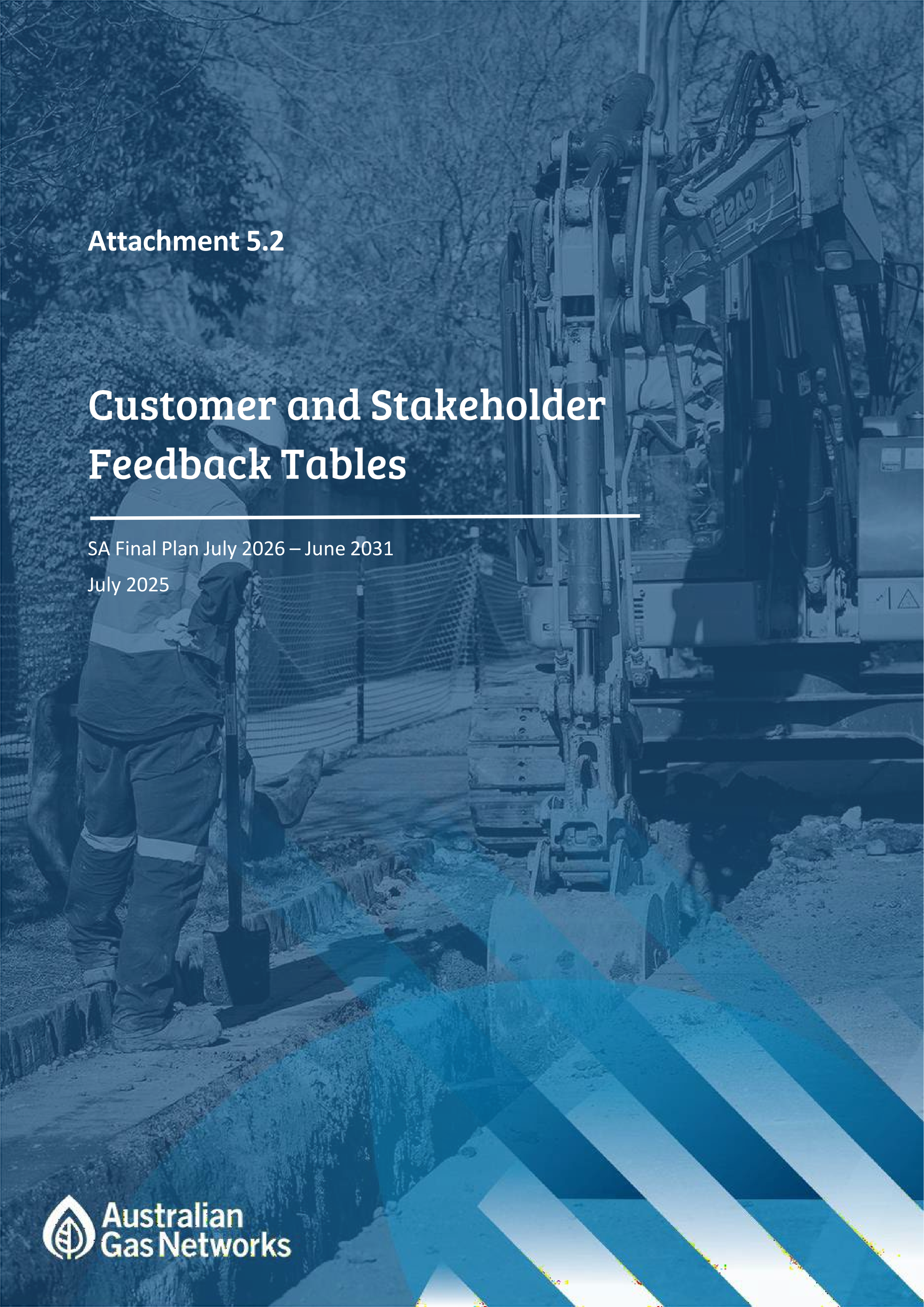

Attachment 5.2

Customer and Stakeholder Feedback Tables

SA Final Plan July 2026 – June 2031

July 2025

Australian Gas Networks

Topic: Future of Gas and Depreciation	
Customer and Stakeholder Feedback	**Our Response**
Stage 1 and 2 Engagement: Developing our Plans	
• Customers want to better understand the network's proposed shift to renewable gas as well as more information on the personal impact that the shift would have.	• Customers had the opportunity to learn more about these plans in sessions, and we have published more as part of this Final Plan.
Stage 3 Engagement: Draft Plan Consultation • **Does the concept of depreciation make sense to you?** • **Are you comfortable with the modelling approach we are taking to depreciation?** • **We are yet to finalise the amount of additional depreciation, but propose to come back and consult with you if the amount is greater than $40 per year. Do you support this approach?**	
Customer feedback: • Some customers expressed a desire to discuss depreciation and the models in more detail. • Some customers were familiar with a different form of depreciation (that used by accountants for tax purposes). • Customers wanted more detail on the final number for depreciation.	• We delved deeper into how depreciation works and the nature of modelling in Phase 3. We also provided information to customers as to where they could read more about our modelling, including a model manual. This detail is in our Final Plan. • We explained and made clear what "regulatory" vs other forms of depreciation were, and how they work • In workshops, we said we would come back to customers if the final number was larger than $40 per bill, which most customers accepted.
SA Reference Group feedback: • There could be a degree of optimism in assumptions underpinning the energy transition and AGN needs to consider the impacts of currently proposed rule changes on depreciation. • Depreciation decisions must be openly explained and supported by modelling of customer impacts over time. • We need clarity on the impacts if accelerated depreciation is not applied during this period, in particular the future price consequences of waiting. • AGN should not avoid the term "accelerated depreciation". • We need to see the "missing chapter" on the future of gas that wasn't in the Draft Plan. • What is the role for sharing the cost of transition between networks and customers and how do options like new connection charges feed into this? • AGN should consider using depreciation as a tool to manage intergenerational equity and avoid future price shocks.	• We have outlined our reasoning in detail in the Final Plan, including where we consider we have been optimistic. We have also directly discussed the current rule change proposals. We have also considered the impacts of broader policy changes, like connection bans. • Our Final Plan contains a detailed description of our modelling, which includes a focus on customer prices and their stability. We also provide the model and a manual. In discussions with customers, we explained how models are used to provide transparency to reasoning. • We have explicitly modelled the consequences on consumer prices of waiting. • We have outlined our reasons for choice of language in this Final Plan, and discussed it with the SARG. We support the need for transparency and openness that underpins the differing views on terminology. • We commonly do not provide all our background materials with a Draft Plan, as many are still being developed. We have provided two chapters detailing the background to the future of gas; this one focusing on the demand side and its consequences for depreciation and Chapter 1 providing detail on supply side strategies for renewable gas. Both have detailed appendices with more information. Our work on depreciation includes a wide range of simulation and analysis of different future states. • We have developed a 3-part "stable risk balance framework" which includes risk sharing, aspects such as connections charges and shown how depreciation fits into this.
Stage 4 Engagement: Refining our Plans	
• The SARG Review Panel requested that they be invited to provide advice on how we respond to their feedback.	• Various business units from AGN (Regulation, Economics and Strategy) met with members of the SARG Review Panel to ensure our response met their expectations.

Topic: Future of Gas and Depreciation (continued)

Final Plan Outcome

- Our Final Plan notes that our modelling approach supports a minimum of $70 million in additional depreciation to meet future risk, but notes that AER practice would deliver $32 million.
- The Final Plan has addressed the SA Reference Group's concerns about the "missing chapter", providing two, along with supporting appendices which cover the demand side, which informs depreciation and keeping long run prices as stable as we can, and another which outlines our supply-side strategies to support the delivery of renewable gas.
- Our approach to modelling to support depreciation includes consideration of a wide range of future market outcomes, including policy responses not yet deployed in South Australia. It includes consideration of customer price outcomes, rather than solely focussing on networks, and shows the impacts of waiting until the next AA.
- We outline how depreciation sits within a framework aimed at maintaining a stable risk balance between networks and customers as the energy sector changes and risks change. This framework has benefited substantially from discussions with stakeholders, particularly the SARG Review Panel, and we thank members for their time to develop our thinking.

<table>
<tr><th colspan="2">Topic: Pipeline and reference services</th></tr>
<tr><th>Customer and Stakeholder Feedback</th><th>Our Response</th></tr>
<tr><td colspan="2">Stage 1 and 2 Engagement: Developing our Plans</td></tr>
<tr><td>We received five submissions on our Draft RSP. We also shared our proposed reference and non-reference services in our customer workshops and with our stakeholder reference groups.
Our stakeholder engagement demonstrated broad support for the continuation of our service offerings, and stakeholders also indicated a preference for the abolishment service (small scale) to be identified as a reference service in the next AA period.</td><td>In our Draft RSP, we asked our stakeholders whether they:
supported the proposed reference services
preferred any classification changes for specific services from reference to non-reference, or non-reference to reference
had any suggestions for improving the descriptions of our services, and
required any additional services.
We proposed that the abolishment service be a reference service in our Final RSP, which we submitted to the AER in June 2024.</td></tr>
<tr><td colspan="2">Stage 3 Engagement: Draft Plan Consultation
Do you think the pipeline and reference services we have proposed are appropriate, or do you think there has been a material change in circumstances that were approved by the AER in November 2024?
Do you think the abolishment reference service should be charged at partial cost recovery or full cost recovery?</td></tr>
<tr><td>We did not receive any further feedback on our proposed services at this stage, apart from on the pricing approach for abolishments.
Some stakeholders indicated a preference for a continuation of the abolishment service being offered free of charge to align with connections.
The Energy and Water Ombudsman SA indicated support for partial cost recovery on safety grounds but also considered that full cost recovery was more sustainable if abolishments were to increase dramatically.
Customer feedback in workshops indicated that they were evenly split about favouring a charge (as opposed to no charge).</td><td>Our Draft Plan reflected the decision by the AER on our RSP (dated November 2024).
Regarding pricing for the abolishment service, we remained open to feedback but acknowledged that the likely approach would be based upon the AER's preferred approach for partial cost recovery and a charge amounting to 20% of the full cost (which is $250 based on our estimated service cost).
However, we also stated that this pricing approach (with partial cost recovery) was not sustainable if there was policy intervention to disincentivise gas connections in SA.</td></tr>
<tr><td colspan="2">Stage 4 Engagement: Refining our Plans</td></tr>
<tr><td>No further feedback was provided on our proposed services and the pricing approach for the abolishment service at this stage.</td><td>We note the current AEMC rule change request (with consultation commencing 12 June 2025) for a full charge to apply to abolishments, without any partial cost socialisation.
Notwithstanding the outcome of this rule change request, we have maintained consistency with the AER's position to date regarding the abolishment charge.</td></tr>
<tr><td colspan="2">Final Plan Outcome</td></tr>
<tr><td colspan="2">Our Final Plan includes the reference and non-reference services approved by the AER in our final RSP, noting there have been no changes to our proposed service offerings since.
We have proposed an abolishment service charge of $250 (representing 20% of the full estimated cost of the service in SA), for consistency with the AER's past decisions on this approach.</td></tr>
</table>

<table>
<tr><th colspan="2">Topic: Operating expenditure</th></tr>
<tr><th>Customer and Stakeholder Feedback</th><th>Our Response</th></tr>
<tr><td colspan="2">Stage 1 and 2 Engagement: Developing our Plans</td></tr>
<tr><td>Customers expect a high level of public safety and reliability for the network.
Customers are satisfied with current customer service levels concerning safety and reliability, with price affordability otherwise most important to them.
Stakeholders also sought consideration of cost savings in our forecasts.</td><td>We consulted on a small insurance step change including its materiality and responded to feedback at a SARG meeting to remove it from our proposed cost base.
We considered other opportunities to achieve savings in our opex forecasts, without compromising the safety and reliability that our customers need and value.</td></tr>
<tr><td colspan="2">Stage 3 Engagement: Draft Plan Consultation
Do you have any feedback on the operating activities we have proposed as part of our forecast for the next AA period?
Do you support our approach to forecasting opex? Is there sufficient information to understand our proposals and the basis of costs included in our forecasts?</td></tr>
<tr><td>One stakeholder supported the change in capitalisation policy and our approach to forecasting UAFG and opex; another supported our IT and renewable gas (hydrogen) initiatives.
The SARG Panel requested more justification for the planned purchase of renewable gas certificates for Hyp Adelaide and other step changes.
The Panel also wanted more information about the UAFG forecasts and assurance that we will seek the most competitive price for UAFG.
Various stakeholders commended the Priority Services Program (PSP) and the Panel suggested further steps to broaden the reach of the program, and to monitor and enhance it.
On trend factors, the Panel supported the productivity growth factor but requested more information on why 0.4% has been assumed.</td><td>We adjusted our proposed step changes following our Draft Plan and have provided more information on all proposed step changes in Section 8.5.1.
Our assumed price for UAFG is based on current market prices and in our Final Plan we have provided additional information on our UAFG strategy and quantity forecasts in Attachment 8.4.
We will continue and expand upon our Priority Services Program into the next AA period, as indicated on the next page.
An explanation of the productivity growth assumption in our Final Plan is provided in Section 8.5.2.</td></tr>
<tr><td colspan="2">Stage 4 Engagement: Refining our Plans</td></tr>
<tr><td>In the SARG meeting of 5 June 2025, stakeholders acknowledged the additional step changes, including those addressing cybersecurity risks, aligned with targeted security profiles.
Stakeholders also acknowledged that the proposed step change related to Hyp Adelaide was part of the anticipated regulatory requirements attached to a jurisdictional scheme, rather than a broader expenditure proposal in our plan for the project.</td><td>We engaged further with stakeholders on the need for the proposed step changes, including:
How the change in capitalisation policy was similar to additional depreciation in that it reduces the growth of the capital base.
The anticipated regulatory requirement to purchase renewable gas certificates.
That the proposed IT transition costs are non-recurrent (with future savings).</td></tr>
<tr><td colspan="2">Final Plan Outcome</td></tr>
<tr><td colspan="2">Our final opex proposal seeks to maintain the safety and reliability of our network, while also achieving emission reductions for a more sustainable energy future. Our forecasts reflect extensive customer and stakeholder feedback and we propose to absorb various costs to achieve price efficiency for our customers.</td></tr>
</table>

<table>
<tr><th colspan="2">Topic: Capital expenditure</th></tr>
<tr><th>Customer and Stakeholder Feedback</th><th>Our Response</th></tr>
<tr><th colspan="2">Stage 1 and 2 Engagement: Developing our Plans</th></tr>
<tr><td>• Customers told us that their top priorities are price and affordability, reliability of supply and maintaining public safety.
• Customers expect a high level of public safety and feel that safety is currently well managed by AGN.
• Customers highly value an uninterrupted supply of gas in their homes and businesses.</td><td>• We proposed to maintain our current levels of safety and reliability, and to ensure that customers continue to be able to communicate directly with AGN through a variety of digital channels.
• We proposed to spend $158.6 million on new residential and business connections to our network.</td></tr>
<tr><th colspan="2">Stage 3 Engagement: Draft Plan Consultation
• Do you have any feedback on the capex activities we have proposed as part of our forecast for the next AA period?
• Do you support our approach to forecasting capex? Is there sufficient information to understand our proposals and the basis of the costs excluded?</th></tr>
<tr><td>• 95% of customers agreed that our Draft Plan met their expectations and reflected what was important in relation to maintaining and growing our network.
• Customers remain interested in learning more about our plans to grow our network.
• SARG members share concern that $156m for new connections will create risk of stranded assets, noting falling demand and policy uncertainty.</td><td>• We invited SARG and RRG members to a Deep Dive on capex to address their questions and concerns about meter replacement, fleet, hydrogen readiness, IT and growth capex.</td></tr>
<tr><th colspan="2">Stage 4 Engagement: Refining our Plans</th></tr>
<tr><td>• Stakeholders would like greater detail on capex (e.g., meter replacements and fleet transition), and raise questions about risk management of hydrogen-related capex.
• Stakeholders raised concern about potential cost overruns associated with IT upgrades, and want assurance of prudent delivery given industry-wide issues with IT implementations.
• Stakeholders share support for AGN's mains replacement program that is nearly complete.
• Stakeholders are mainly supportive in principle about our hydrogen projects, but want more clarity on costs, technical feasibility, sourcing, and customer impact.
• One stakeholder expressed strong opposition towards hydrogen for residential use.</td><td>• Our proposals relating to capex are including in greater detail in Chapter 9 of this document, and include more detail as requested by stakeholders.</td></tr>
<tr><th colspan="2">Final Plan Outcome</th></tr>
<tr><td colspan="2">• $155m for new connections capex which is marginally below the Draft Plan forecast. We are forecasting residential and commercial connections over the next AA will decline relative to the current period benchmark by 15% (34k forecast vs 40k benchmark). If forecast growth does not materialise, the growth capex won't be spent/rolled into the RAB. Only capex incurred is rolled into the RAB, no CESS benefit.
• We've assessed each of the four possible extension projects and have only proposed one (Concordia).
• If required we could reopen the AA to adjust forecasts in response to new policies or evolving market conditions.
• We believe that connection charges are more appropriately addressed at the jurisdictional level (AEMC rule change requests) rather than through an AA proposal process.</td></tr>
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<table>
<tr><th colspan="2">Topic: Demand</th></tr>
<tr><th>Customer and Stakeholder Feedback</th><th>Our Response</th></tr>
<tr><td colspan="2">Stage 1 and 2 Engagement: Developing our Plans</td></tr>
<tr><td>We did not consult with our customers during workshops on our approach to demand forecasting.
Members of our South Australian Reference Group and Retailer Reference Group showed an interest in our demand history and forecasting.</td><td>At many of our SA Reference Group meetings and Retailer Reference Group meetings, we discussed the approach and the importance of understanding key drivers of future demand and our forecasting approach.</td></tr>
<tr><td colspan="2">Stage 3 Engagement: Draft Plan Consultation
Do you support our approach to forecasting demand?
Are there any other factors we should consider in developing our demand forecasts?</td></tr>
<tr><td>SARG members would like AGN to test the demand forecasts against multiple policy and technology scenarios, such as:
South Australia adopting a Victorian-style gas substitution roadmap.
Hydrogen and biomethane not becoming commercially viable within the forecast period.
Stakeholders believe demand forecasts and assumptions should be more explicitly linked to investment decisions and risk mitigation strategies (e.g. accelerated depreciation).
Stakeholders would like AGN to explain how demand projections interact with long-life capex and pricing over time, especially post-2031.
Stakeholders note and acknowledge decline in demand.</td><td>We invited SARG and RRG members to a Deep Dive on demand forecasting to address their questions and concerns.
Core Energy is forecasting demand in between AEMO’s step change and progressive scenarios.
If connections don’t materialise, the capex will not be incurred – this is the main link between the demand and capex forecasts.
If there’s a policy change, we would respond by reopening the Access Arrangement, adjusting demand down, and potentially increasing depreciation as risks would change.
Hydrogen and biomethane not becoming commercially viable within the forecast period would not impact the demand forecast in the next period but would in subsequent periods.</td></tr>
<tr><td colspan="2">Stage 4 Engagement: Refining our Plans</td></tr>
<tr><td>We surveyed our South Australian major users to better understanding their gas usage over the coming five-year period.</td><td>Our proposals relating to demand are included in Chapter 13.</td></tr>
<tr><td colspan="2">Final Plan Outcome</td></tr>
<tr><td colspan="2">Core Energy is forecasting demand in between AEMO’s step change and progressive scenarios.
If connections don’t materialise, the capex will not be incurred – this is the main link between the demand and capex forecasts.
If there’s a policy change, we would respond by reopening the Access Arrangement, adjusting demand down, and potentially increasing depreciation as risks would change.
Hydrogen and biomethane not becoming commercially viable within the forecast period would not impact the demand forecast in the next period but would in subsequent periods.</td></tr>
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<table>
<tr><th colspan="2">Topic: Incentive schemes</th></tr>
<tr><th>Customer and Stakeholder Feedback</th><th>Our Response</th></tr>
<tr><td colspan="2">Stage 1 and 2 Engagement: Developing our Plans</td></tr>
<tr><td>Our customers told us that they were broadly comfortable that the current framework regarding the Efficiency Carryover Mechanism (ECM) and the Capital Expenditure Sharing Scheme (CESS) appropriately incentivises us to incur only efficient opex and to spend efficiently on capital projects.</td><td>During Stage 2 of our stakeholder engagement program, we held SARG and RRG meetings to engage on key areas of our plan, including our proposed continuation of the EBSS and CESS incentive schemes for the next AA period.</td></tr>
<tr><td colspan="2">Stage 3 Engagement: Draft Plan Consultation
Do you support our proposal to maintain the opex efficiency carryover mechanism (ECM)?
Do you support our proposal to maintain the capital expenditure sharing scheme (CESS)?</td></tr>
<tr><td>Stakeholders continued to indicate broad agreement for the ECM and CESS to apply in the next AA period with no concerns identified.</td><td>We presented at our reference group meeting the key opex and capex drivers in the current AA period, including the higher cost environment.
We shared our preliminary incentives forecast for the current AA period.</td></tr>
<tr><td colspan="2">Stage 4 Engagement: Refining our Plans</td></tr>
<tr><td>SARG support the continued application of the EBSS and the CESS in the next AA period.
No further feedback was received.</td><td>Our proposals relating to incentives are included in Chapter 12 of this document.</td></tr>
<tr><td colspan="2">Final Plan Outcome</td></tr>
<tr><td colspan="2">The Final Plan includes a continuation of the opex incentive mechanism (EBSS) and the capex sharing mechanism (CESS) that currently apply for our South Australian network.</td></tr>
</table>

<table>
<tr><th colspan="2">Topic: Revenue and pricing</th></tr>
<tr><th>Customer and Stakeholder Feedback</th><th>Our Response</th></tr>
<tr><th colspan="2">Stage 1 and 2 Engagement: Developing our Plans</th></tr>
<tr><td>Stakeholders and customers have indicated a preference for price stability and predictability concerning our plans
Customers told us that they equate affordability with steady and stable prices.
At the RSP stage, customers and stakeholders indicated majority support for the declining block tariffs to avoid significant bill increases for higher usage customers and continuing with the price cap mechanism to avoid price volatility over an AA period.
The AER did not accept our proposal to continue with our declining block tariff structure unchanged and asked us to consider other options for flattening tariffs. It also requested consideration of a hybrid mechanism for revenue control (combining the weighted average price cap with a revenue-based threshold).</td><td>We have designed our price path such that we can deliver a nominal price cut of 1.0% in year 1 and real price increases of less than 1% in subsequent years, delivering on our commitment to stable pricing in the next AA period.
Based on customer feedback and our own assessments of costs and benefits, we initially proposed in our RSP to continue with the current tariff structure and weighted average price cap approach to revenue control.
In response to the AER's decision on our final RSP, we proposed an adjusted tariff structure in our Draft Plan, with a higher fixed charge and rebalancing of other price tiers to address emission reduction objectives, while still keeping customer bill impacts at reasonable levels.
We also proposed the option of a hybrid mechanism at a revenue variation threshold of 10% for comment.
Our Draft Plan encompassed two cost pass through proposals as practical steps to manage potential Safeguard Mechanism compliance costs and small-scale abolishment costs (when different from forecast).</td></tr>
<tr><th colspan="2">Stage 3 Engagement: Draft Plan Consultation
Do you support our objectives of maintaining stable pricing and aligning revenue with underlying costs in setting our proposed price path? Would you prefer an alternative price path, and if so, on what basis?
Do you support the options we are considering to adjust the tariff structure (and charge weightings), including an increase in the base charge for residential and commercial customers? If not, what approach would you prefer and why?
Do you support the option we are considering for a new hybrid mechanism for revenue control with a 10% revenue variation threshold? If not, would you prefer an alternative approach and if so, why?
Do you support the proposed cost pass through events for the Safeguard Mechanism compliance costs and any unrecovered abolishment costs? If not, would you prefer any alternative approaches, and if so, why?</th></tr>
<tr><td>In general, customers and stakeholders continued to support continuing declining block tariffs but were also supportive of our proposed changes to align with emission reduction objectives which ensure reasonable customer bill impacts only.
One stakeholder recommended replacing the current structure with a flat or inclining tariff structure but also recommended that this must be accompanied by appropriate protections and support mechanisms to counter the adverse bill impacts on households.
Regarding our proposed hybrid mechanism, one stakeholder indicated that it would prefer the retention of the price cap but otherwise, the 10% threshold approach was broadly supported.
Other cost pass throughs were supported as proposed.</td><td>We responded to feedback that the fixed charge increase might impact low gas usage households and reduced the extent of the proposed increases for our residential and commercial tariffs accordingly, with more flattening of variable usage price tiers.
We do not accept comments that a more direct shift toward flat tariffs would be more affordable and equitable for customers; a view which is generally out of step with other stakeholder feedback we received. Our bill impact modelling demonstrates the adverse impact on larger households using gas, as one example of the negative bill impacts that would accompany flat tariffs. A compensation scheme would be inefficient and impractical to implement and would likely add considerable costs to the network.
We acknowledge stakeholders' preference for continuing the price cap mechanism but given the AER's preference for a hybrid mechanism, we have proposed a price cap with a 10% variation (revenue-based) threshold to apply in the next AA period.</td></tr>
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<table>
<tr><th colspan="2">Topic: Revenue and pricing (continued)</th></tr>
<tr><th colspan="2">Stage 4 Engagement: Refining our Plans</th></tr>
<tr><td>With further opportunity to discuss tariff structure options, stakeholders continued to acknowledge the negative customer bill impacts that accompany a direct shift to flat tariffs and how unacceptable they are in the current cost of living environment.
They also noted how such a shift would increase average gas prices for all customers, which is also not desirable during the energy transition amidst other potential price pressures.
There was one suggestion to place higher gas usage customers into different (higher priced) tariff categories, but this would have the same adverse impact on bills, including for larger households and small businesses.</td><td>In response to feedback on our Draft Plan, we held a special reference group meeting on tariff structure to further discuss our engagement approach and the trade-off between emission reduction objectives being achieved (through flatter tariffs) and the negative bill impacts for higher usage customers that this would entail. We also presented an adjusted option for a change in tariff structure (compared with the Draft Plan).
In this option, we reduced the extent of the proposed fixed charge increase in response to feedback about the potential bill increase, albeit small, for low usage customers, and flattened other pricing tiers more moderately to balance revenue outcomes.
We also provided building block and price updates at our final reference group meeting as we refined our Final Plan.</td></tr>
<tr><th colspan="2">Final Plan Outcome</th></tr>
<tr><td colspan="2">Our Final Plan proposes a real price cut of 3.6%, or 1% cut after inflation. We have integrated our proposed tariff structure changes into our proposed prices for residential and non-residential customers in our PTRM model. Our proposed changes to the tariff variation mechanisms are reflected in our AA document (Annexure E) and further explained in Attachment 14.1.</td></tr>
</table>