**AGN Final Plan for South Australian Gas Network July 2026 – June 2031**

**Submission from the South Australian Reference Group Review Panel**


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## 1. Summary and Conclusions

Introduction

The Australian Gas Networks (AGN) gas network in South Australia is subject to full price regulation by the Australian Energy Regulator (AER). This means that every five years AGN submits an 'access arrangement' (AA) to the AER setting out:

- The services offered on the network,
- The price paid for those services, and
- The non-price terms under which access to the network will be provided

over a future five year period. AGN's next period is 1st July 2026 to 30th June 2031. The AER assesses the AA by a 'propose/respond' process whereby the network proposes and the AER responds in a structured timetable. In March AGN published its Draft Plan for stakeholder comments. Following that feedback, AGN has now submitted its Final Plan[1] to the AER. The next steps in the AER's 'propose/respond' process are:

- The AER makes a Draft Decision around November
- AGN will submit a revised AA in February 2026
- Stakeholders have the opportunity to make a submission in February 2026 on the revised proposal and the AER Draft Decision
- The AER will publish its final decision on 30th April 2026

AGN's aim in developing the Final Plan is to have a plan that:

- delivers for current and future customers,
- is underpinned by effective engagement, and
- is capable of acceptance by customers and stakeholders.

The Final Plan prioritises stability as the energy market transition continues – what the Panel have called a 'business as usual' Plan – built on affordability with prices remaining flat in real terms. Unlike the Victoria and the ACT Governments, South Australian Government policy ensures consumers have a choice of gas or electricity. With this supportive policy environment, AGN seeks to build on its deserved reputation for operational excellence – safety performance, high customer satisfaction and stable or falling tariffs. The completion of the mains replacement also means the network is 'hydrogen ready' and the future role of the network as it transitions to renewable gas is a key part of this AA.

While AGN recognises that it faces and increasingly competitive world eg demand per residential customer has fallen 16% over the first three years of the current period 2021-26 AA period and total demand is forecast to fall 2.4%/yr for 2026-31, it believes that it will be able to adapt and have a long term future well beyond 2050. Its long term vision is a sustainable network successfully competing in the market well beyond 2050 with a renewable gas (hydrogen and biomethane) product.

[1] https://www.aer.gov.au/industry/registers/access-arrangements/australian-gas-networks-sa-access-arrangement-2026-31

The Final Plan is supported by a combination of extensive consumer engagement (with the approach based on the AER's Better Reset Handbook[2]), analysis of the prudent and efficient capital and operating costs required to run the business, tariff design for approved pipeline and reference services and analysis of how progress in 2026-31 fits it with its long term vision for a sustainable network.

A key part of this consumer engagement has been AGN's establishment of the South Australian Reference Group (SARG). Membership of the SARG reflects the diversity of the AGN's customer base with organisations representing residential and business customers, major gas users, customers facing vulnerability, multicultural communities, the building industry, property developers and the Ombudsman. In December 2024 the SARG decided to establish a SARG Review Panel, consisting of three SARG members, to engage more deeply on the AA process and prepare submissions to AGN and the AER. Under the Terms of Reference[3] the SARG has been established:

> "... to provide independent and constructive feedback and challenge based on their expertise and insight during the development of AGN SA's 2026-31 regulatory proposal which include a review of:
>
> - AGN's engagement program and associated activities, and
> - AGN's regulatory proposal (Draft and Final Plans)."

The SARG's first submission was on the Draft Plan[4] and highlighted a number of issues that it recommended be considered more deeply in the Final Plan. This second submission provides feedback to the AER on the Final Plan including how AGN responded to our recommendations in our Draft Plan submission. Throughout the AA process the Panel observes customer engagement, participates in SARG's engagement with AGN on key issues, undertakes deep dives on particular topics with AGN, reports back to the SARG on progress and seeks SARG's views and contributions to what the Panel proposes to say in its submissions.

All submissions reflect feedback on behalf of the SARG, not on behalf of the individual constituencies of Review Panel members. A draft of this submission was made available to the full SARG and their feedback incorporated.

Panel Conclusions

*What we said in our Draft Plan submission*

In this submission, the Panel:

- Congratulated AGN on its operational achievements during the current period and how this provided a strong operational basis for 2026-31
- Noted its strong customer focus shown with its emphasis on affordability, the introduction of the Priority Services Program in this period and the extensive consumer engagement in preparing the Plan

[2] https://www.aer.gov.au/industry/registers/resources/guidelines/better-resets-handbook-towards-consumer-centric-network-proposals
[3] See https://gasmatters.agig.com.au/australian-gas-networks-south-australia-access-arrangement-2026-27-2030-31
[4] See pp. 33-57 https://www.aer.gov.au/system/files/2025-07/AGNSA_Attachment%205.4%20Draft%20Plan%20Submissions_PUBLIC_Redacted_0.pdf

- Focussed particularly on the 'future of gas' as we discussed AGN's vision for repurposing the network to transport renewable gas; we argued that there was a 'missing chapter' that should be in the Final Plan providing more detail on how they see their vision being achieved and the risks to that occurring; this would help answer a crucial question - was the proposed $20m accelerated depreciation too low?
- A clear understanding of the longer term direction of AGN is also important in assessing how the shorter term plans covered in the 2026-31 AA contribute to this long term direction
- Made suggestions on the scope of consumer engagement in Stages 4 and 5, particularly around the future of gas and the risks to the 'business as usual' strategy post 2031.

*Panel comments on the Final Plan*

Our focus here is on AGN's response to our Draft Plan submission comments, particularly on the 'missing chapter'.

AGN has provided considerable information for the 'missing chapter' in Attachments 6.1[5] and 6.4[6] to the AA. While we understand the logic flow – the South Australian Government's continued support for customer choice will facilitate the gradual move to increased renewable gas blend over time that will be competitive with renewable electricity to ensure the network has a sustainable life beyond 2050 - we do not agree with it on the basis of the current evidence that we see.

Gas networks like AGN have made considerable progress in developing small scale hydrogen projects to test low level blends in parts of their networks[7]. But the transition to substantial hydrogen blends by energy (not volume) requires large scale hydrogen production to be economic. To produce hydrogen at the Federal Government's target of $2-3/kg (~$14-21/GJ HHV) requires delivered firm renewable energy <$30/MWh[8]. We consider that this is very unlikely in the next 20 years, even if large transmission costs are subsidised. The $2/kg Hydrogen Production Tax Incentive is not going to bridge the gap. Even if delivered electricity prices were down at that level then the competition from electricity would be significant.

Given the above economic factors, the recent closure or suspension of almost all hydrogen development projects across Australia, reflecting similar experience overseas, is not surprising. A sustainable distribution network future built on hydrogen has a very low probability in the absence of a massive additional Government subsidy to ensure an 'economic' outcome ie one where network customers continue to see gas as a real alternative to electricity assuming Government policy allows choice to continue.

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[5] https://www.aer.gov.au/documents/agnsa-attachment-61-future-gas-and-depreciation-20250701

[6] https://www.aer.gov.au/documents/agnsa-attachment-64-energy-transition-20250701

[7] https://www.energynetworks.com.au/news/energy-insider/2023-energy-insider/the-benefits-of-using-australias-gas-networks-to-build-our-hydrogen-industry/

[8] https://www.afr.com/policy/energy-and-climate/huge-cost-cuts-needed-in-solar-for-hydrogen-to-work-arena-20241021-p5kk3d

The Panel considers this 'economic' outcome is very unlikely to occur. Nor is it considered a likely future by other expert forecasting reports, such as the ISP[9] or the Net Zero Australia mobilisation report[10].

While the cost of biomethane may end up being competitive with renewable electricity, we do not have enough information to be confident that there will be the volume of competitive biomethane available to ensure a viable distribution network.

Based on extensive modelling AGN set out its pathway to a long term sustainable network that will continue to operate well beyond 2050. This meant they proposed accelerated depreciation (we continue to prefer this term to AGN's 'additional depreciation') of only $70m for 2026-31 based. AGN reduces that $70m back to $30m to produce a no real increase price path and align with the AER's decision in the 2025-30 Jemena NSW decision to goal seek the level of approved accelerated depreciation to cap price increases at 0.5% real/yr. In landing on the cap, the AER, which was very focussed on current affordability concerns, reduced Jemena's proposal, concluding that[11]:

> "We consider the reduced accelerated depreciation amount strikes a balance between the need for a start of accelerated depreciation to promote efficient investment, and the need to limit the impact of accelerated depreciation on consumers, particularly at a time when energy affordability continues to be a key issue during the energy transition."

The Panel would suggest that this approach has its limitations eg:

- Changes in other variables outside of the network's or the AER's control eg WACC can leave little or no ability to have accelerated depreciation which the AER agrees is required
- Finetuning small changes in network costs may have little impact on the total bill when the commodity component of the bill is increasing strongly; this has been the case in the current AA period when the network component has fallen in real terms and is likely to be the case in the next AA period.

Given our view that a renewable reticulated gas future is very unlikely, we suggest that a higher level of accelerated depreciation than $30m is likely to provide greater intergenerational equity. This may be achieved through the AEMC's decision on the ECA rule change to impose full cost up front connection charges on new residential and small business customers (larger customers already pay these costs). If accepted, it would effectively mean that the forecast new connections capex of $157m in 2026-31 would be recovered as incurred and effectively increase accelerated depreciation to $187m. This may lead to less pressure on the AER to relax the 0.5% cap.

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[9] https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf?la=en

[10] https://www.netzeroaustralia.net.au/wp-content/uploads/2023/09/Net-Zero-Australia-Mobilisation-How-to-make-net-zero-happen-updated-19-Sep-23.pdf

[11] See p. 9 https://www.aer.gov.au/system/files/2025-05/AER%20-%20Final%20decision%20-%20JGN%20access%20arrangement%202025%E2%80%9330%20-%20Attachment%204%20-%20Regulatory%20depreciation%20-%20May%202025.pdf

Were the AEMC to not agree with the ECA rule change then, if the AER wishes to continue with a cap approach, we think there is an arguable basis for it to be higher than 0.5%. For example, 70m accelerated depreciation would result in a one-off 2.5% increase in the total bill 2.5% for an average residential customer - $28 on $1,120. This is significantly less than the bill increases in recent years that have been driven by increases in the commodity component of the bill. We invite the AER to consider whether a cap higher than 0.5% still results in a reasonable trade-off between intergenerational equity and current consumer affordability.

The 'future of gas' discussion with the SARG members and through engagement sessions brought a range of responses. It is a very complex topic that does not lend itself to simple or easy answers. There is a clear preference to maintain customer choice between gas and electricity. But the implications of maintaining that choice are not well understood. All consumers are worried about bill impacts – whether they come from accelerated depreciation or higher costs of renewable gases, or indeed higher costs for natural gas. Larger consumers are also worried about the cost of converting their businesses (assuming it is technically possible) whether to hydrogen or electrification.

The AER has a difficult role within the current gas rules framework built on an assumption of rising gas consumption. The rule changes before the AEMC for full cost connection and abolishment charges will provide some clarity. We look forward to the AEMC's consideration later this year of more comprehensive rule changes proposed by the ECA that could fundamentally change the gas rules and provide the AER with a much more comprehensive toolkit to address the future of gas.

The table summarises the Panel's comments and recommendations on other parts of the Final Plan:

| | |
|---|---|
| Engagement | • AGN have conducted a well-planned and appropriately executed program with a significant number of people involved and has pioneered an excellent online tool in Orbviz<br>• There was substantial uncertainty around the future of gas and care needs to be taken on how the insights from these sessions can be applied in the Final Plan |
| Opex | • We do not support the concept of customer paying for the renewable gas certificates to support the economics of HyP Adelaide<br>• Welcome AGN agreeing to our recommendation that they absorb the small ($0.3m) insurance step change; it is not 'material' and so does not constitute a 'step change' |
| Capex | • Consistent with our views on the renewable gas certificates step change, we do not support customers paying the proposed $8m capex to help the network prepare for hydrogen<br>• We support the ECA rule change on connection charges<br>• The proposed IT expenditure is a large uplift from the current period and we recommend that the AER closely review the implementation |

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|---|---|
| | plan given the many examples of network overspend on IT in recent years |
| Pipeline and reference services | • We previously supported the addition of the abolishment service and continuation of the existing policy of socialising abolishment charges recognising that here are safety and equity concerns about how this might be implemented.<br>• We await the current AEMC review of the JEC rule change supporting full cost abolishment charges |
| Incentive schemes | • We support the continued application of the Efficiency Carryover Mechanism and the Capital Expenditure Sharing Scheme to 2026-31. |
| Revenue and prices | • AGN should be cautious in relying too strongly on the Stage 5 engagement on tariffs and the potential for changes in the declining block structure; customers lacked a clear understanding of the complex issues involved<br>• AGN should provide detailed information on the impact of the AEMC deciding to support the current ECA/JEC rule changes on connection and abolishment charges |

## 2. The Future of Gas

<u>What we said in our Draft Plan submission</u>

This was the major area of comment in the Draft Plan submission. We noted that the AGN approach is shaped by the South Australian Government policy that, at present, supports continued consumer choice, new gas connections and the development of renewable gases such as hydrogen and biomethane. This is in stark contrast to Victoria where the Government is gradually implementing its Gas Substitution Roadmap[12] to restrict the use of gas and encourage electrification.

We noted the vigorous debate on the future of gas being played out in the AER over recent years across access arrangements in NSW, Victoria, the ACT and SA, focussing on the level of allowed accelerated depreciation. In Victoria that level was determined by a goal seek that limited the real price path to 1.5%/year real price growth over 2025-30 with the AER concluding that this[13]:

> "… achieves an appropriate balance between what consumers pay now to mitigate future price increases, and the risk of greater increases in the future if mitigation is delayed."

We described AGN's plan as a 'business as usual' plan with AGN's approach based on a combination of:

- Confidence on SA Government policy continuing to allow new connections beyond 2031 and their support for the development of renewable gas

[12] https://www.energy.vic.gov.au/renewable-energy/victorias-gas-substitution-roadmap
[13] See p. 24 https://www.aer.gov.au/system/files/AER%20-%20AGN%202023-28%20-%20Final%20Decision%20-%20Overview%20-%20June%202023.pdf

- AGN's own views on their ability to develop a commercial renewable gas future to enable gas to effectively compete against electricity and underpin the long term viability of its gas network

AGN provided a work in progress report on their customer choice modelling on how gas can remain competitive and highlighted their progress in introducing hydrogen blend into parts of the network with Hydrogen Park South Australia and Hydrogen Park Adeliade and the agreement with Delorean.

This confidence led AGN to propose a $23.6 million opex step change placeholder for potential State Government support for renewable gas and a relatively small $20m placeholder for accelerated depreciation, though this term is not used, AGN preferring the term 'additional depreciation'. This $20m was 5% of the proposed regulatory depreciation of $385m with an asset base at 1st July 2026 of just over $2b. This compares with AGN's approach in its Victorian gas networks driven by the different Victorian Government policy:

| | Accelerated Depreciation ($m) | | Regulatory Depreciation | | Asset base 1st July 2023 |
|---|---|---|---|---|---|
| | Final Proposal | AER Final Decision (goal seek) | $m | % of regulatory depreciation | $m |
| Multinet | $86m | $53m | $225 | 24% | $1.42b |
| AGN (Victoria/Albury) | $175 | $175 | $288 | 61% | $2.0b |

The Panel commented that:

- We do not think that AGN should discount the chance of a change in South Australian or Federal Government policy over the next 5-7 years
- Unlike the time when the 2021-26 AA was being discussed, there is now a National Gas Objective that explicitly requires consideration of how the proposed expenditure is likely to contribute to reducing Australia's greenhouse emissions
- Affordability issues are paramount in consumers' minds
- Clarity around accelerated depreciation is essential in navigating the energy transition; it can support a fairer and more orderly transition by ensuring costs are recovered more equitably over time; avoiding or downplaying the issue only undermines trust so we need open and honest conversations with stakeholders and consumers about why it might be needed, what it means for bills, and how it fits into broader policy and investment decisions
- The AEMC decision on the ECA rule change supporting full cost connection charges that the ECA believes is in the long term interests of consumers will impact on the effective level of accelerated depreciation[14].

The Panel highlighted the 'missing chapter' to justify this 'business as usual' approach and recommended that this 'missing chapter' discuss:

(i) What is AGN's vision of the role of gas and its network in 2050 and what is their long term pathway to get to there?

[14] https://www.aemc.gov.au/sites/default/files/2025-02/New%20rule%20change%20proposal%20-%20Energy%20Consumers%20Australia%20-%20Gas%20distribution%20networks%20-%20Creating%20additional%20criteria%20for%20the%20applica%20%281%29.pdf

(ii) What are the risks to this central case not occurring and what does that mean for the 2026-31 Plan eg who will bear the residual stranded asset risk?

<u>What AGN is proposing in the Final Plan</u>

AGN's net zero targets are underpinned by a gradual progression in lowering emissions for both the network and its customers:

- Today - Continue replacing distribution mains and enabling third-party introduction of renewable gases to our networks; this includes leadership in interconnection policy and new project development
- By 2030 – to have a 10% blend of renewable gases by volume (~ 3-4% by energy if all hydrogen)
- By 2050 – to transition to 100% renewable (hydrogen and biomethane) and carbon-neutral (natural gas with offsets) to be delivered through a mix of third parry suppliers backed by a mature certification and regulatory framework

Drawing on the Australian Government's Future Gas Strategy[15] and AEMO's 2025 GSOO[16], AGN see an enduring role for gas given their views on the developing competitiveness of renewable gas. Even with the forecast fall in total network demand from 29PJ in 2029 to 26-7 PJ in 2043, AGN see an ongoing role for gas distribution albeit with a changing customer mix – falling residential and commercial building, increased commercial non-building and industrial.

The Final Plan provides extensive commentary on why AGN has this view with additional information and analysis in:

- Attachment 6.1 – details the long run demand modelling, options for future depreciation profiles and how the two interact
- Attachment 6.4 – AGN's net zero ambition and the pathways to achieve that ambition with the competitive supply of renewable gases and the challenges they face.

*Attachment 6.1*

AGN model the energy sector in two periods:

- Out to ~2050 – there is increasing gas vs electricity competition as consumers make their appliance choices
- Beyond ~2050 - networks will operate in a more competitive market because of behind the meter consumer energy resources (solar panels and batteries) that are cheaper that grid sourced energy

Whether renewable gases will be available at a reasonable price is a 'gateway' issue for AGN and Attachment 6.4 argues they will be. Australia will benefit from the significant investment in Europe and the US to develop lower cost technology. There are potential future roles for pipeline gas including distributed electricity generation using fuel cells and transport network support. Some parts of the network could be re-purposed eg undergrounding powerlines.

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[15] https://www.industry.gov.au/publications/future-gas-strategy

[16] https://aemo.com.au/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo

The regulated gas network will continue to operate profitably until the competitive market structure emerges and the network is not regulated – set at 2050. The model then assesses the enterprise value in 2050 (not RAB) in 2050. With a focus of the modelling on residential customers various assumptions are made on the customer numbers in 2050:

- 250,000 residential – about half the current number, who account for ~ 80% total revenue and their number falls over the next 15 years until only 15% of household are connected
- Commercial customer numbers are assumed to stay on the network
- Industrial customers are assumed to be able to sustain a 50% increase over current network charges

Key assumptions relate to appliance prices and relative gas and electricity prices. There are important emerging trends that provide a challenge to gas and electricity networks. Attachment 3 is a report on developments in electricity and gas appliance costs. It concludes (p.4):

> "For typical 3-bedroom homes in South Australia, total ownership costs now favour all electric configurations. This represents a fundamental shift in residential energy economics, driven by technology convergence rather than efficiency improvements alone."

This shift is residential energy economics is the use of cheap rooftop solar. The AER's State of the Market Report cites research saying a well-insulated house with rooftop solar can reduce its network supplied electricity to zero[17]. It is also assumed that new residential and commercial customers pay a substantial portion of their connection costs from 2031. Other assumptions include network capex and opex (driven by number of new customers assuming continuation of exiting policy and whether new customers pay the full cost of their connections) the level of distributed gas fired electricity generation, the likelihood of customers going off grid and the willingness to pay for gas - households will pay a price matched to electricity.

AGN take an optimistic view of the post 2050 competitive market revenue stream and arrive at an enterprise value of $1b in 2050. Then they consider whether the difference between $1b and the combination of the future capex required to 2050 plus the current RAB ($1.8b) can be recovered under the current depreciation schedule. If it cannot, then depreciation to 2050 is increased.

A consumer behaviour model assesses willingness to pay price increases resulting from the increased depreciation. Will customers leave prematurely and the network not be sustainable until 2050? If no, then depreciation is wound back and the model keeps testing until a 'reasonably practical' solution to the level (in 2026-31) and pace (what happens after 2031) of depreciation is found. This 'reasonably practicable' amount of depreciation will allow the business to remain sustainable into the longer term without producing prices that drive customers away. As the network is unregulated from 2050, AGN would take the risk of recovering all of the 2049 closing RAB.

The modelling concludes that additional depreciation in 2026-31 of $70m is the most reasonable to reduce the 2050 RAB to a level that can be supported by the post 2050 competitive market. This level, which would add ~2.5% to the total average bill for a residential customers, is considered a reasonable trade-off between current and future consumers. It is a

[17] See p. 257 https://www.aer.gov.au/system/files/2025-07/State%20of%20the%20energy%20market%202024.pdf

reasonable insurance premium to pay to protect those customers (vulnerable residential customers or hard to abate industrial customers) from significantly higher (>10%) increases if the market is particularly unfavourable to gas and more customers exit the network.

Attachment 6.1 p.13:

> "The 2050 valuation is not a forecast, but a reflection of the level of long-term risk we are currently willing to accept at present, given the context of the South Australian network, current policy settings, the potential we see for market evolution and renewable gas progress as a gateway to the future. The modelling to 2050, in turn, reflects our confidence in reaching that point and unlocking future opportunities. However, if policy settings changed or the future towards 2050 is materially different from these assumptions, then the outcomes would be different and likely require more depreciation."

*Attachment 6.4*

AGN's net zero ambitions for both its own operations and its customers depend on key enablers – regulatory reform (government backed certification); enabling policy ('push' and 'pull' policy levers that support supply and demand of renewables gas); connecting renewable gas projects to the network and customer and stakeholder engagement to support AGN's vision. Just as the electricity system moved from centralised coal and gas to diversified behind and in front of the meter sources, gas will move to a 'multi-vector energy platform' (p.22).

Recent reports to Government on the potential supply of hydrogen and biomethane are cited. The most recent, by ACIL Allen for AEMO in February 2025[18], estimated supply of between 40 - 220 PJ of hydrogen and 250 - 270 PJ of biomethane could be available by 2030, increasing to 200 - 3,200 PJ and 480 - 500 PJ by 2050. Government reports have forecast current hydrogen cost of $5-10/kg ($35.30-70.50/GJ HHV) could fall to ~$1.50-4/kg ($10.60-$28.20/GJ HHV) by the mid-2030s driven by an expected 40-60% reduction in renewable electricity costs and ~90% reduction in electrolyser costs. Adding in the Federal Government's $2/kg hydrogen production tax:

> "...strengthens the case for hydrogen to become cost-competitive with natural gas over the medium to long term."

The discussion of biomethane draws on the same ACIL Tasman report with current costs of $13-35/GJ falling to $10-27/GJ by 2058. The suggest that some biomethane projects might already be competitive citing the Delorean project they will source biomethane from but do not provide a cost for those purchases.

A number of pathways to 2043, based on the AEMO 2025 GSOO data, are presented that flex on the availability of different gases to provide customer choice. The Government reports support the view of (p. 26):

> "...the potential for hydrogen and biomethane to be cost-competitive with natural gas over the longer term"

While there are a range of policies to subsidise the cost of producing hydrogen, there is no national or State based certificate policy to encourage the use of hydrogen. Where hydrogen

[18] https://aemo.com.au/-/media/files/major-publications/isp/2025/acil-allen-2024-fuel-price-forecast-report.pdf

and biomethane are unavailable or limited, natural gas with emissions offsets provides a backstop supply to keep the network viable.

*AGN's proposed additional depreciation*

While the model suggests $70m, AGN has reduced that to $30m due to a combination of:

- A desire to keep tariffs flat in real terms over 2026-31, and
- because of the AER's 'guardrail' approach in its recent decision on Jemena's 2025-30 AA.

In that decision the AER limited accelerated depreciation to that which produced a real tariff increase of 0.5%. AGN has followed the Jemena decision rather than the AER's decision for its Victorian networks which had a cap at 1.5%/yr real increase because of the similarity in NSW and SA policy in allowing new connections. While the Jemena cap is a combination of shorter asset lives and accelerated depreciation, AGN only proposes accelerated depreciation.

<u>Panel Comments on the Final Plan</u>

*Summary*

The Panel greatly appreciates the significant additional information provided by AGN. The final plan does provide a response to both our questions in our Draft plan submission – the pathway to 2050 and the risks of this pathway and what does it mean for the 2026-31. Nevertheless, we have come to a different conclusion on the first which means we have a different view on the second.

| Question | | Response |
|---|---|---|
| (i) | What is AGN's vision of the role of gas and its network in 2050 and what is their long term pathway to get to there? | <u>AGN</u><br>• A combination of competitive renewable gas (hydrogen and biomethane) plus carbon neutral gas will ensure the network has a life beyond 2050 so the level of accelerated depreciation in 2026-31 is a relatively small $70m<br>• This $70m is reduced to $30m to fit in with the AER's 'goal seek' level of accelerated depreciation in its Jemena NSW decision of tariff increases capped at 0.5% real/yr<br><u>Review Panel</u><br>• We do not see a pathway to competitive renewable gas supply in sufficient volumes in a distribution network to enable a viable network to exist in 2050<br>• Electricity has a much higher chance of becoming the preferred choice well before 2050 |
| (ii) | What are the risks to this central case not occurring and what does that mean for the 2026-31 Plan eg who will bear the residual stranded asset risk? | <u>AGN</u><br>• The modelling does not have a 'central' case; the case chosen is based on a range of sensitivity testing to give a reasonable chance of not leading to any regrets in 2031<br><br><u>Review Panel</u><br>• Even though the SA Government strongly supports consumer choice, there are considerable risks around |

| | |
|---|---|
| | the ability of renewable gas to provide a competitive alternative to renewable electricity.<br>• This suggests the $70 accelerated depreciation is likely too low<br>• The approval of the ECA rule change of full cost recovery of connection charges will result in an effective increase of $157m in accelerated depreciation were the change to apply from the 1st July 2026 as ECA proposes; this lessens our concern that $70m (or $30m) is too low<br>• Application of the AER's 0.5%/yr real increase cap to the level of accelerated depreciation seems to have relatively little impact on affordability; were the ECA rule change is not successful, a higher cap seems to be a reasonable balance between intergenerational equity and current affordability. |

While there will be customers who for various reasons seek to remain on the gas network (cannot afford to change or hard to abate industries), the chances of hydrogen playing a role in network gas delivery is very low because of relative cost. While the chances for biomethane might be higher, there is a high risk that it will not be competitive with electricity. That means there may not be enough volume to sustain a viable network. We accept that both hydrogen and biomethane may provide high heat fuel options for 'difficult to electrify' businesses well into the future, but this is more likely in a business specific context rather than being provided through the distribution network.

While the modelling in Attachment 6.1 was looking at consumer sensitivity to relatively small changes in network charges, consumer sensitivity to potentially much larger changes in the commodity component of the delivered gas price should also be considered. The modelling seems to assume that increasing the blend of renewable gases will not result in a large increase in the commodity component of the bill. If that is the case then someone else (Government?) is going to subsidise the cost. The level of announced Government support is very unlikely to do that. AGN is proposing consumers pay for renewable gas certificates in 2026-31. What is the risk consumers will leave the network because of higher commodity prices eg higher certificate cost, which may dwarf higher network prices from accelerated depreciation?

The AGN pathway requires renewable gas costs to come down over that period to so that the price of the lower carbon intense blended product is competitive with electricity. Competitive hydrogen requires electricity prices well below $50/MWh delivered and AGN seems to argue that will occur to reduce hydrogen cost – the Government hydrogen target of $2-3/kg requires delivered electricity of under $30/MWh[19]. Even if those prices occurred (which we think is very unlikely), how many consumers are likely to stay on the gas network? Many more than those who prefer gas no matter the price, those who cannot afford to move and those hard to abate commercial and industrial customers. But their volumes are unlikely to support a viable network.

[19] https://www.afr.com/policy/energy-and-climate/huge-cost-cuts-needed-in-solar-for-hydrogen-to-work-arena-20241021-p5kk3d

The ACT Government has, with very limited exceptions, banned new connections since December 2023[20]. Gas use will be banned from 2045 as part of their policy to achieve net zero by that date. In developing its policy in 2022, the Government considered the use of renewable gas, concluding that[21]:

> "…it isn't realistic for the ACT's entire fossil fuel gas supply to be replaced by a renewable gas alternative.
>
> Why not? Our analysis has found there would be significant barriers. While the gas network and the appliances of existing customers wouldn't need to change if we transitioned to biogas, the largest barrier at present to the feasibility of biogas and hydrogen are the high costs associated with producing renewable gases at volume."
>
> …
>
> Although renewable gases will likely have future uses in the ACT for certain industrial, transport and niche applications, they are simply not suitable to fully replace our fossil fuel gas supply. We need to base our plan around electrifying everything we are able to, with scope for renewable gases to be used for specific purposes in future."

This was at a time when there was considerable optimism about the future economics of hydrogen which has now disappeared as projects close due to poor economics. While the ACT network is quite different from the AGN SA network (size, variety of customers) we are not convinced that these differences lead to a different conclusion in South Australia.

*The potential competitiveness of hydrogen is very uncertain*

In September 2022 the Australian Government predicted[22]:

> "Australia is on track to be one of the world's largest hydrogen suppliers by 2030"

The renewed 2024 strategy[23]:

> "… provides the framework to guide Australia's production, use and export of hydrogen. This will position Australia to become a global hydrogen leader.

It is supported by the Hydrogen Production Tax Incentive[24] and the expanded Hydrogen Headstart Program[25] announced in the 2024-25 Federal Budget as part of the Government's $22.7 billion Future Made in Australia[26] plan.

As AGN has shown, there is no shortage of Government and network initiated reports arguing the case for the green hydrogen with a range of forecasts on the timetable for it becoming economic (however that is defined). The logic was something like – subsidise the early stage

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[20] https://www.climatechoices.act.gov.au/energy/canberras-electrification-pathway/preventing-new-gas-network-connections
[21] See p. 19 https://www.climatechoices.act.gov.au/__data/assets/pdf_file/0009/2052477/Powering-Canberra-Our-Pathway-to-Electrification-ACT-Government-Position-Paper.pdf
[22] https://international.austrade.gov.au/en/news-and-analysis/news/australia-one-of-the-worlds-largest-hydrogen-suppliers-by-2030
[23] https://www.dcceew.gov.au/energy/publications/australias-national-hydrogen-strategy
[24] https://www.ato.gov.au/businesses-and-organisations/income-deductions-and-concessions/incentives-and-concessions/production-tax-incentives/hydrogen-production-tax-incentive
[25] https://www.dcceew.gov.au/energy/hydrogen/hydrogen-headstart-program
[26] https://archive.budget.gov.au/2024-25/factsheets/download/factsheet-fmia.pdf

development ('learning by doing') because Australia has a comparative advantage in renewable energy that can be harnessed to develop a large scale hydrogen industry that can supply domestic and overseas customers. The potential use cases have been quite wide including road transport (esp heavy vehicles), replacing natural gas for heating, ammonia, green steel and decarbonising 'hard to abate sectors'. Networks have also developed a high level case for 100% hydrogen networks[27].

Despite the confident forecasts, the last 12-18 months has seen a significant scaling back of hydrogen ambitions from what was envisaged at the time of the initial optimistic press release:

- The Whyalla hydrogen plant has been shelved as the State Government focusses its efforts and funding on ensuring the steel works continue operating; while the Office of Hydrogen Projects will continue, large functions of that office will be curtailed and wound back[28]
- The Trafigura Port Pirie project was shelved after completion of a feasibility study[29]
- BP has abandoned it's 64% interest in the '$55b' Pilbara project after buying into it in 2022[30]
- Stanwell has withdrawn from the $12.5b flagship Queensland Hydrogen Project (CQ-H2) and has cancelled all of its hydrogen projects following withdrawal of shareholder (Queensland Government) support[31]; its Japanese partner has previously withdrawn in late 2024 citing the increased costs.
- Fortesque has taken a $US150 impairment write down following the abandonment of its electrolyser projects in Arizona and Gladstone[32]; it is left with only a small 50MW project at Christmas Creek in the Pilbara[33] and is now being asked to repay Government subsidies[34]
- Hydrogen projects at Bell Bay have had a succession of proponents as past ones (Fortesque[35], Woodside[36] and Origin[37]) have withdrawn leaving smaller players to try to make the project viable[38]

[27] https://arena.gov.au/knowledge-bank/ahc-100-hydrogen-distribution-networks-victoria-feasibility-study/
[28] https://www.abc.net.au/news/2025-02-20/hydrogen-plant-plans-on-ice/104961150
[29] https://www.abc.net.au/news/2025-03-25/green-hydrogen-project-at-port-pirie-shelved/105092634
[30] https://www.afr.com/companies/energy/bp-ditches-us36b-pilbara-hydrogen-project-20250724-p5mhmh
[31] https://www.theaustralian.com.au/nation/politics/queensland-premier-cans-hydrogen-pipe-dream/news-story/b082008dbb726291badfd0a7e803c62e
[32] https://www.afr.com/companies/mining/fortescue-smashes-export-record-calls-time-on-hydrogen-projects-20250724-p5mheb
[33] It has now removed references to hydrogen projects from its website https://www.afr.com/rear-window/twiggy-forrest-erases-green-hydrogen-projects-from-website-20250804-p5mk5q?utm_content=rear_window&list_name=5655EA70-F54A-4680-8E43-524D4E016C59&promote_channel=edmail&utm_campaign=before-the-bell&utm_medium=email&utm_source=newsletter&utm_term=2025-08-05&mbnr=MjAyMDU1MTE&instance=2025-08-05-06-00-AEST&jobid=31706900
[34] https://www.theaustralian.com.au/nation/politics/fortescue-agrees-to-pay-back-taxpayer-millions-on-failed-hydrogen-projects/news-story/d012f1e9221c38bf1cfb4d1a2e60fbfe
[35] https://www.afr.com/companies/mining/hydrogen-export-dreams-stalled-as-tasmania-looks-inward-20230908-p5e385
[36] https://reneweconomy.com.au/not-enough-renewables-woodside-pulls-plans-for-green-hydrogen-project/
[37] https://research.csiro.au/hyresource/origin-green-hydrogen-and-ammonia-project/
[38] https://reneweconomy.com.au/state-taps-australian-hydrogen-hopeful-to-lead-tasmanias-green-fuel-gambit/

- The Provaris Tiwi Island project has been shelved[39]
- Woodside has taken a $US140m impairment on closing its US hydrogen project[40]
- Kawaskai has withdrawn from the La Trobe Valley coal based hydrogen project[41].

Only two of the original six projects shortlisted for the first round of funding under the Hydrogen Headstart program have received funding[42] – Copenhagen Infrastructure Partners' 1,500 MW Murchison green hydrogen project in Western Australia that was funded in 2024 and, more recently, Orica's proposed 50MW electrolyser Hunter Hydrogen project to generate green hydrogen to replace natural gas feedstock for ammonia production[43]. Origin withdrew from that project in 2024 due to concerns about the cost[44].

In the 2026 ISP, the Accelerated Transition (AT) scenario replaces the Green Energy Exports (GEE) scenario in the 2024 ISP. AEMO notes[45]:

> "Compared to the 2023 Green Energy Exports scenario, the role for hydrogen production is significantly lower, reflecting current uncertainties affecting commercial investment and supportive policy."

The table shows the significant reduction in forecast 2040 electricity consumption associated with hydrogen production in the 2026 ISP:

| ISP Scenario | 2024 ISP – Green Energy Exports[a] | 2026 ISP – Accelerated Transition[b] |
|---|---|---|
| Domestic (TWh) | 50 | 33 |
| Green commodity exports including green steel (TWh) | 183 | 19 |

a) Table 1 p. 5 https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-inputs-assumptions-and-scenarios-report.pdf?la=en

b) Table 1 p.7 https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/2025-inputs-assumptions-and-scenarios-report.pdf?la=en

The current scale of actual hydrogen producing plants is small in relation to what would be needed to provide even a majority of current gas demand whether in South Australia or across the NEM[46].

[39] https://reneweconomy.com.au/gigawatt-size-tiwi-islands-solar-and-green-hydrogen-project-scrapped-after-offtake-land-issues/

[40] https://www.afr.com/companies/energy/woodside-takes-us140m-hit-on-ditched-us-hydrogen-project-20250722-p5mgz5?utm_content=making_news&list_name=EBE726C6-38DF-4725-9BE4-5091999D8384&promote_channel=edmail&utm_campaign=the-brief&utm_medium=email&utm_source=newsletter&utm_term=2025-07-23&mbnr=MjAyMDU1MTE&instance=2025-07-23-12-05-AEST&jobid=31669758

[41] https://www.abc.net.au/news/2024-12-10/coal-hydrogen-hesc-latrobe-valley-japan-kawasaki/104375024

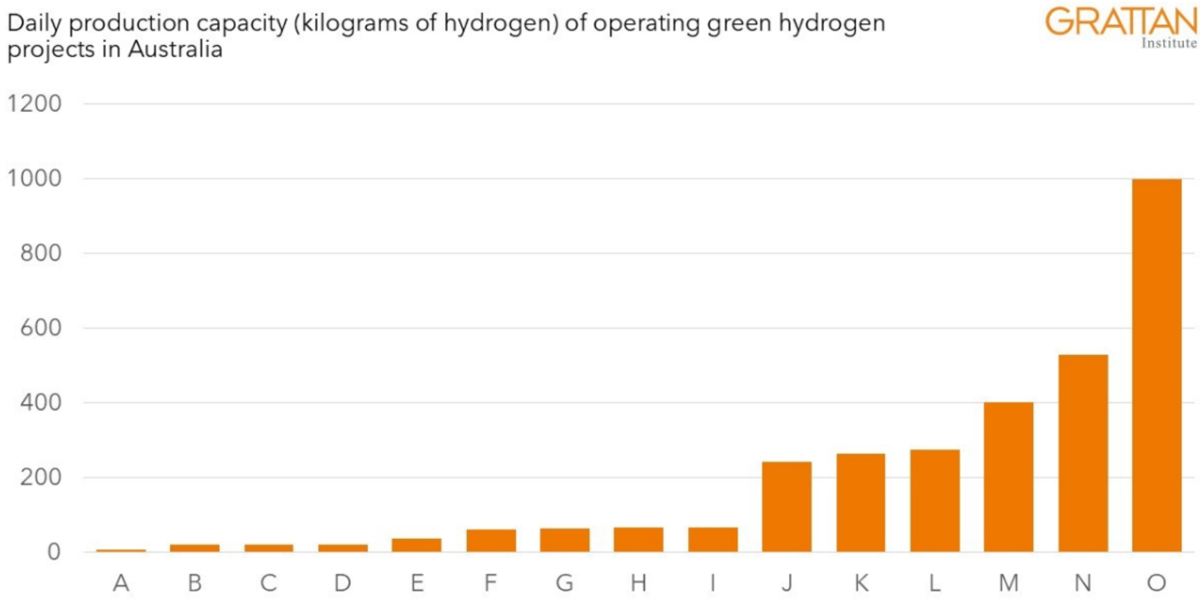
[42] https://reneweconomy.com.au/orica-lands-funding-for-green-ammonia-hub-as-another-2-billion-put-on-table-for-hydrogen-hopefuls/

[43] https://www.orica.com/news-media/2025/orica-awarded-432-million-arena-headstart-funding

[44] https://www.originenergy.com.au/about/investors-media/update-on-hunter-valley-hydrogen-hub/

[45] See p. 6 https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/2025-inputs-assumptions-and-scenarios-report.pdf?la=en

[46] https://grattan.edu.au/news/whats-hampering-hydrogen/




**Source:** Grattan Institute analysis of CSIRO hydrogen project database as at July 2025. ***Project identities***: **A:** Renewable Hydrogen Production and Refuelling Project, Qld. **B:** Hyundai Integrated Hydrogen Production and Refuelling System, NSW. **C:** Swinburne University of Technology CSIRO Victorian Hydrogen Hub and Refuelling Station, Vic. **D:** Canberra Hydrogen Refuelling Station, ACT. **E:** Denham Hydrogen Demonstration Plant, WA. **F:** Toyota Ecopark Hydrogen Demonstration (Toyota Hydrogen Centre), Vic. **G:** ATCO Hydrogen Blending Project, WA. **H:** Hydrogen Park Gladstone, Qld. **I:** Hydrogen Refueller Station Project, WA. **J:** Western Sydney Green Gas Project, NSW. **K:** Hydrogen Production and Research Facility, Tas. **L:** Hazer Commercial Demonstration Plant, WA. **M:** Port Kembla Hydrogen Refuelling Facility, NSW. **N:** Christmas Creek Renewable Hydrogen Mobility Project, WA. **O:** Geelong New Energies Service Station, Vic.

Hydrogen projects of any scale are failing to proceed for a number of reasons[47] - steep learning curve, limited demand given not only the cost to buy but also the cost to enable production processes to use it; the 'chicken and egg' problem - green hydrogen proponents won't invest in high-volume production unless there are large users to buy the product, but large users will not invest in changing their processes unless they are assured of supply; green hydrogen is much more expensive than other types of hydrogen and investment uncertainty.

A major argument for the development of green hydrogen was the potential for 'cheap' renewable power given Australia's resources. ARENA says that to get $2/kg requires $20/MWh delivered for firm renewable power[48]. That is not going to occur in the near future and is very unlikely to occur in the long term. Current green hydrogen costs vary for around $8-11/kg[49]. The AGN model in its HyP Adelaide demonstration plant of just using power when it is below say $30/MWh eg in daylight hours including when prices are negative, is not sustainable in the long term as the high electrolyser costs require high utilisation to get unit costs down. The Government $2/kg production subsidy will not bridge that gap.

Finally, we think that it is very unlikely that the EU and the US will not 'come to our rescue' in technology development to lower hydrogen costs. The Trump Administration's Big Beautiful Bill has significantly narrowed the Biden Administration's Inflation Reduction Act subsidies for hydrogen[50]. That policy change plus rising costs were the reasons why Woodside and Fortesque have closed their US hydrogen projects[51].

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[47] Ibid
[48] https://www.afr.com/policy/energy-and-climate/huge-cost-cuts-needed-in-solar-for-hydrogen-to-work-arena-20241021-p5kk3d
[49] https://www.theaustralian.com.au/nation/politics/wakeup-call-on-green-energy-a-hydrogen-bombshell/news-story/773f261bdb7f11ba3153bea18c0bcd45
[50] https://www.woodmac.com/blogs/energy-pulse/big-beautiful-bill-us-energy/
[51] https://www.nytimes.com/2025/08/11/business/energy-environment/hydrogen-clean-energy.html

*There is some way to go to get confidence that large scale biomethane can be supplied at a competitive price*

The only direct guidance we have is that Delorean has entered into a connection and access agreement with AGN to supply biomethane to customers[52]. Obviously the agreed price is commercially acceptable to Delorean's customers. But the volume is very small – up to 210TJs/yr[53].

AGN cites a February 2025 ACIL Allen report for AEMO arguing that current biomethane costs of $13-35/GJ could fall to $10-27/GJ by 2058[54]. The cost estimates here rely heavily on a previous report prepared for AGIG[55] in September 2024 by Blunomy to quantify the biomethane potential within a 50 km catchment of AGIG assets in SA, Victoria and Queensland. Recoverable potential varies between 16-34PJ/yr. Cost varies from $9.40-$42.30/GJ depending on the feedstock location. On costs:

> "LCOE figures are derived from a preliminary modelling exercise that employs generalised assumptions about cost structures."

The Final Plan was submitted before publication of a further Blunomy study commissioned by ENA[56]. It is part of the ENA's advocacy to expand the Hydrogen Headstart Program and the Hydrogen Tax Credit Incentive Scheme to include biomethane. Given the hydrogen track record there is a lot of funding remaining in those programs. The ENA sees the results as:

> "...offering a pathway to decarbonise industries where electrification is not viable."

Not, it seems, as an alternative for consumers who do have the choice of electrification. But it is still seen as having an important role in 'maximising the value of existing gas networks'.

The study concludes there is 400PJ potential for biomethane (total east coast consumption was 510PJ in 2024) with the first 50PJ/yr being able to be supplied at $10-27/GJ in 2030, $10-25/GJ in 2040 and $10-23/GJ in 2050 ($2025). These production cost forecasts (Slide 25) are based on the ACIL Report cited above and international estimates by the IEA and Wood McKenzie. All cost estimates are very high level where actual costs are very location and raw material specific. The study argues that:

> "Based on ACIL Allen's estimates using AEMO's Progressive Change scenario, supply cost will decrease as policy encourages feedstock recovery, technology progresses, and the market develops."

While this may be the case intuitively, there is no evidence provided to support the level of cost decrease shown for 2030, 2040 and 2050. As was the case with hydrogen cost estimates a few years ago, cost forecasts are based on citing the same conceptual studies. As we have seen with hydrogen we will only get a good idea of costs when full scale feasibility studies are

[52] https://www.agig.com.au/new-agreement-paves-the-way-for-agigs-first-biomethane-connection
[53] https://www.agig.com.au/new-agreement-paves-the-way-for-agigs-first-biomethane-connection
[54] https://aemo.com.au/-/media/files/major-publications/isp/2025/acil-allen-2024-fuel-price-forecast-report.pdf?la=en
[55] https://theblunomy.com/publications/mapping-the-biomethane-potential-around-gas-networks-and-quantifying-the-associated-co-benefits
[56] https://www.energynetworks.com.au/news/media-releases/biomethane-breakthrough-turning-waste-into-energy-new-report-calls-for-biomethane-expansion/

undertaken. That requires Government support and that is not guaranteed. We are still yet to see the details of the proposed State Government renewable gas certificate scheme.

Even if biomethane is competitive with natural gas, AGN has not provided evidence to support the likely sales volume would be sufficient to, along with hydrogen and carbon neutral gas, sustain network viability.

*Little information provided on carbon neutral gas*

This is the backstop if hydrogen and/or biomethane prove uneconomic. Little information is provided on the policy support (or cost to AGN customers) required to ensure this is a viable backstop.

*The AER's approach to capping accelerated depreciation*

In its recent decisions on Victorian gas networks for 2023-28 and Jemena in NSW for 2025-30 the level of accelerated depreciation allowed was a 'goal seek' to achieve a caped price path. In the case of the Victorian networks, it was to ensure a '…base real price path constraint of 1.5%/yr' [57]. For Jemena it was a combination of shortening the economic lives of multiple long-lived asset classes of new capex combined with accelerated depreciation to meet a 'base' real price increase limit of 0.5%/pa[58]. AGN has followed the Jemena decision on the 0.5% cap on accelerated depreciation without any shortened asset lives.

These decisions were considered appropriate to reduce the stranded asset risk and achieve a balance between what consumers pay now to mitigate future price increases, and the risk of greater increases in the future if mitigation is delayed. In landing on the cap, the AER, which was very focussed on current affordability concerns, concluded that:

> "Having carefully assessed the material before us, we consider our final decision approach achieves a balance between what consumers pay now to mitigate future price increases, and the risk of greater increases in the future if mitigation is delayed."

The Panel would suggest that this approach has its limitations eg

- Changes in other variables outside of the network's or the AER's control eg WACC can leave little or no ability to have accelerated depreciation which the AER agrees is required. This was the case for the Jemena decision[59]. Subsequent to selecting a 0% cap in its Draft Decision, the AER found that a higher WACC and lower expected inflation increased the total revenue by 2.7%. Maintaining the 0% cap would only allow the baseline $77m accelerated depreciation that the AER saw as too low. Having the 0.5% cap meant accelerated depreciation increased to $115m, still less than the $157m in their Draft

[57] For Victoria see p. 25 https://www.aer.gov.au/system/files/AER%20-%20AusNet%202023-28%20-%20Final%20Decision%20-%20Overview%20-%20June%202023.pdf

[58] See p. 20 https://www.aer.gov.au/system/files/2025-05/AER%20-%20Final%20decision%20-%20JGN%20access%20arrangement%202025%E2%80%9330%20-%20Overview%20-%20May%202025.pdf

[59] See the discussion at pp. 17-18 https://www.aer.gov.au/system/files/2025-05/AER%20-%20Final%20decision%20-%20JGN%20access%20arrangement%202025%E2%80%9330%20-%20Attachment%204%20-%20Regulatory%20depreciation%20-%20May%202025.pdf

Decision. What if these uncontrollable factors change over the course of AGN’s AA? Will the cap be adjusted?
- Finetuning small changes in network costs may have little impact on the total bill when the commodity component of the bill is increasing strongly; this has been the case in the last five years and is expected to continue being the case for 2026-31 with the network component has fallen in real terms in the current period and is flat in real terms in 2026-31

For example, a $70m accelerated depreciation would result in a one off 2.5% increase in the total bill for an average residential customer - $28 on $1,120. We invite the AER to consider whether a cap higher than 0.5% still results in a reasonable trade-off between intergenerational equity and current consumer affordability.

*Some concluding comments*

The Panel recognises the breadth of discussion that took place among SARG members on the range of responses to the ‘future of gas’ issue. Members expressed a significant degree of uncertainty about the future role of gas, reflecting both practical and policy-level concerns.

For many, electrification seems on some levels inevitable in the long-term, but it was clear that many households and businesses face substantial barriers to making that transition - if they want to make it at all. Certainly, concerns were raised about the tension between remaining on gas and electrifying, as well as potentially waiting for new gas blends - as proposed in AGN's plan - to emerge. Members raised questions about the likely composition, cost and availability of these fuels (hydrogen and biomethane), as well as their long-term compatibility with existing appliances. Many of these concerns sit at a policy level, rather than being addressed directly in AGN's proposal, leaving SARG members unsure about how the broader energy transition decisions will interact with network investment plans.

This lack of clarity adds to the challenge for both consumers and businesses in planning for the future. Bill impacts remain a central concern for all customers. For larger customers the concern extended to questions around how to afford the required investment to electrify (especially if their manufacturing assets still have many years of asset life remaining) to what the options were available for the hard to abate businesses that cannot easily electrify.

Without clarity in how changes in the gas network, fuel mix, and customer base will affect prices, many stakeholders felt it was difficult to assess the affordability of different transition pathways where there were difficult decisions around how much to pay now and how much to leave for future users. The desire to preserve choice and maintain the ability to use gas, whether for cost, personal, or practical reasons, was a recurring theme. These discussions revealed a diversity of views, with some participants more actively engaged and informed about the options, while others approached the issue with a higher level of uncertainty and hesitation.

Overall, the conversation illustrated the complex mix of financial, technical, and social considerations that will need to be addressed to build public confidence in decisions about the future of gas. The AER has a difficult task, within the existing rules framework, in making a judgement on balancing the needs of today’s consumers versus future consumers in today’s affordability concerns.

This rules framework was developed with an underlying assumption that gas would be around a very long time and regulation should seek to increase asset utilisation. That context is undergoing a 180 degrees turn and the rules need to adjust to reflect that turn. While the current

ECA and JEC rule changes on connection and abolishment charges respectively, are a good first step, the more substantive discussion the AEMC is about to initiate on the other ECA[60] rule changes will be crucial to setting the future framework. That discussion will require comprehensive consumer engagement process to enable consumers to fully understand the issues to be able to make informed recommendations on future actions. The results of this review will provide the AER with a much more comprehensive toolkit to address the future of gas.

### 3. Consumer Engagement

<u>What we said in our Draft Plan submission</u>

In our submission on the Draft Plan, the Panel noted and commended the work that AGN had put into consistent consumer engagement – however, we flagged that greater nuance would be needed in interpreting the feedback received.

Across Stages 1 and 2 of the engagement process, several consistent themes emerged. There was a strong desire for AGN to actively minimise price increases and support vulnerable households. Consumers viewed the reliability of gas supply positively and expectations around customer service were also clear. When it came to renewable energy and the future of gas, customers expressed interest but also uncertainty. While many supported a shift toward sustainable energy, they emphasised the need for an affordable, practical transition. There was limited awareness of renewable gases and questions remained about safety, appliance compatibility, and cost impacts.

In Stage 3, participants generally responded positively to AGN's draft plan, particularly the proposed price stability over 2026-31. However, there was limited understanding – particularly from the Panel's observations – of the detailed content of the Draft Plan. It was our view that participants were not provided sufficient opportunity to familiarise themselves with the plan, and even though Orbviz was presented and provided to them during the workshop, the Panel were of the opinion that insufficient time was allocated for meaningful engagement with it. Despite most participants having attended earlier stages, their recall of specific content proved limited during later workshops. The workshop format in Stage 2, which was heavily focused on gathering input, did not provide enough opportunity for deep discussion of complex topics such as tariffs, depreciation, or the future of gas. As a result, the Panel noted that AGN may have missed a key opportunity to deepen understanding and gather more informed feedback on these important issues.

<u>What AGN is proposing in the Final Plan</u>

AGN position their 2026-31 Access Arrangement as being deeply informed by consumer engagement, led by a program that began more than a year prior to submission.

The engagement partner for AGN was KPMG, whose Consumer Engagement report is attachment 5.3 to the Access Arrangement proposal. This report identifies "seven key insights" from the customer engagement workshops that were held over the phases of the engagement program.

These insights are copied below.

[60] https://energyconsumersaustralia.com.au/news/media-release-proposed-gas-rule-changes-ensure-better-consumer-energy-transition

**Customers support AGN's Draft Plan proposals based on stable prices**
Customers stated they were supportive of AGN's commitment to maintain stable prices for the next five-year period and were pleased to see that their feedback on key priority areas had been incorporated into the proposal.

**Customers expect AGN to sustain its excellent safety and reliability track record**
Customers overwhelmingly support AGN's plans to continue its high levels of safety and reliability in the future and expect continued high performance in both areas.

**Customers value a high standard of customer service**
Customers indicated they value quality customer service and expect AGN to continue delivering high levels of customer service.

**Customers are satisfied with AGN's network growth plans**
Customers displayed considerable interest on the topic of the growth of the South Australian gas network and support AGN's future growth developments.

**Maintaining price affordability is a top priority for customers**
Customers view gas affordability as their number one priority, with the majority of customers expressing satisfaction for AGN's proposal to maintain stable pricing via a hybrid declining block tariff approach.

**Fostering a sustainable energy future is important, and customers want to be kept up-to-date on AGN's renewable energy plans**
Customers value a sustainable future and want to be kept informed on AGN's investment plans for decarbonising South Australia's gas supply.

**Customers largely understand depreciation in the context of regulation and want to stay informed**
Customers understand depreciation based on the information that was shared and want to be kept informed on any significant changes to the final depreciation amount before the Final Plan.

AGN suggest that these insights reflect consumer support for their overall proposal – including specific elements like declining block tariffs and accelerated (or, in their words, additional) depreciation.

Panel comments on the Final Plan

AGN have conducted a well-planned and appropriately executed engagement program with a significant number of people involved and has pioneered an excellent online tool in Orbviz. In the Access Arrangement proposal, AGN provides considerable attention to their commitment to engage with consumers and other stakeholders.

On page 9 of the Final Plan (revised) this comment is made to lead off "Plan highlights."

> "Customers are at the centre of our plans. Our Final Plan has been informed by our customer and stakeholder engagement program, which commenced more than 12 months ago."

The SARG agrees that AGN has made considerable effort to engage, to hear and to respond to consumer and stakeholder input. We would expect this for the following reasons:

- AGN is a service business and their business relies on meeting customer needs and expectations.
- The SARG has experienced AGN's commitment to engagement over a number of years and continues to feel that our input is both sought and valued.
- AGN / AGIG has a proven track record of high-quality consumer engagement. AGN won the national 2022 Energy Networks Industry Consumer Engagement Award
- AGN / AGIG has a well-established culture of actively seeking not only perspective from consumer and stakeholders, but they also welcome challenge, including the 'hard questions.' "Hit us with your best shot" is an attitude that AGN has embraced.

The dilemma for the 2026-31 Access Arrangement engagement is the substantial uncertainty that abounds regarding the future of gas, including questions: how realistic are 'green gas' options? What will government policies and programs bring? What is the potential for new technologies and/or substantial cost reductions on existing technologies that are not economically viable at the moment, to change the future of gas?

This dilemma was evidenced by the questions raised by consumers in the engagement workshops. However, we suggest that some care needs to be taken in how the insights AGN have reflected from these sessions (as outlined above) are understood and then applied to perspectives of the extent of consumer support for the AA proposal.

From our perspective some of "insights" and really standard customer expectations of just about any service, while other insights require a little more consideration, particularly the level of detail that can be taken from engagement that occurred and applied to specific expenditure aspects. The following "insights" we regard as relatively standard customer expectations so that there is not much new, applicable insight:

- Customers support AGN's draft plan proposals based on stable prices
- Customers expect AGN to sustain its excellent safety and reliability track record
- Customers value a high standard of customer service
- Maintaining price affordability is a top priority for customers

It is our view that it is further not controversial – or surprising - that the key insight is that cost of living is a major concern across much of the population and so customers are most interested in paying the lowest possible price. From that perspective, declining prices will always be the most appealing option and where that's not possible, consumers will express a preference for stable pricing (this is a mainly separate 'Insight" to the claim that customers support a hybrid declining block tariff approach).

This leaves three "insights" that are potentially more relevant in determining allowed revenue for the 2026-31 Access Arrangement[61]:

[61] The order of these three "insights" has been altered from the published list.

- Fostering a sustainable energy future is important, and customers want to be kept up-to-date on AGN's renewable energy plans.
- Customers are satisfied with AGN's network growth plans
- Customers largely understand depreciation in the context of regulation and want to stay informed.

There was strong interest by AGN customers in sustainable energy in the engagement leading up to the 2021-26 Access Arrangement, particularly the potential for 'green hydrogen.' This keen interest in sustainability and achieving net-zero targets was again evident in the more recent engagement associated with the 2026-31 Access Arrangement. This time there was less focus on hydrogen as the gas of the future and less specificity from AGN about what a sustainable gas energy future looks like. The message was clear though that customers are, in aggregate, looking of a net zero future and definitely want to be kept informed about future renewable gas possibilities and AGN's intentions.

In this context the Panel do not think that customers, in general, are "satisfied with AGN's network growth plans," because beyond 2031 this is not clear. The Panel observed a desire for a sustainable gas future from AGN and customers and customer interest in network growth plans, but could not say that there was support for network growth beyond 2031, meaning tacit rather than enthusiastic support for network growth plans for 2026-31. This discussion is highly correlated with the 'future of gas' questions that we discussed above. However, in this section, we would once again raise that the manner in which the future of gas was presented to workshop participants did not allow for sufficient detail or discussion and could lead participants to believe there is greater certainty about the technical and economic possibility of renewable gas integration into the current system.

On the "insight" of "Customers largely understand depreciation in the context of regulation and want to stay informed," we suggest that the focus here is that customers want to be kept informed, in part because at the consultation forums participants were given a 'place holder' accelerated depreciation annual bill impact of $30/yr with the explanation that modelling was still underway, but there would be further engagement if the average bill impact was greater than this amount. SARG members observed that forum participants understood the general concept and application of depreciation but are less convinced that this general understanding can be translated into support for more finely tuned applications of depreciation including accelerated depreciation.

Finally, as a minor note, the Panel would suggest greater clarity is needed from AGN with regards to their depictions of consumer and stakeholder feedback in their reports. It is unclear from an initial reading of the Final Plan the intended message of the ticks, crosses, and other symbols responding to feedback outlined on pages 54-59 of the engagement chapter of the Plan. Certainly, to some it left the impression that AGN disagreed with the Review Panel's submission (though this has since been clarified with AGN, who have indicated that the symbols reflect stakeholder levels of support for the Plan).

Overall, while the general directions presented in the Access Arrangement proposal have received broad support, there are some aspects of the detail that need to be evaluated and reflected with greater nuance – including AGN's directions beyond 2031, accelerated depreciation and declining block tariffs.

## 4. Operating Expenditure

What we said in our Draft Plan submission

Given that AGN has followed the AER base, trend, step methodology, much of the forecast opex is not subject to consumer comment. We focussed our comments on the discretionary items, UAFG, the Priority Services Program (PSP) and the trend:

- On the step changes – the capitalisation change is a matter for the AER, the purchase of renewable energy certificates needs further consumer engagement on why consumers should subsidise AGN's development of hydrogen generation that has yet to be proved economic, to reduce AGN's stranded asset risk; the small insurance change should be absorbed by AGN
- Strongly supported the PSP program with suggestions to broaden eligibility and awareness, strengthen referral pathways, enhance tailored support services, co-design future program entitlements and monitor and report on program outcomes
- AGN to provide more explanation on why the 0.4% annual productivity factor was chosen given it is 0.5% for electricity networks
- On UAFG - more information to be provided on how the mains replacement has reduced gas leaks and how AGN proposes to source its gas and its incentive to minimise that cost given it is a pass through to consumers

What AGN is proposing in the Final Plan

AGN have used the standard AER base, step, trend methodology as well as some specific forecasts. The table summarises recent history of AER allowances, actual and forecast spend in the current period and AGN's proposed spend in 2026-31.

**Operating expenditure summary $m (2025/2026)**

| 2021-26 | | 2026-31 | | |
|---|---|---|---|---|
| AER allowance | Actual / Forecast | Forecast | % chg vs 2021-2026 AER allowance | % chg vs 2021-2026 Actual / Forecast |
| $382 | $316 | $373[1] | -2.4% | +18% |
| $382 | $316 | $399[2] | +4.5% | +26.3% |

1. Excludes UAFG, debt raising, capitalisation changes and renewable gas certificates.
2. Excludes UAFG, debt raising and capitalisation changes.

AGN presents opex excluding what it considers are 'not within our control for efficiency' ie excluding UAFG, debt raising, change in capitalisation policy and purchase of renewable gas certificates for HyP Adelaide (p.79). The second line includes renewable gas certificates.

AGN argues that the revealed costs in the base year are efficient given the operation of the Effciency Carryover Mechanism and internal and external controls on asset management, procurement and financial governance (p.85).

There are 6 step changes (total $86.5m); up from 4 in the Draft Plan (total $67.1m):

| | Draft Plan | Final Plan |
|---|---|---|
| Change in capitalisation of overheads with more being treating as opex and less as capex; following the approach taken with Multinet in Victoria, a portion of these overheads are more akin to opex than capex; there is no net gain from this reclassification | $32.8m | $32.0m |

| | | |
|---|---|---|
| Purchase of renewable gas certificates for the HyP Adelaide hydrogen facility – a placeholder awaiting clarification of Government policy | $26.3m | $26.0m |
| Transition costs for insourcing a service delivery contract at the end of its 30 year term | $7.7m | $18.6m |
| Higher insurance premiums | $0.3m | 0 |
| Redundant site abolishments for safety | | $4.6m |
| Cybersecurity uplift | | $1.2m |
| Other IT applications and upgrades | | $4.1m |
| Total | $67.1m | $86.4m |

Annual productivity is 0.4%/yr given the more supportive SA policy environment the same as the current period. It has zero productivity for its Victorian gas networks in 2023-28.

<u>Panel comments on the Final Plan</u>

*Base year*

The Panel leaves the AER to assess the efficiency of the base year using its alternative top-down 'base–step–trend' forecasting approach.

*Renewable gas certificates*

AGN is yet to get agreement with the State Government on a renewable gas certificate scheme to support the development of HyP Adelaide. This scheme would provide a subsidy to enable AGN to sell the hydrogen to third parties at an acceptable price. If this agreement is not complete by the time of the revised proposal in February 2026, we expect this step change will be withdrawn. If there is subsequent agreement then it will be a pass through jurisdictional scheme. We make two comments.

First, in the discussion on the State's Energy and Climate Policy in Attachment 6.4, AGN note (p. 10):

> "The South Australian Government maintains a technology-neutral approach to household energy use, prioritising reliability, affordability and consumer choice over mandates or financial inducements."

So, it is difficult to understand why the Government would introduce a certificate scheme for hydrogen use.

Second, is to repeat our comment on the Draft plan – the Panel does not support consumers having to pay for AGN costs of trying to ensure the future of its asset unless it is strongly supported through informed customer engagement. This is also why we do not see this cost fits the category of 'not within our control for efficiency'. These costs are totally within AGN control as it is AGN's decision to develop HyP Adelaide.

*UAFG*

Attachment 8.4 that outlines the UAFG strategy is confidential as it includes detail on likely gas prices. We leave it to the AER to review this and assess the prudency and efficiency of this pass through cost to consumers.

## 5. Capital expenditure

What we said in our Draft Plan submission

Given the level of detail provided, our comments were more qualitative that quantitative focussing on:

- Whether the proposal reflects consumer preferences given the engagement was very high level and on an 'inform' basis
- IT system capex which was $88.1m or 17% of total capex compared to $46.9m (8%) in the current period with the move to the AGN One IT environment; these moves in other network have led to project ending up considerably over budget and over time in implementation with the example given of the Energy Queensland DEBBS system. We looked forward to further information being provided in the Final Plan on how AGN will avoid the problems that have beset other networks for these projects.
- The proposed growth capex of $157m at a period when AGN forecast total demand to fall by an average of 3.2%/yr for 2026-31
- Like all network businesses, AGN is facing strong upward pressures on unit rates and materials, across both growth (eg new connections) and maintenance (eg meter and mains replacement) capex. The final plan will incorporate the result of the April 2025 tender for a range of contractor services.

What AGN is proposing in the Final Plan

The capex forecast is lower than the forecast for the current period reflecting completion of the mains replacement program in the current period.

**Capital expenditure summary excluding debt raising 2021-26 and 2026-2031, $m (2025/2026)**

| 2021-26 | | 2026-31 | | |
|---|---|---|---|---|
| AER allowance | Actual / Forecast | Forecast | % chg vs 2021-2026 AER allowance | % chg vs 2021-2026 Actual / Forecast |
| $644 | $548 | $503 | -22% | -8% |

Capex is forecast using a bottom-up approach with the cost of undertaking each project estimated separately and presented according to AGN's strategic pillars.

Table 9.1: Actual and forecast capex by our strategic pillars, including overheads ($million, 2025/26)

| Vision | Current AA period | Next AA period | Drivers for change |
|---|---|---|---|
| Customer focussed | $196.6 | $215.1 | ✓ New customer connections<br>✓ Higher rates and volumes for meter replacement<br>✓ Digitalisation and modernisation of customer service |
| Operational Excellence | $337.0 | $240.9 | ✓ Lower volume of mains & services integrity programs<br>✓ Continued replacement of older services at Multi-User Sites.<br>✓ Upgrade of field assets (such as regulators and valves) to maintain network integrity, reliability and safety<br>✓ IT integration |
| Leading Employer | $14.7 | $14.5 | ✓ IT infrastructure renewal, upgrade systems for Health Safety and Environment (HSE) and Human Capital Management (HCM), and replacement of vehicles and small plant equipment |
| Sustainable Communities | N/A | $32.5 | ✓ Replacement of protected steel mains, renewable gas adaptation |
| **Total** | **$548.3** | **$503.0** | |

The main part of 'customer focussed' capex is new connections with a forecast $157m to connect around 34,000 new residential and business customers (compared with 37,000 connections in the current period) – 31% of total capex. This includes new homes and businesses in greenfield developments as well as existing homes and businesses which are connecting to the gas network for the first time. This connections capex is made up of the following components:

| Category | $m |
|---|---|
| Residential main | 29.7 |
| Residential service | 91.9 |
| Residential meter | 10.2 |
| Commercial main | 5.1 |
| Commercial service | 15.3 |
| Commercial meter | 5.1 |
| Total | $157.4 |

The lower 'operational excellence' capex reflects the completion of the main replacement investment in the current period after three decades of work.

Panel comments on the Final Plan

*New connections capex*

Whether this capex ends up in the RAB will be influenced by the ECA rule change currently being considered by the AEMC. The rule change has received overwhelming support in the nearly 30 submissions made to the AEMC's Consultation Paper[62]. The one notable submission arguing against it is from the SA Office of the Technical Regulator which represents SA Government policy[63]. It says that the Government has no policy to discourage the use of gas and this is unlikely to change over the period to 2031. The cost of socialising connection charges for small

[62] https://www.aemc.gov.au/rule-changes/updating-regulatory-framework-gas-connections
[63] https://www.aemc.gov.au/sites/default/files/2025-07/16.%20SA%20Technical%20Regulator%20GRC0085%20CP%20Submission.pdf

residential and commercial customers is ~$40/yr per customer which it regards as "…so small that it is almost irrelevant"[64]. Charging the full amount for new connections only acts to disincentivise new gas connections. While the rule change might be appropriate in other States, it is not appropriate in South Australia. Charging for connections can be reconsidered when connections are projected to decline.

AGN have advised that if the ECA rule change on full costs connection charges is accepted by the AEMC and it is in place for the full 2026-3 AA period then this $157m would be recovered from new customers and not put into the RAB. If the AGN methodology[65] of calculating the connection costs is adopted by the AEMC, then connection charges of $120m would be paid covering service pipes and meters. The mains expenditure of $37m would be rolled into the RAB and be subject to the Economic Feasibility Test.

If the ECA methodology applies for 2026-31 that effectively increases accelerated depreciation by $157m.

*Renewable gas readiness*

Consistent with their long term renewable gas vision, AGN propose to spend $8m to help prepare the network for renewable gas. Consistent with our view on renewable gas certificates, the Panel does not support consumers paying for this capex unless there is explicit support from informed consumer engagement.

*IT expenditure*

There are many examples of network overspend on IT projects. Our Draft Plan submission highlighted the experience of Energy Queensland with its 'DEBBs portfolio' of projects that was supposed to support the harmonisation of the Ergon and Ergon network business process and tools after the two entities were merged in May 2016.

Forecast IT spend in the current period is $37m[66]. This increases to $87m in 2026-31 with the increase driven by a $58m spend (SA 241) to bring in-house several of core IT systems at the cessation of a long-standing outsourcing arrangement with APA. There is an $18m opex spend associated with this move. In discussing the deliverability of the plan, AGN note that[67]:

> "We have a successful track record of delivering large IT transformation projects across AGIG, such as the separation of Multinet Gas from United Energy, the AGIG Data Centre and the OneERP project."

The Panel recommends that the AER closely review the implementation plan given the many examples of network overspend on IT projects in recent years.

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[64] See p. 3
[65] https://www.aemc.gov.au/sites/default/files/2025-07/20.%20Australian%20Gas%20Infrastructure%20Group%20GRC0085%20CP%20Submission.pdf
[66] See p. 4 https://www.aer.gov.au/system/files/2025-07/AGNSA_Attachment%209.7_IT%20Investment%20Plan_20250701_PUBLIC.pdf
[67] See p. 23 https://www.aer.gov.au/system/files/2025-07/AGNSA_Attachment%209.7_IT%20Investment%20Plan_20250701_PUBLIC.pdf

## 6. Pipeline and Reference Services

<u>What we said in our Draft Plan submission</u>

We supported the proposed reference and non-reference services in the next period which includes the abolishment service as an ancillary reference service. Our comments focussed on the abolishment services. We noted that the question of who should bear the cost of gas service abolishment – individual consumers or the wider customer base – is a difficult one to answer, both for the Panel but has also proven to be an increasingly debated topic within the broader energy system. While the AER has approved a partial cost recovery model in Victoria, it noted that this is not a long-term solution and warned that as more customers leave the network due to electrification policies pressure on tariffs for remaining users will grow. However, Victoria finds itself in a different policy context than South Australia.

Arguments on either side of the debate appeal to equity. On one side there is the view that higher-income households choosing to electrify should not be subsidized by lower-income households who remain on gas, while the other view contends that full-cost charges create an affordability barrier and undermine genuine consumer choice and an equitable transition. There are also safety concerns, where high abolishment costs may lead to informal and unsafe disconnections. All of these arguments are compelling.

Through AGN's customer engagement, consumers raised these same issues while noting that both connections and abolishments are currently free – and that even when costs are socialized, at present they represent a negligible part of a household gas bill.

Given these considerations, the Panel recommended that AGN continue to offer abolishment at no cost during the 2026-31 period unless clear, evidence-based justification for the introduction of abolishment charges emerges (such as a significant increase in abolishments). We advised that transparent and regular reporting on abolishment trends – disaggregated by customer type – is needed.

Our recommendation was informed by the current low levels of abolishment in South Australia, in contrast with Victoria where policy-driven electrification is driving higher numbers. With improved data collection under the next access arrangement, this issue can be reconsidered at a later date if/when needed. Finally, we noted that this discussion is linked to current AEMC rule change considerations and the question of how to fairly manage stranded asset risks across the gas network.

<u>What AGN is proposing in the Final Plan</u>

AGN is proposing the same services as in the Draft Plan. This covers three haulage services (Domestic, Commercial and Demand haulage), seven ancillary services related to connection, disconnection and metering and the addition of an abolishment service as a reference service. These services account for the vast majority of the current Access Arrangement period revenues and align with reference service factors under the National Gas Rules (NGR), including customer demand, lack of substitutability, and predictable, allocable costs.

The abolishment service aligns with how abolishment services are already treated in their Victorian networks. Currently in SA, abolishment is offered free of charge (apart from an $85 meter removal charge) for public safety reasons to avoid idle network assets.

The abolishment service charge would be determined in the same way as the AER approved approach for the Victorian networks and Jemena in NSW based on partial recovery. The cost of service to customers of $250 represents 20% of the total cost of the service ($1,250) with the remaining costs socialised across other customers.

AGN notes that since the Draft Plan was published the AEMC has published the JEC's rule change to support a full charge to apply to abolishments across all east coast jurisdictions. AGN note (p.78):

> "…we do not consider that the partial cost charging approach is sustainable, particularly an environment of policy intervention to promote permanent disconnection from the gas network. In such a situation, full cost recovery from the customer, as opposed to socialisation across remaining gas customers, is appropriate and consistent with the requirements of the NGR."

Additionally, a small number of ancillary services are proposed as non-reference services due to low demand or variable costs that prevent efficient cost allocation. Overall, the proposal largely maintains the existing service structure, with the key change being the inclusion of the abolishment service as a reference service.

<u>Panel comments on the Final Plan</u>

While the Panel have previously indicated that charging customers for abolishment services is probably inappropriate at this stage of the energy transition, we recognise that the Final Plan includes partial cost recovery for these services. We understand AGN's pursuit of such a model reflects its view that some level of customer contribution may help offset the operational costs associated with abolishments, particularly in an environment of rising pressures on network revenues and the need to manage ongoing service obligations.

That said, the policy landscape remains highly uncertain, with significant developments anticipated in coming years that could materially affect the way abolishment services are priced, funded, and delivered. The AEMC is currently engaging on the JEC rule change that proposes full cost recovery for abolishment services. This is being done in the context of a wider review of the gas regulatory framework given national energy policy directions, consumer protections and the broader objectives of an equitable energy transition. The Panel notes that the JEC proposal received overwhelming support from the nearly 30 stakeholder submissions to the AEMC.

## 7. Incentive schemes

<u>What we said in our Draft Plan submission</u>

We supported the continued application of the Efficiency Carryover Mechanism (ECM) and the Capital Expenditure Sharing Scheme (CESS) to 2026-31.

<u>What AGN is proposing in the Final Plan</u>

AGN proposes to continue both in 2026-31. For the current period they forecast:

- A negative ECM ie decrease in proposed 2026-31 revenue of $9.3m, due to actual opex expenditure being above the allowance
- A positive CESS carryover ie increase in proposed revenue, of $17.4m in 2026-31 due to actual expenditure in the current period being lower than allowed expenditure.

Panel comments on the Final Plan

We continue to support the two schemes applying in 2026-31.

**8. Demand**

What we said in our Draft Plan submission

We did not comment on this issue. We have no particular expertise in demand forecasting and left it to the AER to assess. We did use the demand forecasts to inform our comments on the future of gas.

What AGN is proposing in the Final Plan

AGN's forecasts have been independently determined applying methodologies previously approved by the AER. They are based on the SA policy context discussed above. If connections fail to occur then the capex will not be incurred. If there is a policy change:

- In the next few months, it can be incorporated in the revised AA due to be submitted in January 2026
- From early 2026, then the rules allow a re-opening of the AA within period[68]

Hydrogen and biomethane not becoming commercial in 2026-31 will not impact the demand forecast for 2026-31 but will impact the demand forecast for subsequent periods.

Panel comments on the Final Plan

While recognising that the risk of getting demand forecasts significantly wrong demand risk cannot rest solely with consumers. AGN's demand forecasts should, we suggest, also include some consideration of potential for material variance between forecast and actual demand and implications for risk allocation.

The Panel leaves consideration of the demand forecasts to the AER.

**9. Revenue and Prices**

What we said in our Draft Plan submission

Our discussion focussed on the AER's request that AGN undertake customer engagement on whether there was support for moving away from the current declining block tariffs and how AGN addressed that request in consumer workshops.

The Panel observed that many customers lacked a clear understanding of the current declining block tariff, with some mistakenly believing that using more gas would lower their overall bill. This misunderstanding highlighted a broader issue: the purpose of the tariff structure is not well understood. Additionally, most participants were unaware of how their own gas usage compared to the average household, limiting their ability to meaningfully assess how proposed tariff changes might affect themselves and others. We further noted that the rationale for tariff reform was not sufficiently communicated, leading to participant perception that the

[68] AusNet applied for a re-opener for its 2023-28 AA following changes in Victorian policy discussed above. The AER did not accept the proposal saying that the policy change can be dealt with during consultation on the 2028-33 AA https://www.aer.gov.au/industry/registers/access-arrangements/ausnet-services-access-arrangement-2023-28-variation-proposal

discussion was a narrow technical matter rather than one connected to broader regulatory and energy transition objectives.

The Panel emphasized that meaningful engagement on tariff reform depends on clarity, context, and a deliberate effort to reveal and consider equity impacts across the community, as well as broader outcomes. Information needed to be provided on:

- Why the AER has requested specific engagement on possible changes to the current declining block tariffs and how this fitted into the wider changes in the regulatory framework to achieve a National Gas Objective that included consideration of reducing emissions
- How declining block tariffs work and what is the impact of proposed alternatives on the particular customers involved in the engagement
- How AGN would encourage customers to consider the impacts of tariff structures not only on their own households but also on the wider community, particularly for lower-income customers and those with limited capacity to adjust energy use; this could be supported through the use of distributional analysis and customer impact modelling to facilitate a more informed and equitable discussion.

We recommended that AGN make tariff structure design a key focus of Stage 5 engagement. Participants' ability to provide meaningful input depends heavily on the clarity and accessibility of the material presented. Deeper engagement in the final stage should explicitly acknowledge the trade-offs between fairness, affordability and broader decarbonisation objectives.

<u>What AGN is proposing in the Final Plan</u>

AGN's proposed revenue and pricing strategy results in an initial real (inflation-adjusted) price cut of 1.0% from 1 July 2026 and then the maintenance of stable prices in real terms over the remainder of the period. This follows previous regulatory periods where more substantial price reductions (7% and 21% respectively) were delivered.

In response to a suggestion from the AER on engagement on declining block tariffs and as a result of changing demand, as well as stakeholder feedback, AGN is proposing partial reforms to its tariff structure. These include a modest shift toward flatter tariffs by reducing fixed charges slightly and increasing variable usage charges.

A significant change being proposed by AGN in this Final Plan is the suggested shift from a Weighted Average Price Cap (WAPC) to a modified revenue control mechanism that includes a cap on annual weighted average price changes. AGN's rationale for this change is that it is intended to provide more flexibility to manage under- or over-recovery of revenue due to unforeseen volume changes, particularly in an environment where forecasting demand is becoming increasingly difficult.

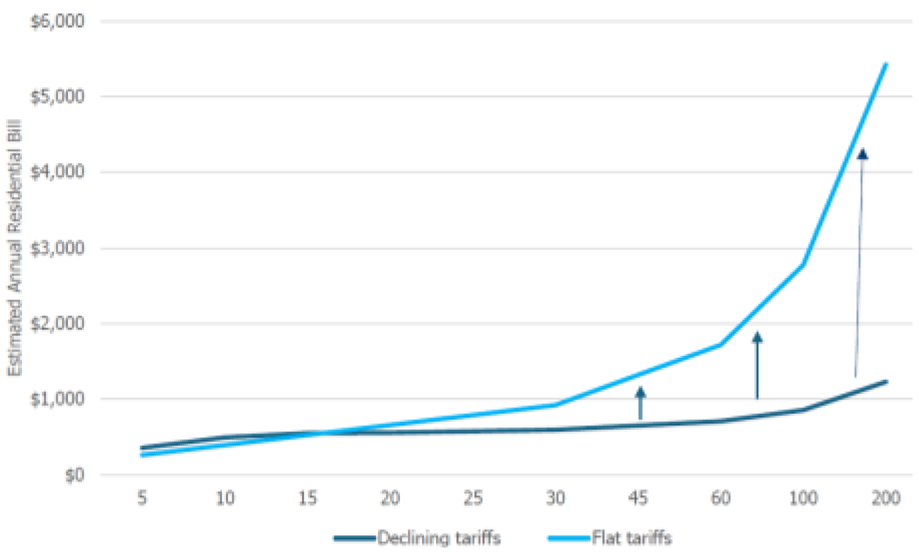
<u>Panel comments on the Final Plan</u>

While the price path proposed by AGN may offer some reassurance to consumers amid ongoing cost-of-living pressures, it occurs in the context of significant structural and policy uncertainty. Notably, demand per residential connection has declined substantially – by over 16% in the first three years of the current period – as households increasingly electrify and improve energy efficiency. This trend, which AGN expects to continue, raises questions about the long-term sustainability of recovering fixed network costs under current volumetric pricing models.

Though the change in tariff structure aligns with efforts to support emissions reduction and reflect changing consumption patterns, there are risks that it introduces distributional concerns. Higher-usage consumers – who may be less able to electrify, particularly where these users are commercial customers – could face increased bills. However, there is a lack of distinction and nuance in the types of higher-usage consumers are and who they might be.

These distinctions are important, as they should shape consumer and stakeholder feedback – particularly when considering whether these users are residential, or commercial/industrial. We found that this particularly skewed discussions with consumers during the workshops, as we have previously canvassed, where there was not a great understanding of what average residential use looks like and the numbers of people that would be affected by price increases vs decreases under a flatter tariff model. The unclear presentation of the impact of declining vs flat tariffs is further demonstrated in the graph below I the Final Plan (p. 143):

Figure 14.1: Estimated annual bill based on 2025/26 tariffs by annual gas consumption (GJ) under declining and flat pricing structures ($ nominal)




The graph misrepresents the increase in prices under a flat tariff structure because of the way the x-axis is scaled. The annual gas consumption values (in GJ) are not evenly spaced, with small, regular increments at the low-consumption end (5, 10, 15, 20, 25, 30) followed by much larger jumps at higher consumption levels (45, 60, 100, 200). These uneven intervals are presented with roughly equal visual spacing, creating a quasi-logarithmic scale that is not clearly labelled as such. This distorts the viewer's perception of how bills increase. Under a flat tariff, costs grow proportionally with consumption, so on a truly linear x-axis the flat tariff line would present as a much steadier slope. Here, however, the uneven axis makes the flat tariff line appear to bend upwards sharply, giving the impression of accelerating price increases at high consumption levels when in fact the increase is constant.

The distortion also exaggerates the visual gap between the declining tariff and flat tariff at the high-consumption end by stretching out this part of the graph, while compressing the low-consumption range where differences are small. Because the x-axis treatment is not explained, viewers may assume it is linear and misinterpret both the rate of increase under flat tariffs and the magnitude of difference between tariff types.

The Panel also has some concerns around the proposed shift away from the WAPC revenue control mechanism. While we understand that this shift could provide a more stable and adaptable regulatory framework for AGN, it does also transfer a degree of volume risk from AGN to customers. In practice, if gas consumption continues to fall faster than expected, customers could face higher unit prices to compensate for revenue shortfalls. This introduces new risks for consumers, particularly those unable to electrify or disconnect from the gas network. Moreover, the shift away from WAPC could diminish incentives for AGN to promote efficient use of the network or to innovate in managing declining demand. The new approach may also be less transparent to consumers, who may struggle to understand how their bills are being affected by broader network revenue dynamics.

In summary, it appears to the Panel that while AGN's pricing and revenue proposals aim to preserve affordability and support a gradual energy transition, they reflect a compromise between competing objectives. The shift to a new revenue control model may offer flexibility in a volatile demand environment but warrants close scrutiny to ensure consumer protections are preserved. Likewise, a partial tariff reform may delay or dilute the broader alignment of network pricing with the energy transition, raising questions about equity and long-term resilience.