Final decision

Australian Gas Networks (SA) access arrangement 2026 to 2031

(1 July 2026 to 30 June 2031)

Overview

May 2026

AUSTRALIAN ENERGY REGULATOR

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List of attachments

This overview forms part of our final decision on the access arrangement that will apply for 1 July 2026 to 30 June 2031 (2026–31 period) for AGN. It should be read with all parts of our final decision.

A number of issues were settled at the draft decision stage or required only minor updates so that detailed attachments to this final decision are not needed. Where this is the case, our draft decision reasons form part of this final decision. The final decision attachments have been numbered consistently with the equivalent attachments to our draft decision.

The final decision includes the following documents:

- Attachment 1 – Capital base, regulatory depreciation and corporate income tax
  - Attachment A – Regulatory depreciation
- Attachment 2 – Capital expenditure
- Attachment 3 – Operating expenditure
- Attachment 5 – Reference services, tariffs and non-tariff components

  Includes: Services covered by the access arrangement, reference tariff settings, reference tariff variation mechanism, and non-tariff components.

Executive summary

The Australian Energy Regulator (AER) exists to ensure energy consumers are better off, now and in the future. Consumers are at the heart of our work, and we focus on ensuring a secure, reliable and affordable energy future for Australia as we transition to net zero emissions. The regulatory framework governing gas transmission and distribution networks is the National Gas Law and Rules (NGL and NGR). Our work is guided by the National Gas Objective (NGO).

As a regulated business, the South Australian gas distribution network service provider Australian Gas Networks Limited (SA) [ABN 19 078 551 685] (AGN), being part of the Australian Gas Infrastructure Group, must periodically apply to us for a determination on network charges. This is submitted in the form of an access arrangement specifying the services it will provide, the tariffs for those services, and the other terms and conditions on which they will be provided.

On 1 July 2025, AGN submitted its access arrangement proposal for the period from 1 July 2026 to 30 June 2031 (2026–31 period). We have now consulted on that proposal, our draft decision and a revised proposal (received 14 January 2026) from AGN in response to our draft decision.

We do not approve AGN's revised access arrangement and this is our final access arrangement decision (final decision) that will apply to AGN for the 2026–31 period. The reasons for our decision are outlined in this Overview and corresponding attachments.

Our final decision

Our final decision is to allow AGN to set gas network charges resulting in the recovery of an expected $1,370.3 million ($ nominal, smoothed) in revenue from consumers for the 2026–31 period. This is a decrease of $16.5 million (1.2%) from AGN's revised proposal.

We estimate that the distribution component of the average annual bill for residential customers would decrease in the first year of the 2026–31 period by $26, followed by an average annual increase of $39 over the remaining 4 years. Similarly, for small business customers we estimate a decrease of $267 in the first year, followed by average annual increases of $399 for the remaining 4 years ($ nominal).

Compared with the current access arrangement period (2021–26 period) our final decision is a decrease of $65.8 million (4.9%) in real smoothed revenue. This is mainly because we allow less depreciation in the 2026–31 period. We approved $29 million ($2025–26) of accelerated depreciation to manage uncertainty about future gas demand, which is much lower than the $250 million accelerated depreciation approved in the 2021–26 period related to AGN's mains replacement program.[1]

Our final decision seeks to promote efficient investment in the network, while recognising the uncertainty associated with the energy transition for AGN's gas network.

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1 AER, *Final decision - AGN(SA) access arrangement 2021-26 - Attachment 4 - Regulatory depreciation*, Australian Energy Regulator, 30 April 2021, p. 8.

Future gas demand uncertainty

Demand is a critical element of a gas access arrangement. It is a key input into the determination of tariffs, and for the expected capital and operating expenditure (capex and opex) required to deliver safe and reliable services. The Australian Energy Market Operator's (AEMO) *2026 Gas Statement of Opportunities* forecasts ongoing declining demand, reflecting less gas use per customer and fewer active connections, due to more efficient appliances and electrification.[2] Nationally, complex questions are being asked about the future of gas pipelines.

South Australia does not have specific policies in place to incentivise customers to transition away from gas. Indeed, the South Australian Government has initiated legislative support for large-scale hydrogen and renewable gas projects.[3] However, even with this policy support AGN expects both overall gas demand and usage per customer to continue declining across all customer groups over the 2026–31 period. For example, AGN expects residential demand to fall by around one-fifth over the 2026–31 period.

AGN's revised demand forecasts are slightly higher than its initial proposal, reflecting forecasting methodology changes requested by our draft decision, despite incorporating fewer forecast new connections due to imposition of upfront connection charges.[4] Our final decision accepts AGN's revised proposal demand forecast. While AGN's overall demand forecast remains consistent with AEMO forecasts, slightly higher forecast demand over the 2026–31 period, compared with its initial proposal, will benefit customers through lower network tariffs than otherwise.

The tariff variation mechanism determines the financial impact of differences between forecast and actual demand on AGN and its customers. AGN's revised proposal accepted our draft decision to apply a hybrid tariff variation mechanism with a 5% revenue sharing threshold and 50:50 sharing of benefits (or costs) between AGN and its customers through lower (or higher) network tariffs than otherwise. The hybrid tariff variation mechanism, incorporating elements of both weighted average price cap regulation and revenue cap regulation, will reduce AGN's incentive to grow the volume of gas carried by its network while mitigating year-on-year tariff volatility associated with revenue caps.

Demand forecasting risk can be mitigated by high-quality forecasting, but also through flexibility mechanisms provided by the regulatory framework. Most relevantly for AGN's demand forecasts, should actual demand be significantly lower than forecasts, AGN may apply to us to reopen its approved access arrangement.

Our assessment of AGN's revised proposal

Ensuring consumers pay no more than necessary for safe, reliable and secure supply is at the heart of our role.

Where network businesses have engaged with consumers to identify the outcomes that are important to them, our role is to carefully assess whether the access arrangement submitted promotes efficient investment in, and operation and use of, natural gas services for the

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2 AEMO, 2026 Gas Statement of Opportunities, March 2026, p. 23.

3 AER, Draft decision - AGN (SA) access arrangement 2026–31 – Overview, November 2025. The *Hydrogen and Renewable Energy Act 2023 (SA)* (HRE Act) how new grid-scale renewable energy and hydrogen production facility developments are to be considered in South Australia.

4 AEMC, Updating the regulatory framework for gas connections, Final determination, December 2025.

long-term interests of consumers in terms of price, quality, safety, reliability and security of supply.

Our final decision approves total capex forecast of $332.3 million ($2025–26) for the 2026–31 period, including overheads and net of capital contributions. This is a reduction of $4.9 million (1.5%) from AGN's revised proposal.

We recognise the further information provided by AGN to support its revised proposal and we have included $68.7 million for ICT capex, which includes recurrent ICT expenditure and AGN's proposed ICT transition project. Our final decision removed $4.3 million in contingency risk allowances associated with the ICT transition project that we considered were not supported by sufficient evidence. We also accepted the majority of AGN's revised proposal metering program of $38.5 million, except for $2.5 million for digital meters.

A significant reduction from AGN's initial expenditure is to forecast connections capex following the Australian Energy Market Commission (AEMC) Connections rule change.[5] In future, newly connecting customers will be required to pay upfront the full cost of connecting to the gas network. This will ensure future connection costs are not added to the capital base, avoiding a cross subsidy that would otherwise be financed by other customers through higher gas bills. Consistent with AGN's revised proposal, we have included $13.9 million for net connections capex, a reduction of $141.1 million relative to our draft decision of $155.0 million.

Our final decision approves higher total forecast opex of $456.7 million ($2025–26) than proposed by AGN because we have included an additional $22.8 million for the forecast costs of customer connection abolishment. This additional expenditure recognises our final decision to socialise a proportion of customer connection abolishment costs across transportation reference service tariffs, and to establish a discounted ancillary reference service tariff, to promote the continued safe operation of the network.

In April 2026, the AEMC also made a final determination on customer-initiated gas abolishments. This will require customers abolishing their gas connections to pay the cost-reflective charge of their abolishment. For AGN, the AEMC's requirement will be imposed for the 2031–36 period. For this 2026–31 period, our final decision has accepted AGN's initial proposal to partially socialise its abolishment tariff. Our decision reflects the safety concerns raised by the Office of the Technical Regulator (OTR), consistent with our previous decisions for other jurisdictions.[6]

Leaving aside the additional connection abolishment costs, we consider AGN's revised proposal satisfies the opex criteria and the criteria for forecasts and estimates. Our alternative estimate of these elements of AGN's total forecast opex (excluding the socialised abolishment costs) is not materially different (0.2% or $0.7 million lower) from AGN's revised proposal. This minor difference is mainly driven by minor adjustments to proposed step changes, as well as mechanical updates to reflect current forecasts.

Our draft decision did not accept AGN's proposed tariff structures for gas transportation. For its volume (small) customer declining block tariffs, our draft decision required AGN to adopt, or transition to, simpler 2-block structures that did not implicitly reward customers for

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5 AEMC, Updating the regulatory framework for gas connections, Final determination, December 2025.

6 See AER, *Final decision - AGN (SA) access arrangement 2026–31 - Attachment 5 - Reference services, tariffs and non-tariff components*, May 2026.

consuming more gas. For its demand (large) customer declining block tariffs, we asked that AGN consider transitioning to flatter tariffs.

AGN's revised proposal has responded by rebalancing tariff blocks to adopt flatter tariffs for its volume (small) customer declining block tariffs from the start of the access arrangement. Our final decision accepts AGN's revised tariffs and considers the movement towards flatter tariffs better contributes to the emission reduction aspect of the NGO.

Accelerated depreciation of gas network assets

Since our 2021 *Regulating gas pipelines under uncertainty* information paper (2021 information paper), we have consistently identified declining demand to be the key driver of rising future network prices. Our recent access arrangement decisions have also continued to highlight that, so long as demand continues to decline, no affordable amount of accelerated depreciation will achieve long-term price stability or mitigate significant increases in network prices over time.[7]

Accelerated depreciation has inherent limitations and cannot, on its own, resolve the challenges faced by the gas networks and customers from structural declining demand. While it can be used as a tool to reduce the magnitude of stranded asset risk, it does not alter the underlying drivers of declining utilisation, such as improved energy efficiency, shifting consumer preferences towards electrification and government policies and incentives.

Our draft decision did not accept AGN's initial proposed $30 million accelerated depreciation, considering there was insufficient evidence that the network faced a level of stranding risk currently needing to be addressed through accelerated depreciation.

Since the draft decision, AGN has revised its depreciation proposal. Its updated forecasts indicate its customer base is expected to decline faster than previously assumed and it included substantially less growth capex following the AEMC rule change. It proposed an increased $70 million in accelerated depreciation, saying this was the minimum amount needed to support the flexibility intended within the regulatory framework, as well as to mitigate risk both to AGN and its consumers.[8]

Compared with the position at the time of the draft decision, current evidence points to increased uncertainty about the future role and utilisation of AGN's gas distribution network, particularly as demand is expected to decline and the long-term viability of alternative pathways such as hydrogen remains unclear. Recent developments in South Australia, including changes to hydrogen-related initiatives, have further reduced confidence that these technologies can materially support future demand, although this remains to be seen.

We recognise the potential stranded asset risk faced by AGN. Allowing some accelerated depreciation ensures AGN is not deterred from making efficient investments as required to maintain safe and reliable services during the transition.

For AGN, our final decision is to shorten the asset lives of the Inlets and Mains asset classes to 30 and 50 years, respectively, resulting in $29 million accelerated depreciation for the

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7 See AER, Regulating gas pipelines under uncertainty information paper, November 2021; AER, *Final decision - JGN access arrangement 2025–30 - Overview*, May 2025.

8 AGN SA, *Revised Final Plan Access Arrangement 2026–31 Overview*, January 2026, p. 5.

2026–31 period. These reduced asset lives better reflect the expected economic life and provides AGN with a reasonable opportunity to recover its efficient investment over the remaining economic life of those assets. We do not consider that accelerated depreciation beyond the reduction to asset lives for Inlets and Mains is warranted for AGN at this time, reflecting the outlook and strength of policy signals surrounding the future role of AGN's gas network in South Australia.

Submissions from stakeholders provided divergent views on whether accelerated depreciation should be applied. Those supporting accelerated depreciation focused primarily on intergenerational equity and stranding risk management, while affordability impacts and the transfer of risk to consumers were raised as strong and consistent concerns by consumer representatives. In this context, the reduced asset lives provide AGN with a reasonable opportunity to recover its efficient costs over the expected economic life of its network, reflecting the current level of risk. Accordingly, we do not consider it appropriate to impose higher prices on consumers through further accelerated depreciation beyond that arising from the revised asset lives.

The energy transition creates significant uncertainty regarding the timing of cost recovery, price impacts and trajectory of declining demand. In these circumstances, exercising caution by retaining flexibility to reassess the role of accelerated depreciation over time better supports an orderly transition and the long-term interests of consumers. It also limits unnecessary price impacts on customers where reduced asset lives already provide a reasonable opportunity for cost recovery over the expected economic life of the network assets.

At the same time we are releasing this final decision, the AEMC is undertaking its Gas networks in transition NGR rule change process. The AEMC's Directions paper notes that the NGR framework alone cannot fully address the uncertainty faced by businesses running gas networks experiencing declining demand.[9] We agree and continue to encourage open and constructive discussion between consumers, network businesses and governments on how the costs of stranded assets associated with past and future capital investments are managed over time.

9 AEMC, *Gas Networks in Transition, Directions paper*, 19 March 2026, p. v.

Contents

1 Our final decision

AGN's proposed access arrangement sets out the services it will provide in the 5 years from 1 July 2026 to 30 June 2031 (2026–31 period), the tariffs for those services, and the other terms and conditions on which it will be provided.

An access arrangement final decision is a decision to approve, or to refuse to approve, an access arrangement proposal.[10] If, in an access arrangement final decision, we refuse to approve an access arrangement proposal, we must propose an access arrangement or revisions to the access arrangement (as the case requires) for the relevant pipeline.[11] Because we have not approved AGN's revised proposal, our final decision is accompanied by a revised access arrangement and tariff schedule.

At the centre of our decision is the forecast total revenue requirement for the provision of the regulated reference services over the next 5 years. In the sections below, we briefly outline what is driving the expected revenue for our final decision, and the key differences between total revenue of $1,370.3 million ($ nominal, smoothed) compared to AGN's revised proposal of $1,386.8 million.

1.1 What is driving revenue

Over time, inflation impacts the spending power of money. To compare revenue from one period to the next on a like-for-like basis, in this section we use 'real' values based on a common year (2025–26) that have been adjusted for the impact of inflation instead of the nominal values above.

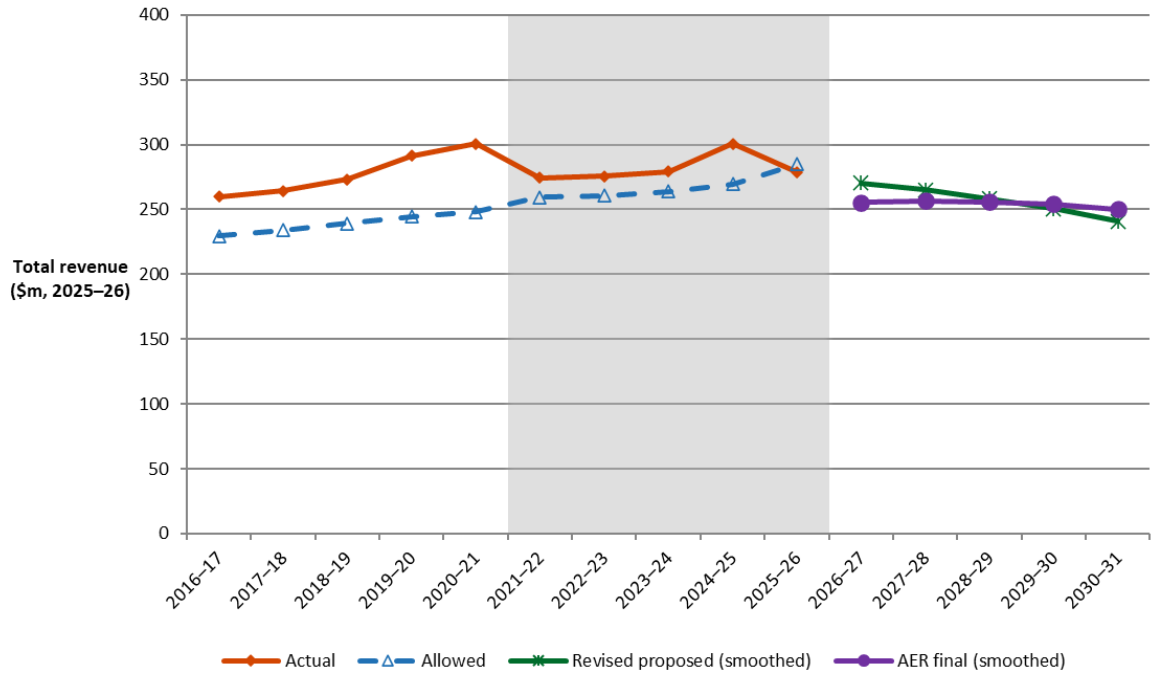
Where the assumptions in AGN's revised proposal would result in total smoothed real revenue that was $53.5 million (4.0%) lower than approved for the current period, the estimated impact of our final decision is a decrease of $65.8 million (4.9%).

Figure 1 shows how real revenue would change over the next 5 years under this final decision, compared to AGN's revised proposal.

10 NGR, r. 62(2).

11 NGR, r. 64(1).

Figure 1 Changes in regulated revenue over time ($ million, 2025–26)



Source: AER analysis.

There are several reasons for this decrease in revenue. Figure 2 highlights the key drivers of the change between the expected real revenue approved for AGN's 2021–26 period and that approved in this final decision for the 2026–31 period. It shows that our final decision provides for decreases in the building blocks for:

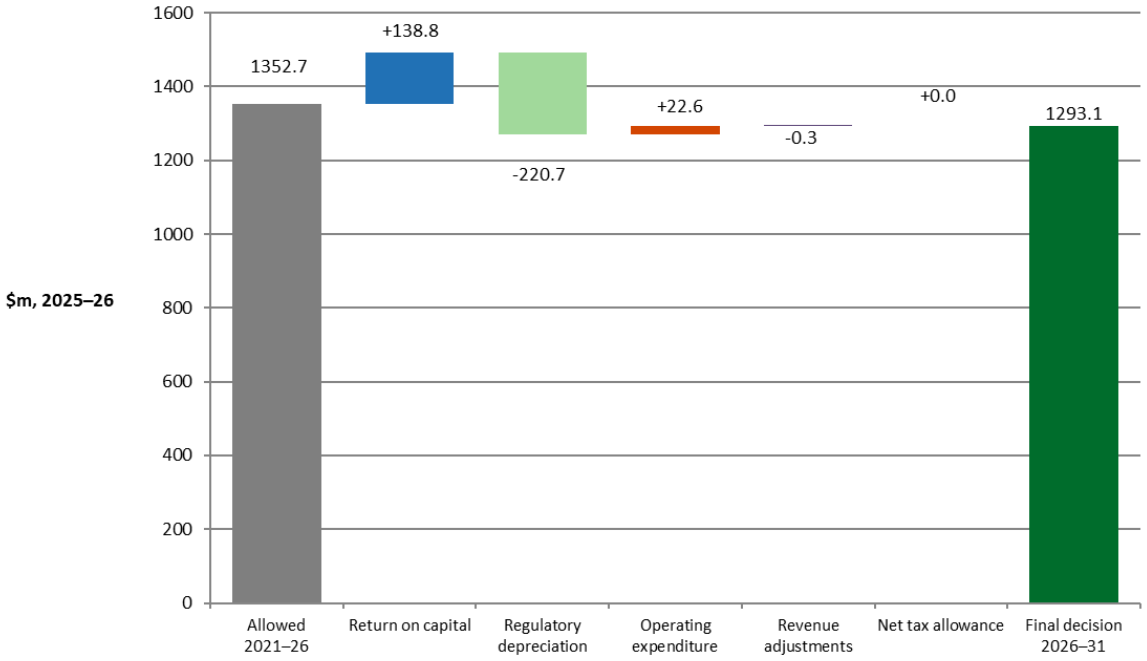
- return of capital (regulatory depreciation), which is $220.7 million (58.9%) lower than the 2021–26 period. This is a key driver of the lower revenue compared to the 2021–26 period. In the 2021–26 decision, we approved $250 million of accelerated depreciation associated with AGN's mains replacement capex program for the 2021–26 period, with the residual value of the replaced assets fully depreciated by the end of the period once those assets were no longer in use. In contrast, our final decision allows $29 million of accelerated depreciation to address stranded asset risk arising from demand uncertainty, resulting in a materially lower regulatory depreciation amount than in the 2021–26 period.
- revenue adjustments, which are slightly lower ($0.3 million or 3.4%) than the 2021–26 period. This reflects a negative Efficiency Carryover Mechanism (ECM) carryover amount for the 2026–31 period, which is partially offset by a positive revenue adjustment from the introduction of the Capital Expenditure Sharing Scheme (CESS) in the 2021–26 period.

Figure 2 also shows that our final decision provides for increases in the building blocks for:

- forecast opex for the 2026–31 period, which is $22.6 million (5.0%) higher than the 2021–26 period forecast. The increase in the 2026–31 period is largely due to the socialisation of abolishment costs.

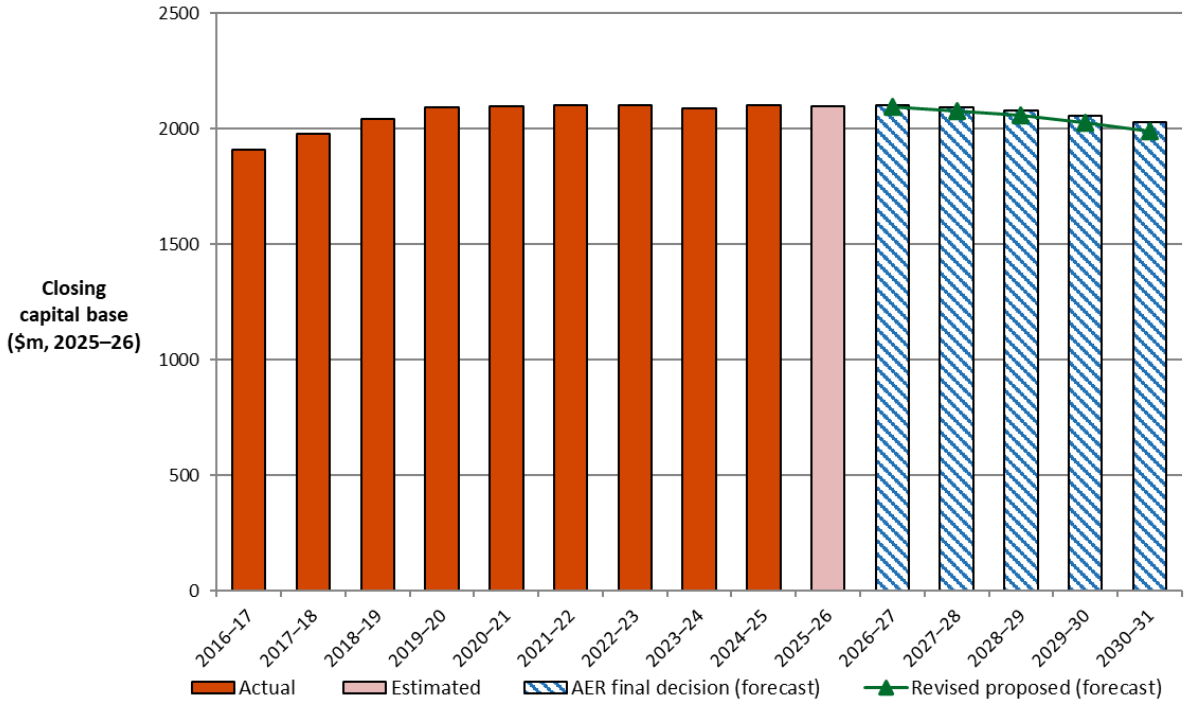
- return on capital, which is based on the opening capital base, forecast capex and rate of return. This is $138.8 million (26.9%) higher than the 2021–26 period. As shown in Figure 3, AGN's capital base is projected to decrease in real terms over the 2026–31 period. The forecast capex for the 2026–31 period is also lower than AGN's historical capex incurred in previous periods, driven by the completion of AGN's extensive mains replacement program over the past decade and reductions in augmentation and associated overheads. The reduction is also driven by the majority of connection related capex no longer entering the capital base, following the AEMC's rule change requiring new gas connections to be funded upfront by connecting customers. However, this reduction in the capital base is more than offset by a higher rate of return being applied to the asset base over the 2026–31 period.

Figure 2 Changes in total revenue between 2021–26 period and 2026–31 period ($ million, 2025–26, unsmoothed)



Source: AER analysis.
Note: Allowed revenue and final decision revenue in the chart are total unsmoothed revenue for the access arrangement period. The 2021–26 allowed revenues (including opex) are converted to real 2025–26 dollars using lagged consumer price index (CPI).

Figure 3 AGN's capital base value over time ($ million, 2025–26)



Source: AER analysis.

1.2 Key differences between this final decision and AGN's revised proposal

In real terms, this final decision would allow AGN to recover a total building block revenue of $1,293.1 million ($2025–26, unsmoothed) over the 2026–31 period.[12] We have made amendments to core components of AGN's revised proposal which have led to a lower revenue outcome. For the 2026–31 period, the main areas of difference between our calculation and AGN's revised proposal is not accepting AGN's revised accelerated depreciation proposal of $70 million and instead reducing the economic lives of its Mains and Inlets asset classes, resulting in a lower $29 million of accelerated depreciation. We also reduced the opex forecast by $7.6 million due to our lower forecast of abolishment ancillary reference service costs.

Movements in market variables have also led to the different revenue outcome in our final decision compared with AGN's revised proposal, all else being equal. These include:

- our updated calculation of AGN's rate of return, which increased slightly to 6.27% from AGN's placeholder estimate of 6.26%.[13] This change, combined with a higher capital base over the period has resulted in a higher return on capital amount determined in the final decision compared with AGN's revised proposal.
- lower expected inflation, based on the Reserve Bank of Australia's (RBA) May 2026 Statement on Monetary Policy (2.48% per annum compared with 2.60% in AGN's

12 Total building block revenue is including Ancillary Reference Services (ARS) costs.

13 Average nominal vanilla weighted average cost of capital (WACC) over the 2026–31 period.

revised proposal), has slightly offset the decrease to the regulatory depreciation amount relative to AGN's revised proposal.

These updates in market variables are a standard part of our decision-making process and do not reflect areas of difference between us and AGN.

1.3 Expected impact of our final decision on tariffs and gas bills

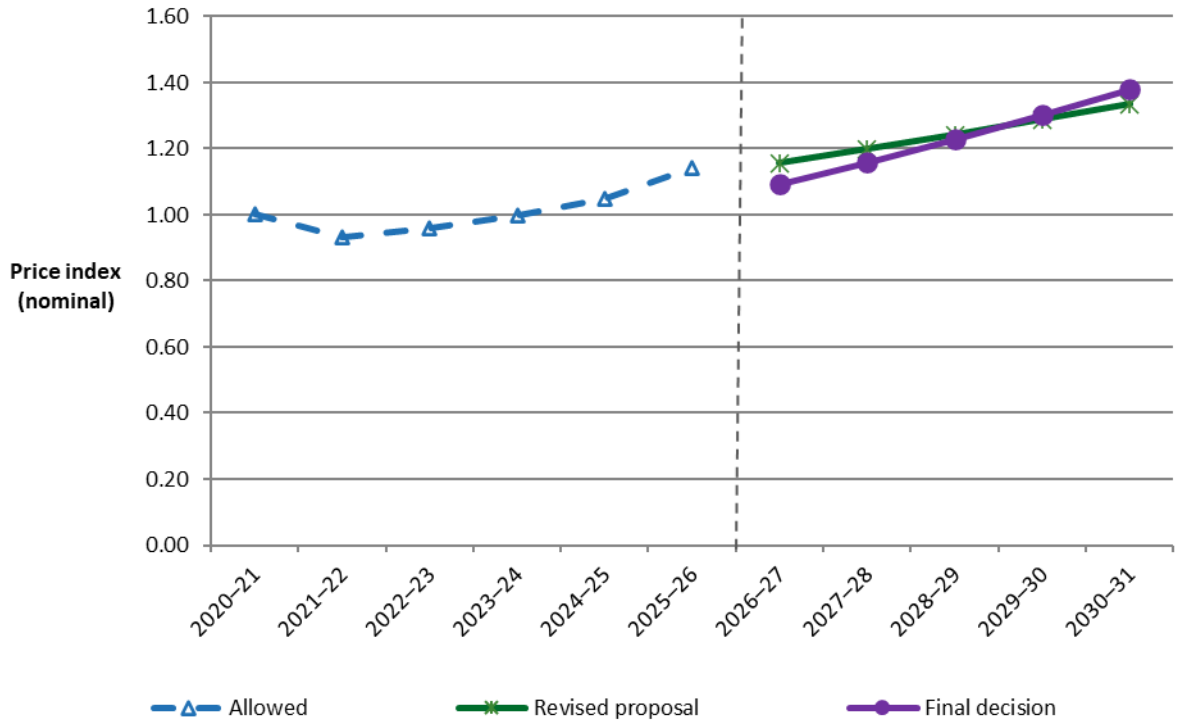
We combine our forecast revenue requirement for AGN with forecast demand to determine its network tariffs. In simple terms, tariffs are determined by dividing costs (total revenue requirement) by total demand. This means that for the same revenue amount, a decrease in forecast demand leads to an increase in tariffs. Similarly, if demand remains constant, a decrease in revenue will lead to lower tariffs.

Both revenue and demand in this final decision are forecast to decline over the 2026–31 period. Demand is forecast to decline at a faster rate than revenue in real terms, resulting in an increase in real tariffs of around 7.1% by the end of the 2026–31 period, or average real increases of 1.4% per annum. However, actual tariffs are not charged in real dollar terms and are impacted by inflation. For illustrative purposes only, and based on our expected inflation, we estimate this final decision would result in an increase in average tariffs of around 21.0% in nominal terms by 2030–31 compared to 2025–26 levels, or an average nominal increase of 3.9% per annum.

Figure 4 shows the indicative tariff paths for AGN's gas transportation reference services across the 2026–31 period. It compares the tariff path under this final decision with that approved previously for the 2021–26 period, and with AGN's revised proposal. These are simple estimates only, calculated in aggregate rather than for individual tariff classes. Note also that while our decision establishes tariffs for year 1 (2026–27) directly, tariffs for years 2 to 5 will be set via the annual reference tariff variation mechanism reflecting actual inflation, updated return on debt and any cost pass throughs.[14]

[14] The annual reference tariff variation mechanism is discussed in section 5.2 and in Attachment 5.

Figure 4 Indicative reference tariffs paths for AGN's reference services from 2026 to 2031 (Price index, nominal)



Source: AER analysis.
Note: Although AGN's revised proposed prices are lower than those in our final decision, this outcome reflects AGN targeting a final-year difference of –9% between smoothed and unsmoothed revenue. Our approach on revenue smoothing is discussed in section 2.2 below.

1.3.1 Potential bill impact

AGN's network charges make up around 50% of its residential and small business customers' gas bills. Other components of the gas supply chain—the cost of purchasing gas from the wholesale market, transmission network charges, and the costs and margins applied by gas retailers in determining the prices they will charge consumers for supply—also contribute to the prices ultimately paid by consumers. These sit outside the decision we are making here but will also continue to change throughout the period.

In nominal terms, which include the impact of expected inflation, this final decision would lead to an increase in the distribution component of gas bills for AGN's customers. We estimate the impact of our final decision on the average annual gas bill, as it is today, would be:[15]

- for a residential customer, a nominal decrease of $26 (2.3%) in 2026–27, followed by average annual increases of $39 (3.4%) from 2027–28 to 2030–31. This corresponds to an average increase of $26 (2.2%) per annum over the 2026–31 period

[15] Our estimated bill impact is based on AGN's proposed typical annual gas usage of 13 MJ per annum for residential customers and 274 MJ per annum for small business customers.

- for a small business customer, a nominal decrease of $267 (2.0%) in 2026–27, followed by average annual increases of $399 (2.9%) from 2027–28 to 2030–31. This corresponds to an average increase of $266 (1.9%) per annum over the 2026–31 period.

1.4 AGN's stakeholder engagement

Consumer engagement during the regulatory process is an important way to provide us with supporting evidence that access arrangements have been aligned with consumer interests and expectations.

We have heard throughout this access arrangement review that stakeholders continue to have diverse views on how the energy transition is to be managed, especially on challenging issues like accelerated depreciation.

AGN's revised proposal engagement with its customers focused on revisiting key issues highlighted by our draft decision and stakeholders on accelerated depreciation and tariff structures.

From AGN's further customer workshop, we heard participants were generally supportive of AGN's proposed $70 million accelerated depreciation proposal, considering it represented a fair intergenerational balance and delivered more collective shared value.[16] While on tariffs, participants preferred an option with a gradual approach to flatter tariffs. Considering this option reduced the risk of bill shock and prevented sudden spikes, offering greater stability and certainty than a transition to faster, flatter tariffs.[17]

The Consumer Challenge Panel sub-panel 33 (CCP33) commended AGN's testing of participants perceptions of fairness, including from several perspectives in the customer workshop. However, noted it was not appropriate to infer from the support from workshop participants that customers in general supported the topics discussed.[18]

CCP33 outlined limitations observed from the customer workshops including the limited representation, and the question of whether this adequately reflects the broader customer base. As well as highlighting the narrow scenario testing of the questions did not give customers the opportunity to consider in-between options (for example, the discussion on accelerated depreciation presented participants with only 2 scenarios).[19]

CCP33 also noted while there has been a lack of independent testing of customer preference, the significant challenge from AGN's South Australian Reference Group (SARG) through the development of AGN's access arrangement has provided CCP33 some assurance of customer preference, alongside improving the clarity of AGN's initial and revised proposals.[20]

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16 AGN SA, *Attachment 5.5 Response to Draft Decision AGN Customer & Stakeholder Engagement Phase 4 Report*, January 2026, p.15.

17 AGN SA, *Attachment 5.5 Response to Draft Decision AGN Customer & Stakeholder Engagement Phase 4 Report*, January 2026, p.19.

18 CCP33, *Advice to the AER - AGN(SA)'s 2026–31 revised proposal and draft decision*, Feb 2026, p.11.

19 CCP33, *Advice to the AER - AGN(SA)'s 2026–31 revised proposal and draft decision*, February 2026, p. 4.

20 CCP33, *Advice to the AER - AGN(SA)'s 2026–31 revised proposal and draft decision*, February 2026, p. 12.

We recognise some stakeholders have expressed some support for accelerated depreciation, including AGN's consumers and the SARG. However, there are stakeholders who continue to express concern that accelerated depreciation is not a viable option.

We also heard from stakeholders the importance of ensuring when discussing accelerated depreciation with consumers that network businesses have meaningfully engaged and provide clear and evidence-based information to prepare consumers for the discussion of how proposals will impact them.

Energy Consumers Australia encouraged us to consider this engagement as a useful indicator of consumer concern about affordability and risk allocation, but cautioned on relying on engagement as evidence that all consumers support and/or agree with accelerated depreciation.[21] The South Australian Council of Social Service (SACOSS) submission observed AGN's approach to how it had previously framed its workshops was largely focused on informing consumers of the preferred position of AGN, rather than genuinely engaging them to shape the proposal.[22]

Stakeholders have acknowledged the positive work undertaken by AGN in its engagement program. CCP33 acknowledging the commitment of the SARG and members of the Review Panel for the depth of challenge they provided AGN. Considering this challenge resulted 'in a much clearer revised plan that is supported by a well-developed narrative around AGN's future.'[23] CCP33 also commended AGN for the 'detailed and easy to follow education pack' provided to participants ahead of the customer workshop.[24]

While we recognise there are some limitations with AGN's engagement, we recognise AGN has embraced the challenge of its SARG who were able to engage more deeply on the access arrangement. It is also encouraging AGN continues to evolve its engagement strategy to reflect the needs and purposes identified for its revised proposal, which included testing different metrics for discussion with its customers that focus on fairness and shared value between all parties.

Consumer support alone does not guarantee any one or more of the assessment criteria have been met in respect of a gas networks access arrangement. In developing proposals to address consumers' concerns, we expect gas networks to appropriately equip consumers with a meaningful opportunity to engage on the issues, including how key components interact across an access arrangement now and into the future.

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21 ECA, *Submission and attachment on AGN (SA) and Evoenergy's 2026–31 revised proposal and draft decision,* February 2026, p. 10.

22 SACOSS, *Submission on AER's Draft Decision and AGN(SA) 2026-31 Access Arrangement Revised Proposal*, February 2026, p. 5.

23 CCP33, *Advice to the AER - AGN(SA)'s 2026–31 revised proposal and draft decision*, Feb 2026, p.9.

24 CCP33, *Advice to the AER - AGN(SA)'s 2026–31 revised proposal and draft decision*, Feb 2026, p.10.

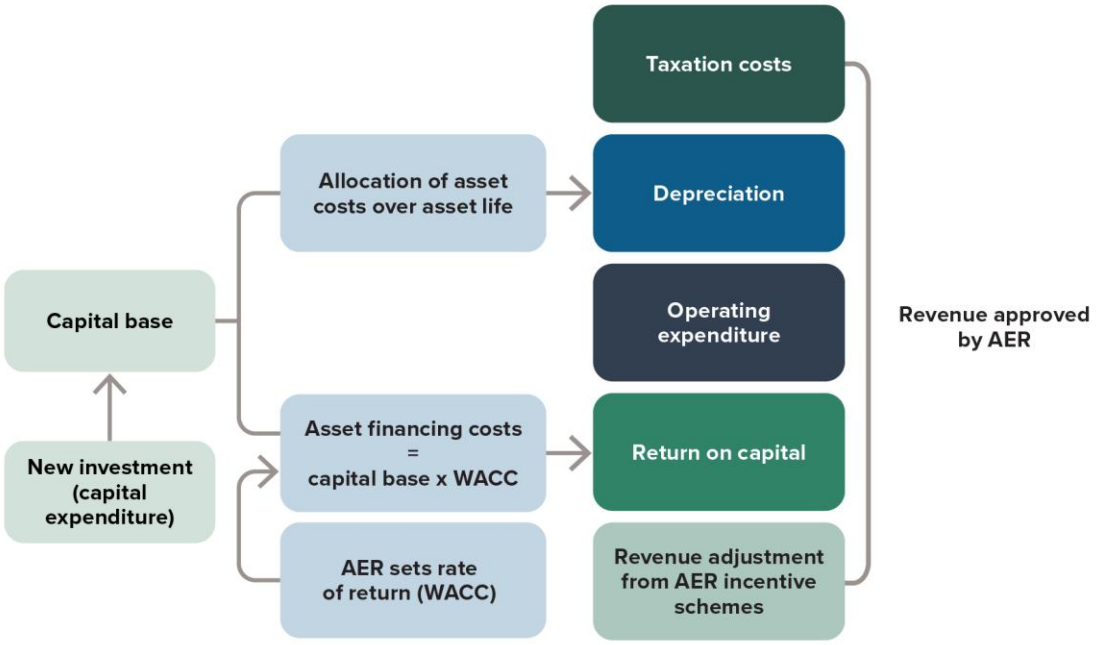
2 Total revenue requirements

The foundation of our regulatory approach is a benchmark incentive framework to setting revenues: once regulated revenues are set for the 5-year period, a network that keeps its actual costs below the regulatory forecast of costs retains part of the benefit. Service providers have an incentive to become more efficient over time, as they retain part of the financial benefit from improved efficiency. Consumers also benefit when efficient costs are revealed, and a lower cost benchmark is set in subsequent access arrangement periods.

AGN's proposed revenue requirement, and our assessment of it under the NGL and NGR is based on 6 cost components or building blocks, illustrated in Figure 5.

- return on the capital base – to compensate investors for the opportunity cost of funds invested in this business
- depreciation of the capital base – or return of capital, to return the initial investment to investors over time
- capex – the capital costs and expenditure incurred in the provision of network services, which directly affects the size of the capital base and, therefore, the revenue generated from the return on capital and depreciation building blocks
- forecast opex – the operating, maintenance and other non-capital expenses, incurred in the provision of network services
- revenue increments/decrements resulting from the application of incentive schemes, such as the ECM and CESS
- estimated cost of corporate income tax.

Figure 5 The building block approach to determining total revenue



Source: AER.

2.1 Final decision on total revenue

The total revenue requirement is a forecast of the efficient cost of providing gas distribution services over the access arrangement period. We determine annual revenue, and the total revenue requirement, in nominal terms that take expected future inflation into account. We use 5-year inflation expectations to convert revenues to nominal values.

Our final decision on AGN's total revenue requirement is $1,370.3 million ($ nominal, smoothed). This is a reduction of $16.5 million (1.2%) from AGN's revised proposal.

Table 1 Final decision on AGN's smoothed total revenue and X factors for the 2026–31 period ($ million, nominal)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
Return on capital	131.4	136.1	140.8	145.6	152.2	**706.1**
Regulatory depreciation	30.9	27.4	31.1	36.9	39.8	**166.1**
Operating expenditure[a]	100.7	99.2	101.8	103.5	107.5	**512.6**
Revenue adjustments	8.8	–2.3	–0.9	–1.1	3.8	**8.3**
Cost of corporate income tax	0.0	0.0	0.0	0.0	0.0	**0.0**
Total revenue (unsmoothed, including ancillary reference services (ARS))	271.8	260.3	272.9	284.9	303.2	**1393.0**
Less: ARS revenue	3.2	3.7	3.9	4.6	5.6	**21.0**
Total revenue (unsmoothed, excluding ARS)	268.6	256.7	268.9	280.3	297.6	**1372.0**
Forecast revenue (smoothed, excluding ARS)	**261.8**	**269.6**	**275.5**	**280.5**	**283.0**	**1370.3**
X factor[b]	6.53%	–3.45%	–3.45%	–3.45%	–3.45%	n/a

Source: AER analysis.
n/a: not applicable.
(a) Including ARS revenue.
(b) Under the CPI–X form of control, a negative X factor is an increase in tariffs in real terms. The X factor for 2026–27 is indicative only. Our decision establishes 2026–27 tariffs directly, rather than referencing a change from 2025–26 tariffs. The X factors for 2027–28 to 2030–31 will be revised to reflect the annual return on debt update.

2.2 Revenue smoothing and tariffs

AGN's tariff variation mechanism for transportation services is currently a weighted average price cap which it proposed to continue, but it also proposed an alternative hybrid mechanism, incorporating elements of both weighted average price cap regulation and revenue cap regulation, for the 2026−31 period. AGN's revised proposal accepted our draft decision requirement that it adopt a 5% revenue sharing threshold for its hybrid mechanism,

rather than its initially proposed 10%. Our final decision is to accept the hybrid tariff variation mechanism in the revised proposal, which includes a 5% revenue sharing threshold. We discuss the hybrid mechanism in more detail in section 5.2.3.

The hybrid mechanism does not change how we determine AGN's gas transportation tariffs ahead of the 2026−31 period. The revenue cap elements of the hybrid mechanism will apply during the period if actual volumes for a regulatory year are more than 5% higher or lower than forecast. Any revenue over or under recovery driven by volumes being more than 5% higher or lower than forecast, will be split equally between AGN and customers.

This means we must determine the weighted average tariff change each year such that the net present value of unsmoothed and smoothed revenue is equal across the 2026–31 period. This average tariff change is known as the 'X factor'.

Our final decision on AGN's revised proposal includes a determination of AGN's total building block revenue (unsmoothed revenue), and a smoothed revenue profile across the 2026–31 period.

The X factors represent the weighted average real change in tariffs. As part of the annual reference tariff variation process applying from 2027–28, we combine the X factors determined in our decision with actual inflation to determine the nominal reference tariffs for the coming year. This means that the prices paid by consumers, and therefore the revenues received by AGN, will change with actual inflation and the annual X factor.

By smoothing the revenues, we aim to minimise price volatility between and within access arrangement periods by keeping the difference between smoothed and unsmoothed revenue in the final year of each period as close as possible, and to provide price signals across tariffs that reflect AGN's underlying efficient costs of providing services. Our standard approach has been to keep a divergence of up to +/–3% between the smoothed and unsmoothed revenues for the last year of the period if this can achieve smoother price changes across the access arrangement periods.

In this final decision, we approve lower revenues than AGN's revised proposal, driven mainly by our decision to allow a lower regulatory depreciation amount. Our final decision also results in lower revenues than those approved for the 2021–26 period in real terms. While revenue in real terms is declining over the 2026–31 period, forecast demand is expected to decline at a faster rate, resulting in higher real prices over the 2026–31 period.

AGN's revised proposed smoothing profile provided an initial price decrease of 1.1% in 2026–27, followed by increases of 1.0% per year over the remaining 4 years of the 2026–31 period. However, this profile resulted in a final-year difference between the smoothed and unsmoothed revenues of –9.0%, which is well outside our target range of +/−3%.

We have smoothed the real decrease in forecast revenues to achieve a relatively stable price path over the 2026–31 period while reducing the final-year difference as much as possible to minimise price volatility at the start of the 2031–36 period. Consequently, we have relaxed our standard target range for the final-year difference between the smoothed and unsmoothed revenues and, in the present circumstances, have determined a final-year

revenue difference of –4.9%. We are satisfied the final decision tariff path appropriately balances price path stability within the 2026–31 period and across periods.[25]

The average annual tariffs in year 1 (2026–27) under our final decision are 5.6% lower in nominal terms than those proposed by AGN, reflecting the lower forecast revenue and our final decision smoothing profile.

While our decision establishes tariffs for year 1 (2026–27) directly, tariffs for years 2 to 5 will be set through the annual reference tariff variation mechanism, reflecting actual inflation, updated return on debt, and any cost pass throughs.[26]

[25] If our final decision had maintained a final-year difference consistent with AGN's revised proposal, and the revenue in the subsequent period remained at or above the 2030–31 unsmoothed revenue level, a significant increase in real revenues and prices would be expected at the start of the 2031–36 period (2031–32) compared with the end of the 2026–31 period (2030–31).

[26] The annual tariff variation mechanism is discussed in section 5.2 and Attachment 5 to this final decision.

3 Key elements of our final decision on revenue

The components of our final decision include the building blocks we use to determine the total revenue requirement. The following sections summarise our revenue decision by building block. The attachments to this final decision provide a more detailed explanation of our analysis and findings.

3.1 Capital base

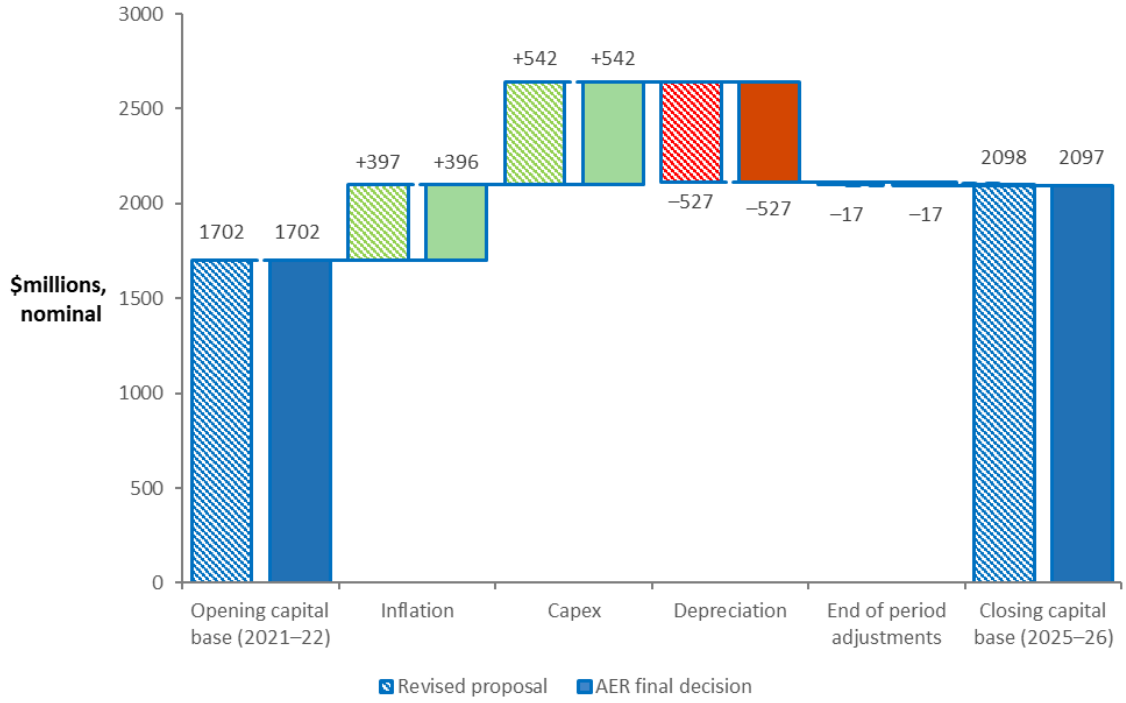
The capital base accounts for the value of regulated assets over time. To set revenue for a new access arrangement period, we take the opening value of the capital base from the end of the last period and roll it forward year by year by indexing it for inflation, adding new capex and subtracting depreciation and other possible factors (such as disposals). This gives us a closing value for the capital base at the end of each year of the access arrangement period. The value of the capital base is used to determine the return on capital and depreciation building blocks.

We determine an opening capital base value of $2,096.6 million ($ nominal) as at 1 July 2026 for AGN. This value is $1.5 million (0.1%) lower than AGN's proposed opening capital base of $2,098.2 million ($ nominal).[27] This reflects our update to the roll forward model (RFM) for actual CPI for 2025–26.

Figure 6 shows the key drivers ($ nominal) of the change in AGN's capital base over the 2021–26 period under this final decision compared to its revised proposal.

[27] AGN, *Attachment 1.6 Roll Forward Model,* July 2025.

Figure 6 Key drivers of changes in the capital base over the 2021–26 period – proposal compared with the final decision ($ million, nominal)



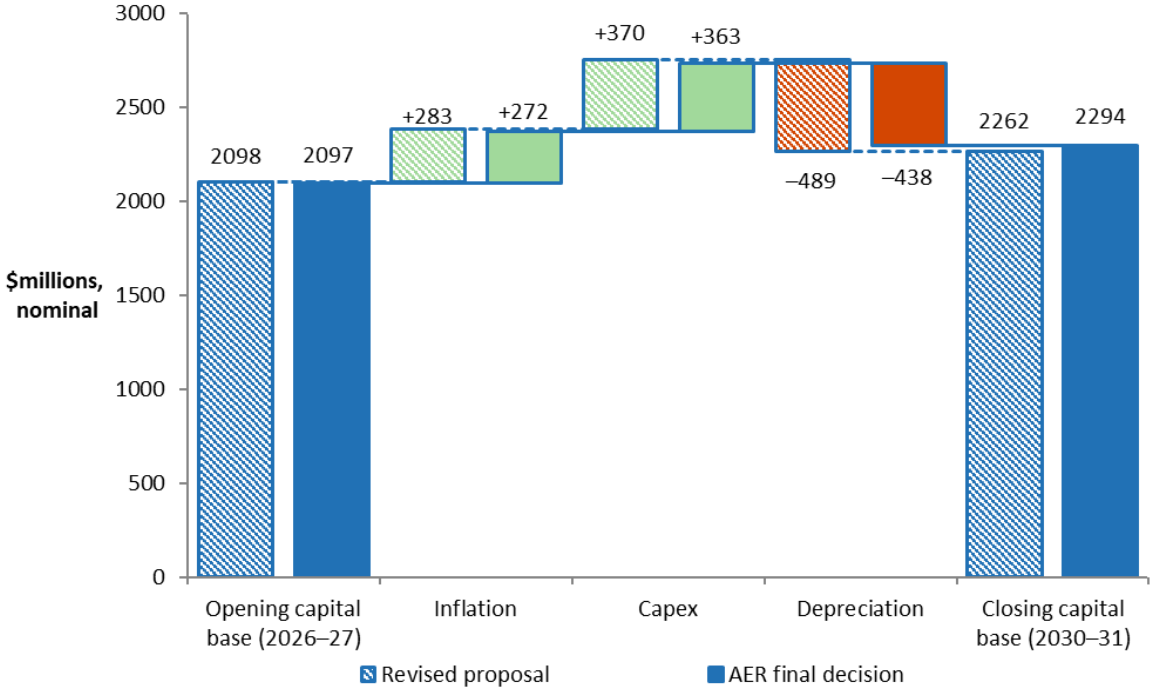
Source: AER analysis.
Note: Capex is net of disposals and capital contributions. It is inclusive of the half-year WACC to account for the timing assumptions in the RFM.

Figure 7 likewise shows the key drivers of the change in AGN's forecast capital base over the 2026–31 period in its revised proposal compared to our final decision. Our final decision projects an increase of $197.1 million (9.4%) to the capital base by the end of the 2026–31 period compared to the $163.6 million (7.8%) increase in AGN's revised proposal.

We determined a projected closing capital base of $2,293.7 million ($ nominal) as at 30 June 2031, which is $32.0 million (1.4%) higher than AGN's revised proposed $2,261.8 million. This higher value is mainly driven by a lower forecast straight-line depreciation determined in our final decision (discussed in section 3.3). It also reflects our final decisions on the opening capital base as at 1 July 2026, expected inflation and forecast capex (discussed in sections 3.2 and 3.4, respectively).

The reasons for our final decision on AGN's capital base are discussed in Attachment 1 of this final decision.

Figure 7 Key drivers of changes in the capital base over the 2026–31 period – proposal compared with the final decision ($ million, nominal)



Source: AER analysis.
Note: Capex is net of disposals and capital contributions. It is inclusive of the half-year weighted average cost of capital (WACC) to account for the timing assumptions in the RFM.

3.2 Rate of return and value of imputation credits

Our 2022 Rate of Return Instrument (RORI) sets out the approach we will use to estimate the return on debt, the return on equity and the overall rate of return.[28]

The return each business is to receive on its capital base known as the 'return on capital', is a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the capital base.

We estimate the rate of return by combining the returns of two sources of funds for investment: equity and debt. The allowed rate of return provides the business with a return on capital to service the interest rate on its loans and give a return on equity to investors.

The estimate of the rate of return is important for promoting efficient prices in the long-term interests of consumers. If the rate of return is set too low, the network business may not be able to attract sufficient funds to be able to make the required investments in the network and reliability may decline. Conversely, if the rate of return is set too high, the network business may seek to spend too much, and consumers will pay inefficiently high tariffs.

[28] AER, *Rate of Return Instrument (Version 1.2)*, March 2024.

We are required by the NGL to apply the RORI to estimate an allowed rate of return[29]. For this final decision, we have applied the 2022 RORI.[30]

AGN's revised proposal adopted the 2022 RORI.[31] Our final decision rate of return of 6.27% (nominal vanilla) is slightly higher than the 6.26% placeholder in the revised proposal.

Our calculated rate of return in Table 2 applies to the first regulatory year of the 2026–31 period. A different rate of return may apply for the remaining years of the period. This is because we will update the return on debt component of the rate of return each year, in accordance with the 2022 RORI, to use a 10-year trailing average portfolio return on debt that is rolled-forward each year. Hence, only 10% of the return on debt is calculated from the most recent averaging period, with 90% from prior periods.

Our final decision accepts AGN's proposed risk-free rate[32] and debt averaging periods[33] because they are consistent with the 2022 RORI.[34]

Table 2 Final decision on AGN's rate of return (nominal)

	AER's draft decision (2026–31)	AGN's revised proposal (2026–31)	AER's final decision (2026–31)	Allowed return over the access arrangement period
Nominal risk-free rate	4.34%	4.83%	4.82%[a]	Constant (%)
Market risk premium	6.20%	6.20%	6.20%	Constant (%)
Equity beta	0.6	0.6	0.6	Constant
Return on Equity (nominal post-tax)	8.06%	8.55%	8.54%	Constant (%)
Return on debt (nominal pre-tax)	4.70%	4.74%	4.75%[b]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	6.05%	6.26%	6.27% [c]	Updated annually for return on debt
Expected inflation	2.55%	2.60%	2.48%	Constant (%)

Source: AER analysis; AER, *Draft decision – AGN SA Access arrangement 2026–31 – Overview*, November 2025, p. 18; AGN, *Attachment 1.5A: Revised Final Plan Post Tax Revenue Model*, January 2026.

(a) Calculated using AGN's actual risk-free rate averaging period of 20 business days ending 27 February 2026.

29 NGL, section 30C.

30 AER, *Rate of Return Instrument (Version 1.2)*, March 2024.

31 AGN SA, *Revised Final Plan 2026–31 – Overview*, January 2026, p. 9; AGN, *Attachment 11.2: Response to Draft Decision on Financing Costs*, January 2026, p. 4.

32 AGN SA, *Attachment 11.1: Averaging Periods – Confidential*, July 2025, p. 1.

33 AGN SA, *Attachment 11.1: Averaging Periods – Confidential*, July 2025, p. 1.

34 AER, *Rate of return Instrument (version 1.2)*, March 2024, cll 7–8, 23–25.

(b) Calculated using AGN's actual nominated return on debt averaging periods.
(c) Applied to the first year of the 2026–31 period.

3.2.1 Debt and equity raising costs

In addition to providing for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. We include debt raising costs in the operating expenditure (opex) forecast because these are regular and ongoing costs which are likely to be incurred each time service providers refinance their debt. On the other hand, we include equity raising costs in the capital expenditure (capex) forecast because these costs are only incurred once and would be associated with funding particular capital investments. Our approach to forecasting debt and equity raising costs is set out in more detail in our previous revenue determinations (for example, see our 2025–30 Directlink Electricity Transmission Determination final decision).[35] AGN has proposed to use our approach to estimate debt and equity raising costs.[36]

Our final decision is to apply a debt raising cost of 8.74 basis points per annum, which has been used to calculate the debt raising costs included in total forecast opex (see section 3.5).

We have updated our estimate for the 2026–31 period based on the benchmark approach using updated inputs. This results in zero equity raising costs.

3.2.2 Imputation credits

Our final decision applies a value of imputation credits (gamma) of 0.57, as set out in the 2022 RORI.[37] AGN's revised proposal also adopted this value.[38]

3.2.3 Expected inflation

As set out in Table 3, our estimate of expected inflation is 2.48%. It is an estimate of the average annual rate of inflation expected over a five-year period based on the outcome of our 2020 inflation review.[39] AGN's revised proposal also adopted our approach.[40]

Table 3 Final decision on AGN's forecast inflation (%)

	Year 1	Year 2	Year 3	Year 4	Year 5	Geometric average
Expected inflation	2.40%	2.50%	2.50%	2.50%	2.50%	2.48%

Source: AER Analysis; RBA, *Statement on Monetary Policy*, May 2026, Table 3.2: Detailed Forecast Table. See the Statement of Monetary Policy

35 AER, *Final decision - Attachment 3 - Rate of Return - Directlink Electricity Transmission Determination 2025 to 2030*, September 2024, pp 4–6.

36 AGN SA, *Attachment 1.5A: Revised Final Plan Post Tax Revenue Model*, January 2026.

37 AER, *Rate of return Instrument (version 1.2)*, March 2024, cl. 27.

38 AGN SA, *Attachment 1.5A: Revised Final Plan Post Tax Revenue Model*, January 2026.

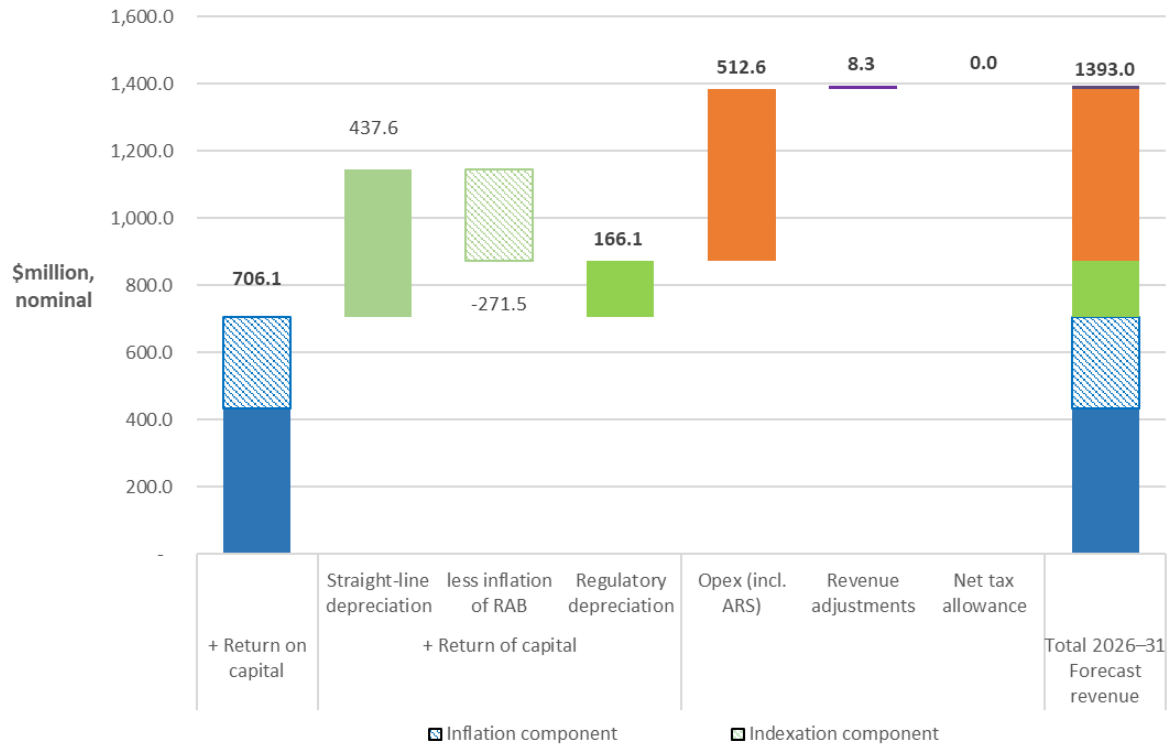
39 AER, *Final position, Regulatory treatment of inflation*, December 2020.

40 AGN SA, *Attachment 1.5A: Revised Final Plan Post Tax Revenue Model*, January 2026.

Our final decision uses the Reserve Bank of Australia's (RBA) May 2026 Statement on Monetary Policy which contains a CPI forecast for the financial year ending 30 June 2027 and 30 June 2028. This means the first two years of the 2026–31 period are based on RBA forecasts and, thereafter, a linear glide-path from year three to the mid-point of the RBA's inflation target band of 2.5% in year five.

Figure 8 isolates the impact of expected inflation from other parts of our final decision, to illustrate its impact on the return on capital and regulatory depreciation building blocks and the total revenue allowance. Other elements held constant, lower expected inflation reduces the return on capital but increases regulatory depreciation.

Figure 8 Inflation components in final decision revenue building ($ million, nominal)



Source: AER analysis.
Note: ARS revenue is included in opex.

3.3 Regulatory depreciation (return of capital)

Depreciation is a method used in our decision to allocate the cost of an asset over its useful life. It is the amount provided so capital investors recover their investment over the economic life of the asset (otherwise referred to as 'return of capital'). When determining the total revenue for AGN, we include an amount for the depreciation of the projected capital base.[41] Under the building block framework, regulatory depreciation consists of the net total of the straight-line depreciation less the indexation of the capital base.

41 Under r. 76(b) of the NGR, depreciation is one of the building blocks for determining total revenue.

We determine a regulatory depreciation amount of $166.1 million ($ nominal) for AGN for the 2026–31 period. This is $39.9 million (19.4%) lower than AGN's revised proposal of $206.0 million.

This reduction is primarily due to our final decision for a lower accelerated depreciation amount (discussed below). Our final decisions on the opening capital base as at 1 July 2026, expected inflation and forecast capex also affect the regulatory depreciation amount (discussed in sections 3.1, 3.2 and 3.4).

The reasons for our final decision on AGN's regulatory depreciation are discussed in Attachment 1 of this final decision.

3.3.1 Accelerated depreciation – stranded asset risk

In this final decision, we do not accept AGN's revised proposed accelerated depreciation amount of $70 million ($2025–26) in full and instead determine a reduced amount of $29 million, by reducing the asset lives of Inlets and Mains asset classes to 30 and 50 years, respectively. We consider that these reduced asset lives better reflect the expected economic lives of these assets, consistent with rule 89(1)(b) and (c), and provide a depreciation schedule that allows recovery of the capital base over the period in which the network is expected to be economically utilised.

Our final decision is to not allow an accelerated depreciation amount beyond that arising from the reduced asset lives. The available evidence does not support a conclusion that any residual stranded asset risk beyond that addressed through reduced asset lives is sufficiently material to warrant further accelerated depreciation at this time, as neither the policy environment in South Australia nor AGN's modelling provide clear or consistent evidence on the likelihood, timing or extent of such risk.

Expected economic lives of AGN's Mains and Inlets asset classes

In this final decision, we determine a reduced standard and remaining asset lives as at 1 July 2026 of 30 and 50 years for AGN's Inlet and Mains asset classes respectively, compared to their current lives of 60 years.

In the draft decision, we did not accept AGN's initial proposal for accelerated depreciation. At that time, we considered there was insufficient evidence that AGN faced a level of stranding risk that needed to be addressed through accelerated depreciation. Both the policy environment in South Australia and AGN's overall proposal suggested the network would continue to play a role in the transition to net zero, and we therefore did not revise the economic lives of AGN's long-lived assets.

Having regard to updated information and developments since the draft decision, we consider that there is sufficient evidence to suggest that the expected economic lives of AGN's Inlets and Mains asset classes are likely to be shorter than their technical lives to some extent.

In particular, while renewable gas and hydrogen pathways remain possible future options, there is currently less certainty regarding their role in the future utilisation of AGN's network in South Australia. This is consistent with AEMO's long-term forecasts indicating a gradual decline in gas demand, particularly for residential and small business customers. AGN's

revised forecasts of growth capex, demand and connections for the 2026–31 period are also lower than those in the draft decision. These developments, taken together, indicate an increased likelihood that AGN's long-lived assets may not be utilised over their full technical lives.

For the 2026–31 period, we consider reduced expected economic lives of 30 years for Inlets and 50 years for Mains more reasonably reflect the period in which these assets can be expected to provide economic services, for the following reasons:

- AGN's Inlets asset class is most exposed to residential/small business electrification and disconnection and are least likely to be economically repurposed for alternative gases, such as hydrogen or renewable gas. This assessment is consistent with AEMO's GSOO outlook for declining residential and commercial gas demand, and with the 30-year economic life we assigned to broadly comparable medium pressure pipeline assets approved for JGN's 2025–30 access arrangement.
- AGN's Mains asset class is exposed to some stranding risk as residential customers disconnect, however the outlook is less clear for industrial demand, and mains may continue to be used to serve remaining demand. We therefore consider a smaller reduction to the expected economic life of mains to be appropriate, consistent with the 50-year life approved for similar assets approved for JGN 2025–30 access arrangement.

Accelerated depreciation beyond that arising from the reduced asset lives

For the final decision, we do not consider that accelerated depreciation beyond the reduction to asset lives for Inlets and Mains is warranted for AGN at this time.

We consider that reducing asset lives for the Inlets and Mains asset classes reflects the increased uncertainty surrounding the expected economic lives of AGN's long-lived assets. However, the available evidence does not support a conclusion that any residual stranded asset risk beyond that addressed through reduced asset lives is sufficiently material to warrant further accelerated depreciation at this time. Accelerated depreciation is not intended to guarantee cost recovery, but to provide a flexible and proportionate regulatory response where justified to address material stranded asset risk under uncertainty.

We consider that reducing the asset lives already provides AGN with a reasonable opportunity to recover its efficient costs over the expected economic life of its network. Given that, we do not consider it appropriate to impose higher prices on consumers through further accelerated depreciation beyond that arising from the reduced asset lives. While the price impacts under AGN's revised proposed $70 million accelerated depreciation is not materially higher than that under the $29 million arising from reduced asset lives alone, we do not consider this, in itself, justifies allowing further accelerated depreciation. Both the policy environment in South Australia and AGN's modelling do not support a conclusion that further accelerated depreciation beyond that arising from the reduced asset lives is required at this time.

The energy transition creates significant uncertainty regarding the timing of cost recovery, price impacts and trajectory of declining demand. In these circumstances, exercising caution by retaining flexibility to reassess the role of accelerated depreciation over time better supports an orderly transition and the long-term interests of consumers. It also limits unnecessary price impacts on customers where reduced asset lives already provide a

reasonable opportunity for cost recovery over the expected economic life of the network assets. This approach is consistent with our Information paper, *Regulating gas pipelines under uncertainty*, which noted that '…regulated depreciation or risk compensation cannot be adjusted without constraint to guarantee cost recovery for the regulated businesses'.[42]

3.4 Capital expenditure

Capex—the capital costs and expenditure incurred in the provision of network services—mostly relates to assets with long lives, the costs of which are recovered over several access arrangement periods. Forecast capex directly affects the size of the capital base and the revenue generated from the return on capital and depreciation building blocks.

Our final decision is to include a total capex forecast of $332.3 million ($2025–26) for the 2026–31 period, including overheads and net of capital contributions. Our final decision approves a lower total forecast capex than AGN's revised proposal of $337.2 million ($2025–26). This is a reduction of $4.9 million ($2025–26) or 1.5%.

Table 4 outlines our alternative estimate of forecast capex and compares this to AGN's revised forecast by capex category

Table 4 Final decision by capex category ($ million, 2025–26)

Category	AGN revised proposal	AER final decision	Difference over capex category ($/%)	
Connections	117.7	117.7[43]	-	-
ICT	73.0	68.7	-4.3	-5.8%
Other Network	92.2	92.2	-	-
Mains replacement	85.5	85.5	-	-
Meter replacement	38.5	36.0	-2.5	-6.6%
Overheads	21.9	21.8	-0.1	-0.5%
Other non-network	7.7	7.7	-	-
Mains augmentation	6.4	6.4	-	-
Telemetry	3.8	3.8	-	-
Gross Total	**446.7**	**439.8**	**-6.9**	**-1.5%**
Less Customer contributions connections (including overheads) (a)	109.5	109.5	-	-
Less Disposals	-	-	-	-
Modelling adjustments		2.1(b)		

42 AER, *Information Paper: Regulating gas pipelines under uncertainty*, 2021, p. 29.

43 The net connections capex is $13.9 million, derived by subtracting the capital contribution of $103.9 million (without overheads) from the gross connections capex of $117.7 million.

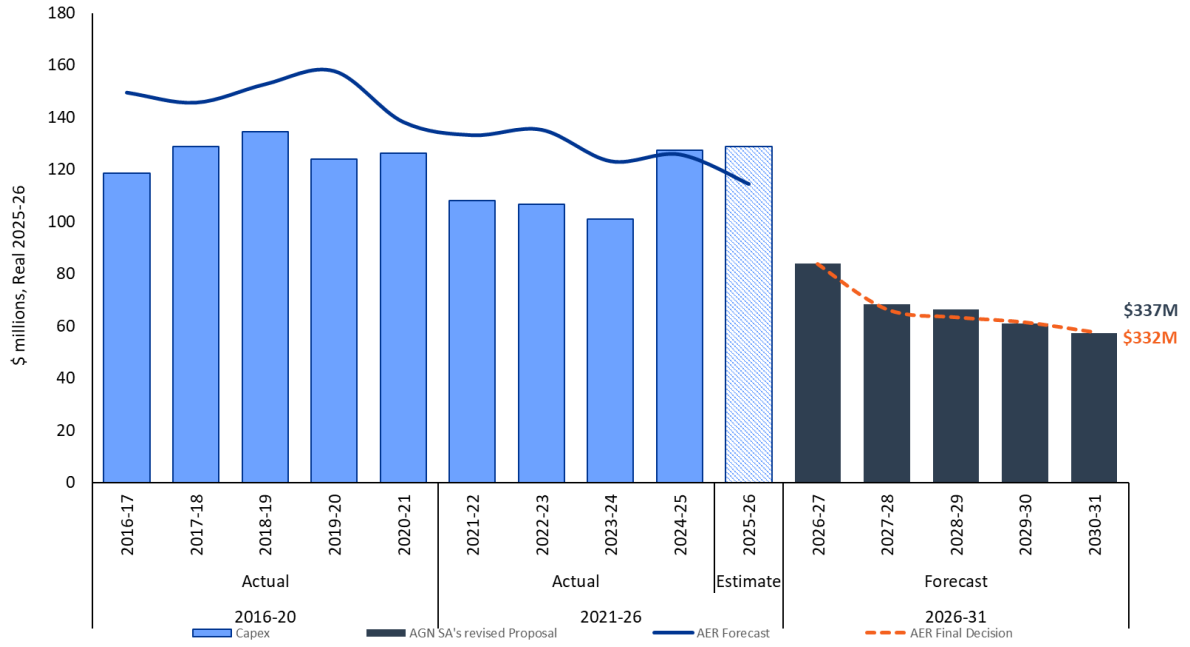
Category	AGN revised proposal	AER final decision	Difference over capex category ($/%)	
Net Total	**337.2**	**332.3**	**-4.9**	**-1.5%**

Source: AER, *AGN access arrangement 2026-31 – Final Decision – Capex Model*, May 2026.
Note: Numbers may not sum due to rounding.
(a) AGN's overheads for the forecast connections is $5.6 million. This offsets the component recovered in the overheads of $21.9 million and ensures that the upfront capital contribution recovers the full cost of the connection and other customers are not cross subsidising the connection costs. The customer connections excluding overheads is $103.9 million.
(b) Our final decision includes standard modelling adjustments for updated inputs to inflation and labour real cost escalation. Consistent with our decisions in previous access arrangements, we have applied real escalation to internal labour only.

Figure 9 compares AGN's actual and forecast capex with our previous capex decisions and our final decision for the 2026–31 period. This shows that our final decision capex forecast of $332.3 million is:

- $299.1 million, or 47.4% less than the capex forecast we approved in our final decision for the 2021–26 period
- $239.8 million, or 41.9% lower than AGN's actual (and estimated) capex for the 2021–26 period.

Figure 9 AGN's historical and forecast capex ($ million, 2025–26)



Source: AER, *AGN access arrangement 2026-31 – Final Decision – Capex Model*, May 2026; AER Analysis.
Note: Nominal figures converted to real dollars 2025–2026.

Overall, we found that the majority of AGN's forecast of $337.2 million is conforming capex. We have not accepted AGN's forecast in full, reducing it by 1.5% because of the differences in our forecasts in ICT and metering. Key drivers of our final decision alternative forecast are:

- **Connections** – we have included, in line with AGN's revised proposal, $13.9 million for net connections capex, a reduction of $141.1 million relative to our draft decision of $155.0 million.

  On 11 December 2025, the AEMC made its rule change for *Updating the regulatory framework for gas connections*, requiring gas network distributors, which are subject to the National Energy Customer Framework for gas, to charge a cost-reflective, upfront connection fee on newly connecting retail gas customers from 1 October 2026 onwards. From this date, we will no longer include connection costs related to new customers in the capital base and regulated entities can only recover these costs from connecting customers as capital contributions.

  AGN has incorporated the capex forecast impacts of the rule change and estimated that it will receive capital contributions of $109.5 million towards the connections under the new rule. The net connections capex of $13.9 million represents the commercial and residential development connection costs incurred up until the implementation of the rule change. We consider AGN's modest forecast of connections for the period 1 July –1 October 2026 to be reasonable.

- **Information and communications technology (ICT)** – we have included $68.7 million for AGN's ICT capex, which includes recurrent ICT expenditure and AGN's proposed ICT transition project but have removed $4.3 million in contingency risk allowances associated with the ICT transition project which we considered were not supported by sufficient evidence.

- **Meter replacement** – we have accepted the majority of AGN's revised proposal metering program of $38.5 million as AGN has provided further supporting information in response to our draft decision. This includes the full volume of residential and commercial metering replacements. However, we consider that AGN has not provided sufficient evidence of the prudency and efficiency of its proposed $2.5 million digital metering program. We have removed this component from our alternative estimate of conforming capex.

We discuss our decision on AGN's capex in more detail in Attachment 2.

3.5 Operating expenditure

Opex is the operating, maintenance and other non-capital expenses incurred in the provision of pipeline services.

Our final decision is to include total forecast opex of $456.7 million ($2025–26)[44] for the 2026–31 period, excluding ancillary reference services and including debt raising costs. Our final decision approves higher total forecast opex than AGN proposed (by $22.8 million) because we have added $22.8 million for the forecast costs of customer connection abolishment. The inclusion of additional opex for customer connection abolishment costs in our alternative estimate of total forecast opex reflects our final decision to socialise a proportion of customer connection abolishment costs across transportation reference service tariffs, and establish a discounted ancillary reference service tariff, to ensure the safe operation of the network. That is, we have amended AGN's full abolishment cost from $1,250

[44] All numbers are in $2025–26 unless otherwise indicated.

to $1,000 and set a partially socialised abolishment charge of $257 – the difference between the full cost and the abolishment charge (i.e.$743) is the socialised portion included in opex and recovered through transportation tariffs (see section 5.2 and Attachment 5 for further detail).

We are satisfied that AGN's revised opex forecast, excluding socialised customer abolishment costs and debt raising costs, of $428.5 million,[45] satisfies the opex criteria[46] and the criteria for forecasts and estimates.[47] This is because our alternative estimate of these elements of AGN's total forecast opex, excluding socialised abolishment costs, is not materially different (1.1% or $4.6 million higher) than AGN's revised proposal. This difference from AGN's revised proposal is mainly driven by minor adjustments or acceptance of proposed step changes, as well as mechanical updates to reflect current forecasts.

We have therefore included AGN's revised opex forecast, excluding socialised customer abolishment costs and debt raising costs, of $428.5 million in our total opex forecast. We have also included $5.5 million of debt raising costs based on our final decision post tax revenue model (PTRM) calculation (see section 3.4.4.1 of Attachment 3).

Table 5 sets out AGN's proposed opex forecast and our alternative estimate, excluding the costs of customer connection abolishments, and the difference between these forecasts.

Table 5 Comparison of AGN's opex proposal and our alternative opex estimate, excluding customer abolishment costs ($million, 2025–26)

	AGN proposal	AER draft decision	AGN revised proposal	AER alternative estimate	Difference $ (%)
Based on estimated opex in 2024–25	**368.7**	**365.6**	**349.0**	**354.1**	**5.1 (1.5%)**
Remove category specific forecasts	**–33.9**	**–34.0**	**–10.1**	**–10.3**	**–0.1 (–1.5%)**
2024–25 to 2025–26 increment	**3.9**	**4.4**	**4.4**	**4.4**	**0.1 (1.5%)**
Trend: Output growth	2.9	2.8	–1.2	–1.2	–0.0 (–0.0%)
Trend: Price growth	7.2	5.2	5.2	5.3	0.1 (1.6%)
Trend: Productivity growth	–4.2	–4.0	–	–	–
Total trend	**5.9**	**4.0**	**4.1**	**4.1**	**–**

45 This is AGN's total opex forecast excluding socialised customer abolishment costs and debt raising costs.

46 Under rule 91 of the National Gas Rules (NGR), opex 'must be such as would be incurred by service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of delivering pipeline services.' Where opex satisfies the test in rule 91, we say it satisfies the opex criteria.

47 Under rule 74 of the NGR, information in the nature of a forecast or estimate must be supported by a statement of the basis of the forecast/estimate. Further, forecasts and estimates must be arrived at on a reasonable basis and must represent the best forecast or estimate possible in the circumstances. Where a forecast or estimate meets the requirements of this rule, we say it satisfies the forecasts and estimates criteria.

	AGN proposal	AER draft decision	AGN revised proposal	AER alternative estimate	Difference $ (%)
Step change: Purchase of renewable gas of origin certificates	26.0	–	–	–	–
Step change: Overheads (capex to opex)	32.0	32.0	32.5	32.5	–
Step change: Transition from APA	18.5	–	19.1	17.5	–1.6 (–0.4)
Step change: Cybersecurity	1.2	–	1.2	–	–1.2 (–0.3%)
Step change: Application upgrades & enhancements	4.1	4.1	4.1	4.1	–
Step change: Abolishments at redundant sites	4.6	–	4.6	4.6	–
Total step changes	**86.5**	**36.1**	**61.5**	**58.7**	**–2.8 (–0.6%)**
Category specific forecasts: UAFG	27.9	14.6	19.7	22.1	2.4 (0.5%)
Total opex, excluding debt raising costs	**458.9**	**390.7**	**428.5**	**433.1**	**4.6 (1.1%)**
Debt raising costs	5.1	5.5	5.5	5.5	–0.0 (0.0%)
Total opex, including debt raising costs	**464.1**	**396.2**	**433.0**	**438.6**	**4.6 (1.1%)**

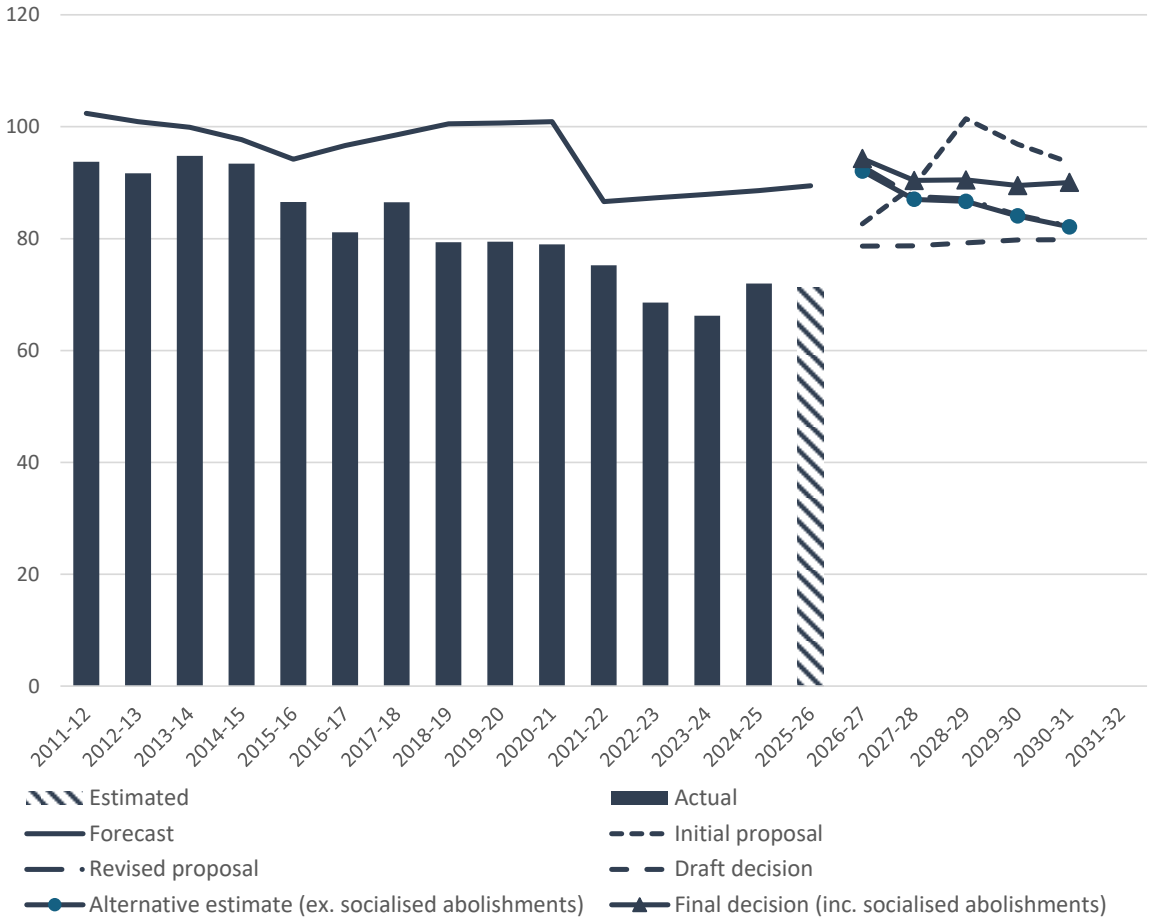
Source: AGN SA, *Attachment 8.1A Revised Final Plan Opex Forecast Model*, January 2026; AER analysis.
Note: Numbers may not add up to total due to rounding. Amounts of '0.0' and '–0.0' represent small non-zero amounts and '–' represents zero.

Our final decision, which is more than AGN's proposed total opex forecast, is:

- $8.0 million (–1.8%) lower than the opex forecast we approved for the 2021–26 period
- $85.2 million (24.4%) higher than AGN's actual (and estimated) opex in the 2021–26 period.

In Figure 10, we compare our alternative estimate of opex (including debt raising costs and excluding abolishment costs) to AGN's proposal. We also show the forecasts we approved for the last three access arrangement periods and AGN's actual and estimated opex.

Figure 10 AGN's historical and forecast opex ($million, 2025–26)



Source: AGN SA, *Regulatory accounts, 2011 to 2026*; AGN SA, *Attachment 8.1_Opex Forecast Model,* 1 July *2025*; AGN SA, *Attachment 8.1A_Revised Final Plan Opex Forecast Model*, January 2026; AGN SA, *Access arrangement, PTRM* (multiple periods: 2011–16, 2016–21, 2021–26); AER analysis.
Note: Includes debt raising costs and movements in provisions.

We discuss the reasons for our alternative estimate of total opex forecast in more detail in Attachment 3.

3.6 Revenue adjustments

Our calculation of total revenue for AGN includes adjustments under the opex ECM and CESS in its access arrangement. These mechanisms provide a continuous incentive for AGN to pursue efficiency improvements in opex and capex and provide for a fair sharing of these between AGN and users.

3.6.1 Capital Expenditure Sharing Scheme (CESS)

Our final decision is to apply a CESS revenue increment of $16.78 million ($2025–26) across the 2026–31 access arrangement period. This CESS revenue increment is calculated using the CESS from the 2021–26 access arrangement period and the corresponding CESS carryover true-up for 2020. It is $0.15 million larger than AGN's forecast CESS revenue increment of $16.62 million ($2025–26).

The difference between our calculations and AGN's revised proposal is due to an update to the capex inputs to reflect actual expenditure, more recent inflation figures and an update to weighted average cost of capital (WACC) input information.[48] Table 6 outlines AGN's proposal and our final decision.

Table 6 Our final decision on AGN's CESS increments ($ million, $2025–26)

	2026–27	2027–28	2028–29	2029–30	2030–31	Total
AGN's proposed CESS increment	3.32	3.32	3.32	3.32	3.32	16.62
AER final decision increment	3.36	3.36	3.36	3.36	3.36	16.78

Source: AGN SA, *Attachment 9.8A Revised Final Plan Capex Forecast Model*, January 2026; AER analysis.
Note; Numbers may not add up due to rounding.

We are otherwise satisfied that AGN's application of the CESS is appropriate, and consistent with the CESS mechanism set out in its access arrangement.

In our draft decision, we set out for AGN to:[49]

- include a tiered sharing factor in its access arrangement
- update its proposed access arrangement in its revised proposal to incorporate voluntary changes in accordance with the CESS guideline mechanism
- provide updated asset performance index targets in its revised proposal with associated calculations and analysis, consistent with its approach for the current period.

AGN responded to our draft decision and we have accepted AGN's proposal to apply the CESS in the 2026–31 period, including the tiered sharing factor and updated asset performance index targets.[50]

However, AGN's CESS provisions in the access arrangement do not reflect the voluntary changes in accordance with the CESS guideline mechanism we requested in the draft decision. We require AGN to make a revision to its access arrangement to incorporate the ability to voluntarily reduce any CESS reward and increase any CESS penalty.

To ensure lower capex does not compromise service standards, the reward amounts are modified by a contingent payment factor. If service standards fall below target levels, reward amounts are reduced. Below a certain service standard threshold, rewards are reduced to 0. Conversely, the CESS will lead to a penalty if the network service provider spends above its approved capex forecast. The contingent payment factor does not apply to penalties, so if a penalty is incurred, it will not be reduced.

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48 AER, *AGN access arrangement 2026-31 – Final Decision – CESS Model*, May 2026.

49 AER*, Draft decision - AGN (SA) access arrangement 2026–31 – CESS Attachment 6*, November 2025, pp. 4–7.

50 See section 5.2 of AGN's 2026–31 Access Arrangement; AGN SA, *Attachment 9.8A Revised Final Plan Capex Forecast Model*, January 2026, and AGN SA, *Attachment 12.3 Response to Draft Decision on Incentives*, January 2026.

The contingent payment factor is used to scale down rewards if service performance is less than the target level.[51] As seen in Table 7, owing to strong performance against its most heavily weighted targets, AGN has an asset performance index of 124.27, leading to a contingent payment factor of 100. This means AGN will receive 100% of its revenue increment as a reward.

Table 7 AGN's reported performance and contingent payment factor

Measures	Actual	Target	Index	Weight	Contribution
Unplanned SAIFI	0.58	0.59	101.13	25.00%	25.28
Unplanned SAIDI	390.14	307.04	72.94	25.00%	18.23
Mains leaks	0.04	0.11	164.30	42.40%	69.66
Services leaks	1.79	3.76	152.40	4.90%	7.47
Meter leaks	8.14	12.35	134.10	2.70%	3.62
Asset performance index	124.27				
Contingent payment factor	100%				

Source: AER, *AGN access arrangement 2026-31 – Final Decision – CESS Model*, May 2026.

3.6.2 Efficiency Carryover Mechanism (ECM)

We have included carryover amounts totalling –$8.9 million ($2025–26), from the application of the ECM in the 2021–26 period. This is $0.2 million higher than AGN's revised proposal of –$9.0 million (that is, a slightly smaller decrement).[52] The differences are due to:

- excluding actual and forecast ancillary reference services for 2019–20 and 2020–21, which increased carryover amounts by $0.5 million
- updating for the latest inflation amounts, which decreased carryover amounts by $0.1 million
- updating 2024–25 actual unaccounted for gas expenditure, based on AGN's reported 2024–25 Regulatory information notice, which decreased carryover amounts by $0.1 million
- updating AGN's forecast allowances for the 2016–21 and 2021–26 periods, according to the respective period's latest PTRM update, which decreased carryover amounts by $0.1 million.

We have also approved AGN's revised proposal that we continue to apply the ECM in the 2026–31 period.

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51 AER, *Draft decision - AGN (SA) access arrangement 2026–31 - Attachment 6 - Capital expenditure sharing scheme*, November 2025, p. 2.

52 AGN SA, *2026–31 Final Plan*, 01 July 2025, p. 123.

We discuss our assessment of AGN's ECM in further detail in Attachment 7 of the draft decision.

3.7 Corporate income tax

Our determination of the total revenue requirement includes the estimated cost of corporate income tax for the 2026–31 period. Under the post-tax framework, this amount is calculated as part of the building blocks assessment using our PTRM. Our adjustments to the return on capital (sections 3.1, 3.2 and 3.4) and the regulatory depreciation (section 3.3) building blocks affect revenues, which in turn impacts the tax calculation.

Our final decision determines an estimated cost of corporate income tax amount of zero for AGN over the 2026–31 period, consistent with AGN's revised proposal. This is because we expect AGN to incur a forecast tax loss in each year of the 2026–31 period.[53] We have determined that $108.7 million in tax losses as at 30 June 2031 will be carried forward to the 2031–36 period where it can be used to offset future tax liabilities. The forecast tax loss arises mainly because of the carry forward of AGN's accumulated tax losses at 30 June 2026.

The reasons for our final decision on AGN's corporate income tax are discussed in Attachment 1 of this final decision.

[53] A forecast tax loss occurs when the forecast taxable income is lower than the forecast tax expense. In this event no tax is payable. Any residual amount of tax loss will be carried forward over to access arrangement periods to offset future taxable income until the tax loss is fully exhausted.

4 Forecast demand

Forecast demand plays an important role in AGN's access arrangement:

- demand is an input into the derivation of AGN's reference tariffs in its access arrangement. In simple terms, tariffs are determined by dividing cost (forecast revenue) by total demand. This means that a decrease in forecast demand leads to an increase in tariffs, and vice versa.
- forecast demand is also a driver of opex and capex, which inform our decision on the total revenue requirement.

The NGR require forecasts and estimates (including the demand forecast) to be arrived at on a reasonable basis and to represent the best forecast or estimate possible in the circumstances.[54]

Our final decision accepts AGN's revised proposal demand forecast which reflects updated inputs and methodological changes by AGN's consultant, Core Energy, in response to our draft decision. While AGN's overall demand forecast remains consistent with AEMO's GSOO forecasts, higher forecast demand over the 2026–31 period will benefit customers through lower gas transportation reference tariffs.

AGN's revised proposal indicated it accepted our draft decision and updated its forecasts to reflect the findings of our consultant, Frontier Economics. Compared to its initial proposal, AGN's revised proposal demand forecast incorporated 2,284TJ (or 8.6%) higher demand for residential customers and 523TJ (or 3.4%) higher demand for commercial customers.[55] Both outcomes are driven by higher forecasts of gas consumption per connection. For industrial customers, AGN's revised proposal incorporates higher Minimum Delivery Quantity (MDQ) (0.3%), driven by forecast stronger growth for some large customers.

AGN's revised demand forecasts are higher than its initial proposal despite incorporating fewer new connections due to the introduction of upfront connection charges, arising from the AEMC's December 2025 final determination of its Connections rule change.[56] We further discuss the impact of the AEMC's final rule in section 3.4 (Capital expenditure) of this Overview and in Attachment 2 (Capital expenditure) of our final decision.

While AGN's revised 2026–31 proposal demand forecasts are higher than its initial proposal, AGN continues to forecast ongoing declines in gas demand and in per connection gas consumption across all customer categories. From 2026–27 to 2030–31, AGN expects average per connection:[57]

- residential consumption to decline from 13.5 TJ to 10.7 TJ

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54 NGR r 74.

55 AGN, *Revised final plan – attachment 13.4 – Response to draft decision on demand*, January 2026, p.7.

56 AEMC, *National gas amendment (Updating the regulatory framework for gas connections) rule 2025*, December 2025.

57 AGN, *Revised final plan – attachment 13.4 – Response to draft decision on demand*, January 2026, p.7.

- commercial consumption to decline from 286 GJ to 264 GJ
- industrial consumption to decline from 50,527 MDQ (TJ) to 47,563 MDQ (TJ).

AGN also now forecasts declining numbers of connections across all customer categories, including residential customer connections. From 2026–27 to 2030–31, AGN expects residential connections to decline by 2.6%, commercial connections by 0.3% and industrial connections by 7.6%.[58]

[58] AGN, *Revised final plan – attachment 13.4 – Response to draft decision on demand*, January 2026, p.7.

5 Reference services and tariffs

AGN's access arrangement specifies the reference service it will provide, the tariffs for those services, and the other terms and conditions on which the services will be provided.[59]

5.1 Services covered by the access arrangement

Determining a service to be a reference service, as compared to it being a non-reference service, makes a significant difference to how the service is regulated. Reference services are subject to our determined maximum prices, or price caps.

Services we determine to be non-reference services are not subject to price regulation, so gas networks set their own charges for non-reference services. We may be called upon to determine the tariff and other conditions of access to non-reference services if an access dispute arises.[60]

Our final decision is to accept AGN's proposed reference services consistent with our November 2024 decision on its 2026−31 reference service proposal.[61]

5.2 Reference tariff setting and variation mechanism

This section first discusses the tariff structures and tariff variation mechanism proposed by AGN for haulage (gas transportation) reference services, then for ancillary reference services, as well as covering the cost pass through mechanism.

Our final decision is to accept AGN's revised reference tariff setting proposal with amendments to:

- reduce the proposed full abolishment cost from AGN's proposed $1,250 to $1,000 for 2026–27
- set a partially socialised abolishment tariff for small scale abolishments at a price of $257 for 2026–27 (the difference between the $257 charge and the $1,000 cost is the socialised amount, $743, accounted for in opex and recovered in transportation tariffs, see section 3.5)

Our final decision is to accept AGN's revised proposal for a weighted average price cap hybrid tariff variation mechanism for gas transportation services, with a 5% revenue sharing threshold. Our final decision is consistent with our draft decision in accepting AGN's proposal to escalate ancillary reference tariffs annually by CPI.

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59 NGR, r. 48(1).

60 NGL, Chapter 5.

61 AER, *AGN (SA) 2026-31 Access Arrangement – Reference service proposal – Final decision,* November 2024.

5.2.1 Gas transportation (haulage) reference services – tariff structures

AGN's revised proposal includes the following changes that respond to our draft decision:

- residential tariffs with a 2-block structure (rather than AGN's initially proposed 3-blocks)
- commercial tariffs (small volume) with a 3-block structure (rather than AGN's initially proposed 4-blocks)

We accept AGN's proposed reference tariff structures. We consider that the revised proposal tariff structures sufficiently reflect the revised NGO and respond to the draft decision requirements, including in considering customer bill impacts.

We consider AGN's revised proposal for residential tariffs of a 2-block structure is in line with the draft decision requirement for flatter tariff structures. We consider declining block structures promote the use of gas. The flatter structures represent movement away from the declining block structure, better contributing to the achievement of the emissions reduction element of the NGO, and have not materially changed customer bill impacts.

We accept AGN's revised proposal for commercial tariffs (small volume) that partially accepted the draft decision by reducing these tariffs to an effective 3-block structure. We accept AGN's explanation, which was supported by customer bill impact modelling, that this is the best approach in the 2026–31 period for commercial tariffs, because further flattening to a 2-block structure could result in an unreasonable redistribution of costs between customers.

Our final decision considered the submissions we received. The SARG supported AGN's changes to residential and small business tariff structures, and the SACOSS supported the move towards flatter tariffs.[62] We note that the Energy and Water Ombudsman South Australia (EWOSA) and CCP33 cautioned that transitioning towards flatter tariffs too fast could cause adverse customer impacts.[63]

The SA Business Chamber submitted that the gas consumption of many large commercial and industrial businesses reflects their operational needs rather than any choice and that many of these businesses operate in hard to abate sectors where there is no technical or commercially viable alternative at this stage.[64] We consider AGN's revised proposal has adequately addressed these concerns and balanced customer impacts with the emissions reduction aspect of the NGO.

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62 SARG Review Panel, *Submission on AER's Draft Decision and AGN(SA) 2026-31 Access Arrangement Revised Proposal,* February 2026; SACOSS, *Submission on AER's Draft Decision and AGN(SA) 2026-31 Access Arrangement Revised Proposal*, February 2026.

63 EWOSA, *Submission on AER's Draft Decision and AGN(SA) 2026-31 Access Arrangement Revised Proposal*, February 2026; CCP33, *Advice to the AER - AGN(SA)'s 2026–31 revised proposal and draft decision*, February 2026.

64 South Australian Business Chamber, *Submission on AER's Draft Decision and AGN(SA) 2026-31 Access Arrangement Revised Proposal*, February 2026.

5.2.2 Ancillary reference services – tariff structures

AGN's initial proposal proposed a socialised abolishment tariff which our draft decision approved as a placeholder for our consideration in a final decision. In anticipation of the AEMC's abolishment rule change, AGN's revised proposal varied its initial proposal to include a single full cost abolishment tariff instead.

While acknowledging AGN's revised proposal, our final decision sets a partially socialised tariff of $257 for abolishments. However, unlike our draft decision, our final decision accepts the same tariff treatment for all abolishments, including for knockdown rebuilds and renovations. The final decision also amends the full cost of the abolishment service to $1,000.

The South Australian Office of the Technical Regulator (OTR) submitted that it supported a wholly ($zero) or partially socialised abolishment tariff on safety grounds for all abolishments. The OTR submitted that abolishing a connection is the safest approach where gas is no longer used at that connection. The OTR noted there are around 4,000 dormant connections in SA and there were 112 safety incidents specific to dormant connections over 2023 and 2024.[65]

While we acknowledge the SARG submission in support of AGN's proposed full cost recovery tariffs for abolishments[66], and the Energy and Water Ombudsman SA's preference for the abolishment tariff to reflect the AEMC's rule change (discussed below)[67], our final decision reflects the safety concerns raised by the OTR. This is consistent with AER decisions on NSW, Victorian and ACT distributors' abolishment tariffs, in placing weight on the advice of technical / safety regulators. The non-socialised portion of $257 also aligns with the $220 we approved for Victorian distributors in 2023 and $250 we approved for Jemena Gas Networks (JGN) in 2025. We acknowledge also SACOSS' submission that a $1,250 abolishment tariff for AGN would present a significant barrier to electrification for low income/low health households.[68]

We note too that our final decision on AGN's abolishment tariff differs from our decision on JGN's 2025—30 access arrangement, for which we required JGN to set a cost reflective abolishment tariff for knock down rebuilds. JGN already had an abolishment reference service and reference tariff, unlike AGN. For AGN, we accept that its differing starting point makes a material difference to what it can reasonably be expected to deliver for the 2026—

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65 The Office of the Technical Regulator - Submission on AER's Draft Decision and AGN(SA) 2026-31 Access Arrangement Revised Proposal - February 2026, pp. 3-5.

66 SARG Review Panel - *Submission on AER's Draft Decision and AGN(SA) 2026-31 Access Arrangement Revised Proposal* - February 2026.

67 Energy & Water Ombudsman SA, *Submission on AER's Draft Decision and AGN(SA) 2026-31 Access Arrangement Revised Proposal* - February 2026. CCP33 - *Advice to the AER - AGN(SA)'s 2026–31 revised proposal and draft decision* - February 2026.

68 SACOSS - *Submission on AER's Draft Decision and AGN(SA) 2026-31 Access Arrangement Revised Proposal* - February 2026.

31 period. A number of submissions noted the practical difficulties of implementing a separate tariff.[69]

We consider that the proposed total cost of $1,250 for the abolishment service is not in line with the comparable cost build-up of other distributors (around $1,000 on average). Consistent with the NGR r.91 requirement that opex be such as would be incurred by a prudent service provider, we consider that a benchmark reduction of 20% is appropriate to lower the price to $1,000. Setting the abolishment cost at $1,000 in 2026–27 and the partially socialised abolishment tariff at $257 results in lowering the socialised cost amount to $743. The socialised amount is accounted for in operational expenditure.

We note that the AEMC published its final rule determination, *Establishing a regulatory framework for retail customer initiated gas abolishment,* on 2 April 2026. The rule establishes a new regulatory framework for disconnections and abolishment that will require abolishment services to be charged at full cost by the gas distributor. Importantly, this rule change provides for phased implementation from 2027 and obligations for AGN will not commence until the start of its 2031–36 period.

In reaching our decision to partially socialise AGN's abolishment tariff for the 2026—31 period, we have accounted for the risk of confusing consumers by establishing what will in-effect be an interim partially socialised tariff. In doing so we have reflected on the need to give the OTR and South Australian Government time to consider whether any policy interventions may be warranted before the AEMC's mandated cost-reflective abolishment tariffs will be implemented from 1 July 2031.

5.2.3 Tariff variation mechanism

AGN's revised proposal adopted the 5% revenue sharing threshold set out in our draft decision and we are satisfied with its weighted average price cap hybrid tariff variation mechanism for transportation reference services.

We consider a hybrid tariff variation mechanism, incorporating elements of both price cap and revenue cap regulation, better reflects the changed regulatory context for provision of gas transportation reference services than a pure weighted average price cap or a revenue cap. A hybrid tariff variation mechanism reduces the incentive for AGN to grow gas demand (better aligning with emissions reduction element of the NGO than a price cap), while mitigating potential tariff year-on-year volatility (which can be a feature of revenue cap regulation).

A hybrid tariff variation mechanism manages the risk of tariff volatility (a risk under a revenue cap) by limiting revenue true-ups to instances when actual volumes are (as per the final decision) more than 5% higher (or lower) than targets. Also, a hybrid mechanism splits 50:50 the revenues associated with actual volumes being outside the 5% upper and lower volume

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69 The Office of the Technical Regulator - *Submission on AER's Draft Decision and AGN(SA) 2026-31 Access Arrangement Revised Proposal* - February 2026. CCP33 - *Advice to the AER - AGN(SA)'s 2026–31 revised proposal and draft decision* - February 2026. SAFRRA Inc. - *Submission on AER's Draft Decision and AGN(SA) 2026-31 Access Arrangement Revised Proposal* - February 2026.

boundaries. This means customers and AGN alike would only be impacted by half of any changes above or below the 5% volume boundaries.

We received no submissions on AGN's hybrid tariff variation mechanism for transportation reference services.

5.2.4 Cost pass through mechanism

Consistent with our draft decision, our final decision is to accept AGN's revised proposal that the cost pass through events available to it in the current period will continue to apply in the 2026–31 period. AGN's revised proposal adopted our definition of cost pass through events as set out in our draft decision.[70]

5.3 Non-tariff components

In addition to its total revenue requirement, demand forecast and resultant tariffs, our decision on AGN's proposed access arrangement includes an assessment of a range of non-tariff components that go to the commercial relationships between AGN and its retailers and other network users. AGN engaged with its stakeholders in developing its 2026–31 proposal, including engagement on its non-tariff components.

In our draft decision, we approved the non-tariff components of AGN's access arrangement for the 2026–31 period. However, encouraged AGN to continue engaging with users on elements of its terms and conditions for its revised proposal.[71]

AGN's submitted revised terms and conditions following feedback from one retailer. We have reviewed the updated revisions provided and consider these reasonable and note, we did not receive any submissions on our draft decision, or on AGN's revised proposal in relation to the non-tariff components.

Our final decision maintains our draft decision to approve AGN's non-tariff components and would encourage AGN's ongoing commitment to continue consulting with users over the next period.[72]

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71 AER, *Draft decision - AGN (SA) access arrangement 2026–31 - Attachment 5 - Reference services, tariffs and non-tariff components*, November 2025, pp. 28-36

72 AGN SA, *Attachment 15.3 Response to Draft Decision on Network Access*, January 2026, p, 2.

6 Revision

We require the following revision to make the access arrangement proposal acceptable as set out in Table 8.

Table 8 CESS revision

Revision	Amendments
Revision 6.1	Amend Section 5.2 Capital Expenditure Sharing Scheme to incorporate voluntary changes to the CESS reward or penalty as described in the updated CESS guidelines.

List of submissions

We received 8 submissions in response to our draft decision and AGN's revised proposal.[73]

Table 9 Submissions received on draft decision and revised proposal

Submission
CCP33
Energy Consumers Australia
Energy & Water Ombudsman South Australia
SAFFRA Inc
South Australia Council of Social Services
South Australian Office of the Technical Regulator
South Australian Business Chamber
South Australia Reference Group Review Panel

[73] Submissions are available on the AER website.

Glossary

Term	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGN	Australian Gas Networks Limited (SA)
APA	Australian Pipeline Limited
capex	capital expenditure
CCP33	Consumer Challenge Panel, sub-panel 33
CESS	Capital Expenditure Sharing Scheme
CPI	consumer price index
ECA	Energy Consumers Australia
ECM	Efficiency Mechanism Carryover
ICT	information and communication technology
NGO	National Gas Objective
NGL	National Gas Law
NGR	National Gas Rules
opex	operating expenditure
PTRM	Post tax revenue model
RBA	Reserve Bank of Australia
RFM	roll forward model
RORI	Rate of Return Instrument
RRG	Retailer Reference Group
SACOSS	South Australian Council of Social Service
SARG	South Australian Reference Group
SoMP	Statement on Monetary Policy
WACC	weighted average cost of capital