JEMENA GAS NETWORKS

REVISED 2025 PLAN

Response to the AER's draft decision

JANUARY 2025

bringing energy to life

JEMENA GAS NETWORKS (NSW) LTD

2025-30 ACCESS ARRANGEMENT REVIEW

The Revised 2025 Plan and its associated attachments comprise JGN’s Revised 2025-30 Access Arrangement Proposal

Dollar values are reported in the value of a dollar in 2024-25 (unless otherwise stated) and exclude the impacts of inflation.

Contents

Overview

Our Revised 2025 Plan seeks to enhance the long-term value of gas for our customers. It intends to find the right balance between accepting substantial parts of the Australian Energy Regulator's (**AER's**) draft decision for Jemena Gas Networks (NSW) Ltd (**JGN**) and maintaining key elements of our proposals that we consider are necessary for us to orderly manage the impact of the energy transition and that are supported by our customers.

Our Revised 2025 Plan aims to balance short and long-term affordability, decarbonisation, safety and reliability, to support the energy transition towards net zero by 2050. A key aspect of our Revised 2025 Plan is to manage the challenges presented by the energy transition through risk management and innovation. Given the uncertain future of gas networks, we have taken a portfolio approach, proposing several initiatives to manage risk over the 2025-30 period that build adaptability into our operations. We expect that for subsequent periods, there will be more certainty as to the future of our gas network, potentially requiring us to adapt or bolster some initiatives.

Our Revised 2025 Plan accepts components of the AER's draft decision where it requires immaterial amendments to our proposal or it approves sufficient funding to enable us to meet the National Gas Objective (**NGO**) to invest efficiently in, and reliably, safely and sustainably operate, the gas network in the long-term interests of our customers in addition to supporting the achievement of the NSW and Australian government emission reduction targets.

Our Revised 2025 Plan provides additional support for components of our Initial 2025 Plan to address concerns raised by the AER in its draft decision. We have also updated our Revised 2025 Plan for new information or changes in circumstances since our Initial 2025 Plan was lodged in June 2024.

Listening to customers and stakeholders

One of our key objectives for this access arrangement review has been to understand the needs and expectations of our customers and stakeholders, and to ensure that our proposals have been truly shaped by them. We undertook an extensive engagement program over a 24-month period, which has tackled head-on the key challenges associated with the energy transition towards net zero and uncertainty surrounding the future role of gas networks.

In addition to understanding customer views and preferences on the services we will provide over the 2025-30 period, we have also sought to genuinely engage on the full spectrum of possible initiatives that can be implemented to help us manage expected declines in gas demand over the period to 2050. To enable this, our customers considered the long-term implications of each initiative under a range of plausible future scenarios. This has enabled them to better understand the risks, consequences and trade-offs that we have considered in developing our 2025 Plan, and the implications of our decisions for customers over the long term.

Throughout the engagement program, our customers provided their views and insights on what they want and value about their gas service, and what they would like us to prioritise as we plan for the energy transition. The feedback we heard from our customers' is summarised into five key values shown in Figure OV.1.

Figure OV.1: Customer values

Affordability	Reliability and Safety	Fairness	Choice	Environment
"Gas is reliable and affordable." (Culturally and Linguistically Diverse Customer Forum)	***"Safety and reliability are important factors to ensure sustainable use of energy in the long run."*** (Customer Forum)	***"To have it fair and equitable for all. Equality and equity and justice is maintained"*** (Customer Forum)	***"Banning gas is not speaking for people, and allowing choice."*** (Customer Forum Recommendation)	***"By utilising the biomethane as an option, we are protecting the environment by having another renewable gas option."*** (Customer Forum Recommendation)
We heard that balancing the rising cost of living is a priority for our customers so that no one is left behind due to the energy transition. Our customers want us to consider affordability over the short and long term when making decisions.	We heard that customers want a safe and reliable gas service.	Our customers want us to consider fairness in context of the energy transition, and its impacts on both existing and future generations, and on our more price-sensitive customers.	We heard that customers want the choice to be able to use gas both now and into the future, and that there should be diversity of supply.	We heard from customers that they want us to contribute to a more sustainable environment in the future.

Most customers and stakeholders we spoke to recognised the need for action now to meet the challenges ahead and to support the transition to net zero emissions by 2050. Our customers have provided their views and insights on what they want and value about their gas service, and what they would like us to prioritise as we plan for an uncertain future. They believe that any decisions we make should be made with the future of all customers in mind. Many of their preferences fell into a 'middle ground' to ensure that our initiatives are set in a balanced manner and that we have the flexibility to readjust our initiatives as we learn more about the energy transition.

Our customers confirmed their support for the Initial 2025 Plan with all Customer Forum participants feeling that we had acted on their recommendations and that we got the balance right in terms of how we positioned the initiatives. Figure OV.2 summarises the Customer Forum voting results on how well we got the balance right.

Figure OV.2: Customer Forum voting on whether JGN had the balance right[1]

Scale	Votes	%	Summary of comments
Love	2	5%	Participants valued the transparent process and level of information provided.
Like	26	67%	Participants noted that their views were heard, thought Jemena got the balance right and captured overall thoughts well.
Live with	11	28%	Participants noted the uncertainty of gas, climate concerns and a lack of urgency regarding renewable options were not fully answered.
Loathe	0	0%	
Lament	0	0%	
Total	**39**	**100%**	

Following the conclusion of the Customer Forum, we appointed Sagacity and JD Insights to conduct in-depth interviews and surveys of the Customer Forum participants to test whether customers trusted the engagement process and understood the topics they deliberated on to make informed recommendations that have influenced our 2025 Plan.

The research by Sagacity and JD Insights confirmed that customers trusted the process, felt valued and were adequately educated to make informed recommendations, which gives confidence that our proposals and initiatives algin with customers' values and expectations.

In September 2024, we reconvened our Advisory Board to reflect on what further customer engagement we should undertake in preparation for our revised proposal. The Advisory Board agreed that any further customer engagement should focus on one key topic - accelerated depreciation. It noted that this engagement should be quantitative in nature, for example a quantitative survey, to triangulate feedback from our Customer Forum and other customers groups.

In response to the Advisory Board's recommendation, we appointed Sagacity and JD Insights to conduct an online survey of 1,000 customers to understand customer preferences on this topic. The online survey also addressed feedback that we received from the Consumer Challenge Panel (**CCP**) that accelerated depreciation required further engagement and that such engagement should validate customers' understanding of what they were being asked.

The survey presented customer bill impacts of varying amounts of accelerated depreciation and asked customers to rank them in order of preference. Over 70% of customers surveyed ranked the two highest price levels of accelerated depreciation—which correspond to $400 million and $300 million over the 2025-30 period—as their first preference, recognising the trade-off between short versus long-term bill impacts and the impacts on customers unable to transition away from the gas network.[2] The survey results confirm the feedback that we received throughout our customer engagement program, from large customers, small businesses, and residential customers, who were supportive of using accelerated depreciation to support smoother bills for customers over the long term. These results provide us with confidence that our 2025 Plan reflects the views of our customers.

1 JGN – BD Infrastructure – Customer forum engagement report; p 23.

2 See section 2.3 for further details on the quantitative engagement on accelerated depreciation.

The AER's draft decision approves many elements of our Initial 2025 Plan

The AER published its draft decision on our Initial 2025 Plan on 29 November 2024. In its draft decision, the AER recognised the high quality of our customer engagement program:[3]

> *We acknowledged the work that JGN undertook in delivering a well-planned, comprehensive, and high-quality consumer engagement program, which delivered transparent and sincere engagement with its customers and stakeholders.*

The AER's positive reflection of our approach to customer engagement played an important role in its decision-making process, which saw it accept many elements of our 2025 Plan, including:

- Our proposal to split our existing single reference service into two reference services - a Transportation Reference Service (**RS**), and an Ancillary RS.
- Our proposed hybrid tariff variation mechanism for the Transportation RS, incorporating elements of both a weighted average price cap and revenue cap.
- Our proposed changes to the volume customer declining block tariff structure for the Transportation RS.
- Approximately 95% of our forecast operating expenditure (**opex**).
- Approximately 80% of our capital expenditure (**capex**) proposal, including capex associated with ICT, augmentation, mains replacement, fleet and property.
- Changes to our Model Standing Offer (**MSO**) so that fewer customers qualify for a free connection.
- Most of our proposed changes to our 2025-30 Access Arrangement (**AA**) and the References Services Agreement (**RSA**).
- Funding for our vulnerable customer program, noting the AER's decision to treat this opex item as a category-specific forecast rather than a step change.

While the AER accepted many elements of our Initial 2025 Plan, there were a number of critical elements that the AER's draft decision disallowed

Although recognising the quality of our engagement, the AER's draft decision disallows, or only partially allows, some critical elements of our proposal that our customers specifically voted in support of, and which are necessary for us to prudently respond to future gas uncertainty amid NSW and Australia's legislated emissions reduction targets. This includes:

- Accepting the need for accelerated depreciation, but reducing our proposal from $300 million to $156 million for the 2025-30 period, which it determined by an entirely different approach than JGN had proposed, or our customer engagement and research had supported, namely its zero real price path approach.
- Our proposed investments in renewable gas connections, for which the AER has included a placeholder allowance of zero.
- Rejecting our proposed opex step change for 5.75 Picarro vehicles[4], which will restrict our ability to implement a more targeted approach to asset management to maintain the safety of our network and more effectively identify leaks and reduce emissions.
- Rejecting our proposal to maintain a cost-reflective abolishment tariff, and instead requiring us to partly socialise the costs of abolishments across the customer base.

We consider that the measures that we proposed in our Initial 2025 Plan are consistent with that of a prudent service provider acting to promote efficient investment in, and efficient operation and use of, gas services for the long-term interests of consumers of gas, as required by the NGO. In not accepting these initiatives, the draft decision will constrain our ability to support a smoother transition to net zero for our customers, reduce emissions, maintain the safety of our network, and our efforts to build adaptability and innovation into our operations.

3 AER, Draft Decision: Jemena Gas Networks (NSW) Access Arrangement 2025–2030, p7.

4 In our Initial 2025 Plan we proposed 8 vehicles for the Picarro leak detection services. Our 2023-24 opex base year includes opex associated with 2 vehicles and a third vehicle we added in quarter 4 of 2024, making 2.25 equivalent vehicles over 2023-24. Therefore, our proposed Picarro opex step change was for 5.75 vehicles.

Customers who remain on the gas network will also be worse off. A primary focus of the AER's draft decision has been to maintain price stability over the short term, which results in transferring price volatility into future periods, thus allocating risks away from the broader base of current customers onto a narrower base of future customers. We consider that allocating risks in this way will not promote the long-term interests of gas customers, which has been a key consideration in formulating our Initial 2025 Plan. It is also entirely inconsistent with the intent of the NGO, the revenue and pricing principles, and rule 89 of the National Gas Rules (**NGR**) depreciation criteria.

The AER's draft decision demand forecast does not reflect a realistic rate of decline

The AER's draft decision also rejected the demand forecast in our Initial 2025 Plan and substituted an alternative forecast prepared by ACIL Allen, which forecasts a lower rate of disconnections for residential customers, and a slower decline in usage per customer for residential and commercial customers. In addition, the AER has not accepted our industrial demand forecast but has used it as a placeholder and requested that we provide additional information and analysis.

We do not consider that AER's draft decision demand forecast reflects a realistic rate of decline as the energy market transitions. This is evidenced by 2023-24 actual volumes and 2024-25 year-to-date actual volumes, which show a decline in demand that is more correlated to our Initial 2025 Plan demand forecast compared with the AER's draft decision.

The AER's draft decision does not provide us with sufficient capex for the 2025-30 period

We welcome the AER's decision to accept many aspects of our capex proposal for the 2025-30 period. However, we do not agree that the AER's draft decision, which reduces our capex by $162 million, will provide us with sufficient capex for the 2025-30 period to enable us to safely and reliably manage our network, or to support a lower emissions energy future for our customers. In particular:

- The AER did not accept our proposed renewable gas connection projects. It noted that this was a new and complex area and at this stage indicated that it was not satisfied that the projects provided a net benefit. It also expressed concerns that if it approves capex on an ex-ante basis, customers may end up paying for projects that do not proceed. While we acknowledge that this is a new and complex area, and appreciate the AER's engagement to date on this critical initiative, these renewable gas projects are essential to unlocking a gas decarbonisation pathway for our customers – particularly those in hard to abate manufacturing sectors who cannot electrify.
- The AER's alternative estimate of meter replacement capex understates the meter replacement capex that we will require and does not take into account the age profile of our meters, the mechanical nature of gas meters, available test data, or Australian good industry practice. It is also inconsistent with other decisions made by the AER for other gas networks.
- The AER did not accept the inclusion of a scope factor allowance for scope risk in our cost estimates as it considered individual project-level cost variations will balance out across our investment portfolio. However, this factor is based on historical differences between early cost estimates and outturn costs and is calibrated to be accurate at the portfolio level. The inclusion of the scope factor allowance is required to produce the best forecast possible in the circumstances, and has been approved by the AER in past decisions for JGN.
- The AER did not accept our proposal to replace end-of-life and obsolete mechanical and electrical instrumentation and control equipment at the Tempe Pressure Reduction Station (**PRS**). We maintain that our Tempe PRS project is required to maintain the functionality, safety, integrity and reliability of our network and meets the conforming capex criteria. Operating a high-pressure facility (supplying 50,000 customers, including 61 industrial customers) to failure puts the community and our employees at risk and could lead to a 25-day outage. It is also not consistent with Australian standards and will breach our regulatory obligations.

The AER has also identified a number of topics where it requires more information before it can finalise its decision on our Initial 2025 Plan

In its draft decision, the AER requested that we provide additional information to inform its final decision on our Initial 2025 Plan. This includes:

- Requiring further explanation of our intended reforms and potential pathways to flatten the tariff structure for both volume and demand customers. This includes providing additional bill impact modelling and potential implementation pathways for us to achieve flatter tariffs for the provision of the gas transportation service.
- Further information to justify the economic valuation of the benefits of the renewable gas connection projects, such as those attributed to avoided gas transportation costs and those relating to the byproducts of biomethane production. It also requires further information to address AER concerns associated with project completion risk and whether consideration should be given to including these projects in a speculative capex account due to concerns over whether the projects will progress in the 2025−30 period.
- Demonstrating that our existing meter fleet is deteriorating at the rate forecast in our Initial 2025 Plan.
- Providing further information on our demand forecast assumptions and updating our forecasts to account for the latest available data.
- Providing additional information to support the proposed opex for ICT projects associated with cloud capacity growth, contract lifecycle management and asset investment optimisation.
- Our interest in offering two abolishment services for small customers—an abolishment service for permanently disconnecting customers with a partially socialised reference tariff and an abolishment service for customers that ultimately intend to reconnect to our network with a cost-reflective reference tariff.

Our Revised 2025 Plan

In response to the AER's draft decision, we have developed our Revised 2025 Plan. Our Revised 2025 Plan will ensure that we can continue to provide our customers with a safe and reliable service over the 2025-30 period, manages our emissions and proposes a number of initiatives aimed at supporting a fair and equitable energy transition for customers over the long term.

We have sought to provide the AER with the additional information it has requested to enable it to finalise its decision on our Revised 2025 Plan. Where we have a different view to the AER on how to best meet the long-term interests of our customers, we have explained our response to the AER's draft decision in this document and its associated attachments. Areas where we disagree have been considered in the context of maintaining key elements of our proposal that have been supported by customers, providing forecasts that we consider represent the best forecast possible in the circumstances, achieving the NGO which includes emissions reduction, or areas where the draft decision has constrained our capability to provide a safe and reliable gas network service, in the long-term interests of our customers.

Key areas of divergence where we provide additional information to address concerns raised by the AER include:

- forecast demand for the 2025-30 period – our Revised 2025 Plan includes an updated demand forecast that incorporates the latest actual demand data and responds to the AER's draft decision, which we consider reflects a more realistic rate of decline as the energy market transitions than the AER's draft decision. We believe that our revised Volume Market demand forecast is very similar to the alternative Volume Market demand forecast prepared by ACIL Allen and adopted by the AER in its draft decision when updated for our 2023-24 actual demand.
- our revised proposal for accelerated capital recovery, which is a critical part of our complementary package of initiatives to prudently respond to future gas uncertainty. Given the current NSW energy transition by 2050, we consider that a $230 million future of gas depreciation allowance is the bare minimum amount required, as it affords JGN an equivalent opening RAB share to what was approved for the Victorian gas distributors.
- our opex forecast, which includes a step change for the Picarro leak detection service, which was not accepted by the AER in its draft decision.

- our capex forecast, which reinstates capex for the eight renewable gas connection projects, includes an updated metering replacement capex forecast to account for updates to unit rates and meter lot failure assumptions, and reinstates capex associated with the Tempe PRS and project risk cost.

Whilst we do not agree with the socialisation of abolishment costs—particularly given likely unintended consequences (as noted by the AER in its draft decision), the strong views expressed by our customers who supported maintaining a cost-reflective tariff for abolishment services, and whether this is permissible under the NGR—we have accepted the AER's draft decision as we understand that it is unlikely to change its views on this matter. However, as suggested by the AER, we propose to offer a new abolishment charge for small customers wishing to permanently leave our network, with a partially socialised reference tariff. Our existing, cost-reflective tariff will remain in place for customers that intend to reconnect to our network.

To address AER concerns that customers may end up paying for renewable gas projects that do not proceed, we have proposed a fixed principle within our 2025-30 AA as an alternative approach to the speculative capex account—the speculative capex account provides little regulatory certainty as it effectively defers the AER's assessment of this capex until the next price review process. The fixed principle would require us to adjust our 2030-35 building block revenue to return any 2025-30 building block revenue approved for renewable gas connections per the AER's Final Decision to the extent we do not incur relevant conforming capex. Noting that the renewable gas industry is still in its infancy, it is imperative that the right investment signals are provided to customers, JGN, and the proponents of these projects that this type of expenditure—when demonstrated to be prudent and efficient and consistent with NGR requirements—will be approved within the regulatory framework.

If accepted by the AER, our Revised 2025 Plan will:

- Help position us and our customers for an uncertain future, by enabling us to take prudent actions now to respond to uncertainty presented by the energy transition.
- Ensure that we can continue providing our customers with safe and reliable gas network services.
- Speed up the capital recovery of our assets so that we can avoid the potential for inequitable recovery of our investments and ensure more stable prices over the long term by reducing the amount of our asset base that must be recovered in future periods.
- Support our customers in reducing their emissions by providing them with access to renewable gas which is needed to achieve the Australian and NSW government's reduction targets.
- Enable us to implement a more targeted approach to asset replacements by utilising innovative Picarro leak detection technology to more efficiently prioritise critical asset replacements. Picarro will also enable us to:
  - ensure public safety, which has been a key concern of the AER's draft decision, by reducing the risk of leaks from the gas network.
  - benefit our customers, and the community, through the target of more significant leaks to optimise reductions in emissions.
  - enable reporting based upon directly measuring our fugitive greenhouse emissions and move away from generic and likely inaccurate benchmark factors, which will provide accurate and timely data to identify the size and location of gas leaks to support our proactive approach to asset management that will help us manage our climate impact by reducing emissions.
  - align with customer expectations in terms of adopting a more targeted approach to asset replacements utilising technology and expanding the Picarro leak detection services to reduce carbon emissions instead of buying carbon credits.

Our forecast revenue requirement

To deliver our Revised 2025 Plan, we are seeking to recover $2,980 million in Transportation RS building block revenue. Our Revised 2025 Plan smoothed revenue is $152 million higher than the AER's draft decision because we have a different view to the AER on some key elements of our Initial 2025 Plan, which we explain in this document and its associated attachments. The key drivers for this difference are:

- Our proposal to include $230 million accelerated depreciation instead of $156 million allowed by the AER in its draft decision

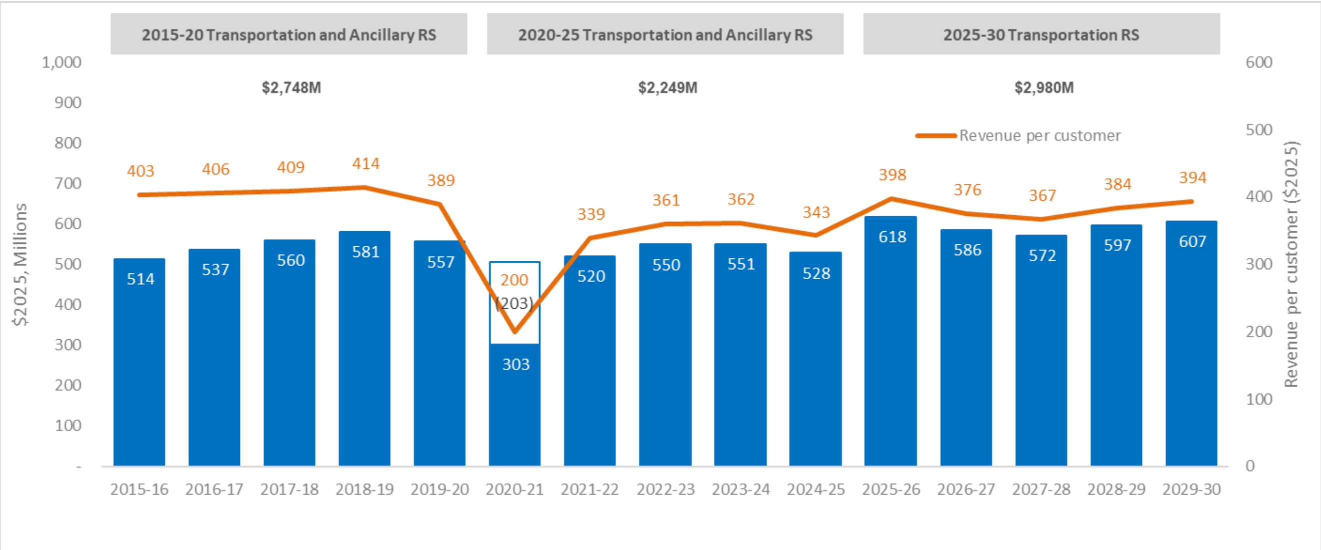
- Updates to the return on capital, to reflect changes in market conditions which have increased our financing costs
- An updated forecast inflation, reflecting the RBA's most recent (November) policy statement
- Our revised opex (including reduced socialised abolishment costs) and capex forecasts.

Table OV.1: Comparison of JGN's proposed revenue with AER's draft decision ($2025, $M)

	JGN's 2025 Plan	AER's draft decision	Revised 2025 Plan
Total revenue requirement (unsmoothed)	2,881.1	2,832.7	2,979.7
Total revenue requirement (smoothed)	2,882.5	2,831.7	2,983.3

Figure OV.3 provides a view of our revenues over the three access arrangement (**AA**) periods from 2015 to 2030. The increase in revenue leads to an average increase in revenue per customer of $21 but is stable (on a per-customer basis) when compared over the three planning periods from 2015-16 to 2025-30.

Figure OV.3: Our building block revenue requirement over the 2015-2030 period



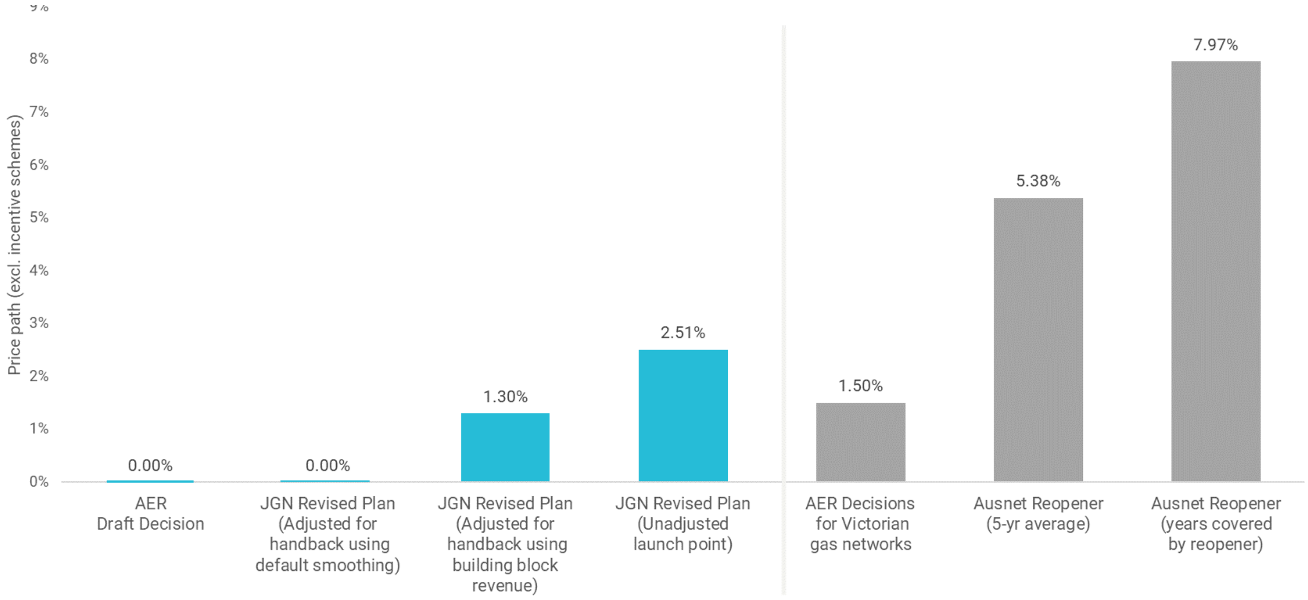
Price path and customer bill impacts

Our Revised 2025 Plan proposes an annual average real price path of 2.98%, or 2.51% excluding incentive schemes. These bill impacts are greater than our Initial 2025 Plan as they incorporate the impacts of our Revised 2025 Plan's higher revenue requirement and lower forecast demand.

Adjusting for the artificially low price path launch point due to the previous period over-recovery[5], Figure OV.4 shows that our revised proposal is consistent with a zero real price path. Figure OV.4 also provides a comparison of the price paths in the AER's draft decision, JGN's Revised 2025 Plan, and Victorian gas distribution networks.

5 During the 2020-25 period, the AER made an adjustment to our building block revenue to return $203 million to customers, following an over-recovery of revenue during the 2015-20 period. This reduced JGN's smoothed revenue over 2020-25 below the building block costs. To improve the comparability between JGN and the AER's recent decisions for Victorian gas distribution networks, we believe the 2024-25 prices—the 'launch point'—should be adjusted to remove the revenue handback, bringing our prices to a more cost-reflective level. We refer to this adjustment as the handback throughout the Revised 2025 Plan. More detail is provided in Attachment 7.2 of our Revised Plan. Additionally, consistent with the AER's treatment in its draft decision, the 0% and 1.3% p.a. price path presented here and in the chart exclude the impact of incentive schemes.

Figure OV.4: Price path comparison between AER draft decision, JGN's Revised 2025 Plan and VIC networks (Real, % p.a., excluding incentive schemes)



When considering JGN's price path, consideration should also be given to movements in the rate of return (WACC). The difference between the updated and previous nominal vanilla WACC estimates for JGN is 1.26%, which is materially higher than the 0.15% difference observed for the Victorian gas distributors.[6]

As accepted by the AER in its draft decision, we are proposing to gradually increase the revenue proportion we recover from our demand customers to enhance the cost reflectivity of our tariffs. Increasing the revenue proportion will mean demand customers pay for a greater share of the renewable gas connection capex, which will support those hard-to-abate industries.

Our Revised 2025 Plan will result in a real network bill increase of 2.82% or $9.1 per year over the 2025-30 period for an average residential customer consuming 15 GJ annually. A typical commercial customer consuming 500 GJ annually will experience a real network bill increase of 4.01%, or $137 per year over the 2025-30 period. For a large industrial customer with 350 GJ of chargeable demand, our Revised 2025 Plan will result in a real network bill increase of 4.05% per year over the 2025-30 period. These indicative bill impacts for our different customer types are shown in Figure OV.5. We also discuss the bill impacts of transitioning to flatter tariffs in chapter 9 of our Revised 2025 Plan.

In developing our Revised 2025 Plan, we have been cognisant of the price impacts on customers both now and into the future. While customers' bills will increase over the next five-year period, the initiatives in our Revised 2025 Plan will provide greater stability to prices over the long term and support the efficient future utilisation of our gas network. Our engagement with our customers has shown that they understand these trade-offs, and recognise the need for action now to meet the challenges ahead and support the transition to net zero emissions by 2050.

6 JGN - Houston Kemp - RP - Att 3.1 - Smoothing cost recovery when gas demand is declining - 20250110 – Public, p.38.

Figure OV.5: Indicative network bill impacts of our Revised 2025 Plan (excluding the impacts of inflation)

* All dollars reported in $2025 real	Residential	Commercial	Industrial
	1.48 million customers	34K customers	388 customers
Indicative bill impact (network component)	2.82% — $9.13 On average per year	4.01% — $137 On average per year	4.05% — $6,681 On average per year

** Note the price impacts are calculated based on 15 GJ annual consumption for a residential customer, 500 GJ for a commercial customer, and 350GJ of Chargeable Demand for an industrial customer.

What our Revised 2025 Plan will deliver for customers

Our Revised 2025 Plan will enable us to continue providing our customers with the safe, reliable and affordable services they expect, and deliver the outcomes set out in Figure OV.6.

Figure OV.6: What our Revised 2025 Plan will deliver

- **Deliver reduced emissions** to meet NSW legislated target reductions consistent with our emissions strategy
- **Connect 70,000 homes and businesses** across NSW and look after our existing customer base
- **Complete our vulnerable customer strategy** and support to vulnerable customers
- Replace manual inspections with **new technology** to efficiently detect leaks
- Implement a **more efficient approach** to asset replacement supported by **new technology**
- **Renew 120 km of old mains** targeting leaks and maintaining the reliability and safety of the network
- **Continuing cloud based software** and remote working to enhance security and efficiency
- **Plan for the future** by proposing eight new biomethane renewable gas connection projects

1. Background

1.1 About JGN's Revised 2025-30 AA Proposal

Jemena Gas Networks (NSW) Ltd (**JGN**) has prepared a revised 2025-30 access arrangement (**AA**) proposal (**Revised 2025-30 AA Proposal**) that responds to the AER's draft decision on JGN's Initial 2025 Plan for the period 1 July 2025 to 30 June 2030.[7]

The Revised 2025-30 AA Proposal comprises the following documents:

- This document, the response to the draft decision (**response to the draft decision,** or the **Revised 2025 Plan**) and all of its associated attachments.
- Further revisions to the AA (which includes a revised Reference Service Agreement (**RSA**)) that respond to issues raised in the draft decision.
- The Initial 2025 Plan and all of its associated attachments, provided to the AER on 29 June 2024.[8] For the purposes of brevity, these documents are not attached to this Revised 2025-30 AA Proposal as they have already been provided. The response to the draft decision and its associated attachments supersedes the information previously provided in our 2025-30 AA Proposal dated June 2024 to the extent that there is any conflict.

Our approach to responding to the draft decision involves:

- Accepting components of the draft decision where it:
  - approves sufficient funding to enable us to invest efficiently in, and safely and sustainably manage, the network in the long-term interests of our customers[9]
  - requires immaterial amendments to our proposal.
- Providing additional support for other components of our 2025-30 AA Proposal to address the concerns raised by the AER in its draft decision for its reconsideration.
- Updating our 2025-30 AA Proposal to take into account new information and or circumstances since our 2025 Plan was prepared.

Attachment 1.1 provides a submission matrix that identifies the documents making up JGN's Revised 2025-30 AA Proposal.

1.2 Presentation of financial information

Throughout this Revised 2025 Plan and its associated attachments, all monetary values are reported in the value of a dollar in 2024-25 and exclude the impacts of inflations unless stated otherwise.

7 Clause 60(1) of the NGR provides that JGN may submit additions or other amendments to its access arrangement proposal to address matters raised in the access arrangement draft decision. Additional matters may be addressed with the AER's approval (clause 60(2)).

8 The documents submitted to the AER on 29 June 2024 have not been resubmitted to the AER.

9 Should the AER consider changing its position on any of these issues, we would expect the opportunity to make submissions on these matters before the final decision, in accordance with section 28 of the Nation Gas Law (**NGL**)

1.3 Attachments

Table 1.1 lists the attachments which provide further background information on our Revised 2025-30 AA Proposal.

Table 1.1: Attachments containing background information on our Revised 2025-30 AA Proposal

Attachment	Name	Author
1.1	JGN - RP - Att 1.1 - Document map - 20250115	JGN
1.2	JGN - RP - Att 1.2 - Confidentiality claims in JGN 2025-30 revised AA proposal - 20250115	JGN

2. Customer and stakeholder engagement program

2.1 Our 2025 Plan reflects our customers' views

One of our key objectives for this access arrangement review has been to understand the needs and expectations of our customers and stakeholders, and to ensure that our proposals have been truly shaped by them. We adopted three key objectives as shown in Figure 2.1. These objectives guided how we engaged with our customers and stakeholders and aligns to our Jemena value, to 'Think like a customer'.

Figure 2.1: Our engagement objectives

We undertook an extensive engagement program over a 24-month period, which has tackled head-on, the key challenges associated with the energy transition towards net zero, and uncertainty surrounding the future role of gas networks. Our engagement program comprised of three key elements:

- An Expert Panel consisting of industry and energy specialists, to develop four plausible long-term scenarios for the NSW energy system, including the role of our gas network.
- An Advisory Board, chaired by Rosemary Sinclair AM and consisting of customer advocates and industry specialists, to consider a full range of possible initiatives that we might adopt during the 2025-30 period to respond to the rapidly changing energy landscape. To better understand the possible long-term implications of these initiatives, they were examined across the four plausible long-term scenarios developed by the Expert Panel. The Advisory Board advised us on which initiatives we should take to our customers, and how we should engage on them.
- A Customer Forum consisting of residential customers. We undertook a deliberative process to deeply understand their values, needs and expectations of the services we provide, and their views on how we should best plan for, and respond to, the energy transition in the face of uncertainty. We examined trade-offs, and the long-term implications of the initiatives we might adopt during the 2025-30 period.

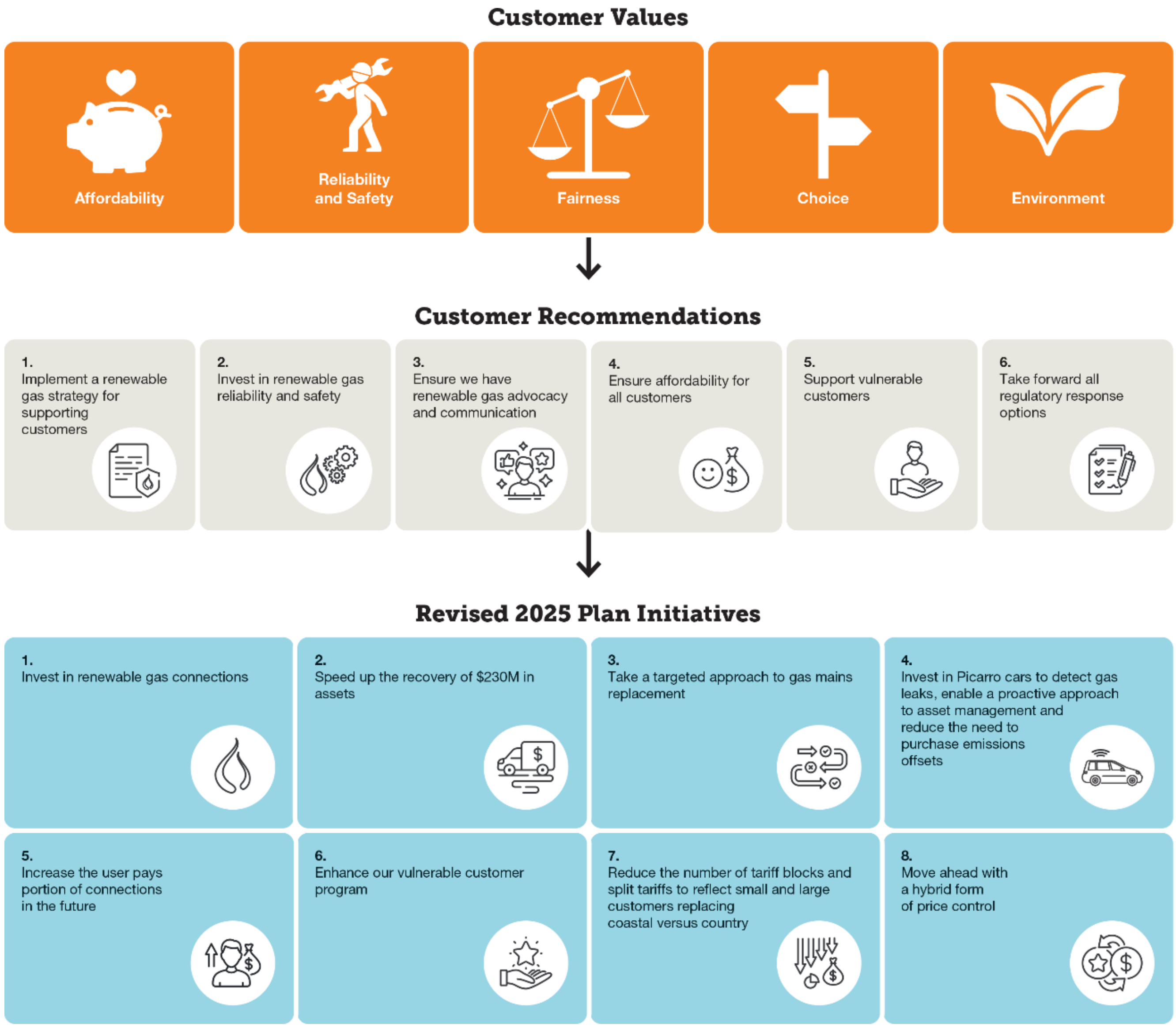
Our engagement program was complemented with extensive customer engagement across the broader community including key voices, a residential customer tariff forum, large users, small business customers, and retailers to ensure that our proposals reflect the views of the customers we service.

In addition to understanding customer views and preferences on the services we will provide over the 2025-30 period, we have also sought to genuinely engage on the full spectrum of possible initiatives that can be implemented to help us manage uncertainty. To enable this, our customers considered the long-term implications of each initiative under a range of plausible future scenarios. This has enabled them to better understand the risks, consequences and trade-offs that we have considered in developing our Initial 2025 Plan and our Revised 2025 Plan, and the implications of our decisions for customers over the long term.

Most customers and stakeholders we spoke to recognised the need for action now to meet the challenges ahead, and to support the transition to net zero emissions by 2050. Our customers have provided their views and insights on what they want and value about their gas service, and what they would like us to prioritise as we plan for an uncertain future. They believe that any decisions we make should be made with the future of all customers in mind. Many of their preferences fell into a ‘middle ground’ to ensure that our initiatives are set in a balanced manner and that we have the flexibility to readjust our initiatives as we learn more about the energy transition.

Our Revised 2025 Plan reinforces our commitment to deliver on the values supported through the Customer Forum recommendations which have informed our proposal. We have sought to maintain the key elements of our proposal that are supported by our customers, although we have also refined the initiatives in our Revised 2025 Plan in response to the components of the AER’s draft decision that we have accepted, or where we understand the AER is unlikely to change its decision. Figure 2.2 shows how our Revised 2025 Plan initiatives align with our customer values and recommendations.

Figure 2.2: Customer Values, Recommendations and Initiatives



2.2 AER draft decision

In its draft decision, the AER acknowledged that we had undertaken an extensive engagement program that was well planned, comprehensive, and high-quality which delivered transparent and sincere engagement with our customers and stakeholders.[10]

The Consumer Challenge Panel (**CCP**) also commended our engagement program and noted that we openly dealt with the future of gas in planning our engagement, and in identifying that longer term goals and requirements are a crucial aspect of developing a 5-year access arrangement proposal. The CCP also praised our early and detailed planning of the engagement program, and the use of broad and deep engagement forums.[11]

While the AER has acknowledged the overall quality of our engagement program, it noted that some stakeholder submissions to the AER Issues Paper raised concerns that our engagement may not have achieved the most meaningful outcomes, particularly on the topic of accelerated depreciation. This included the CCP, who raised concerns with our engagement on accelerated depreciation and questioned customers' understanding of the role of accelerated depreciation. The CCP considered that this topic required further engagement, particularly with residential and small business customers and that such engagement should validate customers' understanding of what they are being asked.[12]

The AER acknowledged the limited time between its draft decision and deadline for submitting our revised proposal, however it did encourage us to undertake further and ongoing engagement with our customers to continue to ensure that customer preferences are reflected in our revised proposal, where possible, and in future proposals.[13]

2.3 JGN response to the draft decision

We believe our 24-month engagement program achieved meaningful outcomes, and the expectations of our customers have been important in shaping our plans. We included the details of our comprehensive engagement program within our Initial 2025 Plan and its associated attachments. Given the limited time post submitting our 2025 Plan, our engagement since then has primarily focussed on the topic of accelerated depreciation.

Advisory Board

In September 2024, we convened our Advisory Board to reflect on:

- The changing regulatory and policy landscape, and what it means for JGN
- Issues raised in the AER's Issues Paper, which was published in August 2024
- Key considerations for JGN in preparation of the revised proposal.

The workshop was independently chaired by Rosemary Sinclair AM and facilitated by KPMG.

A key theme that emerged from the workshop discussions was an acknowledgement of the quality of the engagement that we had delivered to customers and stakeholders to inform our Initial 2025 Plan.

10 AER, Draft Decision Overview: Jemena Gas Networks (NSW) Access Arrangement 2025–2030, p. 7.
11 CCP31, Advice to the AER - JGN 2025–30 Access Arrangement Proposal and Issues paper, Sept 2024, p.19.
12 CCP31, Advice to the AER - JGN 2025–30 Access Arrangement Proposal and Issues paper, Sept 2024, p. 28.
13 AER, Draft Decision Overview: Jemena Gas Networks (NSW) Access Arrangement 2025–2030, p.10.

> "The reason [the AER] are satisfied with those aspects of the proposal is because of the degree of engagement and authenticity of that process……This [conversation today] has been a very good example of our process, which is why we feel that it's an authentic process."
>
> *Advisory Board Chair*

The key objective of the workshop was to seek Advisory Board advice on what we should consider when preparing for our Revised 2025 Plan, including any further customer engagement activities.

The Advisory Board agreed that any further customer engagement should focus on one key topic - accelerated depreciation. Acknowledging the complexity of this topic, the Advisory Board advised further engagement should consider the following engagement principles:

- The audience should be representative of JGN's customer base but capture a different audience to the Customer Forum to avoid engagement fatigue.
- This engagement could be quantitative in nature, for example a quantitative survey, to triangulate feedback already captured from the Customer Forum and validated by the Sagacity and JD Insights research.
- Through a quantitative approach there should be sufficient explanation of the technical concepts involved in accelerated depreciation to enable informed responses.
- Additional specific intervention should be considered to support culturally and linguistic diverse (**CALD**) communities to engage meaningfully in this format.[14]

Quantitative research on Accelerated Depreciation

In light of the Advisory Board's recommendation, we appointed Sagacity and JD Insights to conduct an online quantitative survey to understand customer preferences on accelerated depreciation. The online survey also addressed CCP feedback that accelerated depreciation required further engagement and that such engagement should validate customers' understanding of what they were being asked. To aid customers' understanding, we commissioned two videos to explain the key concepts and trade-offs in relation to accelerated depreciation. These videos formed part of the survey materials.

Acknowledging the complexity of this topic, Sagacity and JD Insights undertook two stages of independent research. These stages involved:

- **Stage 1 - Cognitive testing**: To support the engagement principles recommended by the Advisory Board—to ensure sufficient explanation of the technical concepts involved in accelerated depreciation to enable informed responses, and that consideration be given to CALD communities to engage meaningfully—two rounds of cognitive testing were conducted.

  The first round entailed four customer interviews focused on evaluating the survey script to test customers' understanding, and to identify opportunities to improve and simplify the survey. The script was then fine-tuned and a story board / video script produced. The second round involved four interviews (with different customers to round one) to further refine the survey and video transcripts to ensure that customers understood the topic and the survey questions. The feedback from the cognitive testing informed the final videos explaining accelerated depreciation, uncertainty surrounding the future role of gas networks, and the survey.
- **Stage 2 - Online survey**: A survey of 1,006 JGN customers was then conducted. To encourage a range of perspectives, and ensure that survey participants were representative of our customer base, the recruitment process considered (but was not limited to) gender, age, geography, and language spoken at home.

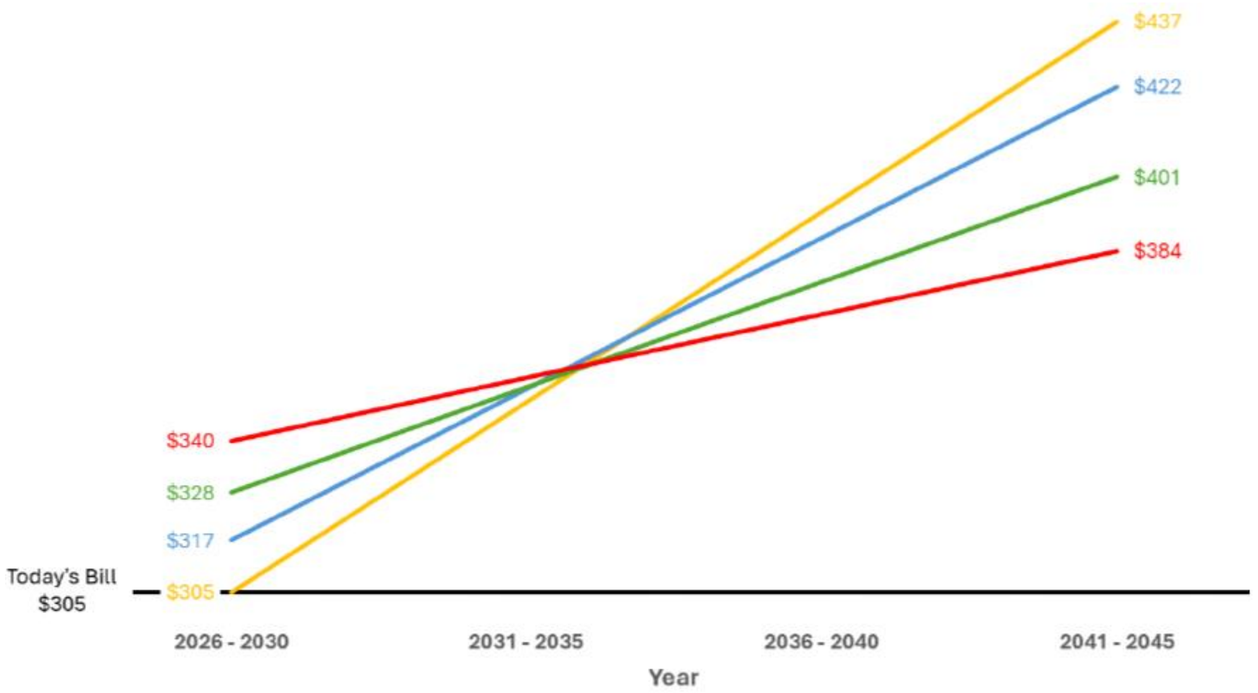
14 JGN - KPMG - RP - Att 2.2 - Advisory Board - Detailed Record - 20240913 – Public, p. 5.

The survey presented different amounts of accelerated depreciation and the impact it would have on customers' bills. Two videos were produced for respondents to watch prior to answering questions at different points in the survey. The first video explained the concept of accelerated depreciation and provided an overview of the uncertainty surrounding the future role of gas networks. The second video explained the factors we had taken into consideration when exploring the different amounts of accelerated depreciation.

After watching the first video, customers were asked to reflect on the content and their understanding of accelerated depreciation. 71% of survey respondents stated they understood the topic 'extremely' or 'very' well. This response was similar amongst those survey respondents who also spoke a language other than English (72%) and those without a tertiary degree (67%).[15]

Customers were then presented with 4 options, as shown in Figure 2.3. The options started from $100 million (yellow) of accelerated depreciation to $400 million (red), which bookend our proposed $300 million (green) accelerated depreciation and the AER's draft decision (mid-point between yellow and blue) of $156 million. This was presented to customers in terms of the impact it would have on their bill.

Figure 2.3: Accelerated depreciation survey options



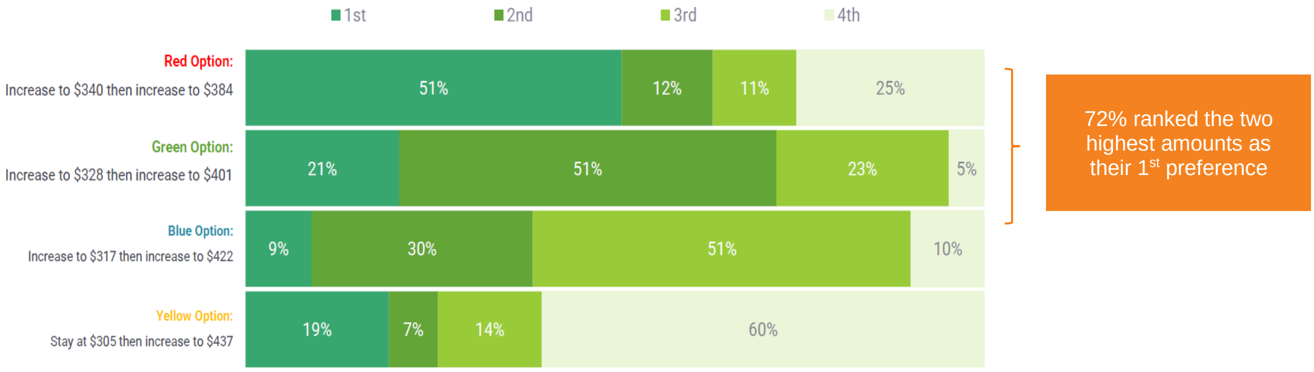
The survey revealed that 72% of participants (see Figure 2.4) preferred the higher options of accelerated depreciation (red and green). Participants were asked who they took into consideration when voting, with the following options provided:

- Your household
- People experiencing financial hardship
- Future generations
- All households with gas
- Other people you know.

The majority of participants (72%) took others outside of their household into consideration when selecting their preferences, including future generations and people experiencing financial hardship.[16]

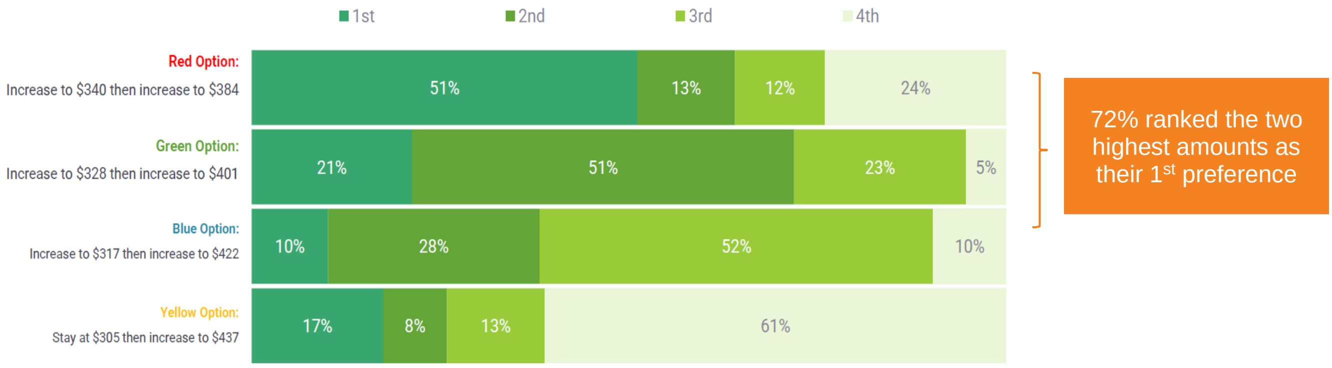
15 JGN - Sagacity - RP - Att 2.1 - Accelerated Depreciation Research Report- 20241206 – Public, p. 11.
16 Ibid, p. 28.

Figure 2.4: Ranking of accelerated depreciation options (first round)



After ranking their initial preferences and nominating who they took into consideration, respondents were shown a second video explaining what we have taken into consideration when exploring options for accelerated depreciation. Participants were then asked to reconsider their preferences. Following this, just over a quarter of participants changed their preferences but there was no overall change to the rankings across the options as shown in Figure 2.5.

Figure 2.5: Ranking of accelerated depreciation options (second round)



The research by Sagacity and JD Insights shows that the majority of customers surveyed supported higher accelerated depreciation options and understood the trade-offs in terms of increasing prices in the short versus the long term. The survey results confirm the feedback that we received throughout our customer engagement program, that large customers, small businesses, and residential customers are supportive of using accelerated depreciation to support smoother bills for customers over the long term.

Large Customer Forum

On 20 August 2024, we hosted a Large Customer Forum during which we provided attendees with an overview of our 2025 Plan, including how the feedback we received from our customer engagement process had shaped our proposal. The forum provided customers with an opportunity to deep dive on the key elements of our 2025 Plan.

Customer Council

Throughout the access arrangement review process, we have maintained a consistent dialogue with our Customer Council, actively seeking its input and guidance at each stage of our engagement process. This has included one-on-ones with a number of Customer Council members to obtain advice on engaging with particular groups, such as small businesses and developers. Following the publication of the AER's Issues Paper[17], we hosted two Customer Council meetings[18] to provide members with updates on the access arrangement review

17 AER, Issues paper on the early signal pathway expectations, Jemena Gas Networks (NSW) access arrangement, August 2024

18 Customer Council meetings were hosted on the 16 September and 25 October, 2024.

process. The first meeting focused on providing members an overview of the AER Issues Paper and the complex issues arising from the energy transition. At the second meeting we provided further updates on the access arrangement review process, providing members with an overview of the AER's information requests on our 2025 Plan.

2.4 Ongoing engagement

We are committed to ongoing engagement to ensure that we achieve our objective to 'Think like a customer' and 'We care'.

Customers and stakeholders throughout the process have expressed a strong desire for ongoing engagement and continued dialogue, to ensure their priorities are reflected in our future plans. There was also a clear desire for us to take a leading role in empowering and educating customers, particularly those experiencing vulnerabilities, to ensure no one is left behind through the energy transition.

We will take the learnings and insights from the engagement process to evaluate our ongoing engagement with our customers. This includes identifying ways in which we can continue the dialogue with customers and stakeholders who participated in the engagement process and developing new approaches to capture their needs and insights on an ongoing basis. We will also ensure continuous engagement with a diverse group of residential customers including young people, seniors and people with a disability to garner richer insights into the lived experiences of those in our network.

We will also strengthen our engagement with our Customer Council, which has been an ongoing source of the voice of customers. The JGN Customer Council was established in November 2011 to build strong working relationships with industry stakeholders, key customers and customer advocates to share their views and provide guidance to Jemena. Based on customer and stakeholder feedback, we tested new engagement activities and approaches with our JGN Customer Council in October 2024. This includes the introduction of sub-committees to allow for deeper and more tailored discussions among the group.

2.5 Attachments

Table 2.1 lists the additional attachments to our Revised 2025-30 AA Proposal on our customer engagement.

Table 2.1: Revised 2025-30 AA Proposal attachments on our customer engagement

Attachment	Name	Author
2.1	JGN - Sagacity - RP - Att 2.1 - Accelerated Depreciation Research Report- 20241206	Sagacity
2.2	JGN - KPMG - RP - Att 2.2 - Advisory Board - Detailed Record - 20240913	KPMG

3. Responding to the energy transition

3.1 How we seek to manage the energy transition

A key aspect to our 2025 Plan is to manage the challenges presented by the energy transition through risk management and innovation. Given the uncertain future of our gas network, we have taken a portfolio approach, proposing several initiatives to manage risk over the 2025-30 period that build adaptability and innovation into our operations.

In formulating these initiatives as part of our Initial 2025 Plan, we assessed how they performed across a number of plausible future energy scenarios and how they interact together. These initiatives are not mutually exclusive and in some cases are complementary, which has been an important consideration to ensure we have taken a balanced and equitable approach when developing our Initial 2025 Plan and our Revised 2025 Plan.

These initiatives are:

1. **Asset Management**: We are changing the way we manage our assets, by taking a more targeted approach to our mains replacement program by using technology (for example, Picarro leak detection services) to better understand the condition of our assets. Using technology to replace assets in a targeted manner will reduce the capex that we incur and the growth of our regulatory asset base, and enable us to more effectively reduce network emissions.
2. **Investing in renewable gas connections**: We believe that renewable gas can play a role in meeting challenges presented by the energy transition. Supporting renewable gas connections from biomethane suppliers will enable customers to access renewable gas sooner and will provide greater energy security from fuel diversification. As the supply of renewable gas grows, this will help retain some of our customer base and lower the risk of asset stranding.
3. **New connections**: We proposed changes to our connections policy requiring more customers to make an up-front contribution if they wish to connect to our network. This change will help to reduce the growth in our asset base, and lower asset stranding risk with minimal impact on customer prices. We submitted to the AER proposed revisions to our MSO so that fewer customers qualify for a free connection.
4. **Accelerated depreciation**: By speeding up the capital recovery of our assets in response to the energy transition we can reduce the potential for inequitable recovery of our investments, and ensure more stable prices over the long term by reducing the amount of our asset base that must be recovered in future periods. We proposed $300 million of accelerated depreciation over the 2025-30 period.
5. **Abolishments**: In line with customer feedback, we proposed to continue our current approach, of a cost-reflective abolishment tariff, which was supported by customers in our engagement program.

We also proposed making changes to our tariff structures so they can be more adaptable and ensure fairness in the way we charge for the provision of our gas network services. We also proposed to move away from a price cap tariff variation mechanism—which sets the way we adjust prices annually over the 2025-30 period—to a hybrid mechanism. This will share volume risks between us and customers and address the AER's concerns around gas networks earning higher than forecast revenues by limiting revenue earnt through volume outperformance.

3.2 AER's draft decision

The AER's draft decision acknowledges the uncertainties presented by the transformation in the energy system, and the Australian Government's goal of reaching net zero, on future gas demand expectations. It also notes that the complexity of the journey to the 2050 emission objective means that there is no single strategy to reach this target.[19]

19 AER, Draft decision Jemena Gas Networks (NSW) access arrangement 2025 to 2030 (1 July 2025 to 30 June 2030), Nov 24, p. V.

To enable us to better manage the energy transition to reach net zero we are pleased that the AER has approved some of our initiatives to manage risk over the 2025-30 period. This includes approving:

- Our proposed transportation reference tariffs to partially flatten the volume customer declining block tariff structure which the AER considers better reflects the emissions reduction objective of the updated NGO.
- Changes to JGN's MSO to require more customers to make an up-front contribution if they wish to connect to our network.
- Our proposed hybrid tariff variation mechanism that blends elements of our existing weighted average price cap with elements of a revenue cap to share volume risk between us and our customers.

Conversely, we are disappointed that the draft decision has not approved, or only partially approved, several other of our proposed initiatives, including:

- Its decision to reduce our proposed accelerated depreciation from $300 million to $156 million.
- Our proposed investments in renewable gas connections, for which the AER has included a placeholder allowance of zero.
- Rejecting our proposed opex step change for 5.75 Picarro vehicles[20], which will restrict our ability to implement a more targeted approach to asset management, to maintain the safety of our network, and to more effectively identify leaks and reduce emissions.
- Our proposal to maintain a cost reflective abolishment tariff.

Not accepting these initiatives will hinder our efforts to build adaptability and innovation into our operations and constrain our capability to support a smooth transition to net zero and reduce emissions. In addition, customers who remain on the gas network will be worse off, since they must both pay for residual abolishment costs and the residual sunk costs not recovered from departing customers.

A primary focus of the AER's draft decision has been to maintain price stability over the short term which results in transferring price volatility into future periods, thus allocating risks away from the broader base of current customers onto a narrower base of future customers. We consider that allocating risks in this way will not promote the long term interests of gas customers which has been a key consideration in formulating our Revised 2025 Plan.

3.3 JGN response to the draft decision

Our Revised 2025 Plan seeks to address the key issues raised by the AER in its draft decision with the aim of demonstrating that our approach to managing the energy transition is prudent and in the long term interests of customers. Our response to the AER's draft decision is shown in Table 3.1.

Table 3.1: Comparison of JGN's proposed emissions reduction programs to AER's draft decision

Energy transition initiative	AER's draft decision	Revised 2025 Plan
Asset Management – Picarro leak detection services	The AER rejected our proposal to purchase 5.75 additional cars to deliver Picarro leak detection services (an opex step change of $20.8 million over the 2025-30 period).	We believe that Picarro is an important innovation as it will help ensure the ongoing safety of our ageing network and allow us better target and more effectively reduce our emissions. Our customers were also supportive of us using this technology to change our asset management approach, and to avoid purchasing carbon offsets. We have re-proposed this opex step change, although we have revised the number of cars associated with Picarro leak detection services to 3.75 (an opex step change of $15.3 million). We provide further detail in chapter 5 and in JGN - RP - Att 5.3 - Picarro - 20250115 – Public.

20 In our Initial 2025 Plan we proposed 8 vehicles for the Picarro leak detection services. Our 2023-24 opex base year includes opex associated with 2 vehicles and a third vehicle we added in quarter 4 of 2024, making 2.25 equivalent vehicles over 2023-24. Therefore, our proposed Picarro opex step change was for 5.75 vehicles.

Energy transition initiative	AER's draft decision	Revised 2025 Plan
Investing in renewable gas connections	The draft decision included a placeholder capex of zero for these projects. The AER noted that it has concerns about the inputs and assumptions used in our business cases, and does not consider enough information was provided in our Initial 2025 Plan to enable it to be satisfied that the projects will provide a net benefit to our customers. It also expressed concerns that if it approves capex expenditure on an ex-ante basis, customers may end up paying for renewable gas connection projects that do not proceed.	In chapter 4 of this document, and in *JGN - RP - Att 4.2 - Renewable gas expenditure - 20250115 – Public* we have addressed the AER's concerns about the inputs and assumptions used in our business cases, and have provided further information to demonstrate that the projects provide net benefits to our customers. To address AER concerns that customers may end up paying for renewable gas projects that do not proceed, we have proposed a fixed principle within our 2025-30 AA. The fixed principle would require us to return any 2025-30 building block revenue arising from any renewable gas project that does not proceed over the 2025-30 period. We provide more information in chapters 7 and 9. We expect that our Demand Market customers will pay for a greater proportion of our renewable gas projects as part of our tariff rebalancing.
New connections	The AER approved our proposed changes to our MSO.	We accept the AER's draft decision – see chapter 9 for more detail.
Accelerated depreciation	The AER accepted our proposal to accelerate depreciation, but only $156 million of our proposed $300 million. The AER determined the reduced amount by capping the average annual real price increase at 0% (excluding the impact of incentive schemes).	We welcome the AER's decision to accept accelerated depreciation, but do not agree with the approach it has used to set the allowance at $156 million. By limiting depreciation during the 2025-30 period the AER's draft decision does not sufficiently act upon the opportunity to reduce stranded asset risk whilst there remains a large customer base. This means the draft decision approach, if retained in the final decision, would: – forego the opportunity to have our largest remaining customer base contribute equitably to existing capital recovery, counter to our current customers' preferences – worsen the accrued problem of investment recovery by driving net growth in our capital asset base by 2030. We have considered the AER's reasons for its draft decision to adopt a zero real price path outcome. We consider that targeting a zero real price path outcome in the current and foreseeable gas demand context: – Is inconsistent with the intent of the NGO, revenue and pricing principles, and rule 89 depreciation criteria – Places undue weight on short-term policy measures (or a lack thereof) and fails to place enough weight on commonly held views about long-term gas demand forecasts amid the NSW legislated transition to net zero by 2050, and – Fails our customer base by burdening future customers (which the AER acknowledges will be fewer) with higher prices than would otherwise be the case. If the AER is to continue its real price path outcome approach, it should only be applied once it accounts for the $203 million revenue handback. Taking this approach results in an accelerated depreciation allowance of $230 million. We provide further detail in chapter 7 and *JGN - RP - Att 7.2 - Depreciation - 20250115 – Public*..

Energy transition initiative	AER's draft decision	Revised 2025 Plan
Abolishments	The AER's draft decision partially socialises the costs to abolish customers' connections across the rest of the customer base. In addition, the AER has rejected our proposed tariff for abolishments on the basis that it is greater than that charged by the Victorian gas distributors. The AER also suggested splitting the abolishment service into two categories, which recognises that approximately two-thirds of current abolishments are undertaken on properties undergoing renovations, where customers ultimately reconnect to our network after the renovation is completed.	We do not agree with socialisation of abolishment costs—particularly given likely unintended consequences as noted by the AER in its draft decision, whether it is permissible under the rules, and because our customers supported fully cost reflective charging for abolishment services. However, we have accepted the AER's draft decision as we understand it is unlikely to change its decision. As suggested by the AER, we will introduce a new abolishment service charge that is partially socialised. We propose that these new charges will be available from 1 July 2026, once we have implemented the necessary system and process changes to enact them. We provide further detail in chapter 5 and 8 and in *JGN - RP - Att 7.1 - Abolishments - 20250115 – Public*.
Tariff structures	The AER has approved our proposed changes to transportation reference tariffs but has requested further analysis and explanation of how fast we intend to flatten the volume customer declining block tariff over the 2025-30 period. It also requested that we provide bill impact modelling showing potential implementation pathways to achieve flat tariffs, for both volume and demand market customers.	In our Revised 2025 Plan we have provided information outlining how we can flatten the volume market customer declining block tariff via our annual tariff variation mechanism, and modelling showing potential implementation pathways to achieve flatter tariffs for volume customers. We are not proposing to amend the tariff structures for our demand customers in the forecast regulatory period. These large industrial customers are very different to our volume customers and even minor tariff changes can result in major bill shocks, which could significantly impact their competitiveness. Further, we are not able to engage on this topic with our large demand customers in the short timeframe between the AER's draft decision and our revised proposal. We consider a more prudent and appropriate approach is to consult with these customers on tariff transition during the next regulatory period for implementation in the subsequent access arrangement periods. We provide more detail in chapter 8 and *JGN - RP - Att 8.1 – Pricing - 20250115 – Public*.
Tariff variation mechanism	The AER approved our proposed hybrid tariff variation mechanism.	We accept the AER's decision on our hybrid tariff variation mechanism and provide more detail in chapter 8 and *JGN - RP - Att 8.1 – Pricing - 20250115 – Public*.

Our Revised 2025 Plan endeavours to provide the information that the AER requires to approve the key initiatives outlined above. Importantly, we consider that these initiatives will enable us to appropriately manage the risk associated with the energy transition over the 2025-30 period, will help us build greater adaptability into our operations, and provide our customers with the option of continuing to use gas into the future. The initiatives also facilitate our ability to operate our network reliably and safely, and play our role in reducing emissions in the long-term interests of our customers.

3.4 Attachments

Table 3.2 lists the attachments to our Revised 2020-25 AA Proposal which provide further information on our response to the AER’s draft decision on our planned response to the energy transition.

Table 3.2: Revised 2025-30 AA Proposal attachments supporting our planned response to the energy transition

Attachment	Name	Author
5.3	JGN - RP - Att 5.3 - Picarro - 20250115	JGN
4.2	JGN - RP - Att 4.2 - Renewable gas expenditure - 20250115	JGN
7.1	JGN - RP - Att 7.1 - Abolishments - 20250115	JGN
7.2	JGN - RP - Att 7.2 - Depreciation - 20250115	JGN
8.1	JGN - RP - Att 8.1 – Pricing- 20250115	JGN

4. Our capital expenditure requirements

4.1 AER draft decision

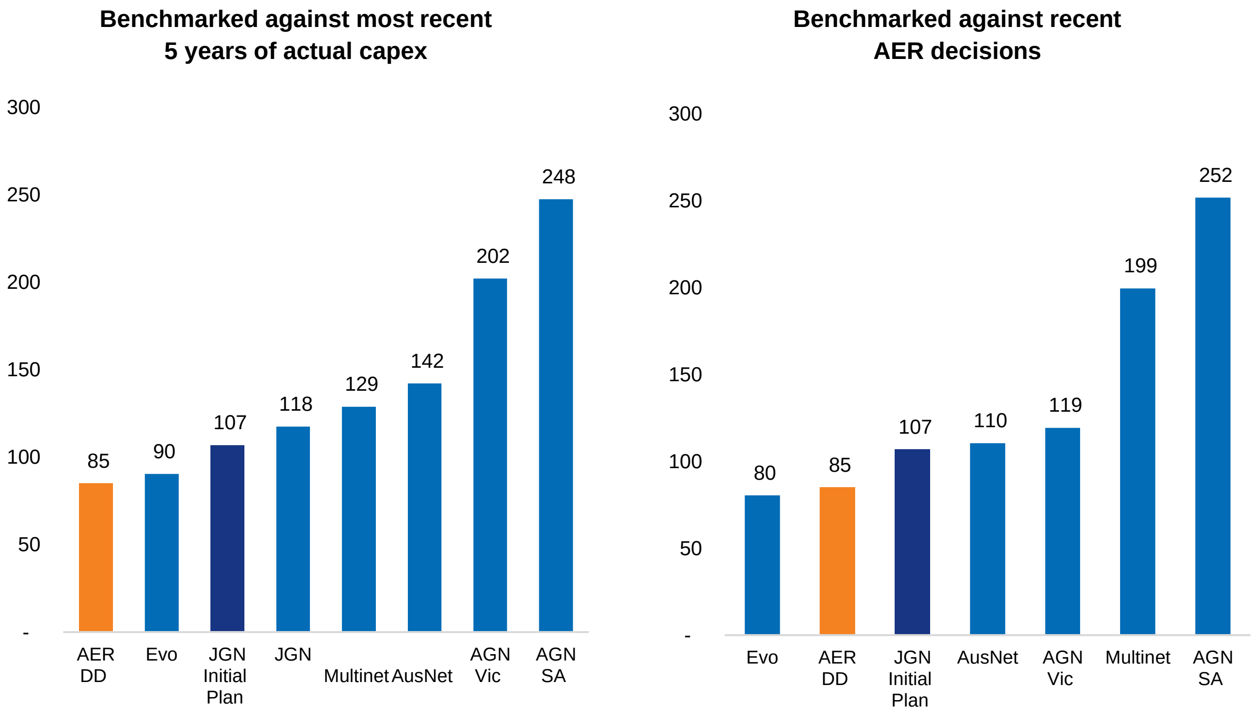
Our Initial 2025 Plan identified three key investment drivers for the 2025-30 period. To connect customers and provide access to our network (consistent with regulatory obligations and customer expectations), play our role in reducing emissions (e.g. by enabling renewable gas), and to keep our ageing network safe and reliable for as long as our customers need us to.

Despite already being one of the most capital efficient energy networks regulated by the AER – gas or electricity – and with many elements of our network reaching end-of-life, we proposed capex of $832.5 million, $80.2 million (9%) less than the 2020-25 period. We proposed a very lean program to ensure our plan was affordable and capable of acceptance by the AER.

The AER's draft decision accepted the bulk of our proposal only raising concerns with a small number of elements. However, the non-acceptance of these elements has an outsized impact on our program reducing net capex by 20% to $670.1 million.

The combination of our very lean proposal with such a large reduction by the AER results in one of the lowest capex allowances ever set. It is significantly lower than the allowances for all other gas distribution businesses (except for Evoenergy[21]) and significantly lower than actual capex currently being incurred by all Australian gas businesses (on a net capex per customer basis) as shown in Figure 4.1.

Figure 4.1: AER's draft decision net capex per customer allowance benchmarked ($2025, capex per customer)



Such a low allowance is insufficient for a network of our scale, age and condition. Not only is the accepted program insufficient to maintain the safety and integrity of our network – the AER's adjustments of our cost estimates mean that we will be unable to deliver all approved projects. Constraining capex to within the AER's draft decision allowance is highly likely to result in unacceptable safety risks to the community, and risks breaches to our safety and technical regulatory obligations. This is inconsistent with the first of the two components of the NGO.

21 A much younger network built using modern materials and limited connections.

Further, it will prevent us from facilitating 6.7 PJs of renewable gas – essential to deliver 0.4% and 1.0% of the emissions reductions need to achieve the Australian and NSW government's 2030 emission reduction targets. This is inconsistent with achieving a lower emissions energy future for our customers and the second of the two components of the NGO.

4.2 JGN response to the draft decision

While we are concerned with the draft decision allowance, we have identified areas where we can accept the AER's draft decision. These include digital metering,[22] data logger batteries and our defective metering program reducing meter replacement and ICT capex. These items, together with updated escalation and overheads which affect most categories, reduce our capex forecast by $14.9 million.

However, we are unable to accept the AER's draft decision in respect of connecting renewable gas, the scope factor allowance included in our cost estimates, our planned meter replacement forecast volumes and our project to replace obsolete end-of life equipment at Tempe Pressure Reduction Station (**PRS**). Accepting these reductions would prevent us from maintaining the safety and integrity of our network, meeting our regulatory obligations and reducing emissions.

A summary of our response is set out in Table 4.1.

Table 4.1: JGN's response to the key elements of the AER's draft decision on capex

Draft Decision	JGN's response – Revised 2025 Plan
Connections Capex - Renewable Gas	
The AER did not accept our forecast of $80.8 million due to concerns around the economic value of these projects given potential alternative uses for biomethane feedstock.	We do not accept the AER's draft decision and have retained our proposed renewable gas projects. We have updated our analysis to take into account the AER's feedback by considering a counterfactual where feedstock is used for electricity generation. We found that each of our proposed projects continue to provide net economic benefits in the order of $3.35 billion. We have included $79 million in our Revised 2025 Plan. We have also proposed a fixed principle to deal with the AER's concern of completion risk, which we discuss in chapters 7 and 9. We provide more detail in *JGN - RP - Att 4.2 - Renewable gas expenditure – 20250115.*
Scope Factor Allowance	
The AER did not accept the inclusion of an adjustment for scope risk in our cost estimates, totalling $43.1 million across all projects. It considered individual project-level cost variations will balance out across our investment portfolio.	We do not accept the AER's draft decision. Contrary to the AER's hypothesis, project level scope risk does not balance out at the portfolio level. This is well known and recognised by the Association for the Advancement of Cost Engineering and AEMO (who make similar adjustments in the Integrated System Plan). We provide 10-years of evidence that our cost estimates are exceptionally accurate *only* when scope factor allowance is included. We also note that our cost estimation methodology has been unchanged for 10 years, has been reviewed and accepted by two separate technical engineering consultants and accepted by the AER in two previous decisions. Accordingly, we retained the inclusion of the scope factor allowance across our project cost estimates (included for all network projects and affecting most capex categories). We provide more detail in section 1 of *JGN - RP - Att 4.1 - Capital expenditure – 20250115*.

22 As requested, we have also removed ICT related to digital meters. The AER also asked that we provide information on the volume and cost of meters that need to the replaced in the absence of this program. We have made no adjustment as this is not necessary as our digital metering program was costed up on an incremental basis.

Draft Decision	JGN's response – Revised 2025 Plan
Planned Meter Replacement	
The AER did not accept our planned meter replacement forecast ($67.1 million) substituting an alternative forecast based on a historical average ($29.4 million), a cut of $37.7 million.	We do not accept the AER's draft decision. We provide evidence demonstrating that our forecasting assumptions around meter accuracy (for meters which have not yet been tested) are exceptionally optimistic – and in turn our forecast is lower than reasonable alternative forecasting approaches. For example, our 2025 Plan assumes residential gas meters will continue to be accurate until 35-years of age. This is significantly longer than: – Assumptions applied by all other Australian gas distribution businesses and approved by the AER or the ERA (18 – 25 years). – What we had and the AER assumed for the 2020-25 period (25 and 25.01 years respectively) – Applying a similar approach, but with updated information, to what we applied in our 2020 Plan and the AER applied in its final decision (30 years or 28.29 years). We are not aware of any gas business globally operating gas meters to 35 years of age. In contrast, the AER's approach of taking a historical average does not take into account the age-profile of our meters, their mechanical nature, available test data or Australian good industry practice and in turn is not consistent with Rule 74.[23] We provide more detail in section 2 of *JGN - RP - Att 4.1 - Capital expenditure – 20250115*.
Tempe PRS	
The AER did not accept our proposal to replace end-of-life equipment at Tempe PRS at a cost of $5.7 million, and suggested that we consider updating our CBA analysis for the economic value resulting from increased safety and integrity that arises by replacing it	We do not accept the AER's draft decision. We have retained our Tempe PRS project and provide further information on how the functionality, safety and reliability of our network cannot be maintained without the project. Operating a high-pressure facility (supplying 50,000 customers, including 61 industrial customers) to failure puts the community and our employees at risk, will lead to a 25-day outage, is not consistent with Australian standards and will breach our regulatory obligations. We have updated our economic analysis to value emissions benefits and apply a more realistic (but still very conservative) value of reliability. This shows that our preferred option provides the highest economic value – even without quantifying the primary drivers of the project (safety, integrity and compliance). We note that requiring a positive net economic value is not consistent with the Rules, past AER decisions, the decisions of other economic regulators, the views of technical engineering consultants previously relied on the by AER, safety regulators, our technical regulatory requirements or accepted Australian gas industry practice. Our Tempe PRS project is included in facilities and pipes capex. Refer to section 3 of *JGN - RP - Att 4.1 - Capital expenditure – 20250115* for further detail.

We have also included the following updates in our Revised 2025 Plan:

- **2024 meter accuracy results** – we found that two lots of meters tested at 30 years of age did not pass their accuracy tests and must be replaced to comply with our regulatory requirements. In our Initial 2025 Plan we had assumed that these meters would be accurate until 35 years of age. This increased our forecast by $13.7 million.

23 Which requires forecasts to be arrived at on a reasonable basis and to represent the best forecast possible in the circumstances.

- **Implementation of a new abolishment service charge** – we have included $900,000 capex to be incurred in 2025-26 to support the implementation of a new abolishment service charge as discussed in section 9.6.
- **Our Revised 2025 Plan demand forecast** – for forecast connections that have been updated based on 2023-24 actuals and the latest Housing Industry Association (HIA) data. Due to changes in the mix of connections this increased capex by $6.0 million.
- **2023-24 RIN data** – as our connection and metering unit rates[24] are based on a 4-year average of the most recent RIN data available. This increased our connections and metering forecast capex by $5.5 million each.
- **Our revised approach to Picarro** – reducing our capex forecast by $0.2m (two less cars).
- **2023-24 actual inflation -** in the connections forecast model. In making this update we also identified an inflation calculation error which we corrected.[25] Together these changes increased our capex forecast by $9.5 million.
- **Other updates** – to revised escalators, updated inflation (applied to our project cost estimates) and the calculation of overheads. Collectively these updates reduced forecast capex by $5.2 million.

Overall, we have reduced our 2025 Plan by $12.0 million by accepting elements of the AER's draft decision; however, this has been offset by an increase of $34.8 million driven by updated inputs now available. We have made no change to any project or forecasting methodology to increase our forecast. A comparison of our forecast at the category level is shown in Table 4.2.

Table 4.2: Comparison of JGN's proposed 2025-30 capex to AER's draft decision ($2025, $M)

	JGN's 2025 Plan	AER's draft decision	Revised 2025 Plan
Connections	354.8	273.9	372.5
Meter replacement	158.6	110.8	171.1
Facilities and pipes	117.0	97.6	114.5
IT	45.9	45.9	40.9
Augmentation	15.1	13.5	14.8
Mains replacement	62.5	52.9	61.2
Other[26]	54.6	53.1	53.9
Overheads	23.7	22.5	26.4
Gross total	**832.5**	**670.1**	**855.2**
Contributions	15.9	16.1	17.1
Disposals	2.6	2.6	2.6
Net total	**813.9**	**651.5**	**835.6**

24 As well as programs forecast based on a straight 4-year average of historical costs.

25 Specifically, Sheet calc|inflation row 11, the index between real mid-year and nominal mid-year. This has been flagged in purple in our revised plan Connections capex forecast model.

26 This includes property, fleet and SCADA (the system which controls our network).

4.3 Attachments

Table 4.3 lists the attachments to our Revised 2025-30 AA Proposal which provide further information on our response to the AER's draft decision and our revised capex forecast.

Table 4.3: Revised 2025-30 AA Proposal attachments on our forecast capex

Attachment	Name	Author
4.1	JGN - RP - Att 4.1 - Capital expenditure - 20250115	JGN
4.2	JGN - RP - Att 4.2 - Renewable gas expenditure - 20250115	JGN
4.3M	JGN - RP - Att 4.3M - Capital expenditure forecast model - 20250115	JGN
4.4M	JGN – RP – Att 4.4M – Metering replacement volume forecast model - 20250115	JGN
4.5M	JGN – RP – Att 4.5M – Metering replacement capex forecast model - 20250115	JGN
4.6	JGN - Oxford Economics - RP - Att 4.6 - Input cost escalation - 20241216	Oxford Economics
4.7	JGN - Frontier - RP - Att 4.7 - Renewable gas expenditure technical note - 20241220	Frontier Economics
4.8M	JGN - Frontier - RP - Att 4.8M - Revised 10056139 Lilli Pilli CBAM - 20241220	Frontier Economics
4.9M	JGN - Frontier - RP - Att 4.9M - Revised 13127805 Blue Gum CBAM - 20241220	Frontier Economics
4.10M	JGN - Frontier - RP - Att 4.10M - Revised 13127877 Huon Pine CBAM - 20241220	Frontier Economics
4.11M	JGN - Frontier - RP - Att 4.11M - Revised 13127883 Kauri CBAM - 20241220	Frontier Economics
4.12M	JGN - Frontier - RP - Att 4.12M - Revised 13128085 Wollemi CBAM - 20241220	Frontier Economics
4.13M	JGN - Frontier - RP - Att 4.13M - Revised 13128087 Coolabah CBAM - 20241220	Frontier Economics
4.14M	JGN - Frontier - RP - Att 4.14M - Revised 13128093 Iron Bark CBAM - 20241220	Frontier Economics
4.15M	JGN - Frontier - RP - Att 4.15M - Revised 13128098 Red Gum CBAM - 20241220	Frontier Economics
4.16M	JGN - RP - Att 4.16M - Connections capex forecast model - 20250115	JGN
4.17M	JGN – RP – Att 4.17M – Revised Tempe PRS CBAM - 20250115	JGN
4.18M	JGN - Frontier - RP - Att 4.18M - Electricity counterfactual Lilli Pilli CBA model - 20250110	Frontier Economics
4.19M	JGN - Frontier - RP - Att 4.19M - Electricity counterfactual Blue Gum CBAM - 20250110	Frontier Economics
4.20M	JGN - Frontier - RP - Att 4.20M - Electricity counterfactual Huon Pine CBAM - 20250110	Frontier Economics
4.21M	JGN - Frontier - RP - Att 4.21M - Electricity counterfactual Kauri CBAM - 20250110	Frontier Economics
4.22M	JGN - Frontier - RP - Att 4.22M - Electricity counterfactual Wollemi CBAM - 20250110	Frontier Economics
4.23M	JGN - Frontier - RP - Att 4.23M - Electricity counterfactual Coolabah CBAM - 20250110	Frontier Economics
4.24M	JGN - Frontier - RP - Att 4.24M - Electricity counterfactual Iron Bark CBAM - 20250110	Frontier Economics
4.25M	JGN - Frontier - RP - Att 4.25M - Electricity counterfactual Red Gum CBAM - 20250110	Frontier Economics

5. Our operating expenditure requirement

5.1 AER draft decision

Our Revised 2025 Plan opex forecast for our Transportation Reference Service (**RS**), compared with our 2025 Plan and the AER's draft decision, is shown in Table 5.1.

Table 5.1: Comparison of JGN's proposed and revised 2025-30 Transportation RS opex to AER's draft decision ($2025M)

	Our 2025 Plan	AER's draft decision	Revised 2025 Plan
Total opex[27]	1,155.2	1,161.7	1,148.5

The AER's draft decision included $66.4 million for forecast costs of small customer connection abolishments. The AER's alternative estimate of the total opex forecast, excluding small customer connection abolishments opex, is $1,095.4 million. This compares with our proposed opex of $1,155.2 million, or $59.8 million lower (5.2%) than JGN's proposed opex forecast.

We largely accept the AER's draft decision other than for:

- Substitution of alternative customer number forecasts derived by ACIL Allen in calculating our output growth trend.
- Socialising all small customer connection abolishments and setting our abolishment costs at the same level as Victorian network businesses.
- Rejection of 5 of our 8 proposed Picarro cars.
- Categorising our Jurisdictional charges (licence fees) as an opex step change rather than a category specific forecast.

We have updated our base year for audited results and where appropriate updated components to be consistent with any changes made in other parts of our Revised 2025 Plan.

5.2 JGN response to the draft decision

Our Revised 2025 Plan seeks to address the key issues raised by the AER in its draft decision with the aim of demonstrating that our opex forecast represents the best forecast in the circumstances. Table 5.2 summarises the key elements of our response to the AER's draft decision on opex. More detailed responses are contained within *JGN - RP - Att 5.1 - Operating expenditure - 20250115 - Public*.

Table 5.2: JGN's response to AER draft decision on opex

2025 Plan	AER draft decision[28]	JGN response – Revised 2025 Plan
Base year		
Selection of base year	Found that JGN's base opex is likely to be efficient based on our 2023-24 estimate opex, noting that it will finalise its view on whether 2023-24 opex is an appropriate choice of base year when it considers our actual 2023-24 opex.	We accept the AER's draft decision on our estimated 2023-24 base year opex and have submitted our audited 2023-24 total opex excluding category specific forecasts of $190 million for its consideration, which is closely aligned with our estimate of $191 million total opex submitted in the Initial 2025 Plan. While the total opex for Transportation RS and Ancillary RS is the same, the small increase in Transportation RS opex is due to lower than expected ancillary activities.

27 Including debt raising costs and socialised abolishment costs, excluding ancillary reference service costs.

28 AER Draft decision Jemena Gas Networks (NSW) access arrangement 2025 to 2030 (1 July 2025 to 30 June 2030), Attachment 6 – Operating expenditure, November 2024, revision 6.1 and section 6.1.

2025 Plan	AER draft decision[28]	JGN response – Revised 2025 Plan
Adjustments to base year	Accepted our adjustment of $2.5 million for Software as a Service (**SaaS**) costs in the base year.	We accept the AER's draft decision on the treatment of SaaS adjustment to our base year, and have updated the number for the actual SaaS costs in 2023-24 of $2.1 million.
	Modified our annual adjustment for incremental ICT project opex from $2.4 million to $2.1 million, or from $12.0 million to $10.7 million over the 2025-30 period. The AER did not accept our forecast project opex for replacing 8,000 end of life chronic no access meters with remote meters.	We accept the AER's draft decision on our incremental ICT project opex.
	Accepted the adjustment to our base year for removing the Ancillary RS costs, estimated at $21.9 million.	We have updated the Ancillary RS costs to actual audited costs of $17.5 million. The lower costs resulted from lower volumes of Ancillary RS activities than expected.
Forecast trend		
Output growth	We proposed an average annual output growth of 0.6%, which increased our proposed opex forecast by $19.0 million. The AER forecast average annual output growth of 0.2%, resulting in $7.7 million increase in its alternative estimate of total opex, or $11.3 million less than what we proposed. This was driven by the AER adopting its alternative customer number forecasts prepared by ACIL Allen, excluding disconnections in the output measure, and a calculation change in averaging the output growth across econometric models.	We do not agree with the alternative demand forecasts prepared by ACIL Allen, and the approach of excluding disconnected customers. We discuss our reasoning and amended demand forecasts in chapter 6. We have also updated the model calculations to account for the average output growth of econometric models correctly[29]. Based on our revised customer number forecasts, including disconnected customers, and updating the calculation of output growth, we propose $15.6 million for output growth. See section 3.1 in *JGN - RP - Att 5.1 - Operating expenditure - 20250115 - Public* for more details.
Price growth	We proposed an average annual price growth of 0.7%, which increased our total opex forecast by $19.2 million. The AER updated DAE forecasts in its alternative estimate, which resulted in an average 0.7% growth, increasing its total opex alternative estimate by $18.7 million.	We have updated our price growth inputs for the latest available information from Oxford Economics which results in an average annual price growth of 0.6%, increasing our total opex forecast by $17.7 million. See section 3.1 in *JGN - RP - Att 5.1 - Operating expenditure - 20250115 - Public* for more details.

29 The AER's draft decision opex model included a calculation for averaging the output growth across all econometric models. However, it inadvertently included four models with two blank ones of zero inputs, when there are only two available models. It underestimated JGN's actual output growth. We have, therefore, updated the calculation in our revised proposal opex model to correctly account for the average of two econometric models instead of four.

2025 Plan	AER draft decision[28]	JGN response – Revised 2025 Plan
Productivity growth	The AER is satisfied that our approach is reasonable and adopted our forecast average annual productivity growth factor of 0.9%.	We accept the AER's draft decision and have updated the dollar amount as a result of other changes to opex forecasts. We note that our 0.9% productivity adjustment is the highest among all recent decisions for electricity and gas distribution networks. It shows our significant commitment to deliver cost savings to our customers. In its draft decision, the AER suggested that we absorb any increased opex within the trend allowance rather than seeking step changes or specific forecasts, particularly for Picarro devices and our emissions reporting obligations. Our substantial productivity adjustment—resulting in a negative output growth net of productivity—makes it particularly challenging to absorb additional opex within the trend component. We request the AER to assess our step change proposals in light of our significant productivity commitments and the cost reductions we aim to deliver for the benefit of our customers.
Step changes		
Emissions measurement – Picarro leak detection services	Rejected our proposed forecast opex step change on the basis that it is not satisfied that we have demonstrated that the proposed uplift to 8 Picarro units is prudent and efficient for emission reduction measurement and reporting purposes. The AER is instead satisfied that the prudent level is the 3 Picarro units JGN currently has in operation.	We do not accept the AER's decision. We consider that 3 vehicles (units) approved by the AER in its draft decision is not the most prudent and efficient option, and would not deliver maximum net benefits to our customers. Instead, as an interim plan, we consider that we adopt an alternative survey plan approach whereby we survey poor quality areas each year and undertake periodic surveys for our good areas. Our engineering modelling and calculations suggest that this can be achieved with 6 vehicles, instead of 8. We provide our reasoning and additional information in section 5.3.
ICT services for new projects	Modified our opex step change forecast for ICT services for new recurrent projects to remove ongoing opex for chronic no access meters from $15 million to $14.7 million over the 2025-30 period, and included some placeholder decisions based on our proposed forecasts for part of the ICT program pending further information on: 1. Cloud capacity growth 2. Contract Lifecycle Management 3. Asset Investment Optimisation.	We accept the AER's draft decision to remove ongoing opex for chronic no access meters, resulting in an ICT opex step change of $14.6 million over the 2025-30 period. We provide further information associated with the AER's placeholder decisions on ICT services for new projects in section 5.4.
Emissions reduction – Climate change	Rejected our proposed forecast opex step change.	We accept the AER's draft decision.
Pipeline Integrity Management Program	Modified our opex step change from $28.1 million to $17 million over 2025-30 period to remove double counting resulting from the PTRM adjustment for 2024/25 opex forecast.	We accept the AER's draft decision.

2025 Plan	AER draft decision[28]	JGN response – Revised 2025 Plan
Customers experiencing vulnerability support	Reclassified our proposed opex step change to a category specific forecast ($2.7 million over the 2025-30 period).	We accept the AER's draft decision.
Category specific forecasts		
Jurisdictional charges (licence fees)	Reclassified as an opex step change.	We do not accept the AER's draft decision and propose that jurisdictional charges remain a category specific forecast with an annual true-up in the price control formula. This is because they are uncontrollable costs with high year-on-year variations. Our proposed treatment reduces the potential for an arbitrary ECM outcome and maintains alignment with other regulatory frameworks including electricity networks. See section 6.1 of *JGN - RP - Att 5.1 - Operating expenditure - 20250115 – Public* for more details.
Unaccounted for gas (UAG)	Modified the basis of how we calculate our UAG allowance, resulting in our forecast UAG decreasing from $145.8 million to $141.7 million over the 2025-30 period.	We accept the AER's approach to calculating our UAG allowance. We have revised our UAG allowance to $139.3 million based on our revised demand forecasts and applying the AER approach to calculating UAG per its draft decision.
Safeguard mechanism	Rejected our proposed category specific forecast on the basis that it is recovered through the tariff variation mechanism.	We accept the AER's draft decision to recover safeguard mechanism costs (or return safeguard mechanism revenue) via the tariff variation mechanism.
Debt raising costs	Modified our forecast debt raising costs from $9.7 million to $9.5 million over the 2025-30 period.	We accept the AER's draft decision and have updated the values to reflect revised proposal forecasts, resulting in debt raising costs of $9.6 million.

2025 Plan	AER draft decision[28]	JGN response – Revised 2025 Plan
Small customer connection abolishments	Included additional opex for small customer abolishment costs to socialise a proportion of small customer connection abolishment costs across transportation reference service tariffs, and establish a discounted ancillary reference service tariff, to ensure the safe operation of the network.	We do not agree with the AER's suggestion that our abolishment costs should be the same as Victorian network businesses. We consider that our abolishment charges should remain cost-reflective. Our customers also expressed support for maintaining a cost-reflective abolishment charge. We note that correspondence cited by the AER in its draft decision from the NSW safety regulator within the NSW Department of Climate Change, Energy, the Environment and Water (**NSW DCCEEW**) indicates that it supports the socialisation of abolishment tariffs, meaning that the AER is unlikely to change its draft decision on this matter. Therefore, although we disagree with AER's rationale for socialising a proportion of small customer connection abolishment costs across Transportation RS tariffs, we have decided to adopt the option of adding a new abolishment service charge for a Standard Residential Connection where there is no current or anticipated redevelopment, renovation or other construction works at a discounted price of $250. The difference between the $250 charge for this abolishment service and our standard cost-reflective charge for other abolishment services of $1,472 will be socialised. This results in an additional $16.3 million opex compared with the AER's draft decision of $66.4 million. These new services will apply from 1 July 2026 once we have implemented the necessary system and process changes to enact them. We provide our reasoning and additional information in *JGN – RP - Att 7.1 – Abolishments - 20250115 - Public.*

5.3 Emissions measurement – Picarro leak detection services

To play our role in delivering Australia's lower emissions energy future, we identified the need for greater visibility of leaks across our network. Accordingly, over the 2020-25 period, we trialled innovative Picarro technology which provides granular and accurate data on the location and size of leaks.

In 2023 we deployed 2 vehicles to replace our existing 5-yearly walking survey, required to comply with our regulatory obligations. We purchased a third vehicle in early 2024 to enable the measurement of emissions reductions from network pressure reduction and targeted mains replacement initiatives. This results in 2.25 vehicles included in our 2023-24 base year.

In developing our Initial 2025 Plan, we identified that enhanced use of this technology – in particular surveying 100% of our network each year with 8 vehicles – will improve the safety of our network, reduce emissions and lower Safeguard Mechanism costs (and network bills) by facilitating the move to direct emissions measurement.

Using innovative technology, to more frequently and more accurately detect emissions, as part of a leak detection and repair (LDAR) program is now accepted good industry practice. LDAR – in particular the use of new technology and frequent inspections – is now mandated in Europe and will likely soon be required in the United States.

Further, adopting Picarro technology is consistent with the AER's desire for gas network businesses to pursue innovative projects that help more efficiently manage the network consistent with the NGO. It is also consistent with what our customers told us (with 94% Customer Forum support) to reduce network emissions rather than relying on the purchase of carbon credits.

The AER's draft decision did not accept our proposal to increase the number of vehicles to 8. The primary reason was that it considered adopting 3 to 5 yearly surveys and using engineering calculations and modelling would be sufficient to move to direct emissions reporting.

We consider that the draft decision did not give adequate consideration to the safety benefits or reduction in actual emissions achieved from enhanced surveys. We note that reducing *actual* not reported emissions is what is required to address the threat of climate change and is the focus of the NGO. Further we believe it is in the community's best interests from a safety perspective to identify gas leaks annually rather than 5-yearly given the technology now exists to do so.

We also note that since lodging our Initial 2025 Plan the Government has clarified its position on future changes to emissions reporting. The Government has made an in-principle decision to introduce higher-order emission reporting methods – required to report emissions based on Picarro data.[30] However, in making these changes it will consider international reporting frameworks, such as OGMP 2.0 and the Measurement, Monitoring, Reporting and Verification (MMRV) framework.

Accordingly, it is unlikely that emissions data based on data from 3 or 5 year surveys will be of sufficient quality for direct emissions reporting. This is because under OMGP 2.0 members are expected to work towards achieving 'level 5' reporting (which requires annual reporting) while using data 3 to 5 years old would result in a 'D' or 'F' grade under the proposed MMRV framework.[31]

We have considered the AER's feedback about the potential for engineering modelling and calculations. Estimating emissions based on partial surveys would require us to undertake spatial-temporal extrapolation – which is only possible if we obtain sufficient representative sample data. Given the diverse nature of our network – given the range of materials, ages, pressures, soils and geography of each part of our network – we would need to collect data from a large number of samples to reasonably estimate network conditions and degradation and in turn emissions across all network types. We consider that spatial-temporal extrapolation is not possible with 3 vehicles.

Our additional engineering analysis identified that the minimum number of vehicles required to undertake spatial-temporal extrapolation is 6. Under this approach we will survey poor quality areas of our network each year and undertake less frequent periodic surveys for good areas.

We have also received the following new information since we submitted our Initial 2025 Plan:

- Safety benefits – recent events indicate that the public is reporting fewer leaks than we had anticipated. This means the improved safety outcomes from more frequent inspections and in turn a more effective LDAR program are greater than initially expected.
- Leak data – key insights include:
  - It is more efficient to focus on leak detection rather than leak repairs as a small number of leaks drive the majority of emissions. Our latest Picarro data shows the top 10% of leaks are responsible for 52% of our fugitive emissions. Greater leak detection data enables us to focus on the largest and highest value leaks and improve the effectiveness of our repair program.
  - Network deterioration is random and continuous. Leaks have been identified across all network areas including in those in good condition. In areas we have surveyed twice we have found new large leaks within a year, highlighting the benefits of regular inspections.

30 See here. We also note that the introduction of a new emissions reporting methodology is implemented through a legislative instrument determined by the Minister for Climate Change and Energy. An act of parliament is not required. And see Climate Change Bill 2022 Revised Explanatory Memorandum.

31 See slide 19 and 20 here.

- Gas Supply Acts amendments – Picarro leak detection is consistent with the NSW government proposed amendments to enhance governance, safety, and operational efficiency of the regulatory regime established by Pipelines and Gas Supply Acts.[32]

Taking into account the new information available, we have re-evaluated our approach by considering the status quo (3 vehicles), spatial-temporal extrapolation (6 vehicles) or maintaining our approach to survey 100% of the network (8 vehicles). Based on economic analysis, we have changed approach in our Revised 2025 Plan to move to adopting a staged approach (option 4) where we adopt spatial-temporal extrapolation before moving to 100% annual surveys (in the 2030-35 period). This option delivers similar benefits to 8 vehicles although it comes at the risk that data quality is not sufficient to move to direct emissions measurement. In this case we will need to purchase additional Picarro units in the 2025-30 period.

Accordingly, we have reduced our step change to 3.75 vehicles (down from 5.75) in our Revised 2025 Plan. We believe that moving to 6 vehicles represents a prudent and efficient approach, consistent with accepted good industry practice, and will enable us to:

- Ensure public safety, which has been a key concern of the AER’s draft decision, by reducing the risk of leaks from the gas network.
- Optimise the benefits to our customers, and the community, of reducing emissions. The most efficient approach to emissions management requires accurate information as to the size and location of the leaks from the gas network. Given the network is continually deteriorating more frequent inspections are required to materially reduce emissions.
- Move to direct emissions measurement for reporting purposes. This is critical to ensuring that consumers do not pay more than necessary under the Safeguard Mechanism. Over time, if we continue to report costs under the current reporting method consumers will pay higher costs as we will report more emissions than we actually emit.

Our revised approach remains consistent with customer expectations who endorsed our proposal to expand the use of Picarro leak detection to reduce carbon emissions instead of buying carbon credits.

We note that with 6 vehicles we will bear the risk over 2025-30 period if the government accepts our proposal to move to direct emissions measurement, requiring 8 cars. Our alternative approach reduces our forecast opex step change for Picarro leak detection services from $20.8 million to $15.3 million over the 2025-30 period.

We provide further detail on our revised forecast Picarro leak detection services in section 4.1 of *JGN - RP - Att 5.1 - Operating expenditure - 20250115 - Public* and *JGN - RP - Att 5.3 - Picarro - 20250115 – Public*.

5.4 Further information

This section summarises the further information requested by the AER in its draft decision on some of our opex step change forecast for ICT services.

5.4.1 Cloud capacity growth

In its draft decision, the AER raised concerns that our proposed annual growth rate of 15% for cloud capacity appears excessive. The AER requested more information to justify the basis for this forecast.

32 See https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/public-consultations/pipelines-and-gas-supply-acts

In response to evolving business needs and technological advancements, JGN has embraced cloud computing in accordance with accepted good industry practice.[33] As a result, our projection for cloud capacity growth stands at a conservative estimate of 15% per year, highlighting overall net savings in terms of our storage and compute processing costs. It should be noted that the 15% forecast growth is related to the organic growth of existing systems and does not relate to the growth associated with new projects or new systems coming online; these project-related cloud costs are accounted for separately in project-related forecasts.

This forecast growth aligns with industry insights, and is driven by the following key drivers:

- Security
- Compliance
- Backup and disaster recovery
- Vendor-driven
- Innovation – data-driven decision making

More detail is available in section 4.1.1 of *JGN - RP - Att 5.1 - Operating expenditure - 20250115 – Public*.

5.4.2 Contract Lifecycle Management

In its draft decision, the AER requested that we provide information on the annual expenditure on the legacy systems that will not be incurred following the implementation of the Contract Lifecycle Management (**CLM**) project. Further, the AER wants to understand how these savings have been accounted for in the proposed non recurrent opex for this project.

Following the implementation of the CLM system, existing systems will need to be retained and so there are no associated savings. Further, we expect any operating efficiency savings will be offset by the increased volume and complexity of contract lifecycle management work due to increased complex regulatory and legislative obligations.

More detail is available in section 4.1.2 of *JGN - RP - Att 5.1 - Operating expenditure - 20250115 – Public*.

5.4.3 Asset Investment Optimisation

In its draft decision the AER supports the benefits of this project and found that the associated costs appear prudent and efficient pending confirmation. However, the AER has requested that we provide details of the costs to support the legacy system, and how these costs (or cost savings) have been accounted for in the proposed costs for this project.

We confirm that there are no legacy system licencing or support opex cost savings. We also confirm that there are no opex savings related to front line staff.

More detail is available in section 4.1.3 of *JGN - RP - Att 5.1 - Operating expenditure - 20250115 – Public*.

33 As required in rule 91 of the NGR.

5.5 Attachments

Table 5.3 lists the attachments to our Revised 2025-30 AA Proposal which provide further information on our response to the AER's draft decision on our revised opex forecast.

Table 5.3: Revised 2025-30 AA Proposal attachments on our forecast opex

Attachment	Name	Author
5.1	JGN - RP - Att 5.1 - Operating expenditure - 20250115	JGN
5.2M	JGN - RP - Att 5.2M - Operating expenditure forecasting model – 20250115	JGN
5.3	JGN - RP - Att 5.3 - Picarro - 20250115	JGN
5.4	JGN - DCCEEW - RP - Att 5.4 - Implementation of PICARRO Vehicle Mounted Leak Survey Methodology Response - 20241119	DCCEEW
7.1	JGN - RP- Att 7.1 - Abolishments - 20250115	JGN

6. Forecasting new connections and gas consumption

6.1 AER draft decision

In its draft decision the AER does not accept JGN's demand forecast, and substituted an alternative forecast prepared by ACIL Allen for our **Volume Market** customers that includes a lower:

1. rate of disconnections and abolishments for residential customers
2. decline in usage per residential and commercial customer.

ACIL Allen prepared its alternative forecast by assuming that usage will be in line with historical usage based on regression analysis. Based on advice from ACIL Allen, the AER encouraged us to provide further information and more transparent justification for our assumptions in our Revised 2025 Plan to support our demand forecast, and to update our forecasts for the latest available data.

For our **Demand Market** forecast the AER is not satisfied that our forecasts for Tariff D demand represents the best forecast under the circumstances. It included our forecast as a placeholder, and requested further information and analysis in support of our forecast.

6.2 JGN response to the draft decision

The AER's draft decision[34] requires that we amend our demand forecast in our access arrangement to reflect the AER's draft decision for Tariff V.

We do not agree with the AER's reasoning and / or analysis for doing so and do not accept the AER's alternative demand forecast for our Volume Market.

We have considered feedback from the AER (and ACIL Allen) in its draft decision, and where appropriate addressed concerns raised by the AER. We engaged CORE Energy & Resources (**CORE**) to revise our demand forecast and engaged Frontier Economics to complete an independent review of CORE's initial and revised Volume Market forecast demand, and the AER's alternative Volume Market forecast demand. We note that whilst we have been given access to the *'ACIL Allen JGN forecast adjustment'* spreadsheet which sets out its alternative forecast for our Volume Market, many of the inputs are hard coded making it difficult to analyse how ACIL Allen has determined its various adjustments to our Volume Market forecast. The adjustments also have not been adequately explained by ACIL Allen in its review report to the AER.

We have adopted CORE's revised Market Volume and Demand Market forecasts in our Revised 2025 Plan.

We note that our actual demand over 2023-24, particularly average demand per connection for our Volume Market, is significantly lower than we anticipated in our Initial 2025 Plan demand forecast and those in ACIL Allen's alternative demand forecast. The lower average demand per connection for our Volume Market has continued over the period 1 July to 31 December 2024.

Our Revised 2025 Plan seeks to address the key issues raised by the AER in its draft decision with the aim of demonstrating that our demand forecast represents the best forecast in the circumstances. Table 6.1 summarises the key elements of our response to the AER's draft decision on demand.

34 AER Draft decision Jemena Gas Networks (NSW) access arrangement 2025 to 2030 (1 July 2025 to 30 June 2030), Attachment 12, November 2024, table 12.5 revision 13.1.

Table 6.1: JGN's response to AER draft decision on demand

	AER draft decision	JGN response
Volume (Tariff V) market		
Residential connections and average demand	The AER forecasts that our residential demand will fall by 3.3%, compared with our forecast fall of 8.2% over the 2025-30 period. This difference is driven by adopting ACIL Allen's proposed alternative forecast for: – disconnections on the basis that while disconnection rates are likely to increase over the next 5 years, it does not consider that we have justified an exponential increase, particularly in the absence of subsidies or other incentives of sufficient size to support switching – the final 3 years average demand based on modelling of regression analysis of historical usage, and modified for the impact of price differentials between electricity and gas. The AER flagged the opportunity for us to provide further information and analysis to support our forecast demand in our revised proposal. The AER accepted our forecast residential new connections.	We have proposed a modified Volume Market forecast for residential customers to reflect the latest available information at the time of our Revised 2025 Plan (including 2023-24 actual demand and HIA data and a new rate of increase to disconnections and abolishments). This has resulted in significant changes to our net disconnection forecasts and demand per connection, with an overall 3.5% reduction in residential demand over the 2025-30 period. A summary of our revised residential connections and average demand average forecast is set out in section 6.3.
Commercial connections and average demand	The AER forecasts our commercial demand will fall by 7.6% compared with our forecast fall of 15.2% over the 2025-30 period. This difference is driven by adopting ACIL Allen's proposed alternative forecast for the final 3 years average demand based on modelling of regression analysis of historical usage, and modified for the impact of price differentials between electricity and gas. The AER flagged the opportunity for us to provide further information and analysis to support our forecast demand in our revised proposal. The AER accepted our forecast commercial customer numbers.	We have proposed a modified Volume Market forecast for commercial customers to reflect the latest available information at the time of our Revised 2025 Plan (including 2023-24 actual demand). This has resulted in us varying our forecast disconnections and abolishments driven by different electrification assumptions, with an overall 12.1% reduction in commercial demand over the 2025-30 period. A summary of our revised average demand for our commercial customers and resulting demand forecast is set out in section 6.3.

	AER draft decision	JGN response
Demand (Tariff D) market		
Industrial connections and demand	The AER is not satisfied that our forecasts for Tariff D demand represents the best forecast under the circumstances. It included our forecast as a placeholder, and requested further information and analysis in support of our forecast. Our Demand Market forecasts over the 2025-30 period were reduced connections of 2.8% and 8.3% lower annual contract quantity.	We have proposed a modified Demand Market forecast to reflect the latest available information at the time of our Revised 2025 Plan (including 2023-24 actual demand and public announcements). The most significant change was to remove the termination of activity by a large, surveyed customer who had previously indicated a large annual load would be maintained through to 2030. In addition, CORE revised its adjustment to the base forecast to address an expected structural change in future consumption due to efficiency measures, energy saving technology investment and appliance/fuel switching. This has resulted in 2.6% lower annual contract quantity over the 2025-30 period. A summary of our revised average demand for our Demand Market customers and resulting demand forecast is set out in section 6.3.

Our revised demand forecast represents the best forecast possible in the circumstances

We consider that our observations and revised demand forecasts are arrived at on a reasonable basis, that represent the best forecast possible in the circumstances, as required by rule 74(2) of the NGR. Further, we consider that our revised demand is most likely to provide us with a reasonable opportunity to recover at least the efficient costs we incur in providing reference services, as required by the revenue and pricing principles relating to scheme pipelines in clause 24(2)(a) of the NGL. This is because our forecast demand is:

1. a driver of our forecast opex and capex (new connections), making up a significant part of our total revenue requirement
2. an important input into the derivation of our reference tariffs. Under our hybrid price cap form of control we bear the full risk of variations that are within +/- 5% from our demand forecast.
3. an important consideration in assessing the magnitude for accelerated depreciation allowance.

Given the highly uncertain future of gas, it is in our interests that we accurately forecast our demand over the 2025-30 period and minimise variations between actual and forecast demand. We consider that our revised demand forecast reflects a more realistic rate of decline as the energy market transitions than the AER's draft decision. Therefore, we consider that our revised forecast demand is more appropriate than the AER's alternative demand forecast in its draft decision.

Mid-period variation

We note that whilst the AER is open to us applying mid-period to vary our 2025–30 access arrangement if the trajectory of its demand is substantially different to its final decision under Part 8 Division 10 of the NGR[35], it is not our preferred outcome. Re-opening our access arrangement is very time consuming for everyone, particularly with limited resource availability in a challenging environment as the energy market transitions, leading to inefficiencies. We consider that our observations and revised demand forecasts are arrived at on a reasonable basis, that represent the best forecast possible in the circumstances, as required by rule 74(2) of the NGR.

35 AER draft decision, Jemena Gas Networks (NSW) access arrangement 2025 to 2030 (1 July 2025 to 30 June 2030), Attachment 12 – Demand, section 12.4.1.

6.3 Our revised demand forecast

We do not accept the AER's alternative demand forecast for our **Volume Market**.

ACIL Allen prepared its alternative forecast for our Volume Market, which the AER relied upon, by assuming that usage will be in line with historical usage based on regression analysis. Our 2023-24 actual average demand per connection for our Volume Market and over the period 1 July to 31 December 2024, is significantly lower than we anticipated in our Initial 2025 Plan demand forecast and those in ACIL Allen's alternative demand forecast. After adjusting for these actual results, the ACIL Allen alternative Volume Market forecast is significantly impacted.

Further, we note that because of the regression modelling approach relied on by ACIL Allen in developing its forecast demand, even after adjusting its analysis for our actual 2023-24 demand and potentially demand from 1 July to 31 December 2024, we consider that the regression analysis could mute the level of reduction in average volume market consumption over the 2025-30 period. This is likely to understate the likely rate of declining average demand per customer as the energy market transitions.

In preparing our revised **Demand Market** forecasts, CORE has modified them to reflect the latest available information at the time of our Revised 2025 Plan, including 2023-24 actual demand and public announcements, and has revised its adjustment to the base forecast to address an expected structural change in future consumption due to efficiency measures, energy saving technology investment and appliance/fuel switching.

Our revised demand forecast

We consider that our revised demand forecast, developed by CORE and which includes updated data for 2023-24, reflects a more realistic rate of decline than the AER's draft decision, and represents the best forecast possible in the circumstances, as required by rule 74(2) of the NGR. Furthermore, as demonstrated by Frontier Economics' analysis, our revised Volume Market demand forecast is very similar to the Volume Market demand forecast prepared by ACIL Allen, and adopted by the AER in its draft decision, once adjusted to account for our 2023-24 actual demand (ACIL Allen adjusted).

A summary of our revised demand forecast (as prepared by CORE) compared with our Initial 2025 Plan and the AER's draft decision are set out in Table 6.2 showing the net movement over the 2025-30 period. We have also included for our Volume Market the ACIL Allen adjusted and Frontier Economics alternative forecasts.

Table 6.2: Comparison of JGN's demand forecasts over the 2025-30 period (% movement)

	Our Initial 2025 Plan	AER's draft decision	ACIL Allen adjusted[36]	Frontier Economics	Revised 2025 Plan
Volume (Tariff V) market					
Residential connections	-1.6%	+0.4%	-0.6%[37]	-0.6%[38]	-0.6%
Residential average demand	-6.6%	- 3.7%	-3.9%	-3.2%	-3.0%
Residential demand	**- 8.2%**	**-3.3%**	**-3.6%**	**-3.0%**	**-3.6%**
Commercial connections	-2.0%	- 2.0%	-4.9%[39]	-4.9%[40]	-4.9%
Commercial average demand	-13.5%	- 5.8%	-6.0%	-3.0%	-7.5%

36 ACIL method applied to new data (Model 2 with COVID years).

37 Frontier Economics assumed CORE's revised proposal forecast figures for residential connections.

38 Ibid.

39 Frontier Economics assumed CORE's revised proposal forecast figures for commercial connections.

40 Ibid.

	Our Initial 2025 Plan	AER's draft decision	ACIL Allen adjusted[36]	Frontier Economics	Revised 2025 Plan
Commercial demand	**-15.2%**	**- 7.6%**	**-10.6%**	**-7.8%**	**-12.1%**
Demand (Tariff D) market					
Industrial connections	- 2.8%	- 2.8%	NA	NA	-2.1%
Annual contract quantity (ACQ)	**- 8.3%**	**- 8.3%**	**NA**	**NA**	**-2.6%**
Maximum daily quantity (MDQ)	**-10.5%**	**-10.5%**	**NA**	**NA**	**-2.6%**

Notes:

- In our Initial 2025 Plan, we measured the annual movement/change over the period, whereas in its draft decision the AER measures the total change over the period. We have disclosed our demand movements over the 2025-30 period on the same basis as the AER in its draft decision throughout this chapter.
- The lower movement over the 2025-30 period of our Revised 2025 Plan demand forecast compared with our Initial 2025 Plan is driven by our lower 2023-24 actual demand which is partially offset by adjustments made by CORE.
- The slightly larger decrease over the 2025-30 period of the ACIL Allen adjusted demand forecast compared with the AER's draft decision is driven by our lower 2023-24 actual demand.

The key reasons for the differences between our Revised 2025 Plan demand forecasts and the AER's draft decision are:

1. Residential average connections – CORE has updated its forecasts for new HIA data which has lower forecast commencements.
2. Residential net disconnections and abolishments – the ACIL Allen approach to developing forecasts of disconnections does not distinguish between disconnections and abolishments, whereas CORE does. CORE has applied a new rate of increase to disconnections and abolishments, which reflects a deferment/lower near-term rate of growth of disconnections.
3. Residential demand/connection – our lower actual 2024 result which impacts the forecast materially.
4. Small Business/Commercial average connections and demand/connection – the variance between the AER's and our forecast disconnections and abolishments driven in part by different electrification assumptions.
5. Demand Market/ Tariff D forecasts have been reduced for the termination of activity by a large, surveyed customer who had previously indicated a large annual load would be maintained through to 2030. Our lower actual 2023-24 result which impacts the forecast. In addition, CORE revised its adjustment to the base forecast to address an expected structural change in future consumption across a range of industrial segments due to efficiency measures, energy saving technology investment and appliance/fuel switching.

Independent review of our Market Volume forecasts concludes they are not unreasonable

We note that the independent review completed by Frontier Economics on our Volume Market demand forecast concluded that:

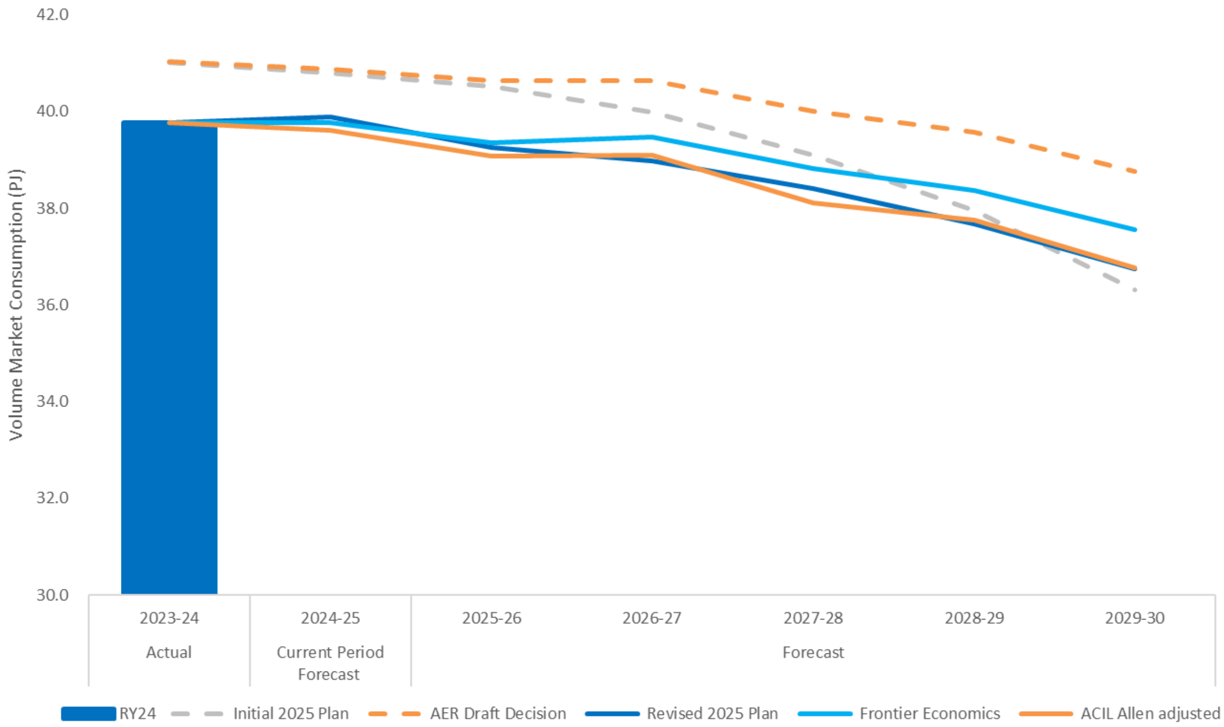
- For the residential market[41]: 'Our preferred econometric model provides forecasts that are very similar to CORE's revised forecasts and our estimation of what ACIL's existing models would deliver when applied to the new data which suggests that CORE's revised forecasts are not unreasonable.'
- For the commercial market[42]: Frontier Economics notes that its econometric approach implicitly assumes that historical trends are a good guide to the future. CORE's and ACIL Allen's forecasts suggest that historical trends are not a good guide in forecasting commercial demand per connection and both have made adjustments to their forecasts to amend the historical trends for the future likely impact of the energy transition. However, Frontier Economics notes that due to data and time constraints, it has not considered whether adjustments (by including other variables in and/or by making post-model adjustments to its econometric model) should be made to its forecast based on historical trends.

Our Volume Market forecast closely aligns with the ACIL Allen adjusted forecast

Figure 6.1 shows the comparison of our initial and revised Volume Market forecasts compared with the AER's draft decision, and the Frontier Economics ACIL Allen adjusted forecast and its alternative forecast. It shows that our revised Volume Market forecast closely aligns with the ACIL Allen adjusted forecast.

We note that it is inappropriate to directly compare the CORE and ACIL Allen forecasts to the Frontier Economics forecast for the total Volume Market given that Frontier Economics has not had the time or data to consider the need for making adjustments to historical trends for the commercial demand to account for likely future changes, such as changes resulting from the energy market transition. Rather, the Frontier Economics alternative forecast serves to demonstrate the reasonableness of the CORE revised forecast.

Figure 6.1: Comparison of JGN's Volume Market forecasts with the AER's and Frontier Economics alternative forecasts



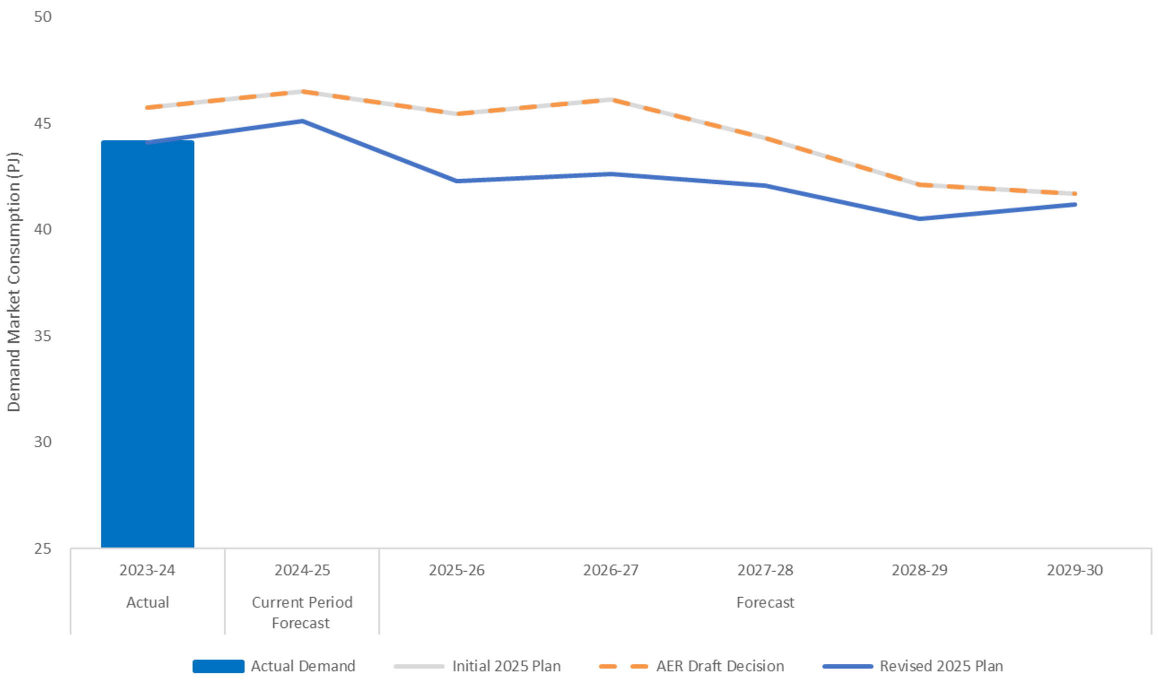
41 JGN - Frontier Economics - RP - Att 6.6 - Demand technical note – 20250109, section 2.7.

42 JGN - Frontier Economics - RP - Att 6.6 - Demand technical note – 20250109, section 3.7.

Our revised Demand Market consumption is forecast to decline at a lower rate than our Initial 2025 Plan

Figure 6.2 shows the comparison of our initial and revised Demand Market forecasts (the AER adopted our initial Demand Market forecast as a placeholder). It shows that our revised Demand Market forecast has been impacted by the lower 2023-24 demand, the impact in 2025-26 of the removal of a large customer and the net effect of structural adjustments made by CORE. Our revised Demand Market forecast is expected to be at a similar level to what we forecast in our Initial 2025 Plan in 2029-30 (i.e. the forecasts converge in 2029-30). This results in our forecast reduction in ACQ and MDQ of 2.6% over the 2025-30 period, which is much lower than we had forecast in our Initial 2025 Plan.

Figure 6.2: JGN's revised Demand Market forecasts



If the AER does not accept our revised demand forecast and develops an alternative forecast, then it needs to address the issues above in its alternative forecast.

We consider that our revised demand forecast reflects a more realistic rate of decline as the energy market transitions than the AER's Draft Decision and that they are arrived at on a reasonable basis, that represent the best forecast possible in the circumstances, as required by rule 74(2) of the NGR. Therefore, we have adopted CORE's revised Market Volume and Demand Market forecasts in our Revised 2025 Plan.

JGN - RP - Att 6.1 - Demand forecast - 20250115 – Public provides a detailed response to the AER's draft decision and on the basis of how we and CORE have considered the AER's draft decision and developed our revised demand forecasts. Attachments *JGN - Core Energy - RP - Att 6.2 - Demand Forecast Report - 20250115 – Public* and *JGN - Frontier Economics - RP - Att 6.6 - Demand technical note – 20250109* provide further support.

6.4 Attachments

Table 6.3 lists the attachments to our Revised 2025-30 AA Proposal which provide further information on our response to the AER's draft decision and our revised demand forecast.

Table 6.3: Revised 2025-30 AA Proposal attachments on our demand forecast

Attachment	Name	Author
6.1	JGN - RP - Att 6.1 - Demand forecast - 20250115	JGN
6.2	JGN - Core Energy - RP - Att 6.2 - Demand Forecast Report - 20250107	Core Energy
6.3	JGN - Core Energy - RP - Att 6.3M - NSW Demand Forecast Model – 20250107	Core Energy
6.4	JGN - Core Energy - RP - Att 6.4M - NSW EDD Index Model – 20250107	Core Energy
6.5	JGN - Core Energy - RP - Att 6.5M - Weather Normalised Demand Model - 20250107	Core Energy
6.6M	JGN - RP - Att 6.6M - Demand forecast mapping model - 20250115	JGN
6.7	JGN - Frontier Economics - RP - Att 6.7 - Demand technical note - 20250109	Frontier Economics

7. Our revenue requirement

7.1 Revenue

7.1.1 AER draft decision

The AER's draft decision on our total Transportation RS revenue requirement is $2,831.7 million ($Real 2025, smoothed). This is a reduction of $50.8 million (1.8%) from our Initial 2025 Plan. This is mainly driven by reductions to our proposed accelerated depreciation, capex and opex, which we discuss in the following sections.

Table 7.1 sets out the AER's draft decision on our total revenue requirement (by building block) for each year of the 2025–30 period, the total revenue after smoothing, and the x-factors it has determined for use in the tariff variation mechanism.

Table 7.1: Total revenue requirement in the AER's draft decision ($2024-25, $M)

	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Return on capital	218.4	217.2	215.8	213.7	210.0	1,075.1
Depreciation (return of capital)	87.5	92.8	99.5	105.6	110.9	496.2
Operating expenditure	232.2	226.0	229.1	232.4	242.0	1,161.7
Incentive schemes	36.3	4.4	(15.5)	5.3	6.1	36.7
Net tax allowance	11.1	11.7	12.4	13.3	14.5	63.0
Annual revenue requirement	**585.5**	**552.1**	**541.3**	**570.3**	**583.5**	**2,832.7**
Smoothed revenue	**567.7**	**571.2**	**567.7**	**565.9**	**559.2**	**2,831.7**
Price path (in real terms)	0.47%	0.47%	0.47%	0.47%	0.47%	
Price path excluding incentives (in real terms)	0%	0%	0%	0%	0%	

7.1.2 JGN response to the draft decision

Our response to the AER's draft decision is outlined in sections 7.2 to 7.7.

7.1.3 Revised proposal revenue forecast

Table 7.2 details our Revised 2025 Plan unsmoothed and smoothed Transportation Reference Service revenue and X factors for the 2025-30 period. We have prepared this forecast using the AER's PTRM in accordance with rule 76,[43] and in developing these forecasts, the total revenue requirement represents only costs which are attributable to the Transportation Reference Service.

43 JGN's PTRM is included as Attachment 7.5.

Table 7.2: Total revenue requirements in JGN's Revised 2025 Plan ($2024-25, $M)

	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Return on capital	228.2	227.4	227.5	226.5	222.9	1,132.6
Depreciation (return of capital)	105.0	110.4	116.3	122.1	128.9	582.7
Operating expenditure	233.3	228.5	228.0	227.1	231.5	1,148.5
Incentive schemes	36.5	4.7	(15.1)	5.6	6.7	38.4
Net tax allowance	14.9	15.1	15.1	15.7	16.8	77.5
Annual revenue requirement	617.9	586.1	571.8	597.1	606.8	2,979.7
Smoothed revenue	**574.1**	**588.4**	**599.4**	**607.8**	**613.5**	**2,983.3**
Price path (in real terms)	2.98%	2.98%	2.98%	2.98%	2.98%	
Price path excluding incentives (in real terms)	2.51%	2.51%	2.51%	2.51%	2.51%	

7.2 Regulated asset base

7.2.1 AER draft decision

The value of the assets we use in providing our services is known as our capital base, or regulated asset base (**RAB**). This represents the unrecovered capex we have incurred to provide services to our customers. In our Initial 2025 Plan we estimated that the value of our asset base at the start of the 2025-30 period would be $3.87 billion ($ nominal), and that it will increase by approximately 4%, to $4.04 billion ($ nominal) by the end of the period.

In its draft decision, the AER has determined an opening value of our capital base of $3.86 billion ($ nominal) which is $7.3 million ($ nominal) lower than our proposed opening capital base of $3.87 billion ($ nominal) as at 1 July 2025. This reduction is mainly due to the AER's update to the estimated consumer price index (**CPI**) input for 2024–25 in the roll forward model (**RFM**) with the Reserve Bank of Australia's (**RBA**) forecast, published in its August 2024 Statement on Monetary Policy, and reflecting updated economic conditions.[44]

For the draft decision, the AER adopted an estimated inflation of 3.00% for 2024–25 and a forecast inflation of 2.85% for 2025–30, compared to our proposed 3.20% for 2024–25 and 2.79% for 2025–30 in the Initial 2025 Plan. For the final decision, the AER will update its CPI input for 2024–25 to account for the actual CPI published by the Australian Bureau of Statistics and the forecast 2025–30 inflation based on the latest RBA Monetary Policy Statement (February 2025).

Table 7.3 provides an overview of our Initial 2025 Plan capital base roll-forward, the AER's draft decision, and our Revised 2025 Plan forecast.

Table 7.3: Forecast value of JGN's RAB ($nominal, $M)

	JGN Initial 2025 Plan	AER Draft Decision	JGN Revised 2025 Plan
Opening RAB at 1 July 2025	3,870.3	3,863.0	3,853.1
Closing RAB at 30 June 2030	4,041.1	4,034.7	4,133.5

44 AER, Draft decision - Jemena Gas Networks (NSW) access arrangement 2025 to 2030 (1 July 2025 to 30 June 2030), Nov 24, p.14.

The closing RAB at 30 June 2030 is calculated by rolling forward the opening RAB by indexing it for inflation, adding conforming net capex, and subtracting depreciation. The AER's draft decision has not approved our proposed roll forward of the capital base. In its draft decision, the AER has estimated the closing value of our capital base (at 30 June 2030) as $4.03 billion ($ nominal). The key drivers for the AER's decision not to approve our proposed inputs to the roll forward of the capital base, are:

- Forecast capex—the AER reduced our forecast capex by $174.5 million ($ nominal, discussed in more detail in section 4).
- Estimate of inflation—the AER has updated our proposed expected inflation rate of 2.79% per annum over the period to 30 June 2030 with its own forecast of 2.85% (discussed above)
- Depreciation forecast—the AER reduced our regulatory depreciation forecast by $175.3 million ($nominal) in line with its assessment of our forecast depreciation (discussed in section 7.5).

7.2.2 JGN response to the draft decision

JGN has proposed a closing 2030 RAB of $4.13 billion ($ nominal) based on –

- Higher net capex of $915.7 million ($ nominal) compared to AER's approved $713.7 million ($ nominal), the reasons for which are discussed in chapter 4.
- Higher depreciation of $635.4 million ($ nominal) compared to AER's approved $542.1 million ($ nominal), the reasons for which are discussed in section 7.4.
- Lower estimated 2024-25 inflation of 2.60% and forecast 2025-30 inflation of 2.80%, based on the RBA's November 2024 Monetary Policy Statement.

7.2.3 Revised proposal capital base forecast

Table 7.4 provides our roll forward of RAB from 1 July 2025 to 30 June 2030.

Table 7.4: Our Forecast RAB from 2025-26 to 2029-30 ($nominal, $M)

	2025-26	2026-27	2027-28	2028-29	2029-30
Opening balance	3,853.1	3,953.8	4,058.8	4,126.9	4,144.7
Net capex	208.6	221.6	194.5	154.2	136.8
Straight line depreciation	(215.8)	(227.3)	(240.0)	(252.0)	(264.1)
Inflation on opening balance	107.9	110.7	113.6	115.5	116.0
Closing balance	**3,953.8**	**4,058.8**	**4,126.9**	**4,144.7**	**4,133.5**

7.3 Rate of return

7.3.1 Rate of return overview

Our Initial 2025 Plan was based on applying the AER's 2022 Rate of Return Instrument with placeholder observations. We used a placeholder rate of return (specified as a nominal vanilla weighted average cost of capital (**WACC**)) of 5.21% (5-year average) for the 2025-30 period. The instrument requires JGN to nominate risk-free rate and return on debt averaging periods which JGN did in its Initial 2025 Plan.

7.3.2 AER draft decision

In its draft decision, the AER accepted our method for calculating the WACC but revised our estimate using updated market data and a different inflation assumption. The AER also accepted our proposed averaging periods.

7.3.3 JGN response to the draft decision

JGN has further updated the market observations and rate of return placeholder estimate for its Revised 2025 Plan. The rate of return will be updated in the AER's final decision using observations in our approved averaging periods.

7.3.4 Revised proposal rate of return

Table 7.5 sets out the placeholder rate of return in our Initial 2025 Plan, the AER's draft decision, and our Revised 2025 Plan.

Table 7.5: JGN's forecast rate of return (%)

Parameter	Initial 2025 Plan	Draft Decision	Revised 2025 Plan
Return on Equity	6.90%	7.67%	8.28%
Return on debt (5-year average)	4.08%	4.67%	4.66%
Inflation	2.79%	2.85%	2.80%
Leverage	60%	60%	60%
Gamma	57%	57%	57%
Corporate tax rate	30%	30%	30%
Nominal vanilla WACC (5-year average)	**5.21%**	**5.87%**	**6.11%**

7.4 Regulatory depreciation

Regulatory depreciation represents repayment of an invested asset over time, equivalent to repaying principal on a loan. Including forecast regulatory depreciation in our revenue requirement enables us to recover our investment in our network over the economic lives of our assets and provides important cashflow to fund new replacement assets so that we can continue to provide our services safely and reliably.

7.4.1 AER draft decision

The AER accepted our proposed method to calculate the regulatory depreciation allowance—straight line depreciation less annual inflation indexation of the projected capital base. The AER also accepted the need for accelerated depreciation but, in deciding the amount of accelerated depreciation, it adopted a different approach to our proposed approach which was informed and supported by economic research[45] and the expectations of our customers.

45 Future of Gas modelling which formed part of JGN's 2025 Initial Proposal.

JGN proposed $658.2 million depreciation in the Initial 2025 Plan. Of this, the AER approved only $496.2 million depreciation. The key reasons for its decisions were:

- $162.5 million lower capex approved for 2025-30 period (see chapter 4 and *JGN – RP – Att 4.1 – Capital expenditure – 20250115 - Public* for more details)
- $143.8 million lower accelerated depreciation approved in order to achieve a zero real price path whilst asserting that JGN's policy risk for asset stranding is less than that which applied at the time of making its June 2023 Victorian AA determinations (see *JGN – RP – Att 7.2 – Depreciation – 20250115 - Public* for more details).

7.4.2 JGN response to the draft decision

We have carefully considered the AER's reasoning for its $156 million draft decision for accelerated depreciation. The AER's depreciation draft decision observed:

> *We consider the benefit of accelerated depreciation in terms of reducing stranded asset risk is greatest while there is still a large customer base to share the cost recovery of the capital base.*[46]

However, fundamentally the AER's draft decision does not sufficiently act upon this opportunity by limiting depreciation during the next AA period to less than the amount of RAB growth our asset will experience. This means the draft decision approach, if retained in the final decision, would:

- forego the opportunity to have our largest remaining customer base contribute equitably to existing capital recovery, counter to our current customers' preferences
- worsen the accrued problem of investment recovery by driving net growth in our capital asset base by 2030.

We have considered the AER's reasons for its draft decision to adopt a zero real price path outcome. We consider that targeting a zero real price path outcome in the current and foreseeable gas demand context:

- Is entirely inconsistent with the intent of the NGO, revenue and pricing principles, and rule 89 depreciation criteria
- Places undue weight on short-term policy measures (or a lack thereof) and fails to place enough weight on commonly held view about long-term gas demand forecasts amid the NSW legislated transition to net zero by 2050, and
- Fails our customer base by burdening future customers (which the AER acknowledges will be fewer) with higher prices than would otherwise be the case through both:
  - the lower depreciation amount, and
  - the way it has applied its real price path approach.

The regulatory framework requires that the AER must consider each element of the building block decisions on their individual merit consistent with the NGR, including being cognisant of price outcomes for customers in a consistent manner across those decisions. For example it is inconsistent to provide a $144 million lesser rate of recovery of existing investments based on a price outcome, whilst at the same time increasing prices through $66.4 million of opex socialisation to provide subsidies to customers abolishing their gas connection in clear disregard for the causer pays principle.

46 AER, depreciation draft decision, November 2024, p.15.

The short term real price path outcome is not in customers' long term interests

A short term outcome of achieving a zero real price path outcome is not likely to be in the long term interests of customers in an uncertain future. Such a constraint contributes to the socially regressive outcome of early electrifiers being subsidised by those who don't have the means to do so prior to the end of their appliance lives or due to a lack of agency to do so in Sydney's highly constrained rental market.

This inherently short term approach also ignores the long-term electrification scenarios developed by our Expert Panel and considered by them to be the most likely versions of the future[47] that JGN should be planning to best meet our customer's long-term interests.

In this long-term context, our revised proposal of $230 million of accelerated depreciation better addresses the underlying problem of demand decline compared to the AER's short-term price constraint approach. This conclusion was also reached by Houston Kemp in its report:

> *Finally, the AER proposes a constant real price path, starting from the final prices in the current regulatory period. It has done so to be 'prudent' and allow 'a measured start to accelerated depreciation while maintaining price affordability for consumers'. By its approach, the AER appears to prioritise near or short term price stability for existing gas consumers. However, we find that maintaining price affordability over the short term will cause price volatility to be transferred into future periods, thus allocating risks away from the broader base of current customers onto a narrower base of future customers. Allocating risks in this manner will not promote the long term interests of gas consumers.*[48]

Profiling remaining depreciation to reflect declining gas demand out to 2050 is in customers' long term interests and better avoids socially regressive subsidies

Falling gas demand means negative growth in the market for reference services is efficient under the depreciation criteria in NGR rule 89. It reflects the changing preferences of consumers and availability of competing technologies. The key task is now ensuring that the pace of capital recovery does not prematurely accelerate the pace of demand reduction. While being a requirement of rule 89, it is also important for achieving our NSW emissions reduction interim goals because accelerating electrification prior to sufficient renewable energy supply will be counterproductive to those targets and potentially to electricity system reliability.

Adopting our proposed pace of depreciation promotes a more efficient pace of negative growth than the AER's draft decision by:

- as the AER explains, reprofiling more depreciation now would mitigate potential price increases in the future beyond 2030, in turn encouraging fewer customers to leave gas networks prematurely, and
- reprofiling more depreciation now enables our gas network to remain financially viable and competitive on price with other energy sources for a longer period, thereby facilitating:
  - a more orderly energy transition without accelerating gas price increases
  - a more equitable energy transition allowing more customers to benefit from the use of the remaining lives of their gas appliances.

Our proposal is also more consistent with the rule 89 depreciation criteria. In its report (provided at *JGN - Houston Kemp - RP - Att 3.1 - Smoothing cost recovery when gas demand is declining - 20250110 - Public*), Houston Kemp has compared how our initial proposal of $300 million and its reasoning compare with the AER's draft decision against the rule 89 depreciation criteria, concluding that JGN's proposal is more consistent with most of these criteria.

47 KPMG, Gas Networks 2050: Future scenarios summary report. Final report; January 2023, p.23

48 *JGN - Houston Kemp - RP - Att 3.1 - Smoothing cost recovery when gas demand is declining - 20250110 - Public*, p.iv

The short term zero real price path approach as applied in the draft decision will exaggerate price shocks

The short term zero real price path approach as applied in the draft decision uses a launch point and rate of change that both exacerbate future price shock, for: 1) building block cost realignment, and 2) AA changes if short term NSW gas policies transpire.

If a price growth rate approach is applied in a final decision, it must avoid these price shock outcomes by accounting for:

A cost reflective launch point | The price path constraint cannot be applied to an unsustainably low launch point having regard to our actual efficient cost of supply. The draft decision fails to recognise that our current prices are not reflective of the efficient building block levels. This is due to the large 2015-20 over-recovery handback during the 2020-25 period that materially reduced them below sustainable costs. It also fails to recognise the difference between the updated and previous nominal vanilla WACC estimates for JGN is 1.26%, which is materially higher than the 0.15% difference observed for the Victorian gas distributors[49]

Not creating future price shock | The combination of a deflated launch point and zero real price path is that the AER's draft decision would result in the AER's price path necessarily triggering a price rise of at least 4.2%[50] moving into the subsequent (2030-35) AA period to realign our revenues with our cost of supply (as required in the electricity rules[51] and has been the AER's standard practice for price paths in gas AAs too[52]) – an outcome which would clearly be counterproductive to the AER's price path outcome logic.

A policy reflective real price path | The zero real price path target is inconsistent with the AER's average 1.5% real price path approach for the Victorian gas distribution networks' 2023-28 AAs. We note that this approach was decided in June 2023 *before* the Victorian connections ban was announced making the circumstances of that decision not materially different to JGN's from a short term jurisdictional gas policy perspective. Moreover, when Victorian gas policy measures did subsequently transpire, Ausnet's reopener application now seeks a real price path of 6.47% above the AER's decision for the remaining 3 years of its AA.

Our initial proposal was a prudent multi-limbed approach to the energy transition

Our Initial 2025 Plan included a number of carefully balanced, complementary measures to respond to the changes we are facing into as a result of the energy transition. These include: renewable gas connection projects; changing our Model Standing Offer to require more customers to make an up-front contribution when connecting to the network; proposing expenditure targeted to reduce emissions (such as Picarro), revenue rebalancing to industrial users, and accelerated depreciation. We have had to do this in an environment where the outlook for energy policy in NSW is uncertain, including in terms of timing of electrification and the eventual energy mix. We consider that the measures that we have proposed are consistent with that of a prudent service provider acting to promote efficient investment in, and efficient operation and use of, gas services for the long term interests of consumers of gas as required by the NGO.

We note that contrary to stakeholder submissions, our Initial 2025 Plan to increase depreciation by $300 million relative to the historical depreciation pace does not represent any form of windfall payment. It is an NPV neutral repayment of our investments that reflects a depreciation profile that better promotes an efficient pace of gas demand decline in the market for reference services.

49 JGN - Houston Kemp - RP - Att 3.1 - Smoothing cost recovery when gas demand is declining - 20250110 – Public, p.38.

50 The 4.2% is taken from cell R44 of the *X-factors* sheet of the step 2 Post Tax Revenue Model (**PTRM**) included with the AER's draft decision. It is calculated as the relative difference between the smoothed and building block revenues in the 2029-30 year. We say 'at least' because the 4.2% is a comparison of revenue. If – consistent with the trend reflected in the demand forecast for the 2025-30 period adopted in the draft decision – demand were to reduce from 2029-30 to 2030-31, then the price impact would be even greater than a 4.2% price increase.

51 NER rule 6.5.9(b)(2).

52 AER, Draft decision Jemena Gas Networks (NSW) access arrangement 2025 to 2030 Overview, November 2024, p.13.

We have lessened our accelerated depreciation request to the average amount approved in Victoria prior to their short term gas transition policy measures.

Given the current NSW energy transition by 2050 we consider that a $230 million future of gas depreciation allowance is the bare minimum amount required as it affords JGN an equivalent opening RAB share to what was approved for the Victorian gas distributors—see Table 7.6. This minimum amount must be coupled with the AER providing us the opportunity to undertake complementary renewable gas projects, and innovate in how we optimise costs through programs like Picarro.

Our $230 million proposal is supported by the results of a statistically representative quantitative survey of our customers, in which 72% of respondents ranked the two highest levels of accelerated depreciation—which correspond to $400 million and $300 million—as their first preference.[53]

Considering our Revised 2025 Plan's higher revenue requirement and lower forecast demand, our revised proposal delivers an average annual residential network bill of $331 over the 2025-30 period[54], which is within the range of bill impacts corresponding to those for the $300 million and $400 million accelerated depreciation options, of $328 and $340 respectively.Our lower revised future of gas depreciation allowance is also consistent with the amount that can be recovered under an appropriately adjusted real price path approach, as discussed below.

Our revised proposal is a modest yet necessary response to better support an efficient energy transition. Table 7.6 shows JGN's revised proposal is only recovering 6% of its opening RAB in its accelerated depreciation proposal which is:

- less than the amount of at least 20% needed for each of the next five AA periods to support full RAB recovery by 2050, and
- in line with the average RAB share accelerated for Victorian gas distribution networks' decisions, noting Ausnet's revision proposal is even higher.

Table 7.6: Comparison of adjusted RAB recoveries

Gas distribution network	Accelerated Depreciation as % of Opening RAB
JGN – Initial 2025 Plan	7.8%
JGN – AER Draft Decision	4.0%
JGN - Revised 2025 Plan (proposed)	**6.0%**
Average Vic gas distribution networks	6.1%
Ausnet – Reopener (proposed)	9.4%

If the AER retains its draft decision approach, it must address the launch point and rate of change issues

If the AER does not accept our revised proposal of $230 million accelerated depreciation, and chooses to maintain its real price path outcome approach, then it needs to adjust its approach for:

1. The prices it is launching from as these:
   a) are artificially deflated below our cost of supply due to the $203 million revenue handback for previous period over-recovery

53 JGN - Sagacity - RP - Att 2.1 - Accelerated Depreciation Research Report - 20241206 - Public

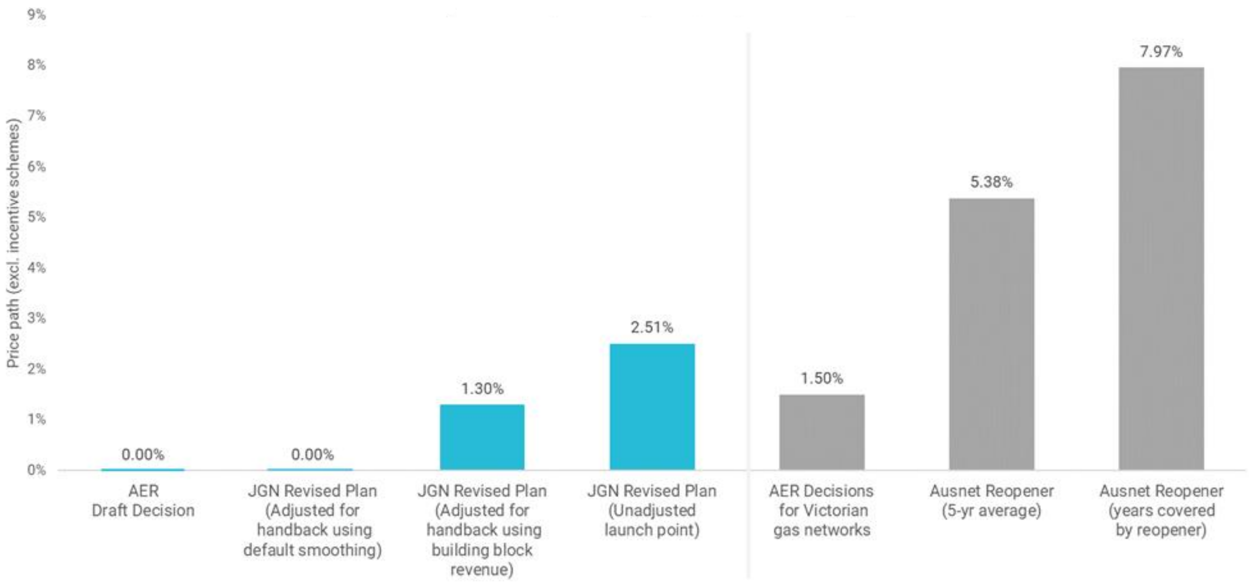
54 Refer to Figure 8.1, $331 is the average annual bill over the 2025-30 period.

   b) would result in the AER's price path necessarily triggering a price rise of at least 4.2%[55] moving into the subsequent (2030-35) AA period to realign our revenues with our cost of supply (as required in the electricity rules and has been the AER's standard practice for price paths in gas AAs too[56]) – an outcome which would clearly offend the AER's pricing outcome logic.

2. An equivalent price path change (i.e. up to 1.5% real) as it afforded Victorian gas networks recognising that:
   a) the policy information available at the time of that determination was not the more certain gas connections ban and full connection contribution policy that was subsequently implemented
   b) setting of that policy since the determination has driven an even higher required price outcome in the reopener application made by Ausnet which needs an additional 6.47% real increase per year for the final 3 years of its AA period
   c) JGN's $300 million proposal was calibrated down for the NSW policy status and did not target full RAB recovery by the binding NSW 2050 net zero target date as shown in Table 7.6 above
   d) if policy certainty did transpire in NSW, JGN would be seeking higher 2025-30 depreciation to achieve cost recovery amid that policy (e.g. recovery of JGN's existing investment by 2050 would require depreciation in each AA period from now until then of at least $773 million per 5 year period *on average*[57]).

Adjusting for the above launch point issues as we have done in Figure 7.1 shows that, when the handback is properly accounted for, our revised proposal of $230 million is consistent with a zero real price path. Our proposal also better aligns our 2030 smoothed revenues to within 1.13% of the building blocks for that year, thereby avoiding the 4.2% future price shock inherent in the AER's draft decision approach.

Figure 7.1: Price path comparisons (Real, % per annum)



55 The 4.2% is taken from cell R44 of the *X-factors* sheet of the step 2 PTRM included with the AER's draft decision. It is calculated as the relative difference between the smoothed and building block revenues in the 2029-30 year. We say 'at least' because the 4.2% is a comparison of revenue. If – consistent with the trend reflected in the demand forecast for the 2025-30 period adopted in the draft decision – demand were to reduce from 2029-30 to 2030-31, then the price impact would be even greater than 4.2%.

56 AER, Draft decision Jemena Gas Networks (NSW) access arrangement 2025 to 2030 Overview, November 2024, p.13.

57 The $773 million was calculated by taking the opening RAB (as at 30 June 2025) of $3.9 billion (from cell J57 of the *PTRM input* sheet of the step 2 PTRM included with the draft decision) and dividing it by the five 5-year regulatory periods up to 2050 (i.e., 2025–30, 2030–35, 2035–40, 2040–45, and 2045–50). In reality, this value is likely to understate the amount of real depreciation required in the earlier periods because it does not seek to smooth out recovery over those periods to reflect the decline in demand. Nor does it recognise that real depreciation will need to increase over time to recover new capex incurred.

7.4.3 Revised proposal depreciation

Our Revised 2025 Plan seeks regulatory depreciation for the 2025–30 period totalling $582.7 million of which $230 million is our revised proposal for accelerated capital recovery. This investment recovery is a critical part of our complementary package of initiatives to prudently respond to future gas uncertainty amid NSW and Australia's legislated emissions reduction targets. Our proposal is $86.6 million higher than the AER's draft decision. The key reasons for this are –

- $184.1 million higher capex for 2025-30 period (see chapter 4 for more details)
- $73.8 million higher accelerated depreciation for 2025-30 period (see Attachment 7.2 for more details)

Table 7.7 provides a summary of our revised plan.

Table 7.7: JGN's forecast regulatory depreciation in the Revised 2025 Plan ($2024-25, $M)

	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Straight line depreciation	209.9	215.1	220.9	225.6	230.0	1,101.6
Inflation on RAB opening balance	(104.9)	(104.8)	(104.6)	(103.5)	(101.1)	(518.8)
Regulatory depreciation	**105.0**	**110.4**	**116.3**	**122.1**	**128.9**	**582.7**

7.5 Corporate income tax

Company tax is a cost for all companies. The regulatory framework enables network companies to recover the efficient tax costs from customers as adequate compensation for the cost of tax is necessary to ensure that sufficient funds are available to meet our tax obligations.

7.5.1 AER draft decision

In its draft decision, the AER has accepted our proposed method for calculating the corporate income tax allowance, including our proposed tax depreciation method and depreciation rates and the value of the 1 July 2020 opening tax asset base (**TAB**) (with minor adjustment).

7.5.2 JGN response to the draft decision

We accept AER's approach to estimating corporate tax allowance. However, due to revision in our cost and revenue estimates our revised proposal includes a $14.5 million higher tax allowance compared to the AER's draft decision.

7.5.3 Revised proposal tax

We have updated our corporate income tax forecast to reflect our revised building block revenue for the 2025-30 period and updated estimate of opening TAB as at 1 July 2025.

Table 7.8 provides our revised tax building block costs.

Table 7.8: JGN's forecast tax allowance in the Revised 2025 Plan ($2024-25, $M)

	2025-26	2026-27	2027-28	2028-29	2029-30	Total
Taxable income	115.5	116.8	117.3	121.3	129.9	600.9
Corporate income tax	34.7	35.0	35.2	36.4	39.0	180.3
less: Imputation credits	(19.8)	(20.0)	(20.1)	(20.7)	(22.2)	(102.8)
Tax allowance	**14.9**	**15.1**	**15.1**	**15.7**	**16.8**	**77.5**

7.6 Revenue adjustments

Revenue adjustments are made to building block costs to deal with incentive schemes and other adjustments needed to give effect to rule requirements. In the current 2020-25 period, we are subject to two incentive schemes—an Efficiency Carryover Mechanism (**ECM**) and a Capital Expenditure Sharing Scheme (**CESS**). In our Initial 2025 Plan, we proposed to the continuation of the two schemes over the 2025-30 period. We also proposed modifying the CESS to exclude renewable gas connections capex for the 2025-30 period.

7.6.1 AER draft decision

The AER has accepted the continuation of the CESS and the estimation of our incentives revenue for the 2025-30 period. However, the AER has rejected the exclusion of renewable gas connections capex from our 2025-30 CESS because it believes that JGN can exert a greater degree of control over renewable connections capex than it can on regular connections[58] capex. The AER also proposed that we amend the 2025-30 CESS to align with the electricity CESS which has a tiered sharing factor consistent with AER's update to the CESS mechanism in April 2023.

The AER has accepted the continuation of the ECM and the estimation of our incentives revenue for the 2025-30. The AER has requested that JGN change the treatment of license fees from category specific cost to step change cost. This would make the license fee assessable under ECM in the 2025-30 regulatory period. The AER also requested a number of changes to the exclusions under the ECM in the AA.

7.6.2 JGN response

We consider that there is limited ability for JGN to influence renewable gas connections and that regulation should allow innovation by promoting more of these connections - we therefore do not accept AER's decision to include these in our CESS mechanism. The exclusion of renewable capex from CESS is also consistent with our proposal to seek a fixed principle on renewable gas connection capex which includes a true-up of revenue requirement (see section 9.3 and clause 3.14 of the AA for more information). We accept AER's recommendation to change our CESS mechanism to have the tiered sharing factor. See section 13.1(f) of our revised AA for more details on how we have amended the CESS.

We do not agree with the AER's draft decision to include licence fees in the operation of the ECM. The licence fees vary significantly year on year, which we have no control over. Including such a volatile amount in the ECM could result in arbitrary gains or losses on the carryover amount. In addition, in the AER's decisions for electricity distribution networks, costs such as licence fees are generally treated as jurisdictional schemes, which are excluded from the Efficiency Benefit Sharing Scheme (**EBSS**). We believe it is important to maintain consistency in the incentives framework between gas and electricity networks. While the AER requested alignment in CESS between gas and electricity, the inclusion of licence fees in ECM creates a misalignment between gas and electricity networks for this identical cost category. We explain our proposal to treat licence fees as an opex category specific forecast in more detail in section 6.1 of *JGN - RP - Att 5.1 - Operating expenditure - 20250115*.

58 The AER's draft decision defines 'regular connections' as all connections except renewable gas connections

7.6.3 Revised incentive scheme

JGN has amended the CESS mechanism to include the tiered sharing factor and to align the mechanism with our proposed renewable gas capex fixed principle.

JGN has retained its current ECM for the 2025-30 period which excludes license fees from efficiency assessment. For the AER's requested amendments to the AA on ECM exclusions, we provide our response in section 9.5.

7.7 Attachments

Table 7.9 lists the attachments to our Revised 2025-30 AA Proposal which provide further information on our response to the AER's draft decision.

Table 7.9: Revised 2025-30 AA Proposal attachments

Attachment	Name	Author
3.1	JGN - Houston Kemp - RP - Att 3.1 - Smoothing cost recovery when gas demand is declining - 20250110	Houston Kemp
4.1	JGN - RP - Att 4.1 - Capital expenditure - 20250115	JGN
5.1	JGN - RP - Att 5.1 - Operating expenditure - 20250115	JGN
7.2	JGN - RP - Att 7.2 - Depreciation - 20250115	JGN
7.2A	JGN - RP - Att 7.2A - Illustrative 2020-25 PTRM excluding revenue handback - 20250115	JGN
7.3M	JGN - RP - Att 7.3M - Depreciation model - 20250115	JGN
7.4M	JGN - RP - Att 7.4M - PTRM - Step 1 - 20250115	JGN
7.5M	JGN - RP - Att 7.5M - PTRM - Step 2 - 20250115	JGN
7.6M	JGN - RP - Att 7.6M - Roll Forward Model - 20250115	JGN
7.7M	JGN - RP - Att 7.7M - ECM model - 20250115	JGN
7.8M	JGN - RP - Att 7.8M - CESS model - 20250115	JGN
7.9M	JGN - RP - Att 7.9M - Rate of return model - 20250115	JGN

8. Pricing

8.1 AER draft decision

The AER's draft decision accepted most elements of our tariff proposal, including:

- merging of coastal and country pricing zones
- splitting volume customers into small (under 200 GJ consumption per annum) and large (over 200 GJ)
- recovering proportionally more revenue from demand customers
- increasing the fixed charge for large volume customers
- reducing volume tariff price blocks from six to four and flattening the declining block structure for our volume customers.[59]

The AER approved all aspects of JGN's proposed reference tariff variation mechanisms for the 2025–30 access arrangement period except for the:

- annual transportation reference tariff variation mechanism, which the AER stated should not include provision for levies and licence fees and
- proposed CPI-X adjustment for our annual ancillary reference tariff variation mechanism, for ancillary reference services, which the AER stated should be revised to reflect CPI adjustments only.

Regarding our proposed ancillary reference service tariffs, the AER's draft decision accepted all of the proposed individual tariffs except for our proposed volume customer abolishment service.[60] The AER's draft decision reduced the level of our proposed abolishment cost by 25% down to $1,104 and then socialised most of this cost, producing an abolishment tariff of $250.[61]

AER's draft decision requested:

- more clarity on further incremental changes during the 2025-30 period (revenue recovery from demand customers and flattening the volume customer declining block tariff structure)
- further work to achieve flatter tariffs
- consideration by JGN on whether a 10% side constraint is too broad and whether it would be appropriate for JGN to amend the side constraint to 2%.

8.2 JGN response to the draft decision

Table 8.1 summarises the key elements of our response to the AER's draft decision on our proposed tariff structures and other pricing elements of our proposal.

We also held a workshop with AER staff on 5 December 2024 to discuss the topics the AER requested further consideration and work from JGN. The analysis we presented to the AER in this workshop is also presented in *JGN - RP - Att 8.1 - Pricing - 20250115 - Public*.

59 AER, Draft decision – JGN (NSW) access arrangement 2025 to 2030, Attachment 9 – Reference tariff setting, November 2024, p. 1.
60 Ibid, p. 2.
61 Ibid.

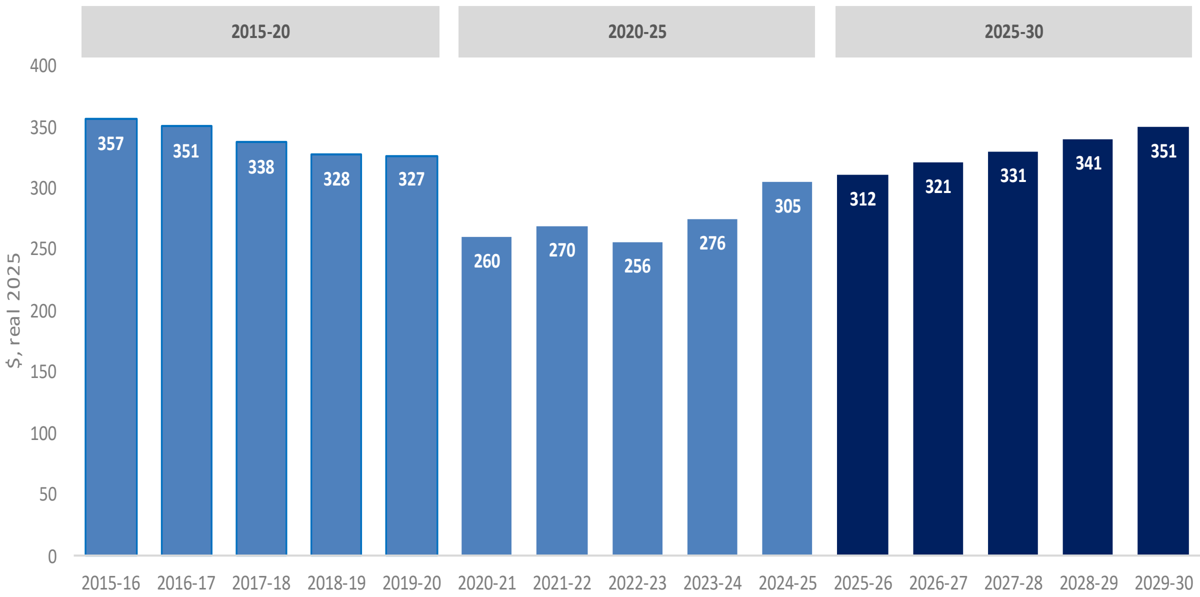
Table 8.1: JGN's response to AER draft decision on pricing

AER draft decision	JGN response
JGN to consider options including moving incrementally to flat tariffs, for both volume and demand customers	*JGN - RP - Att 8.1 - Pricing - 20250115 - Public* outlines: – that JGN will aim to transition volume market customers to flatter declining block tariffs over the next regulatory period – this transition will be achieved via JGN's annual tariff variation proposal – the bill impacts of this transition for our volume market customers – that we are unable to transition our demand market customers to a flatter declining block structure over the 2025-30 period as it can have unintended consequences on their competitiveness. However, we will start consultation with our demand customers on tariff options to flatten the tariff structure for the 2030-35 period.
The AER's draft decision also discussed whether further consideration is required on whether a 10% side constraint is too broad and whether it would be appropriate for JGN to amend the side constraint to 2% to align with other gas distributors.	Our revised proposal advocates retaining a 10% side constraint, primarily because it will allow us to rebalance more revenue to our demand market customers.
The AER also approved our proposed reference tariff variation mechanism, except for the transportation tariff variation mechanism, which the AER states should not include provisions for levies and licence fees.	Our revised proposal advocates to include these levies and fees in our true-up calculations, as discussed in chapter 5.
The AER's draft decision is to reduce the level of JGN's proposed volume customer abolishment cost by 25% to align with other networks bringing it down to $1,104, and to socialise most of that cost, giving an abolishment tariff of $250.	Our revised proposal maintains our initial proposal abolishment cost of $1,472 for Standard Residential Connections where there are current or anticipated redevelopment, renovation or other construction works. We caution the AER against relying on high level benchmarking of our abolishment costs with other gas network businesses in different jurisdictions without adequately accounting for the activities that each business must undertake to complete an abolishment in its jurisdiction. There are material differences between NSW and other jurisdictions, including due to legislative and contractual relationships with other relevant stakeholders, such as councils. Any comparison must account for jurisdiction differences, including the ability the network has to control certain works, the activities that each network must undertake, and how these activities may vary across networks. Therefore, we submit that the AER's proposed reduction of our small customer abolishment tariff from $1,472 to $1,104 to align with networks operating under different circumstances in other jurisdictions is not appropriate. We accept the partial socialisation of abolishment costs and the ancillary service abolishment charge of $250 for Standard Residential Connections where there are no current or anticipated redevelopment, renovation or other construction works. See *JGN – RP – Att 7.1 – Abolishments – 20250115 – Public* for more details.
AER did not approve JGN's proposed CPI-X tariff variation mechanism for ancillary services and that JGN's access arrangement should instead apply simple CPI adjustments to escalate these tariffs	Our revised proposal accepts AER's draft decision.

8.3 What our Revised 2025 Plan means for prices

Our Revised 2025 Plan will implement several initiatives to position JGN for the future but also account for current cost of living pressures. Our revised proposal is measured and aims to ensure our gas network remains competitive as we transition to a renewable gas network, which is an important attribute contributing to keeping prices lower for remaining customers as demand reduces across the network. We expect the price impact for a typical residential customer on our network would increase marginally from the current 2020-25 period into the 2025-30 period, as illustrated in Figure 8.1.

Figure 8.1: Annual network bill for a typical residential customer consuming 15GJ per annum[62]



Source: JGN analysis

8.4 Attachments

Table 8.2 lists the attachments to our Revised 2025-30 AA Proposal that provide further information on our response to the AER's draft decision.

Table 8.2: Revised 2025-30 AA Proposal attachments on Pricing

Attachment	Name	Author
7.1	JGN – RP – Att 7.1 – Abolishments - 20250115	JGN
8.1	JGN – RP – Att 8.1 – Pricing - 20250115	JGN

62 In the 2020-25 period, a $203 million downward adjustment was made to our 2020-25 building block costs to return revenue over-recovered during the 2015-20 period. Without this downward adjustment, the annual network bill would be higher over the 2020-25 period.

9. Accessing our network

9.1 AER draft decision

The AER's draft decision largely approves the services we offer, and the terms and conditions set out in our RSA.

There are two propositions made in the AER draft decision which we have addressed in detail in our Revised 2025 Plan, which relate to abolishments and renewable gas connections.

The AER suggested that we split our abolishment service for small customers, and consistent with this suggestion, we propose to implement a new abolishment charge for a standard residential connection abolishment which does not relate to construction, and has a partially socialised reference tariff from 1 July 2026. We will continue to offer a standard residential connection abolishment which relates to construction at a fixed rate and all other abolishments will be individually priced (reflecting a cost reflective tariff).

In response to the AER's concern that our renewable gas projects do not proceed, we have included a fixed principle in our AA which ensures that we repay our customers to the extent that our actual conforming renewable gas project capex for the 2025-30 AA Period is less than any renewable gas project capex allowance.

9.2 JGN response to the draft decision

Table 9.1 summarises the key elements of our response to the AER's draft decision on our services.

Table 9.1: JGN's response to AER draft decision on our services

	AER draft decision	JGN response
Access Arrangement - our reference services	The AER accepted the reference services set out in our 2025−30 access arrangement proposal, which are consistent with the AER's decision on our initial reference service proposal.	We accept the AER's draft decision to split our existing single reference service into two reference services from 1 July 2025 being our: – gas transportation service (haulage including metering) – ancillary reference services.
Access Arrangement - ancillary reference services	Whilst the AER accepted our ancillary reference services, it suggested there may be benefit to re-naming JGN's disconnection and abolishment services to temporary disconnection and permanent disconnection (abolishment) respectively. The AER also encouraged us to offer two abolishment services for small customers; one for permanently disconnecting customers with a partially socialised reference tariff, and one for reconnecting customers that would be priced at our fully costed abolishment reference tariff.	We do not agree with renaming of our disconnection and abolishment services. However, as suggested by the AER, from 1 July 2026 we are proposing to offer certain residential customers with a partially socialised reference tariff, accompanied by an adjustment to our tariff variation mechanism to true up the costs associated with the socialisation- see section 2.6 of schedule 4 of our Access Arrangement. We discuss these amendments further in section 9.4 chapter 5, chapter 8 and in *JGN - RP - Att 8.1 - Pricing - 20250115 - Public*.
Access – Arrangement – Cost Pass Through Events	The AER proposed various amendments to the proposed cost pass through events, predominately to align with decisions for other networks.	We have largely accepted the AER's suggested changes and discuss this further in section 9.6.

	AER draft decision	JGN response
Access Arrangement – fixed principle	The AER indicated in its draft decision that it is concerned about completion risk of our proposed renewable gas connections projects and it also seeks better information to demonstrate prudency and efficiency.	To deal with these concerns, we are proposing a fixed principle to repay our customers any renewable gas project revenue allowance over the 2025-30 period for renewable gas project capex which we do not incur as conforming capex. We discuss in further detail in section 9.3.
Access Arrangement – CESS	The AER rejected our proposal to exclude renewable connections capex from the CESS on the basis that JGN can exert a greater degree of control over renewable connections capex than it can on regular connections.	As discussed in section 7.6, we have amended the CESS calculation to be consistent with the fixed principle on renewable gas connection capex for the true-up of revenue requirement.
Access Arrangement – ECM	The AER made a number of suggested changes to costs that are to be excluded from the operation of the ECM	We largely accept the AER's suggested changes other than those noted in section 9.5.
Model Standing Offer	The AER accepted our MSO proposal to offer a Basic Connection Service: Residential Meter Kit, with all other connections offered as negotiated connections. The AER also noted that our 'newly categorised 'negotiated' basic connection services will be grouped with JGN's pre-existing non-reference service category of 'negotiated services'.	We accept the AER's draft decision. However, we note that our Negotiated Connection Service under our MSO is a requirement under Part 12A of the NGR in order to access our Transportation RS, and does not form part of pre-existing non-reference service categories. We are planning to implement our new MSO by the end of March 2025, and look forward to the AER confirming its decision on the MSO in February 2025. Our initial demand forecast for residential connections was prepared on the basis of our proposed MSO, and our revised demand forecasts have been prepared on the basis of us accepting the AER's draft decision.
RSA	The AER accepted our proposed amendments to our terms and conditions for connection set out in our RSA.	We accept the AER's draft decision and the other further amendments proposed to the RSA are those necessary for the proposed change providing for two tariffs for our abolishment service for small customers, including associated terminology changes and very minor corrections.

9.3 Fixed principle for renewable gas projects

In its draft decision, the AER expressed concerns that if it approves capex on an ex-ante basis, customers may end up paying for renewable gas connection projects that do not proceed. It suggested that JGN could use the speculative capex account for these projects in lieu of it approving an ex-ante capex allowance. We do not agree with this approach—the speculative capex account provides little regulatory certainty as it effectively defers the AER's assessment of this capex until the next price review process. Furthermore, we believe that we have provided strong evidence that this expenditure meets the capex criteria within the NGR, and is consistent with the NGO.

Noting that the renewable gas industry is still in its infancy, it is imperative that the right investment signals are provided to customers, JGN, and the proponents of these projects that this type of expenditure, when demonstrated to be prudent and efficient and consistent with rule requirements, will be approved within the regulatory framework.

To address AER concerns that customers may end up paying for renewable gas projects that do not proceed, rather than adopting a speculative capex account approach, we have proposed a fixed principle. The fixed principle requires us to adjust our 2030-35 building block revenue to return any 2025-30 building block revenue approved for renewable gas connections per the AER Final Decision to the extent we do not incur relevant conforming capex (i.e. the return on capital, return of capital, and tax allowance). The fixed principle is set out in clause 3.14 of our 2025-30 AA (see *JGN – RP - Att 9.1 – Draft decision response - Compare of 2020-25 and Revised Proposal 2025-30 AA – 20250115 and JGN - RP - Att 4.2 - Renewable gas expenditure - 20250115)*.

The intent of the fixed principle is for JGN to pay back to customers any building block revenue—rate of return, depreciation and tax—for renewable gas connection capex allowed for in the AER's final decision, but not incurred over the 2025-30 period. If JGN was to spend more capex on renewable gas connection projects than provided for in the AER's allowance, then the fixed principle would not apply. If JGN was to spend less capex on renewable gas connection projects than provided for in the AER's allowance, or incurred costs which were not considered conforming capex (for example, because the project failed to proceed), the fixed principle would apply.

JGN submits that it is appropriate that renewable gas connection capex is approved on an ex-ante basis, as this will provide the renewable gas industry with the regulatory and financing certainty required to commit to these renewable gas projects, while the fixed principle should provide comfort that customers will not be required to fund capex should these projects not proceed. Together, the proposed provisions operate to facilitate the achievement of both limbs of the NGO.

9.4 Abolishments

We do not agree with renaming of our disconnection and abolishment services. This is because during the current 2020-25 AA process, JGN established the term 'Abolishment' to replace 'Decommissioning and meter removal,' responding to customer and retailer preferences and to avoid confusion with temporary disconnections. This terminology and definition is important to ensure clarity for customers and has since been widely adopted by the industry including Australian Gas Networks, Multinet Gas Networks and AusNet. Introducing new or amended definitions would create market confusion and unnecessary administrative burden.

Clear distinctions between disconnection and abolishment are essential to help customers / users accurately understand and request the appropriate service. We also avoid using the term permanent disconnection because there is a tendency for the permanent qualifier to be dropped, leading to confusion with temporary disconnections, which are fundamentally different services. We note that we have one abolishment service (now proposed to have different tariffs applying depending on the classification of the customer and delivery point characteristics), as the actions taken for abolishments, whether permanent (for example, for electrification) or temporary (for example, for a knock down and rebuild), are analogous. For this reason, it would be confusing to separate this service into two (or more) separate services and rename one to a name more aligned with the disconnection service.

However, as suggested by the AER, we are proposing to add another Abolishment charge for residential customers with a partially socialised reference tariff. This results in our Abolishment service charges ($2025-2026) increasing from the current two, to three as follows:

- $250 per meter for a Standard Residential Connection where there are no current or anticipated redevelopment, renovation or other construction works. This new charge will be partially socialised for the shortfall between $1,472 and $250 per abolishment.
- $1,472 per meter for a Standard Residential Connection where there are current or anticipated redevelopment, renovation or other construction works (existing charge).
- Individually priced for all other abolishments (existing charge).

We propose that these apply from 1 July 2026 when we have the necessary systems and process in place to enable them to be offered.

We have reflected the above change to our Abolishment charge in clause 18 of our RSA for the service definition and in Schedule 3 Initial Reference Tariff Schedule of our Access Arrangement for the charges.

Refer to *JGN - RP - Att 7.1 - Abolishments - 20250115 – Public* for more details on our proposed changes to our Abolishment service charges.

9.5 ECM

The AER proposed a number of changes to the ECM that it considered should be made in addition to the amendments we proposed in our Initial 2025 Plan. We agree with the AER's proposed amendments set out in section 8.5 of *Attachment 8 – Efficiency carryover mechanism* of its draft decision other than as set out in Table 9.2.

Table 9.2: AER proposed amendments to exclusions in the ECM which we have modified or do not agree with

ECM exclusion	AER draft decision	JGN response
Jurisdictional charges	Delete clause 12.1(h)(ii) of our AA given the AER's draft decision to treat jurisdictional charges as an operating step change rather than as a category specific cost.	As set out in chapter 5, we do not agree with the AER's proposed reclassification of jurisdiction charges and have left them as a category specific cost. Therefore, the ECM exclusion remains applicable.
Safeguard Mechanism costs	Amend clause 12.1(h)(iv) of our AA to read: the Safeguard Mechanism costs that appear in Opex and are recovered through the reference tariff variation mechanism true-up.	As set out in chapter 5, we accept the AER's proposed true-up mechanism of the Safeguard Mechanism costs, which is covered under the 'Carbon Costs' term within the automatic adjustment factor in the tariff variation mechanism. Given the uncertain policy environment, we consider that apart from the current carbon scheme, the Safeguard Mechanism, it is appropriate that the exclusion also applies to other potential carbon schemes that might be introduced and imposed upon JGN over the 2025-30 period. For example, if there was a change in Federal government, there is a likelihood that new carbon schemes would be introduced. Therefore, we have proposed that the Safeguard Mechanism <u>and other Carbon Scheme costs</u> that appear in Opex are recovered through the reference tariff variation mechanism true-up. We note that although we have proposed to adopt the terminology requested by the AER, the 'Carbon Costs' defined term could be used to the same effect.
Opex excluded from ECM	Amend clause 12.1(h)(ix) of our AA to read: any cost that the AER determines to exclude from the operation of the efficiency carryover mechanism in the relevant period, which would not promote the NGO.	Clause 12.1(h)(ix) currently reads as 'any other costs that the Service Provider and the AER agree to exclude from the operation of the efficiency carryover mechanism.' The inclusion of the proposed new clause 12.1(h)(ix) is undesirable as it would create further and material regulatory uncertainty, in an environment where there is significant existing uncertainty about the impacts of the energy transition. Further, it may be inconsistent with the NGO and the NGL. The proposed provision would empower the AER to exclude certain costs at any time up to and including the point at which it is determining the efficiency gain/loss for the relevant access arrangement period. This would result in JGN being unable to incur opex with confidence about how the expenditure would be treated for the purpose of the mechanism. Opex which might reasonably be assumed to be prudent and compliant expenditure when incurred, might at a later date cease to qualify for the efficiency mechanism.

ECM exclusion	AER draft decision	JGN response
		Also, allowing retrospective exclusions, which is what would occur given the ECM carryover is determined as part of a reset, does not provide us the opportunity to change our spending to reflect a view that such expenditure is to be excluded from the ECM. We potentially would consequently be unfairly penalised under the ECM. Such uncertainty may not only render the mechanism ineffective, it may also be inconsistent with the NGO, and non-compliant with s24 of the NGL which requires a service provider to be provided with effective incentives to promote economic efficiency of the services provided. In addition, the NGO and the NGL, as well as other provisions of our Access Arrangement (including the other paragraphs of Access Arrangement clause 12.1(h)) extensively set out the opex criteria which our expenditure must meet in order to comply with our regulatory obligations and for the purposes of the efficiency mechanism. We are concerned with the AER having the unbalanced power to exclude costs without agreement from us, as intended in the current clause. This appears inconsistent with the duty of administrative decision making to accord procedural fairness to those impacted by the decisions, as it is unclear whether we would receive any prior notice or how we would be afforded the right to be heard before such a determination was made by the AER. For these reasons, we do not accept the AER's proposed change.
Classification of costs	Include a new clause 12.1(j) of our AA, which reads: Where the Service Provider changes its approach to classifying costs as either capital expenditure or operating expenditure during the Access Arrangement Period, the Service Provider will still report the actual operating expenditure, to align the accounting treatment of expenditure within a period with that in the approved expenditure for that period (reflecting the AER's final decision on this access arrangement)	We propose a slight amendment to the AER's proposed change to ensure that the reporting only relates to the consistent application of the ECM and CESS with the AER's approved allowances, and not for any other reporting purposes, for clarity and to utilise defined terms as follows: Where the Service Provider changes its approach to classifying costs as either capital expenditure or operating expenditure during the Access Arrangement Period, when reporting such costs for the purposes of the efficiency carryover mechanism and CESS, the Service Provider must classify the actual operating expenditure in the same manner as the accounting treatment of expenditure as at the date of the AER Final Decision.

9.6 Cost Pass Through Events

The AER suggested a number of changes to the pass through provisions we proposed in our Initial 2025 Plan, largely on the basis that this would create consistency with access arrangements of other gas service providers. We have accepted the majority of the AER's proposed amendments and set out below the reasons where we have made modifications or not agreed. Table 9.3 contains a summary of the proposed changes to the 2025-30 AA from our Initial 2025 Plan.

The AER has proposed a number of insertions of the word "materially" in the cost pass through definitions. JGN has not accepted these suggestions, on the basis that there are already applicable provisions which specify how to determine whether costs are material, by reference to a clear calculation and govern whether costs may be passed through under the relevant provisions (see clauses 3.6(a) and 3.6(b)). Accordingly, the addition of "materially" is unnecessary and introduces ambiguity in the document as it is unclear how to assess what might be considered material under this additional reference and whether it is a different threshold to the one expressly set out.

JGN has not accepted the AER's proposed wording in limb (a) of the definition for Regulatory Change Event, as changing the defined term may have unintended consequences for other provisions unless many consequential changes were made throughout JGN's document suite. JGN notes that using the actual AA defined term within this definition does not change the substantive meaning of the defined term and maintains consistency within JGN's AA.

JGN has accepted the AER's proposed deletion of the word "judicial" from the definition of Service Standard Event, but remains of the view that it is appropriate that judicial decisions be included in this definition as common law may impact the costs of providing services in the same manner as legislative changes or administrative decisions.

Table 9.3: Summary of proposed changes set out in Revised Proposal AA

Pass Through Provision	2025 AA Reference	Summary of proposed change
Annual Variation Notice	3.9(a)	JGN accepts the AER's proposed change of date for submission of variation notice from 15 April to 15 March.
Notification and AER determination of cost pass throughs	3.6(a) & 3.6(b)	JGN accepts the AER proposed change to materiality threshold calculation from 1% of smoothed revenue to 1% of unsmoothed revenue.
Insurance Coverage	Definitions	AER language accepted other than materiality language and minor update for consistency with language proposed by the AER for other definitions throughout the document.
Insurer Credit Risk	Definitions	JGN accepts the AER's proposed wording.
Natural Disaster	Definitions	JGN accepts the AER's proposed wording, but notes that the drafting of limb (a) of this definition may not reflect the intended meaning and may have little if any application. This is on the basis that it would be difficult to imagine a scenario where a service provider might cause a natural disaster such as a cyclone.
Regulatory Change	Definitions	JGN accepts the AER's proposed wording other than change to defined term and materiality language.
Service Standard	Definitions	JGN accepts the AER's proposed wording other than materiality language.
Tax Change	Definitions	JGN accepts the AER's proposed wording other than minor changes for clarity and consistency. JGN is of the view that these changes do not change the intended meaning of the definition.
Terrorism	Definitions	JGN accepts the AER's proposed wording.

9.7 Attachments

Table 9.4 lists the attachments to our Revised 2025-30 AA Proposal which provide further information on our response to the AER's draft decision on our services.

Table 9.4: Revised 2025-30 AA Proposal attachments on accessing our network

Attachment	Name	Author
4.2	JGN - Att 4.2 - renewable gas expenditure - 20250115	JGN
7.1	JGN - RP - Att 7.1 - Abolishments - 20250115	JGN
8.1	JGN - RP - Att 8.1 - Pricing - 20250115	JGN
9.1	JGN – RP - Att 9.1 – Draft decision response – Compare of 2020-25 and Revised Proposal 2025-30 AA - 20250115	JGN
9.2	JGN – RP - Att 9.2 – Draft decision response - Compare of 2020-25 and Revised Proposal 2025-30 RSA - 20250115	JGN
9.3	JGN – RP - Att 9.3 – Draft decision response - Compare of Initial and Revised Proposal 2025-30 AA - 20250115	JGN
9.4	JGN – RP - Att 9.4 – Draft decision response - Compare of Initial and Revised Proposal 2025-30 RSA - 20250115	JGN
Access Arrangement	JGN – RP - 2025-2030 - Access Arrangement - 20250115	JGN
RSA	JGN – RP - 2025-2030 - Reference Service Agreement - 20250115	JGN

Abbreviations

Term	Definition
AA	Access Arrangement
AACE	Association for the Advancement of Cost Engineering
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIC	Average Incremental Cost
CALD	Culturally and Linguistic Diverse
Capex	Capital Expenditure
CCP	Consumer Challenge Panel
CESS	Capital Expenditure Sharing Scheme
CLM	Contract Lifecycle Management
CORE	Core Energy
CPI	Consumer Price Index
DAE	Deloitte Access Economics
EBSS	Efficiency Benefit Sharing Scheme
ECM	Efficiency Carryover Mechanism
GJ	Gigajoules
GSOO	Gas Statement of Opportunities
HIA	Housing Industry Association
JGN	Jemena Gas Networks (NSW) Ltd
KPIs	Key Performance Indicators
MSO	Model Standing Offer
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NPV	Net Present Value
NSW DCCEEW	NSW Department of Climate Change, Energy, the Environment and Water
OGMP	Oil and Gas Methane Partnership
Opex	Operating Expenditure
PRS	Pressure Reduction Station
RAB	Regulated Asset Base
RBA	Reserve Bank of Australia
RFM	Roll Forward Model
RIN	Regulatory Information Notice
RS	Reference Service
RSA	Reference Service Agreement
SaaS	Software As a Service
TAB	Tax Asset Base
UAG	Unaccounted for Gas
WACC	Weighted Average Cost of Capital
WPI	Wage Price Increase