evoenergy is not deterred from making efficient investments required to maintain safe and reliable services for an ageing network in the long-term interest of consumers. However, any amount of accelerated depreciation must be balanced against price impacts and affordability. There is a real risk that adopting a policy of accelerating depreciation, without clearly defined limits, would be likely to result in large and repeated increases in future gas prices. This would not align with the long-term interests of customers, as it risks the use of the network (including the number of customers) to decline faster than anticipated, which further increases the risk of asset stranding and of costs being borne by an even smaller number of customers in the future. As such, in determining the amount of accelerated depreciation for this draft decision, we have applied a 'base' real price increase limit of 4.0% as a guardrail.*

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[82] *We disagree with the AER's assertion that, once additional depreciation is allowed, it will lead to "large and repeated price increases" (Evoenergy Draft Decision, Attachment 1, p14) in future. We note the case of our DBNGP network in WA where, having received a change in depreciation in 2021, we deemed this to be sufficient, and asked for no extra depreciation in 2026 (see the ERA's decision, available here). Prices in the forthcoming AA are lower than they would have been without the change made to depreciation previously.*

[83] *We understand from discussions with Evoenergy that the 4 percent headline rate reported by the AER includes jurisdictional charges that were part of a cost pass-through in Evoenergy's proposal and which the AER has subsumed into opex, and that the actual price change due to the change in depreciation the AER proposes is more like 1.5 percent or roughly what the AER allowed for our Victorian networks.*

We have particular concern with the "as such" which begins the final sentence of the quotation above; there is nothing in the Evoenergy decision that we can see which underpins it, no analysis which leads from a concern about excessive price rises (what level of price rise in the short or long term would be excessive is likewise left unexamined) to a conclusion that a 4 percent real price increase (actually a 1.5 percent real price increase due to depreciation, as noted above) is the appropriate balance point, and not some other number. Why, for example, is 3 percent, or 5 percent not a better "guardrail"?

In respect of the short run price impacts, one approach would be to start with a relatively high price increase and test to see whether that would create excessive consumer disconnection leading to a death spiral situation by testing how consumers react to the price change from a depreciation change over the next AA period.[84] The same test with a smaller price increase could be run until the AER could satisfy itself that the price increase does not have an undue impact on customer disconnection. It does not appear that this sort of analysis or testing has been undertaken. The AER presents its approach as follows (Attachment 1 p27):

> *Our draft decision is to apply a 4.0% 'base' real price increase limit when determining the amount of accelerated depreciation. Setting this limit on price increases, in our judgment, best ensures the depreciation schedule will be adjusted consistent with the requirements of rule 89 of the NGR, in particular rule 89(1)(a).*
>
> *Table 1.5 demonstrates the price impact of accelerated depreciation in our draft decision compared to Evoenergy's proposal. Our draft decision results in a real price increase of 4.5%, after adding back the incentive scheme amounts. This translates to an increase in the average residential bill of $37 per annum for the 2026–31 period. Had we accepted Evoenergy's proposed $105 million of accelerated depreciation (including the use of the 'sum-of-the-years' digits depreciation method), the real price increases would be materially higher at 15.3% per annum. This translates to a significantly higher average residential bill increase of $118 per annum.*

Having established viable short term price changes, the AER could then look to the long term price consequences of the short-term price changes it believes are sustainable by again considering consumer reactions to price, but in the long run.[85] All else being equal, the lower is the price change now, the more RAB is left for recovery later, and the higher will be the prices which future customers, particularly if exogenous forces drive their numbers down, need to pay. It is not apparent that the AER has considered long run price consequences. Instead, the decision states that (Attachment 1 p27):

> *Therefore, we consider that a reduced accelerated depreciation amount of $47 million strikes a balance between the need for a meaningful level of accelerated depreciation to promote efficient investment, and the need to limit the price impact of accelerated depreciation on consumers, particularly for vulnerable customers and those facing challenges during the energy transition. It also shares some of the stranding risk between Evoenergy and a larger customer base while there is still an opportunity to do so.*

[84] *The AER could equally start low and increase prices; it is the testing, not the direction of price movement, which is key.*

[85] *Equally, the AER could start with the long-term price consequences, and then see the short run impacts, or it could iterate between the two. It is the testing of outcomes, not the order of testing, which matters. We note also that the short and long run consumer choice models could be contained in the same model, as they are in the AGN SA case.*

The AER does note (Attachment 1 pp 20-21) the in-principal issue of prices being too high or too low, and what that might do to efficient investment in and use of the network.[86] However, it does not appear to test either its own or Evoenergy's proposed price paths against these principles. On p21 it states that the "sum of the digits" approach "not dynamically link the level of depreciation with the revenue and price outcomes" as it does not allow the flexibility for reference tariffs to change, and notes the potential for its own approach to offer more flexibility, but the possibility that its own approach is more flexible is not a substitute for testing the real price path which the AER has settled upon.[87]

In their expert report (Attachment 6.6 – pp 3-4), Incenta note the arbitrary nature of the limits imposed by the AER, the lack of economic merit or any meaningful interpretation of the National Gas Rules. Incenta also note the lack of justification to do the kind of "balancing" between consumer and investor interests given that they are aligned in that consumer interests can only continue to be met if needed investment continues to come forth (see discussion below on the investment consequences of the AER's approach). Finally, Incenta note the AER's lack of consideration of the incentives of networks to charge high prices when demand is constrained, which leads the AER to impose limits where they may not be required.[88]

Our proposed approach

We consider that a more robust approach, for any proposal concerning a change in depreciation, is to test that change in a consumer choice model. That is, a model which tests how consumers react to a change in gas prices brought about by a change in depreciation, with a specific focus on whether it changes their decision to disconnect from or connect to the network. In this way, the hypothesis that a price change of X percent could lead to a death spiral as customers disconnect can be tested. If true, additional depreciation is reduced. We have proposed such a model in each of our proposals to the AER, including in our AGN SA proposal.

Not all networks have proposed such a model, and we accept that our model is not perfect. Moreover, we acknowledge that all the data needed for a perfect model may never be possible to gather. However, we consider that it is possible to develop a model which at least allows some bounds to be set, and to formally channel what evidence does exist into outcomes in a transparent way and, most importantly of all, to test both the proposals of networks and of the AER in a robust fashion.

We note that a consumer choice model does not remove all need for regulatory judgement. In the first instance, perfect data will never exist (although better data are emerging all the time as the energy transition takes hold and consumers change behaviour), and so the modelling will never give precise "optimal" results.

In the second instance, the model may say that a price rise of, for example, 20 percent for the next AA, is sustainable, but the AER may have other reasons why it considers that this level of price increase is not in keeping with the NGR. The model should not prevent the AER from

[86] *We note also that in Attachment 5 of its AGN SA Draft Decision (p11), the AER motivates flatter tariffs on the grounds that they would satisfy the emissions reduction requirements of the NGO by raising prices for higher gas consumption. More depreciation would also lower emissions by raising price, but the emissions reduction component of the NGO does not appear to be part of the AER's arguments around acceptable amounts of depreciation; in either the Evoenergy Draft Decision or that for AGN SA.*

[87] *We agree that a sum of the digits approach is not directly linked to producing prices which consumers will be willing to pay (as distinct from our tilt approach, which investigates price paths in this way quite explicitly), but the AER appears to be assuming that, once set in a sum of the digits approach, the depreciation schedule will never be changed in future. We note that the AER can change depreciation schedules at any AA and is not bound to continue with a sum-of-the-digits approach if it proves unviable. We therefore think this change of inflexibility is unjustified.*

[88] *The AER's 2021 information paper Regulating Gas Pipelines Under Uncertainty (available here) also picks up on this point; see p29*

exercising its discretion in these instances. However, the reasons for doing so must be clearly articulated in the context of the NGO and RPP so that all stakeholders can have confidence in the decision.

Closing windows for action on depreciation

A simple reading of the AGN SA and Evoenergy Draft Decisions together suggests that the AER considers it too soon to do anything the case of AGN SA, and too late to do anything substantive to deal with stranding risk in the case of Evoenergy. This raises the question of where the AER considers that the "window" for action in respect of depreciation lies. Most particularly, it highlights the risk that the AER, by waiting too long to "open the window" on depreciation (or not opening it enough when it does so), the AER may render the tool less effective than it could otherwise be.

The seminal work upon which changes to depreciation based on changes in market conditions is based is the Crew and Kleindofer paper which discussed a WoOPS or "Window of Opportunity Past".[89] The basic point of the authors, who are responding to an earlier paper by Schmalensee that suggested an "invariance" proposition for depreciation schedules,[90] is that, in a world where market power does not last forever, there is no invariance in depreciation schedules, but rather there is a window within which regulators can act before the (falling) prices of a substitute mean that changing depreciation schedules produce a regulatory building block price which is above the price of a substitute. When the window closes, regulation ceases to be an effective constraint on market power, as there is no market power to constrain. The WoOPS model, in other words, points to a limit for regulation, and formalises how regulators can act within that limit to allow for the maximum likelihood of asset recovery.[91]

Within the WoOPS framework, the opening and closing of the window on depreciation are linked. Simply put, since the RAB can only be depreciated once, the earlier the change to depreciation is made, the lower will be the future RAB and the longer the network will remain sustainable against the falling prices of its substitutes. Conceptually, if the window is opened early enough, then the regulatory building block price might end up being below that of a substitute for decades longer than would otherwise be the case.[92]

At present, there is very little clarity about when the AER might "open the window" for AGN SA on additional depreciation, which makes its longer-term sustainability questionable. More broadly, there is little clarity across decisions for different networks which might allow stakeholders to understand how wide the AER might open the window if and when it decides

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[89] 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.
[90] Schmalensee, R. 1989. "An Expository Note on Depreciation and Profitability Under Rate-of-Return Regulation." Journal of Regulatory Economics 1(3): pp293 -298, available here. This in itself suggests some caution in assuming that current depreciation schedules should be afforded some kind of special status, even absent of major market changes. For example, the JEC proposal to the AEMC requiring networks to show a particular asset might not be used in 20 years before being allowed any change in depreciation schedules appears out of step with the relevant economic theory and seems more in line with status-quo bias.
[91] Note that this does not mean that Crew and Kleindorfer's framework considers investors at the expense of customers; in fact it is the opportunities available to customers which set the limits.
[92] With this in mind, we disagree with the AER's assertion on p22 of Attachment 1 of the Evoenergy Draft Decision that "so long as demand continues to decline, no affordable amount of accelerated depreciation will be able to achieve long run price stability". This is mathematically unsound; if the decline in demand is exogenous, then for every demand pathway, there will be a corresponding flat price path, involving an initial price hike and then a flat price path which results from the decline in costs (driven chiefly by a falling return on and of capital as the RAB bets smaller) matching the decline in demand. Whether that initial price hike is "affordable" is a matter of the speed of demand decline and the willingness to pay on the part of consumers. Absolutist statements such as this one are unhelpful in managing the energy transition as they close off potential approaches before they are even assessed.

to do so, as we discuss in the preceding section where we outline the issues with the AER's real price path approach.

This, in turn, makes it difficult for stakeholders such as customers with long horizons (like industrial customers) or new energy market players such as producers of renewable gas to plan for their own long-term, given ongoing regulatory uncertainty about what (if anything) the AER might do about depreciation.

We note that Crew and Kleindorfer were alive to the problems caused by regulatory hesitancy when it comes to changing depreciation, where they point out:[93]

> *These (the regulatory impacts of their research) are that regulatory authorities can act in a penny-wise, pound- foolish manner with respect to capital recovery; attempts to decelerate capital recovery, when anticipated by the regulated firm, lead to under-investment, cost increases, and welfare decreases. They may also lead to viability problems for the firm to the extent that competitive forces become the driving force in pricing, thus pre-empting regulatory capital recovery pricing trajectories.*

To avoid this outcome, we would urge the AER to provide stakeholders with a consistent framework by which the opening and closing of the window can be better anticipated. This assists networks, their customers, and other players such as those who invest in renewable gas manufacturing and credit rating agencies (see Section 1.4.11.4.11.4.1, on signalling).

The unintended consequences of the AER's approach on the regulatory compact

Perhaps the most concerning aspect of the AER's decision in relation to Evoenergy is what it signals to investors about how the AER's views about the regulatory compact appears to have changed. The AER couches its decision merely in terms of keeping a "balance" between different concerns, stating that its depreciation decision:[94]

> *…strikes a balance between the need for a meaningful level of accelerated depreciation to promote efficient investment, and the need to limit the price impact of accelerated depreciation on consumers, particularly for vulnerable customers and those facing challenges during the energy transition.*

The AER appears to deliberately limit the "reasonable opportunity" Evoenergy has to recover its efficiently incurred capex. The AER has acted so that, if the future pans out exactly as it predicts is most likely, Evoenergy will be unable to recover its efficiently incurred capex.[95] This would appear to imply a walking back from the regulatory compact on the part of the AER, and it is unclear whether or not that is what is intended. However, it could have far-reaching implications for investment and sovereign risk.

We outline below what we understand from the Evoenergy Draft Decision and why it raises concerns.

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[93] *See Crew and Kleindorfer 1992, p58.*
[94] *AER Evoenergy Draft Decision Attachment 1 p28 (available here)*
[95] *In our submission to the AEMC (see Section 3 of Attachment 1, available here) we refer to this in the context of regulatory "intent" in respect of the recovery of efficiently incurred capex.*

How the AER treats the regulatory compact

To begin this discussion, we note a point of agreement with the AER, where it notes:[96]

> *We consider that while section 24(2) of the NGL sets out the principle that networks be provided a '… reasonable opportunity to recover at least the efficient costs the service provider incurs…', it does not mean gas consumers must guarantee that the regulated businesses recover these costs without considering price affordability and stability. The revenue and pricing principles are matters we are required to take into account, but they are not binding in all circumstances. We balance them against other considerations under the NGL, NGO and NGR.*

We agree that the RPP is not a guarantee of asset recovery, regulators cannot make promises to protect networks from markets turning out very differently from planned under all circumstances; the central point of the WoOPS model. However, it is also clear that a regulator should not act so as to cause a network to be unable to recover its efficiently incurred capex when an option exists to do so (see Incenta expert report, Attachment 6.6 p12)

This was well understood by those who developed the National Gas Rules at their outset, as were the risks involved, and they designed the way in which depreciation was intended to change flexibly according to market changes. This can be seen in their reasoning; (Attachment 6.6 pp 15-16)

> *The regulatory asset base represents the regulator's view of the market value of the regulated business at any point in time. Accordingly, the regulator can be interpreted as making an implicit commitment to ensure that the market value of those assets does not fall below the regulatory asset base over time. The objectives of encouraging efficient investment will only be met if this remains a credible commitment.*
>
> *This has important implications for the design of the regulatory depreciation profile. In particular, in order to ensure that the regulatory asset base remains at or below the market value of the assets, the regulatory regime must permit each distribution licensee to have their capital returned at a rate that keeps pace with the decline in the economic value of their assets. This in turn implies that regulatory depreciation must at least keep pace with economic depreciation. This will ensure that the value of the distribution licensee should not be placed in a position in the future where it is not able to set tariffs that are expected to recover the benchmark revenue requirement.*
>
> *…*
>
> *As the assessment of economic depreciation requires a view to be taken on all of these factors, its assessment is a complex and information intensive exercise. Hence, the estimation of economic depreciation will involve a degree of imprecision. The potential complexity of determining economic depreciation, combined with the likely imprecision, suggest that a relatively simple method for calculating regulatory depreciation would be appropriate. However, as information on the factors that influence economic depreciation will be revealed over time, there should also be a preparedness to review the method at future price reviews. In addition, this level of uncertainty, coupled with the advantages of reducing the*

[96] *AER Evoenergy Draft Decision Attachment 1 pp25-6 (available here)*

level of risk faced by the distribution licensees, suggests that the method should err on the side of exceeding, rather than lagging, expected economic depreciation.

Incenta also point out (Attachment 6.6 – p 16) how this allowed prices to be lower than would have been the case with a less flexible depreciation regime, which would then have been priced by investors, increased the cost of service.

The aspect of the decision which causes particular concern is pp 16-18 of Attachment 1 of the Evoenergy Draft Decision where the AER considers Evoenergy's proposal to cap asset lives at the policy-induced network closure date of 2045. The AER, in short rejects that approach and instead puts in place asset lives which are longer than the life of the network as a whole.

The Evoenergy Draft Decision appears to assert that, despite the ACT's policy position, and the high likelihood of closure in 2045, the likelihood is not 100 percent.[97] It also argues that renewable gas policy for industrial customers has not yet been set, whilst admitting (on the same page – see p19) that industrial customer loads would not be enough to support the network required to serve them. The decision notes that ACT government policy might get even less favourable in future, with potential appliance bans, and appears (this part of the AER's argument is unclear) to argue that this motivates waiting.

Under this approach, the only way that Evoenergy would be able to recover its efficient capex, and the only way that the regulatory compact could be met, is if current policy settings change to be more favourable. In simpler terms, it appears that the AER 's Draft Decision denies Evoenergy the "reasonable opportunity" to try and recover, if not all of its invested capital, at least as much as is feasible given where policy and market pressures lie.

It is not clear whether this is the intended approach or whether the consequences have been considered. We discuss some of these consequences below, noting that further detail is provided in our submission (available here) to the AEMC's process whereby we outlined our concerns that the rule changes being proposed might give regulators the incentive to act to weaken the regulatory compact.

Investment consequences flowing from how the AER treats the regulatory compact

The most important consequence of the AER's decision in Evoenergy will be on investment. Note that this is not just gas network investment, but across the energy sector. The key issue is not how much investors might lose in the case of Evoenergy, but the signal the AER's decision is sending on how it "balances" short term consumer price increases by virtue of the evidentiary and reasoning basis of its decisions.

In their expert report Incenta (Attachment 6.6 – p 3), apart from questioning the "balancing" exercise the AER undertakes, notes that the reasonable opportunity to recover efficiently incurred capex component of the Revenue and Pricing Principles, far from being something which are "not binding in all circumstances" but rather just part of different factors the AER must "balance",[98] is in fact the cornerstone of regulation around the world, and cautions against overturning it when it produces prices that are "inconvenient".

As we point out in our submission to the AEMC (available here), concerns about investment incentives are often studied from the context of preventing government opportunism, whereby

[97] We point out the inconsistency of the AER's position with respect of AGN SA. There, the AER argues that the SA Government policy position is supportive and hence the AER need take no action; ignoring the possibility that policy might turn less supportive in future. For Evoenergy, the AER admits that the ACT Government policy position is firmly set against gas but relies on the possibility that this policy setting might change to limit its action.
[98] See p26 of Attachment 1 of the Evoenergy Draft Decision.

governments change the rules after sunk investments have been made by investors to take advantage of them. We present a number of case studies from the literature where government opportunism has caused problems of sovereign risk, often for decades, in the affected jurisdictions.

One key means of avoiding government opportunism in the literature is strong, independent regulation, as the incentives upon regulators are held to be different to those on politicians, who seek to please the stakeholders who will vote them back in, and who might prefer lower prices on goods and services provided via infrastructure with high sunk costs.

In our submission to the AEMC, we provide some evidence from Moodys (see p45 of the submission) who make their view on this sort of approach quite clear; a regulator who sets depreciation below asset recovery would contribute towards a sub investment grade rating for the companies regulated by that regulator. This is a clear signal to regulators of the importance of the regulatory compact to investors.

We consider that the AER's Evoenergy Draft Decision, if sustained, runs a very real risk of triggering concern from investors; particularly if acted upon by Moodys or other agencies in their credit rating reports.

The impact is not limited to gas. The electricity transition to renewable fuels required tens of billions of dollars to be invested, to be recovered via a regulatory framework over 50 plus years. If investors see how quickly the approach can change in gas, and there is not sufficient transparency and evidentiary basis underpinning such a change (as evidenced by the Evoenergy decision), then their perception of the risks their future investments might face if policy or market forces turn out to be less favourable towards their investment could change very rapidly. For this reason, we would urge the AER to reconsider the stance it has taken on Evoenergy.

Appendix A Summary of Phase 4 Customer Workshop – Depreciation

Feedback from stakeholders highlighted the inherent difficulty of engaging customers on depreciation and the limitations of testing costs through a single scenario point. Recognising the complexity, we refined our approach to test two contrasting scenarios, enabling a deeper exploration of the trade-offs in depreciation outcomes.

Scenario-based engagement

We developed two clearly defined depreciation scenarios for customers to consider:

- No additional depreciation is to be recovered from customers in the next AA period
- $70 million additional depreciation is to be recovered from customers in the next AA period

The use of two contrasting scenarios enabled customers to examine the trade-offs between different depreciation pathways, including impacts on affordability, the energy transition, and fairness across customer groups and stakeholders.

To provide assurance that feedback was informed, participants were asked to respond to a series of comprehension questions testing their understanding of the key features and impacts of each scenario, prior to providing their views.

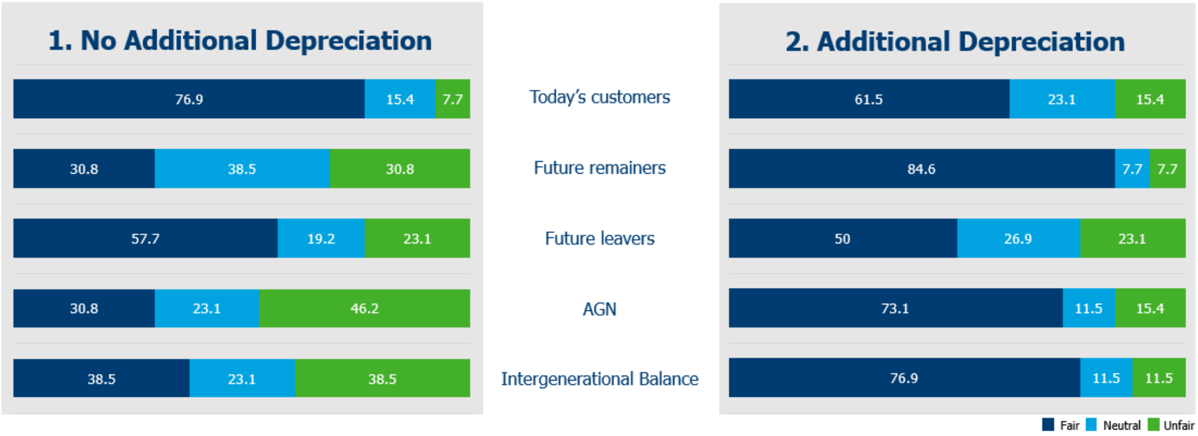
As outlined in the independent KPMG Phase Four Customer Engagement Workshop report (Attachment 5.5), customer comprehension was high across both depreciation scenarios. Participants demonstrated strong understanding of the core concepts and impacts, with particularly high levels of comprehension for Scenario 2 ($70 million additional depreciation) at 95%. Understanding of Scenario 1 (no additional depreciation) was also strong overall at 87%, with some variation across individual aspects of the scenario.

Fairness assessment

Drawing on the pre-reading materials and scenario explanations, participants were asked to consider the fairness of each depreciation scenario across customer and stakeholder groups, including potential impacts on customers in future Access Arrangement periods.

The purpose was not to identify which outcome participants considered to be the fairest overall, but to understand their assessment of how fair each scenario was for the different groups that may be impacted. Participants could indicate that they believed both or neither were fair. Results of this consultation activity are shown in Figure 1.3 below.

Figure 1.33 Assessed fairness of depreciation scenarios



Discussion and qualitative feedback

The discussion and qualitative feedback reflected a range of views, with participants weighing impacts differently depending on whether they focused on current or future customers. Many participants considered additional depreciation to be fair, noting that "by paying a little more now we will reduce future impacts on customers". Others described the approach as providing better balance over time, with one participant stating, "I think this is the best option, as we were to pay a little bit more now to reduce future impacts."

Those that did not support additional depreciation noted the impact on current customers, with one participant noting that "current customers pay more per year", highlighting the trade-offs involved.

Outcomes

Overall, Scenario 2 ($70 million additional depreciation) was perceived as the fairer balance, with 73% of participants somewhat or strongly agreeing that this scenario represents a fair and reasonable balance between all parties.

While views were not universal, the combined qualitative and quantitative evidence indicates a stronger overall preference for additional depreciation when fairness is considered across customer groups and over time.