Attachment 9.13

Response to Draft Decision on Capital Expenditure

Revised Final Plan 2026/27 – 2030/31
January 2026

PUBLIC

Australian Gas Networks

1. Response to Draft Decision on Capital Expenditure

We are forecasting $446.7 million of gross capex (or $337.2 million net of customer contribution connections) for our SA network in the next AA period. This capital investment is essential to maintain our strong track record in network safety, reliability and customer service.

1.1. Overview

This attachment sets out our response to the AER's Draft Decision on capital expenditure (capex) for our SA gas distribution network over the next (2026/27 to 2030/31) Access Arrangement (AA) period. The AER in its final decision allowed $428 million over the next AA period. In comparison our revised gross capex forecast of $446.7 million is $18.7 million (4%) higher than the AER's Draft Decision, or $56.3 million (11%) lower than the Final Plan.

We have included our original forecast expenditure for meter change and revised IT transition costs. In addition, we have adjusted our connection forecast down to reflect that with the introduction of the AEMC rule change we expect a reduction in connection numbers. We have also made an allowance for the impact of the AEMC's connection rule change, resulting in an estimated customer contribution towards growth connections expenditure of $109.5 million.

On a net perspective after deducting contributions pursuant to the AEMC's connections rule change, we propose to invest $337.2 million capex, which is $90.8 million (or 21%) lower than the AER's Draft Decision, and $165.8 million (or 33%) lower than our Final Plan.

In its Draft Decision, the AER modified our capex forecast as follows:

- included a placeholder amount of zero for the IT Transition and Cyber Security business cases pending some clarifications in our response;
- reduced our domestic meter replacement forecast by lowering the forecast volume to the estimated volume for the current 2021-2026 AA period;
- removed digital metering that we proposed for inaccessible sites; and

  reduced capitalised overheads following the lower AER's alternative capex estimates.

The AER accepted the remainder of our capex forecast across the other categories.

We are responding to the areas which were not accepted in the AER's Draft Decision by:

- demonstrating that the preferred option in the IT Transition business case (Lift/Shift & Merge) is the most prudent and efficient option for Australian Gas Networks (AGN) customers and providing evidence that the costs relate only to AGN;
- maintaining our Final Plan position to uplift cyber security at $1.5 million and demonstrating why this level of cyber security is necessary given the current IT threat environment;
- re-proposing $28.0 million for domestic meter replacement and responding to some concerns around the data presented in our Final Plan;
- retaining the digital metering program for inaccessible or unsafe sites and explain the measures taken in the past to attempt to remain compliant with our regulatory obligations;

- removed new connections capex from the forecast regulatory asset base as per the Australian Energy Market Commission's (AEMC) connections rule change which will come into effect in October 2027; and
- modifying the capitalised overheads.

Additionally, we have refreshed the inflation forecast, with 2025/26 CPI being updated from 3.0% to 3.3%, based on the latest available RBA Statement on Monetary Policy. We have revised real cost escalation by removing the construction industry in our labour price growth forecasts, following the AER's Draft Decision.

The key aspects of the Draft Decision that we are responding to are:

1.1.1. IT Transition

The original commencement date for the IT transition project was brought forward by 19 months to 1 December 2025, and we have updated the forecast accordingly. We have taken the opportunity to refine the forecast for the IT transition project by providing additional substantive information to support the prudency and efficiency of the preferred option and associated cost estimates. As the transition has now commenced, we are in a position to refine the original forecast with updated estimates of effort for each phase of the transition and of labour rates actually being paid to vendors after a competitive tender process. This enables us to respond to the AER's concerns in respect of the labour rates used in the Final Plan forecast.

In its Draft Decision, the AER also sought further information on the options considered (i.e. Lift/Shift and Merge versus Lift/Shift) and the costs assumptions underlying each. Our revised Final Plan also demonstrates that the Lift, Shift and Merge option is the more prudent and efficient option based on cost and risk.

We have also addressed the AER's concerns around the allocation of these costs to AGN. We demonstrate that we are only seeking recovery of costs that relate to AGN and allow us to provide gas distribution (haulage) services to AGN SA network customers. We provide detailed information on:

- the group of companies known as AGIG and its relationship to AGN;
- the IT environment across AGIG and how it relates to AGN; and
- our approach to allocating shared costs between the AGIG entities, and between AGN's networks.

1.1.2. AEMC Rule Change

In light of the AEMC's final determination for *Updating the regulatory framework for gas connections*, which requires gas network distributors to charge a cost-reflective, upfront connection fee on newly connecting retail gas customers from October 2026[1], we've modified our growth capex including mains and services reticulation and meters installation, by removing them from the forecast regulatory asset base. Core Energy has also forecasted a lower number of gross connections due to the impact of the rule change.

Table 1.1 provides an overview comparing our Revised Final Plan capex forecast to the AER's Draft Decision and our Final Plan for the 2026-2031 AA period. The reduction in growth capex

[1] AEMC Rule determination 11 December 2025 - National Gas Amendment (Updating the regulatory framework for gas connections) Rule 2025

flowing from the AEMC's rule change reflects the estimated impact of reduced connections as a result of the upfront charge. The estimated revenue impact of customers choosing to pay the upfront charge is reflected through "Customer contribution connections" which offset the gross capex.

1.1.3. Metering

We are responding to some questions the AER raised in its Draft Decision including providing further information on some data queries and in relation to the increased periodic meter change forecast in the next AA period. We are also responding to the AER's concerns around a safety driven digital meter forecast for inaccessible properties.

1.1.4. Cyber Security

We are responding to some concerns raised by the AER in relation to our cyber security program.

Further details of our response can be found in Section 1.4 below.

Table 1.1: Comparison of our Revised Final Plan capex forecast for the 2026- 31 AA with the AER's Draft Decision and our Final Plan ($ million, 2025/26)

Capex forecast for AA 2026-31	Final Plan	AER Draft Decision	Revised Final Plan	Variance to Draft Decision
Mains Replacement	84.9	84.9	85.5	0.6
Meter Replacement	38.4	28.0	38.5	10.5
Augmentation	6.4	6.4	6.4	-
Telemetry	3.8	3.8	3.8	-
IT system	92.3	28.8	73.0	44.2
Growth	155.0	155.0	117.7	-37.3
Other distribution system assets	91.9	91.9	92.2	0.3
Other non-distribution system assets	7.7	7.7	7.7	-
Capitalised overheads	22.6	21.6	21.9	0.3
Gross Total	**503.0**	**428.0**	**446.7**	**18.7**
Customer contribution connections[2]	-	-	-109.5[3]	-109.5
Disposals	-	-	-	-
Net Total	**503.0**	**428.0**	**337.2**	**-90.8**

1.1.5. Capex forecast for 2021 – 2026

We have invested $439.8 million ($2025/26) of capex during the current AA period up to June 2025 and are forecasting to invest a further $128.6 million, totalling $568.4 million by the end of the period.

Our projected spend of $568.4 million in the current AA period represents an increase of $20.0 million compared to our Final Plan estimate which was included in the capital base as part of the AER's Draft Decision. The main drivers to the higher capex forecast are:

[2] Customer contribution connections relate to growth capex and have been removed from gross capex in accordance with the AEMC's final rule change. Contributions disaggregated by capex driver category are provided in Attachment 9.8A (Revised Final Plan capex model)

[3] In our Revised Final Plan, customer contribution connections of $109.5 million include overheads of $5.6 million. Accordingly, our net capitalised overheads (excluding customer contribution overheads) are $16.2 million.

- Updated 2024/25 actuals: $12.1 million less than our Final Plan forecast, reflecting lower mains replacement volumes, partially offset by higher inlet volumes due to stronger-than-expected new residential connections in brownfield areas; and
- Updated 2025/26 forecast: $30.8 million higher than the Final Plan forecast, reflecting increased IT capex and Other non-distribution system capex following the updated timing of the transition, with Lift & Shift commencing on 1 December 2025.

Table 1.2 provides an overview comparing our Revised Final Plan net capex forecast (excluding capital contributions) for the current AA period with the AER's Draft Decision and our Final Plan.

Table 1.2: Comparison of our Revised Final Plan capex forecast (net of capital contributions) for the 2021-26 AA with the AER's Draft Decision and our Final Plan ($ million, 2025/26)

Capex forecast for AA 2021-26	Final Plan	Draft Decision	Revised Final Plan	Variance to Draft Decision
Mains Replacement	223.5	223.5	199.4	-24.1
Meter Replacement	21.1	21.1	19.6	-1.5
Augmentation	10.1	10.1	8.7	-1.4
Telemetry	2.0	2.0	2.1	0.1
IT system	38.9	38.9	67.1	28.2
Growth	133.5	133.5	139.4	5.9
Other distribution system assets	56.7	56.7	61.1	4.4
Other non-distribution system assets	5.8	5.8	10.1	4.3
Capitalised overheads	56.9	56.9	60.9	4.0
Net Capex (excluding capital contributions)	**548.4**	**548.4**	**568.4**	**20.0**

1.2. Stakeholder and customer feedback

In preparing the revised Final Plan we have continued to engage with stakeholders, including our South Australian Reference Group (SARG) and Retailer Reference Group (RRG).

A summary of the feedback provided on our capex is provided in Table 1.3 below.

Table 1.3 Summary of customer and stakeholder feedback

Customer and Stakeholder Feedback	Our Response
On our mains replacement and other network capex: • Energy Consumers Australia (ECA) submitted that AGN's proposed mains replacement and other network costs should be brought to zero or minimised where practicable except where safety overwhelmingly requires replacement or other costs now.[4]	• We consider our network capex including mains replacement program reflects reasonable expenditure that a prudent asset manager should incur to address the safety and reliability of the network. This capex was also accepted by AER.
On our metering replacement capex: • ECA recommended limiting meter replacement to end-of-life obligations under the Gas Metering Code, reducing the metering allowance below the current period, and requiring AGN to demonstrate costs under a compliance-only, strictly necessary meter replacement approach.[5]	• We do not agree that meter replacement should be limited solely to end-of-life obligations under the Gas Metering Code. A compliance-only approach focused narrowly on technical end-of-life criteria would not address broader safety, billing accuracy and customer protection obligations, including the requirement to support annual actual meter reads and manage risks at inaccessible or hazardous sites. • The proposed metering replacement program reflects the minimum level of expenditure necessary to meet AGN's regulatory, safety and service integrity obligations. Limiting replacements to a strictly end-of-life basis would perpetuate known compliance and safety risks, rely on prolonged estimated reads, and be inconsistent with prudent and efficient network operation, particularly given the availability of reasonably practicable alternatives such as digital metering.

[4] Energy Consumers Australia – Submission on AGN(SA) 2026–31 Access Arrangement Proposal – August 2025, p. 9.
[5] ECA, ibid, p. 9.

Customer and Stakeholder Feedback	Our Response
On our IT expenditure: • ECA and the SARG noted that our proposed ICT expenditure is a large uplift from the current period and recommended that the AER closely review the implementation plan given the many examples of network overspend on ICT in recent years.[6]	• We acknowledge this is an increase in IT expenditure compared with history, with the IT Transition capex the major cost driver. Historical costs reflect the costs according to the long-term O&M contract with APA which has come to an end. The IT environment must be transitioned from APA's IT environment regardless of where it is transitioned to – the transition is unavoidable. We have conducted an extensive tender process to derive the best possible market rates and have recommended the Lift, Shift and Merge option which will deliver synergies in the long-term, which is in the best interests of our customers.
On our Growth capex: • Stakeholders shared concern that new connection capex will create stranded asset risks amid falling demand and policy uncertainty, noting its treatment will be influenced by the AEMC's rule change on Updating the regulatory framework for gas connections, which requires newly connecting customers to pay upfront connection costs rather than socialising and recovering the costs from existing customers. • Consumer Challenge Panel (CCP) Sub-Panel 33 expected AGN to remove growth capex from the proposal, and to update the demand forecasts, customer numbers and implications on opex, if the AEMC gas connection rule change takes effect at the start of the next AA period.[7] • SARG noted if the AGN methodology of calculating the connection costs is adopted by the AEMC[8], then connection charges of $120m would be paid covering service pipes and meters. The mains expenditure of $37m would be rolled into the RAB and be subject to the Economic Feasibility Test.[9]	• The AEMC Rule change final determination on 11 December 2025 requires gas network distributors to charge newly connecting retail gas customers cost-reflective connection charges upfront from 1 October 2026. We've updated our demand forecast to reflect the associated impact on gas service demand and connection volumes. • For the connection related capex including mains and services reticulation and meters installation, we will no longer add them to the regulatory asset base and recover through network tariffs. Our detailed treatment of connection capex is set out in Section 1.4.1 of this paper.

[6] ECA, ibid p. 9 and SARG Review Panel – Submission on AGN(SA) 2026–31 Access Arrangement Proposal – August 2025, pp. 6–7
7 CCP33 Advice to AER on Australian Gas Networks South Australia Access Arrangement Proposal 2026-31 (Final Plan July 2025), p.29.
8 https://www.aemc.gov.au/sites/default/files/2025-07/20.%20Australian%20Gas%20Infrastructure%20Group%20GRC0085%20CP%20Submission.pdf
9 SARG, as above, pp. 28-29

Customer and Stakeholder Feedback	Our Response
On our renewable gas adaption capex: • There were concerns about the future of hydrogen as a future natural gas replacement commonly raised by the South Australian Council of Social Services, SARG, ECA and the Energy and Water Ombudsman SA. • SARG and ECA do not support customers paying for renewable gas projects to help the network prepare for hydrogen.[10]	• Our renewable gas adaptation capex is largely readiness investments such as weld procedure and hardness testing, incompatible parts replacement and pipeline repair equipment. As the AER has accepted this investment, we have made no further modifications.

1.3. AER Draft Decision

1.3.1. Actual and forecast capex in the current AA period

The AER accepted AGN's actual capex for the 2021/22–2023/24 period as conforming capex and has included our estimated capex for 2024/25 and 2025/26 in the capital base as a placeholder. The AER will assess whether AGN's actual capex in 2024/25 is conforming capex in the Final Decision and the 2025/26 forecast will be trued up in its next decision in five years' time.

1.3.2. Forecast capex for the next AA period

In its Draft Decision the AER has approved conforming net capex of $428.0 million ($2025/26), representing a reduction of $74.9 million (14.9%) from the $503.0 million proposed in our Final Plan. This reduction primarily reflects that the AER did not accept AGN's proposed IT expenditure ($63.5 million reduction) and meter replacement ($10.4 million reduction).

In particular, the AER has formed an alternative view of conforming capex for the IT and metering capex categories by:

- including a placeholder of zero dollars for the IT transition project and Cyber Security business cases, while providing AGN with an opportunity to demonstrate the prudency and efficiency of the proposed option and expenditure;
- reducing domestic meter replacement volumes thereby reducing the associated capex, and removing digital metering for inaccessible sites; and
- reducing capitalised overheads to reflect the lower level of capex resulting from the AER's alternative estimates above.

The AER has accepted the $155.0 million forecast connection costs for the purposes of the Draft Decision but expects AGN to remove these costs in the Revised Proposal, in line with the AEMC's final rule decision. The AER also expects AGN to update the demand forecast to reflect the impact of upfront customer connection charges, which will reduce the number of forecast new connections.

The AER's Draft Decision in respect of our capex forecast by capex category for the next AA period is further summarised in Table 1.4 below.

10 SARG, as above, p. 6 and ECA, as above, pp. 3-4.

Table 1.4: Summary of the AER's Draft Decision on our forecast capex proposal for next AA period ($ million, 2025/26)

	AER Draft Decision	AER Comment
Mains Replacement	Accept	Accepted $84.9 million for our proposed mains replacement capex, confirming the program is reasonably required to proactively manage safety and compliance requirements, and that the proposed volumes and unit rates are reasonable.[11] Acknowledged the major phase of our two-decade long mains and services replacement program has concluded, leaving the proposed program for the next AA reduced by 61% relative to the current period, and targeting small-scale, proactive safety and compliance works including: • replacing [redacted] km of protected steel mains; • 105 km of inline camera inspections and associated reinforcement and testing • renewal and replacement of multi-user sites assets. The AER considers the program reflects reasonable expenditure for prudent asset management to address the safety and reliability of the network.
Meter Replacement	Modify	Accepted our proposed replacement program for industrial and commercial (I&C) meters. The reduction of $10.4 million (or 27%) from AGN's proposed expenditure of $38.4 million relates to[12]: • Reducing the forecast volumes of domestic meter replacements to align with estimated volumes for the current 2021–26 AA period. The AER considers the proposed volumes are likely to be overstated and requires further information on meter installation year and lifespan of meter families; • Rejecting the digital meter program for inaccessible places and for some commercial customers, noting that unread meters due to access issues affect only around 1.3% of customers and low-cost alternative reading methods are available.
Augmentation	Accept	Accepted our proposed two augmentation projects – Angle Vale in the north and Seaford and Aldinga in the south over the next AA period on the basis that the projects are in line with good industry practice to maintain the required supply pressure at the extremities of the network and the expenditure is reasonable as the lowest direct cost option was adopted.[13,]
Telemetry	Accept	Accepted our forecast capex relating to our ongoing telemetry program over the next AA period and confirmed the step up in expenditure compared to the

[11] AER, Draft Decision, Attachment 2, Table 2.4 – Mains replacement, p. 11.
[12] AER, Draft Decision, Attachment 2, Table 2.4 – Meter replacement, p. 11 and A.2, pp. 19 - 23
[13] AER, Draft Decision, Attachment 2, Table 2.4 – Mains augmentation, p. 12.

	AER Draft Decision	AER Comment
		current period is justified by reasonable drivers including:[14] • replacing Remote Terminal Units to proactively mitigate obsolescence risk; • installing additional Supervisory Control and Data Acquisition (SCADA) points and facilities, and establishing a shared 24/7 monitoring room between AGN's networks in South Australia, Victoria and Queensland are appropriate and efficient investments to enhance real-time network monitoring and manage supply and safety risks.
IT	Modify	Accepted our business-as-usual IT capex but included a zero-dollar placeholder for the IT transition and Cyber Security business cases on the following grounds:[15] • IT transition: - AGN's preferred Option 2 (Lift/Shift & Merge) shows marginal cost savings over Option 1 (Lift/Shift) over 10 years. As such, additional benefits and further information is required to demonstrate Option 2 is more prudent and efficient; - The proposed costs include general contingency risk allowances, high labour rates and hours compared to current market estimates, therefore require a detailed cost benefit assessment, supported by underlying calculations and assumptions, including clear the scope of work and project-specific analysis to substantiate the labour rates and time estimates, and risk allowance. • Cyber Security: AGN already complies with its cyber security obligations under the *Security of Critical Infrastructure (SOCI) Act*. The proposed uplift to SP-3 is not adequately justified, as it lacks economic analysis and does not demonstrate clear consumer benefits. • Cost attribution: For both the IT transition and the cyber security uplift, the AER is unclear as to whose costs AGN seeks to recover, considering that AGN hasn't clearly articulated that the costs are directly attributable to the AGN business. Further clarification of the corporate structure and cost allocation methodology (to AGN) are therefore required.
Growth	Modify	Included our proposed $155.0 million ($2025-26) direct cost for connection capex as a placeholder, expecting us to remove the forecast connection costs for the 2026–

[14] AER, Draft Decision, Attachment 2, Table 2.4 – Telemetry, pp. 12-13
[15] AER, Draft Decision, Attachment 2, Table 2.4 – ICT, pp. 9 -10 and A.1, pp. 14- 19

	AER Draft Decision	AER Comment
		31 AA revision in revised proposal,[16] in response to the Australian Energy Market Commission's (AEMC) gas connection rule change which requires gas network distributors to charge a cost-reflective, upfront connection fee on newly connecting retail gas customers. This means that from the rule change effective date onwards, connection capex will no longer be recovered from all customers. Additionally, the AER expected upfront customer connection charges to have an impact on new connections and expected us to update our demand forecast in the revised proposal.
Other distribution system assets	Accept	Accepted our proposed $91.9 million direct cost for Other network capex, and considered the proposed investments are sufficient to meet safety and compliance requirements on the network. The investments include:[17] • pipeline modifications for inline inspections; • steel pipework corrosion management; • replacement of isolation valves; and • replacement of non-compliant domestic meter sets, a front-end engineering design study to assess corrosion of the Torrens River bridge and associated pipeline structure, underground asset protection, and replacement of end of life I&C meters Additionally, the AER also accepted our proposed renewable gas readiness capex. The investments include weld procedure and hardness testing, incompatible parts replacement and pipeline repair equipment.
Other non-distribution system assets	Accept	Accepted a range of other projects to be delivered over the next AA period, including ongoing plant and equipment upgrades, vehicle replacements, and end-of-life replacement for a leak detection monitoring vehicle. The AER considered our investments are in line with historical spend and accepted industry standards for safety and more efficient emissions tracking.[18]
Capitalised overheads	Modify	Reduced our forecast overhead costs to $21.6 million, which is $1 million (or 4.4%) less than our final plan proposed, as the overheads are an allocated portion of total forecast capex, requiring a downward adjustment following the lower alternative forecast of total capex. The adjustment to capitalised overheads also reflects

[16] AER, Draft Decision, Attachment 2, Table 2.4 – Connections, p.9
[17] AER, Draft Decision, Attachment 2, Table 2.4 – Other – network, pp 10-11
[18] AER, Draft Decision, Attachment 2, Table 2.4 – Other non-network, p12

	AER Draft Decision	AER Comment
		the impact for capex categories for which overheads have been allocated.[19,]
Real cost escalation	Modify	Accepted our approach of forecasting price growth as a weighted average of forecast labour price growth and non-labour price growth. Accepted using an average of 2 forecasts for the South Australian utilities industry to forecast labour price growth—one prepared by Deloitte Access Economics (the AER's consultant) and the other by our consultant, BIS Oxford Economics. The AER also accepted applying a forecast non-labour real price growth rate of zero. However, the AER applied only Wage Price Index (WPI) growth rates for the utilities industry in its labour price growth forecast and did not include construction industry forecasts, because the distribution of natural gas through mains systems is included in the electricity, gas, water and waste services (utilities) industry, under the Australian and New Zealand standard industrial classification.[20]

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

1.4. Our Response to the Draft Decision

For the current AA period, we have updated for actual capex incurred in 2024/25 (consistent with our RIN submission) and provided an updated forecast for 2025/26 capex to reflect the updated timing and costs of the IT transition project.

In the next AA period, we propose to invest $337.2 million capex, which is $90.8 million (or 21%) lower than the AER's Draft Decision but $165.8 million (or 33%) lower than our Final Plan.

A summary of our response to the AER's Draft Decision on our forecast capex proposal for the next AA period is found in Table 1.5 below.

Table 1.5: Summary of our response to the AER's Draft Decision on our forecast capex proposal for the next AA period ($ million, 2025/26)

	AER Draft Decision	Our response	Our comment
Mains Replacement	Accept	Accept	Accept the AER's Draft Decision. We have updated our forecast of immediately expensed capital expenditure to reflect the mains replacement program less camera inspection, which reflects our expensing for tax purposes in the statutory accounts.

[19] AER, Draft Decision, Attachment 2, Table 2.4 – Overheads, pp 12.
[20] AER, Draft Decision, Attachment 3, pp 13 -15.

	AER Draft Decision	Our response	Our comment
Meter Replacement	Modify	Reject	We reject the AER's Draft Decision and re-propose $38.5 million for our meter replacement program. The revisions we make in our Revised Final Plan forecast include the following: • re-proposing $27.9 million for the replacement of domestic meters; • re-proposing $2.5 million for the digital metering; and • accepting the AER's decision of $8.0 million for the I&C Meter Replacements.
Augmentation	Accept	Accept	Accept the AER's Draft Decision.
Telemetry	Accept	Accept	Accept the AER's Draft Decision.
IT	Modify	Modify	We are providing further support to our IT forecast in response to the AER's Draft Decision by: • Proposing $42.6 million[21] for IT transition capex, reflecting an updated delivery timeframe with costs now straddling the current and next AA period; • re-propose $1.5 million of cyber security capex; and • provide clarification on the corporate structure and cost allocation methodology (to AGN). More information can be found below and in Attachments 9.14, 9.15, 9.16 and 9.17 of our Revised Final Plan.
Growth	Accept as a placeholder	Modify	We have modified our growth capex for the next AA period as follows: • We are proposing $13.9 million for connection capex, a reduction of $141 million relative to the Final Plan, reflecting the AEMC's final rule change on *Updating the regulatory framework for gas connections* which will come into effect early in the next AA period. More information can be found below and in Attachments 13.1A, 13.2A and 13.4.

[21] The $42.6 million ($Jun 2026) represents the escalated IT transition capex. For ease of reference, this corresponds to $41.0 million ($Dec 2025) un-escalated capex as quoted in our Revised Final Plan Attachment 9.14.

	AER Draft Decision	Our response	Our comment
Other distribution system assets	Accept	Accept	No changes to the AER's Draft Decision.
Other non-distribution system assets	Accept	Accept	No changes to the AER's Draft Decision.
Capitalised overheads	Modify	Modify	We have modified our forecast overhead costs to $16.2 million (excluding customer contribution overheads of $5.6 million), as the overheads are an allocated portion of total forecast capex following the lower forecast of total capex.
Escalation	Modify	Accept	We have accepted AER's Draft Decision and made the following modifications: • Removed the construction industry in our labour price growth forecasts; and • Updated our WPI forecasts to reflect the Deloitte Access Economics' latest July 2025 forecast as used by the AER in its Draft Decision

Note: In this 'traffic light' table, green shading represents the acceptance and orange represents a modification and red shading represents a rejection.

1.4.1. Growth Capex

The AEMC's final determination on *Updating the regulatory framework for gas connections* came into force on 11 December 2025, requiring gas network distributors to charge newly connecting retail gas customers cost-reflective connection charges upfront from 1 October 2026.[22] Accordingly, connection related capex including mains and services reticulation and meters installation will no longer be added to the regulatory asset base and recovered through network tariffs.

We've incorporated the forecast impacts of the rule change in our revised Final Plan, and updated our demand forecast to reflect the associated impact on new connections and total demand.[23] We have assumed a one-month lag before customer sensitivity to the change fully materialises. We forecast a reduction of approximately 6,700 new connections over the 5 years of the next AA, representing a decline of around 22%, which is a major contributor to the $37.3 million reduction in connections capex in the revised plan. We believe that this estimate is conservative and the impact of the rule on new connection volumes may in fact be more pronounced.

In our revised Final Plan, we've classified new gas connection capex as customer-contributed capital which offsets gross connection capex and is not rolled into the capital base as the costs of connection will be received from new customers.

[22] AEMC Rule determination 11 December 2025 - National Gas Amendment (Updating the regulatory framework for gas connections) Rule 2025
[23] See Attachments 13.1A and 13.2A of our Revised Final Plan.

As a result of the AEMC rule change we forecast total connection direct capex of $117.7 million over the next AA (including the originally proposed $4.9 million for trunk main reticulation in Concordia). As a result, our growth capex forecast is 24% lower than the $155 million proposed in our Final Plan.

We estimate that we will receive customer contributions of $109.5 million toward these connections. This will result in net direct connection capex of $13.9 million, which represents the Concordia trunk main and connection costs incurred up until the implementation of the AEMC rule change in October 2026.

More information, including further support for our proposed connection capex can be found in Attachment 9.8A Revised Capex model and our demand forecast. Table 1.6 below provides an overview of our net growth capex forecast for the next AA period under the Revised Final Plan, comparing against the AER's Draft Decision and the Final Plan.

Table 1.6: Comparison of our new connection capex forecast with the AER's Draft Decision ($ million, 2025/26)

Growth Assets	Final Plan	AER Draft Decision	Revised Final Plan	Customer Contribution (including overhead)
Mains	33.2	33.2	23.3	22.6
Inlets	102.3	102.3	77.7	75.2
Meters	14.6	14.6	12	11.6
Growth new areas – trunk mains	4.9	4.9	4.9	-
Total cost including escalation	**$155.0**	**$155.0**	**$117.7**	**$109.5**
Associated overheads	7.3	7.3	5.7	
Total cost including escalation& Overheads	**$162.3**	**$162.3**	**$123.4**	**$109.5**

1.4.2. Domestic meter replacement

While we remain committed to delivering our meter replacement program at the lowest sustainable cost, we do not consider AER's Draft Decision provides the best forecast of the replacement volumes required in the next AA period. In our revised Final Plan, we have maintained that our Final Plan forecast to replace [redacted] meters over the next AA period, equivalent to an average of approximately [redacted] meter replacements per year, is prudent and efficient.

1.4.2.1 Increased roll out initial technical life standards and improved meter management

The lower volumes observed in the current AA were largely due to the increased rollout of domestic meters from 2007 onwards with an approved initial life of 18 years (compared with a technical life span range between 10 and 15 years for earlier meters), combined with our Field Life Extension (FLE) efforts and other improvement initiatives. The extension of certain meter family lives has deferred the replacement activities meaning many are now due for replacement in the next AA period. This is why the volumes will be lower in the current period than those required in the next period.

1.4.2.2 Compliance-driven replacement program

Additionally, periodic meter replacement is a compliance driven program required to maintain meter accuracy and ensure customers are correctly charged for gas usage. In developing our forecasts, we have had regard to the regulatory obligations set out in the South Australian Gas Metering Code , AS 4944 and the *National Measurement Act*, as well as the requirements of Rules 79 and 91 of the National Gas Rules (NGR). The proposed replacements also align with customer priorities, being safety, reliability and integrity.

1.4.2.3 Meter family age profile and lifespan

We've provided further information on meter installation periods, remaining in-field populations, approved technical lives, and the expected replacement windows in our revised Final Plan to support our forecast. This evidence demonstrates that the proposed replacement volumes are prudent and consistent with the service life of the existing meter fleet.

1.4.2.4 Data inconsistencies clarification

In response to the AER's concerns regarding inconsistencies between installation volumes referenced in AGN's 2021–26 meter replacement program and those presented in the 2026–31 proposal, we have reviewed the underlying datasets and confirm that the figures remain accurate and therefore have not been revised. For clarity, Figure 3.1 in Attachment 9.5 shows the number of domestic meters *still installed* in the field as at November 2024, grouped by installation year. This remaining in-service population excludes meters that have already been replaced or removed and is therefore *lower* than original installation volumes.

More detailed information can be found in Attachment 9.18 Response to Draft Decision on Meter Replacement.

1.4.3. Digital metering for inaccessible sites

While acknowledging that installing digital meters to improve meter access may be prudent for some customers, the AER rejected our proposed digital metering program in the Draft Decision and sought further information on the program's efficiency. We have re-proposed $2.5 million for targeted digital metering in our Revised Final Plan supported by the arguments below.

1.4.3.2 Low uptake of customer self-read alternatives

While the lower-cost alternatives for meter reads are available, these options mostly rely on customers actively providing their own meter reads. Historical evidence demonstrates persistently low uptake of customer-driven solutions, reflecting the inconvenience involved and limiting their effectiveness as a reliable substitute for physical or digital reads.

1.4.3.3 Safety and compliance risks

Due to safety and access constraints at hazardous or inaccessible sites, more than 6,000 customers on AGN's network have not received a physical meter read for over 12 months, with some meters unread for several years. This is inconsistent with our compliance obligations to provide accurate and timely meter data to retailers and to operate in a safe manner, protecting our employees and contractors.

1.4.3.4 Long term operational sustainability

The rapid transition to smart metering across the electricity and water sectors reduces economies of scale for manual meter reading services, increasing the unit cost and eroding supply-chain support for analogue meters. As manual reading services and manufacture support diminish, AGN faces increasing operational, compliance and safety risks in continuing to rely on physical reads at hazardous or inaccessible sites.

More detailed information can be found in Attachment 9.18 Response to Draft Decision on Meter Replacement.

1.4.4. IT Transition

AGN's gas distribution networks have been operated and maintained by APA since 2007. APA has not provided operating and maintenance (O&M) services to other entities within the AGIG group. Consistent with its strategy of focusing on being an owner and operator of its own energy infrastructure, APA has advised its intention to cease providing O&M services to AGN. As a result, the systems within the APA IT environment previously utilised to operate and maintain AGN's networks need to be transitioned to ensure the continued safe and reliable operation of the networks.

To provide operational certainty, maintain stability and manage transition risk, the transition activities have now commenced. To support this, APA is providing transition services, commencing from 1 December 2025 until the bulk of systems have successfully migrated across to our technology environment under the 'Lift and Shift' phase. Accordingly, while our original Final Plan assumed Lift/Shift would commence on 30 June 2027, our revised Final Plan reflects the updated timing of the transition having commenced on 1 December 2025.

Our IT transition program proposed for the next AA period covers the transition of these systems from the APA technology environment into our technology environment under a Lift and Shift followed by Merge approach.

In its Draft Decision, the AER has sought further information on the options considered (i.e. Lift/Shift and Merge versus Lift/Shift) and the costs assumptions underlying each. There were also some questions in relation to the corporate structure and relationship between AGIG and AGN.

As the program is now underway, our cost estimate in this revised Final Plan is informed by the actual costs we are incurring, reflecting both labour unit rates and the required scope of work. Our revised forecast for AGN SA is therefore $67.4 million of capex in total, with capex of $41.0 million falling into the next 2026/27 to 2030/31 AA period.

Our revised Final Plan demonstrates that the Lift, Shift and Merge option is the more prudent and efficient option based on cost and risk. It also justifies the rates, effort and contingency assumptions and explains the cost allocation methodology, demonstrating that AGN customers will only pay costs directly attributable to the services they receive.

Further detail is provided in Attachments 9.14 and 9.15 of the revised Final Plan.

1.4.4.1 Long term operating costs

We do not agree with the AER's concern that the Option 2 (Lift/Shift and Merger) may not represent the lowest cost option over the next 10 years, "given the rate of change of ICT technology and the rapid payback of associated ICT assets."[24] As such, we have provided additional information and economic analysis demonstrating Option 2 (Lift/Shift & Merge) delivers greater benefits than Option 1 (Lift/Shift), both quantitatively and qualitatively.

Under the Lift, Shift and Merge approach the APA technology environment is replicated and operated in parallel as a standalone environment within AGN's technology environment. Merge activities are to eliminate duplicated applications and migrate data to the preferred applications, thereby reducing ongoing cost and risk.

- There is an additional ongoing operational cost of $3.8 million per annum for AGN SA to keep running the two disparate sets of systems in perpetuity. Therefore, the earlier we can merge systems, the earlier the reduction in ongoing operating costs can be realised; and
- After completion of Lift/Shift, maintaining two disparate sets of systems perpetually poses multi-faceted risks: operational hurdles (increased complexity, error rates, slower incident response), cyber security vulnerabilities, financial inefficiencies (duplicated infrastructure, licensing, support contracts), compliance challenges, reduced agility strategically (vendor lock-in, integration barriers), and diluted staff skills and low morale.

Additionally, the benefits of the Merge extend well beyond IT cost savings in the long run, as streamlined and standardised systems create broader economies of scale that ultimately benefit AGN customers. Under the proposed timing, these benefits will be available toward the end of the next AA period and will inform the base operating expenditure for the subsequent AA period.

1.4.4.2 Project Costs

Commensurate with the additional detail that has gone into our planning and estimates, we have now applied more granular assessment of contingency to the Lift and Shift activities. Rather than assume a general 25% contingency, we have looked at the risk associated with each Lift and Shift activity and allocated an individual contingency amount.

We have reduced the contingency associated with the Integration Management Office, Infrastructure Delivery, and Lift and Shift – Integrate activities to 15%. We have then applied only a 10% contingency to the Lift and Shift – Separate activities.

This results in an average contingency of 12.7% across the lift and shift phase, or $15.1 million.

We have maintained 25% contingency for the merge activities because we do not have additional detail in our planning and estimates to apply a more granular assessment of contingency to the merge activities.

We have removed the contingency applied to Infrastructure Currency and Refresh, as fewer project risks apply to these activities.

We have completed a competitive tendering process for the infrastructure and solution delivery components of the project, which has informed our updated external labour rates. This analysis shows that the KPMG rates used in the original estimate are not the highest rates when assessing

[24] AER, Draft Decision, AGN (SA) access arrangement 2026 to 2031, Attachment 2 – Capital Expenditure, November 2025, p.15

the four vendors side-by-side. The rates received in the IT Transition tender from various bidders indicate that the rates used in the original Final Plan forecast were reasonable.

We have updated the number of effort days for the Lift and Shift component of the IT Transition in this revised Final Plan to reflect more recent information now that the project is underway. The Final Plan forecast of effort days remains within the range of tender bids received and is consistent with our current assessment of the effort required.

1.4.4.3 AGN Company structure and cost allocation

In its Draft Decision, the AER disallowed the costs associated with the transition of AGN's IT systems and AGN's cyber security projects proposed for the next period. On both these matters the AER raised uncertainty about whether these costs are appropriately allocated to AGN as the regulated entity.

To address this uncertainty and demonstrate we are only seeking recovery of AGN IT costs that allows us to provide gas distribution (haulage) services to AGN SA network customers, we have included Attachment 9.17 in the Revised Final Plan. This attachment provides detailed information on:

- the group of companies known as AGIG and its relationship to AGN;
- the IT environment across AGIG and how it relates to AGN; and
- our approach to allocating shared costs between the AGIG entities, and between AGN's networks.

We highlight that our cost allocation approach is:

- unchanged from previous revenue determinations across all AGIG entities;
- consistent with the cost allocation used for our regulatory information notice (RIN) reporting for AGN SA; and
- consistent with accepted regulatory practice.

IT Transition costs relate solely to AGN, as the project is wholly driven by the need to transition AGN's systems out of APA's IT environment. Given that AGN operations (in SA and other states) are the sole cause of these costs, it is appropriate that the costs are 100% allocated to AGN (i.e. no costs should be incurred by AGIG entities that are not part of AGN, i.e. MGN or DBP). Costs are subsequently allocated to each individual AGN network on the basis of the number of customers on each AGN network as a proportion of the total number of AGN customers (35.2% for AGN SA).

1.4.5. Cyber security

We do not accept AER's Draft Decision to include a zero-dollar placeholder for the cyber security business case and maintain our originally proposed $1.5 million capex forecast for the next AA period is prudent and efficient.

To clarify, our proposed option is not targeting SP-3 standards during the next AA period. Rather, our expenditure is designed to address identified gaps in our data privacy and access control capabilities and maintain our current SP-1 compliance.

We consider it necessary to continue to invest in our cyber security maturity in a growing threat environment, including to meet new regulatory obligations. We expect SP-2 to become an obligation within the next five years, and the investments proposed for the next AA period will provide a solid platform for achieving that maturity level. The proposed investment is not designed to achieve SP-3.

Further information to address the AER's specific concerns about Cyber security is provided in Attachment 9.16 Response to Draft Decision on IT Cyber Security*.*

1.4.6. Overheads

Our revised Final Plan reflects total overhead costs of $16.2 million (excluding $5.6 million customer contribution connections overheads), representing the allocated share attributable to capex categories from the revised total forecast capex.

1.5. Summary

1.5.1. Our performance in the current AA period

We have invested $439.8 million ($2025/26) of capex during the current AA period up to June 2025 and are forecasting to invest a further $128.6 million, totalling $568.4 million by the end of the period.

As part of AGN SA Reset RIN 2026-31, we submitted Appendix B[25] which provided the supporting information as required under Section 4.3 (Capital expenditure) of the RIN. The current AA capex forecast presented in Appendix B reflects our Final Plan forecast. Appendix B sets out the following variations by capex driver categories, accompanied by variance analysis:

- the current AA capex forecast compared with the capex allowance
- the next AA capex forecast compared with the current AA capex forecast

In our revised Final Plan, we have updated our current AA period capex forecast. Our projected net capex (excluding capital contributions) for the current AA period is $568.4 million ($2025/26), which is $20.0 million higher than the Final Plan estimate included in the capital base as part of the AER's Draft Decision.

The key drivers of this increase are:

- Updated 2024/25 actuals: $12.1 million lower than the Final Plan forecast, driven by lower mains replacement volumes, partly offset by higher inlet volumes due to stronger-than-expected residential connections in brownfield areas.
- Updated 2025/26 forecast: $30.8 million higher than the Final Plan forecast, reflecting increased IT capex and Other non-distribution system capex following the updated timing of the transition, with Lift & Shift commencing on 1 December 2025. (see Attachment 9.14 and 9.15 of our revised Final Plan for further detail).
- Updated inflation forecast: December 2025 CPI updated from 3.0% to 3.3%, based on the latest available RBA Statement on Monetary Policy.

A summary of our current AA period capex is provided in Table 1.7.

[25] AGN SA - Appendix B Supporting Information 4.3 Capital expenditure AA Period Variances 20250701 | Australian Energy Regulator (AER)

Table 1.7: Revised Final Plan current AA period capex summary ($ million, 2025/26)

	2021/22	2022/23	2023/24	2024/25	2025/26	Total
Mains Replacement	43.6	45.3	40.5	45.1	25.0	199.4
Meter Replacement	4.3	3.7	2.6	3.5	5.5	19.6
Augmentation	0.0	0.4	2.7	2.2	3.5	8.7
Telemetry	0.3	0.5	0.2	0.6	0.5	2.1
IT system	10.8	6.1	3.0	13.5	33.7	67.1
Growth	25.8	27.3	27.0	30.3	29.0	139.4
Other distribution system assets	10.8	9.4	11.2	15.4	14.4	61.1
Other non-distribution system assets	0.9	0.8	1.5	1.5	5.3	10.1
Capitalised overheads	11.2	10.5	11.7	15.6	11.8	60.9
Net Capex (excluding capital contributions)	**107.8**	**104.0**	**100.4**	**127.6**	**128.6**	**568.4**

Despite an aggregate increase of $20.0 million ($2025/26) to the current AA capex forecast in the revised Final Plan, the variation relative to the AER approved capex allowance remains consistent with that presented in Appendix B, being $71.4 million (11%) lower than the approved allowance.

At the capex driver category level, the variations relative to the allowance are also largely consistent with those set out in Appendix B, apart from IT capex. For a detailed explanation of the drivers of these variations, this paper should be read in conjunction with Appendix B.

This higher-than-benchmark IT capex primarily reflects the commencement of transition of AGN's IT system in Dec 2025 (as detailed in the Section 1.4.4 of this paper).

A summary of the variation between the current AA capex forecast and the capex allowance is provided in Table 1.8.

The lower-than-allowance capex reflects our ongoing efforts to achieve efficiencies and maintain strong performance relative to the benchmark allowance under the Capital Expenditure Sharing Scheme (CESS).

Table 1.8 Capex by Driver (Net of Capital Contributions) for the current AA – Forecast compared to Allowance ($ million, 2025/26)

	Revised Final Plan forecast	Allowance	Variance to Allowance	Variance % to Allowance
Mains Replacement	199.4	287.5	-88.1	-31%

	Revised Final Plan forecast	Allowance	Variance to Allowance	Variance % to Allowance
Meter Replacement	19.6	23.2	-3.6	-16%
Augmentation	8.7	13.1	-4.3	-34%
Telemetry	2.1	2.2	-0.1	-5%
IT system	67.1	49.7	17.4	35%
Growth	139.4	142.4	-3.0	-2%
Other distribution system assets	61.1	56.1	5.0	9%
Other non-distribution system assets	10.1	5.7	4.4	77%
Capitalised overheads	60.9	59.7	1.2	2%
Net Capex (excluding capital contributions)	**568.4**	**639.8**	**-71.2**	**-11%**

** Positive variations indicate overspending, while negative variations represent underspending

1.5.2. Capex in the next AA period

Our revised Final Plan capex forecast (net of customer contributions) is $337.2 million over the next AA period, representing a reduction of $165.8 million compared to our Final Plan and a reduction of $90.8 million compared to the AER's Draft Decision. This outcome reflects the following changes:

- reproposing $42.6 million for the transition of AGN's IT systems, supported by evidence demonstrating that the preferred option (Lift/Shift & Merge) is the most prudent and efficient approach for AGN's customers, and that the associated costs relate solely to Australian Gas Networks (AGN);
- maintaining our Final Plan position to uplift cyber security at $1.5 million, with supporting justification that this level of investment is necessary given the current IT threat environment;
- maintaining our Final Plan position to replace of [redacted] domestic meters over the next AA period under a compliance-only, strictly necessary meter replacement approach;
- retaining digital metering program for inaccessible or unsafe sites, following all reasonably practicable avenues to comply with our regulatory obligations;
- modifying connection capex according to the AEMC's final connection rule change; and
- updated capitalised overheads based on the revised capex forecast

Our revised Final Plan net capex (excluding capital contributions) for the next AA period is summarised in Table 1.9 below.

Table 1.9: Summary of Revised Final Plan Net Capex Forecast for the Next AA Period ($ million, 2025/26)

	2026/27	2027/28	2028/29	2029/30	2030/31	Total
Mains Replacement	16.7	16.8	17.2	17.4	17.3	85.5
Meter Replacement	8.3	6.9	6.7	7.9	8.7	38.5
Augmentation	-	4.0	-	2.4	-	6.4
Telemetry	1.2	0.7	0.7	0.6	0.6	3.8
IT system	24.6	11.9	18.9	8.7	9.0	73.0
Growth	8.9	5.0	-	-	-	13.9
Other distribution system assets	17.2	18.9	18.4	19.4	18.2	92.2
Other non-distribution system assets	3.4	1.0	1.3	1.5	0.5	7.7
Capitalised overheads	3.7	3.0	3.2	3.1	3.1	16.2
Net Capex (excluding capital contributions)	**84.0**	**68.4**	**66.4**	**61.1**	**57.4**	**337.2**

Table 1.10 provides a comparison between the net capex forecast for the next AA period and the net capex forecast for the current AA period.

The net capex forecast for the next AA period represents a reduction of $231.2 million (41%) relative to the current AA period, primarily driven by the removal of connection capex, as detailed in Section 1.4.1 in this paper. Apart from this, the remaining variations at the capex driver category level are largely consistent with those set out in Appendix B of the AGN SA reset RIN. For a detailed explanation of the drivers of these variations, please refer to Appendix B.

Table 1.10: Capex Variance by Driver (Net of Contributions) – Current vs. Next AA Forecast ($ million, 2025/26)

	Next AA Capex	Current AA Capex	Variance	Variance %
Mains Replacement	85.5	199.4	-113.9	-57%
Meter Replacement	38.5	19.6	18.9	96%
Augmentation	6.4	8.7	-2.3	-26%
Telemetry	3.8	2.1	1.7	81%
IT system	73.0	67.1	5.9	9%
Growth	13.9	139.4	-125.5	-90%
Other distribution system assets	92.2	61.1	31.1	51%
Other non-distribution system assets	7.7	10.1	-2.4	-24%
Capitalised overheads	16.2	60.9	-44.7	-73%
Net Capex (excluding capital contributions)	**337.2**	**568.4**	**-231.2**	**-41%**

** Positive variations indicate overspending, while negative variations represent underspending