Consumer
Challenge
Panel

CCP24 Advice to the Australian Energy Regulator on Australian Gas Networks South Australia Draft Plan for Access Arrangement July 2021-June 2026

Consumer Challenge Panel (CCP) Sub-Panel CCP24

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Acknowledgements

CCP24 wishes to acknowledge the cooperation and support of AGN and AER staff, who have generously provided information and insights to assist the sub-panel in its review of the business's Draft Plan.

We also advise that to the best of our knowledge this report neither presents any confidential information nor relies on confidential information for any comments.

1. Introduction

This Statement of Advice is provided to the Australian Energy Regulator (AER) from Consumer Challenge Panel, sub-panel 24 (CCP24) in response to the Draft Plan published by Australian Gas Networks South Australia (AGN) in preparation for the Access Arrangement Review 2021-26 for the South Australian gas network. The Access Arrangement Proposal (AAP) is due to be lodged with the AER by 1st July 2020. The AGN Draft Plan, "Five Year Plan for our South Australian Network" was released in February 2020, with responses sought from consumers and other interested stakeholders by 17th April 2020.

In common with current practice for the majority of regulated network businesses operating in the National Energy Market, AGN has embarked on an early engagement program with its customers in order that customer needs are well understood by the business leading up to preparation of the next Access Arrangement Proposal. The Draft Plan has been published following completion of the majority of the consumer engagement activities associated with the price reset.

In responding to the Draft Plan, this document considers the information presented with the intention of:

- considering the linkages between the observed consumer engagement and the issues raised in the Draft Plan;
- providing feedback to AGN on matters of importance to consumers generally, including revenue trends, focus areas for expenditure, and trends in efficiency;
- highlighting the areas where further consultation may be warranted leading up to lodgement of the Access Arrangement Proposal; and
- identifying any areas of importance to customers that may not yet be evident in the Draft Plan.

We present this report with the intended audience of:

a) The AER, to provide an early indication of how closely the Draft Plan reflects the outcomes of the early engagement programs;
b) AGN, to assist in engagement leading to the submission of the Access Arrangement Proposal; and
c) informed customers and stakeholders who are taking an interest in, or actively participating in, this regulatory process.

It is important that the Draft Plan is not seen simply as a summary of the eventual Access Arrangement Proposal (AAP), but rather as a tool to facilitate conversation, comment and feedback. CCP24 encourages AGN to seek and consider any feedback from stakeholders, and listen to the sentiment, questions and emotion presented in the responses to the Draft Plan. CCP24 will continue to take a keen interest in how feedback on the Draft Plan continues to influence the Access Arrangement Proposal.

Note: As in the Draft Plan, all financial information in this report is presented in real 2020-21 dollars, unless otherwise stated.

Context

This Draft Plan and the subsequent Access Arrangement Proposal are developed in an environment of change and policy uncertainty.

(i) Government moves to a net zero emissions target

Globally there are moves by many governments to commit to carbon emission reduction targets and to seek energy from renewable sources. While much of the focus of these considerations relates to electricity, the issues are arguably more prescient and more urgent for the gas industry. Commitments to zero carbon emissions often set 2050 as a completion date, thirty years from now.

The South Australian Government has recently set an aspirational target of net zero emissions by 2050, and AGN has advised that the Government is expected to move to legislate this following publication of its formal Climate Change Strategy due in mid-2020.

Gas infrastructure business pipelines have asset lives of double that time, so decisions made now have implications for the future of gas businesses. AGN is clear that it considers itself to have a long-term future, with hydrogen as the gas for domestic and commercial heating applications into the longer-term future, that is, beyond 2050.

(ii) COVID19

The other significant issue that has arisen as AGN has released the Draft Plan has been the emergence of COVID19, a global crisis that has unfolded after the consumer engagement undertaken by AGN in developing this Draft Plan. Our consideration of the questions posed has been in the same pre-COVID19 world. We await further advice from AGN in their AAP in July on how they plan to incorporate this into their proposal – in particular what impact it is expected to have on demand forecasts. We also recognise that from a consumer engagement point of view, COVID19 has reduced the capacity for face-to-face engagement with customers and stakeholders concerning the issues raised in the Draft Plan. However, this does not discount the importance of consumer engagement, it just means that the engagement mechanisms need to be adjusted.

Vision

Section 4 of the Draft Plan carries the heading "What We Will Deliver" and includes discussion about the three elements of the AGN vision, these being:

- delivering to customers
- a good employer
- sustainably cost efficient.

We observed that AGN gives strong emphasis to these three areas of their vision, and they continue from regulatory period to regulatory period. The vision statements are important because AGN uses them to set performance targets which they then test with customer surveys and provide a basis for regular reporting to senior management, the Board and the public.

We observed that AGN use their vision to drive their customer focus and to measure ongoing performance, probably in a manner of greater emphasis than some other network businesses.

The Draft Plan both reports on "our track record" for the current regulatory period and specifies measurable performance targets for the 2021/22 -2025/26 regulatory period.

Access Arrangement proposal capable of acceptance

In the next section we provide commentary on the engagement that CCP24 has observed with AGN and the direct engagement that we have also been a part of. From our very first discussions with AGN, there was a clear statement of intent that the Access Arrangement Proposal lodged by AGN would be capable of acceptance by the AER. We will return to this theme at the end of this advice by providing our observations about what we consider would need to change, from the Draft Plan, for the lodged Access Arrangement Proposal to be heading towards capability of acceptance by the AER

The Draft Plan

AGN's Draft Plan was released nearly five months in advance of the date for lodgement of the Access Arrangement Proposal, allowing stakeholders sufficient time to engage with its contents in detail. Overall, this is one of the best written Draft Plans that CCP24 members have seen with complex topics clearly described and appropriate levels of detail for a Draft Plan, showing that customers and their understanding of the issues are respected and valued. We congratulate AGN on a well written, clearly presented Draft Plan with a good balance of detail, data and narrative.

There is, of course, room for improvement. We highlight two for AGN to consider as it prepares its AAP:

- The discussion around price changes can be confusing when 'real' price changes are presented in a way that is not immediately obvious to customers who perhaps better understand nominal price changes eg how much is my bill going to change on 1st July 2021 vs 30th June 2021?
- While the Draft Plan sets out the positive story around the future of hydrogen (Box 2.1) there is little discussion of the pathway if the work to develop an economic hydrogen pathway takes longer than is currently expected. It would be very useful to see AGN provide a narrative around this, including the impact on consumers' stranded asset risk and potential accelerated depreciation in the 2026-31 and subsequent regulatory periods. CCP24 presents further discussion of this issue in the Attachment to this Advice, "Gas Futures: Considerations of Hydrogen Opportunities and Stranded Asset Risk".

The following sections present CCP24's responses to the questions posed by AGN in the Draft Plan.

2. Customer and Stakeholder Engagement

Q1. Do you have any feedback on our customer and stakeholder engagement program?

By way of background, AGN has planned a four-stage program of engagement with customers and stakeholders. The summary diagram from the Draft Plan is reproduced below and identifies the four stages as:

- stage I in the first half of 2019 with a focus on strategy and research
- stage II, the second half of 2019 with a focus on developing the Draft Plan
- stage III, for February, March 2020 with a focus on consultation on the Draft Plan
- stage IV, up to lodgement of the Access Arrangement Proposal with its focus on refinement and engagement.

The CCP24 subpanel did not observe any stage I activity as much of this happened prior to the establishment of the subpanel, however the subpanel has observed many of the stage II and stage III consultation activities.

Stages 1 and 2 of engagement are now complete >

Stage 1 Strategy and research	Stage 2 Developing our Draft Plan	Stage 3 Consultation on our Draft Plan	Stage 4 Refinement and engagement
Feb - May 2019	**May - Nov 2019**	**Feb 2020**	**1st Half 2020**
Purpose We engaged with stakeholders to better understand customer needs and to consult on our proposed engagement approach.	**Purpose** In this stage we ran a series of engagement activities designed to inform the development of our Draft Plan.	**Purpose** This stage focuses on consultation on our Draft Plan.	**Purpose** Consultation feedback from Stage 3 will be used to finalise our plan.
IAP2 Spectrum CONSULT/INVOLVE	**IAP2 Spectrum** INVOLVE/COLLABORATE	**IAP2 Spectrum** CONSULT/INVOLVE	**IAP2 Spectrum** INFORM/INVOLVE/CONSULT
Engagement Activities • In April 2019 we published and distributed our Draft Customer and Stakeholder Engagement Plan for consultation • We met with key stakeholders • We expanded our South Australian and Retailer Reference Groups • We continued to meet regularly with our reference groups, Government agencies and key stakeholders • We established partnerships with stakeholders for engagement with the broader community and customers.	**Engagement Activities** • We held regular meetings with our South Australian and Retailer Reference Groups and key stakeholders • We launched our online engagement portal Gas Matters • Stakeholders were kept updated through our website • We held information sessions to help stakeholders gain a better understanding of the gas industry and current issues • We met with and surveyed large industrial customers • We held iterative workshops with a broad cross section of customers across South Australia • We held 3 co-design workshops with industry experts to consider how we could further assist vulnerable customers.	**Engagement Activities** • Publish and distribute Draft Plan • Meetings/ briefings with key stakeholders • Customers workshos • Follow up Co-design workshop • Reference Group meetings • Deep dive engagement sessions (on demand).	**Engagement Activities** • Publish and distribute Final Plan (together with a customer and stakeholder consultation guide).
Key Deliverables **This Stage 1 Engagement Report** In July 2019 we published our engagement strategy: Stage 1 Stakeholder Engagement Report.	**Key Deliverables** **Stage 2 Engagement Report** In January 2020 we published summary reports of customer and stakeholder input into developing our Draft Plan and outcomes of our co-design workshops.	**Key Deliverables** **Draft Plan** As part of our Draft Plan we will report on all customer and stakeholder feedback, and how this has influenced our plans.	**Key Deliverables** **Final Stakeholder Engagement Report and submission of our Final Plan to AER** A summary report of customer and stakeholder engagement feedback and input across all stages of our engagement program.

We have observed that one of the major processes comprised interactive workshops across the AGN geographic region, involving household and small business customers with active inclusion of people from culturally and linguistically diverse (CALD) backgrounds. The same group of people was invited to participate in workshops of a similar format in each of phase 1, 2 and 3. The AGN summary of location, customer segment and participation for the first 2 phases is shown below.

Location	Customer Segment	Phase 1 Workshop Attendance	Phase 2 Workshop Attendance	Return Rate (%)
Adelaide	Residential customers	20	15	75
Adelaide	Business customers	19	17	89
Adelaide	CALD customers	21	16	76
Port Pirie	Residential and business customers	16	14	88
Barossa	Residential and business customers	17	11	65
Murray Bridge	CALD customers	10	6	60
Mt Gambier	Residential and business customers	25	22	88
	TOTAL	**128**	**101**	**77**

Since the release of this chart in the Draft Plan, we have observed high return rates of people attending the phase 3 workshops.

While the repeat workshops were no doubt the centrepiece of the AGN engagement strategy, we have also observed meetings of the South Australian Reference Group (SARG) which is an ongoing group of a range of stakeholders. AGN also meets regularly with a Retailer Reference Group. Joint meetings of the SARG and Retailer Reference Group were held in late March and early April 2020, online, as social distancing was coming into effect as a response to the COVID19 virus.

We are also aware of other engagement activities including online engagement through a website, separate meetings with large industrial customers and 3 co-design workshops exploring approaches to assist vulnerable customers.

As a subpanel we were able to observe most of the stage II and stage III workshops, meetings of the South Australian Reference Group, joint meetings of the Reference Group and Retailer Reference Group and vulnerable customer co-design workshops.

We note that KPMG was employed to support the engagement process.

Our overall observations were that all engagement activities were well-run, and the participants engaged actively. The CEO and/or other senior staff members participated in every workshop and eagerly sought out the views of customers. Furthermore, people who were part of engagement activities clearly enjoyed their time listening, debating and contributing.

While it is a simple measure, it is instructive that 10 pages of the 120-page Draft Plan, a significant amount, tabulates topics discussed by customers and stakeholders and AGN's responses which we opine are strongly evident throughout the Draft Plan.

The phase 3 engagement program dealt specifically with the Draft Plan and asked all participants for direct response to four specific questions as well as feedback on any topic raised in the Draft Plan.

We expect that AGN will include reports on the phase 3 engagement in the AAP.

The engagement program has been well-planned, well delivered, open respectful and dare we say, engaging. We observe that it has been a comprehensive program with no questions "off the table".

We note that in terms of the IAP2 spectrum, most of the engagement activities occurred in the consult / involve section of the spectrum. We observe that AGN is well-placed to move more of their engagement into the involve / collaborate stage of the spectrum. The "promise to the public" of the collaborate place on the spectrum is "we will look to you for advice and innovation in designing and conducting the research and incorporate your advice and recommendations to the maximum extent possible." We suggest that this "promise to the public" is particularly relevant with the 'future of gas' issues that AGN will be grappling with over the next AA period.

Q2. Have we considered customer and stakeholder feedback and responded appropriately in this Draft Plan?

It is significant to note that AGN has developed a series of performance measures that are based on regular surveying of customers and which are reported widely through the business, to the South Australian Reference Group, and more broadly. The results from their performance measurement during the current regulatory period is given in section 3 of the Draft Plan and indicates that seeking and responding to customer feedback is a part of 'business as usual' for AGN. This means that there is a basis from which we can observe that customer feedback is broader than the development of and Access Arrangement Proposal.

This said, on page 41 of the Draft Plan AGN lists customer and stakeholder feedback comments regarding aspects of the Draft Plan and provides their response to each one, so there is clear evidence of responsiveness to customer and stakeholder feedback.

During stage III workshops of the engagement strategy, which were considering the Draft Plan, we heard the following topics being discussed as matters that we would expect reflected to a greater extent or in greater detail, in the final Access Arrangement Proposal.

a. Future of gas / low carbon future

We observed that across the workshops, this was a topic that consumers most wanted to hear about with questions about how hydrogen would work as the reticulated gas supply. There was also a strong interest in what it would mean for customers, including safety, and questions about product replacement and timelines.

While the Draft Plan includes clear information about the low carbon drivers for hydrogen and to a lesser extent bio methane, we suggest that the Access Arrangement Proposal will need to include more information about the following:

- Commonwealth and State government policy about hydrogen, including key decision points / timelines;
- key elements of the most likely pathway to hydrogen including what a transition from say 10% injection to 100% hydrogen would look like and implications for customers about possible appliance replacement and timelines;
- the role of the various stakeholders in hydrogen: governments, gas retailers, researchers and AGN's involvement;

- the range of potential future costs that would be borne by customers; and
- communication, information and education, particularly about hydrogen.

b. Other topics that were covered in the stage lll workshop, participant feedback and AGN responses.
c. Price path (which is considered in response to question 21)

3. Pipeline and Reference Services

Q3. Do you think then pipeline and reference services we have proposed are appropriate?

Consumer engagement supports retention of the existing services and this is consistent with the Reference Services Proposal approved by the AER in November 2019, so the answer to Q3 is "yes".

4. Operating Expenditure

On a 'like for like' basis, proposed opex expenditure is almost the same as the current period forecast. The increase in the total proposed 2021-26 opex is driven by two factors:

(i) a reduction in the level of capitalised overheads ie what is currently part of capex is now proposed to be part of opex, and
(ii) increased costs to purchase gas for unaccounted for gas (UAFG)

$20/21	Current Period 2015-21		2021-26
	AER allowance	Forecast	Forecast
Opex (excl UAFG)	340	281.5	281.3
Proposed change in capitalisation			23.4
UAFG		39.0	48.8
Total opex	340	320.5	353.6

AGN are proposing 2019/20 as the base year and claim that it is efficient. There are no step changes. On trends – labour costs increase in real terms by 0.8%/yr and material costs increase at the rate of inflation. Productivity growth is assumed at zero. Options to provide UAFG by renewable gas are explored.

Q4. Do you support investment in a vulnerable customer assistance Program? Do you have any feedback on the activities we have proposed?

Our observation is that responding to vulnerable customers is an ongoing aspect of AGN's work program and so we would anticipate some further development of thinking about vulnerable customer assistance between the release of the Draft Plan and lodging the Access Arrangement Proposal.

In the Draft Plan, AGN identifies four vulnerable customer assistance program opportunities that they are currently considering:

- priority services register that allows proactive contacting of customers in circumstances such as outages;

- rebates or discounts for connection fees or plumbing assistance;
- policy advocacy for vulnerable customers; and
- specialised training programs for customer facing service roles.

It could well be argued that the first, third and last of these opportunities should be part of business for an energy network business and so should be a responsive part of 'business as usual'.

Support for the second measure would need to be tested with a broader customer base since this measure would most likely come at a cost. We expect that cost would be absorbed by AGN. We look forward to hearing from AGN about the feedback that they receive about this question from their ongoing engagement.

We also note that consideration of vulnerable customer assistance is likely to gain a sharper focus during the COVID19 period where there may well be heightened community awareness of the need to support vulnerable members of society.

Q5. Do you support investment in replacing lost gas with renewable gas to reduce carbon emissions?

The AGN consumer engagement on this issue involved presentation of the following options showing the increase in the annual bill for each.

How much?	How green?	Bill Impact (Estimate)
Replace 20% lost gas with renewables	• 12 tonnes carbon reduction • 4,000 cars off the road	$1.50
Replace 40% lost gas with renewables	• 21 tonnes carbon reduction • 7,200 cars off the road	$3
Replace 100% lost gas with renewables	• 46 tonnes carbon reduction • 16,000 cars off the road	$5.50

Given the comparatively small bill impacts and the overall strong response to engagement around supporting further action on reducing carbon emissions, it was perhaps not surprising to see relatively strong support for at least some replacement of UAFG with renewable gas. We think that providing engagement participants with additional data showing the cost/t CO_2 reduced from this initiative compared to other carbon reduction initiatives AGN is considering, would have assisted their consideration of the proposal.

Q6. Do you support investment in an Education Centre and learning program to help position South Australia as a leader in hydrogen technology?

This question was one of four focus questions that were asked during the phase 3 consultation workshops and from our observations the topic that received the greatest diversity of participant responses.

We suggest that there are three aspects of this question that AGN (and the AER) may want to consider should this proposal be included in the Access Arrangement:

1. To what extent should the benefits from an Education Centre (assuming that there are net benefits) be paid for by AGN customers when the benefits are likely to be broader than purely for AGN customers. In other words, with whom could the costs of an Education Centre be shared for example State Government, universities, TAFE, Clean Energy Council, Australian hydrogen strategy, philanthropists etc
2. What are the benefits for AGN customers from establishing an Education Centre?
3. What is the level of support from AGN customers?

CCP24 has reservations about funding an investment in an Education Centre from regulated revenue. The benefits to AGN customers are not clear. CCP24 considers that, assuming there are benefits to South Australian gas customers from an Education Centre at a time of growing interest in renewable gas, then any (minimal) contribution from AGN customers should be to leverage funding from sources other than AGN.

Q7. Do you have feedback on the activities at the Education Centre should perform? For example:

- Staffed centre, open to the public, housing hydrogen appliances, information packs etc?
- Primary school education program, including regional outreach
- Stakeholder centre, open for Government and industry meetings – positioning SA as a leader in the renewable gas space?

Should AGN include funding allocation for an Education Centre as part of its Access Arrangement Proposal, we would expect that the AER would have more up-to-date information and a broader than South Australian perspective than we have now, for example COAG Energy Council views on the topic, the development of the Australian hydrogen strategy, and we would also anticipate the AER seeking advice from national renewable energy agencies for their perspective.

We do not consider it appropriate to CCP24 to comment on this question, other than to observe that it is a question about which AGN is seeking stakeholder and customer input.

Q8. Do you support our approach to forecasting opex? Is there sufficient information to understand our proposals and the basis of the costs included in our forecast?

AGN is using the AER's base-step-trend approach. To be able to fully understand and support the approach requires a range of information:

- Details on relative performance among gas distribution networks – this is not available now but, given the recent AER initiation of expanded network reporting[1] should be available in a few years' time;
- Details on historical performance of AGN - which is available.

Given the data that is available, we can say that AGN has shown in the current period that it has improved its opex productivity significantly compared to the last period but we have no idea how that places it in a league table with other regulated gas distribution networks.

We leave it to the AER to assess whether the proposed base year of 2019/20 is "efficient" as defined in the rules. Given the significant reduction from allowed opex we expect that the base year ($52.9m) will be seen as efficient.

However, given that forecast opex for 2021-26 (excluding changes in capitalisation and UAFG) is almost identical to the forecast for 2015-21, but 2021-26 capex is forecast to decrease by 5% and total demand is forecast to fall by 4% then, either:

- it is not obvious that opex efficiency will continue to improve in 2021-26, or
- it will continue and AGN expects to maximise the EBSS benefits in 2021-26.

AGN seeks to argue (p.66) that applying the AER productivity methodology used in electricity to gas would lead to a reduction in network productivity based on AGN's Victoria and Albury gas network over 2018-22. AGN has proposed a 0% productivity and argue this should be accepted by consumers as it results in no increase in opex over 2021-26.

We find this logic difficult to accept. It appears there has been a significant improvement in opex productivity in the current period. AGN seems to be arguing that this is irrelevant in estimating what might be achieved in 2021-26. We would suggest otherwise.

This debate around opex productivity is an example of the constraints that consumers have in assessing gas network efficiency in the absence of AER benchmarking data. The debate around opex productivity for electricity networks where EBSS applies is a combination of:

- how much of movements of the efficiency frontier moving outwards (ie productivity incentivised by a network acting as a profit maximising firm), and
- the selection of the 'not materially inefficient' benchmark for the base year and application of the EBSS,

both of which impact on the share of efficiency gains that accrue to consumers and what is retained by network owners.

The AER accepted consumers' submissions that in a regulatory framework designed to replicate what occurs is a workably competitive market, a portion of that movement (0.5%/yr) should go 100% to consumers with any additional improvement being shared 70/30 under EBSS. As the AER noted in its final decision[2]:

"an annual operating expenditure productivity growth rate of 0.5 per cent reflects a reasonable forecast of the productivity growth a prudent and efficient electricity distributor can make."

[1] See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/priorities-and-objectives-for-reporting-on-regulated-electricity-and-gas-network-performance

[2] See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-our-approach-to-forecasting-opex-productivity-growth-for-electricity-distributors/decision

The absence of this incentive applying to gas networks means there is no incentive for a prudent and efficient gas network to offer any productivity gain that is not covered by the EBSS.

While it is pleasing to see AGN not proposing any step changes, saying it will absorb positive step changes, the transparency around this decision could be improved by examples of negative step changes that are expected to occur (apart from reductions in pass through regulatory/compliance costs). We would be very surprised if there are none.

In our Advice on the Evoenergy Gas Network Draft Plan for 2021-26, we suggested that given the ACT Government policy of zero net emissions by 2025 and their subsidisation of consumers moving from gas to electricity, there is no basis for Evoenergy spending on marketing to convince customers to switch from a low efficiency to a high efficiency gas appliance. Given the expected similar policy from the SA Government in the near future, we would consider that AGN marketing to convince consumers to switch from a low efficiency to a high efficiency gas appliance only be an approved expenditure until the anticipated Government policy change is legislated.

We do not support the proposed continuation of forecasting future labour cost trends by using the average of the two consultant forecasts – Deloitte and BIS Oxford - but expect to see the AER's final position on this matter in the forthcoming final decision on the Jemena Gas NSW network. We consider this perspective to be particularly pertinent to the impact of COVID 19 virus which is resulting in higher rates of unemployment and even more income uncertainty for many people than was the case before the onset of the virus. We note that over recent years real incomes for a growing number of people have been falling. There is a growing risk that increasing AGN labour rates, in real terms, when many customers are coping with static or declining real incomes, could fray at the social licence that AGN has actively developed.

Finally, we note that the current UAFG cost estimate based on a continuation of the current approach of purchasing methane, requires greater transparency. AGN is yet to receive its consultant's forecast of the volume of UAFG for the forecast period and in the interim have applied the average of the last three years. Our particular interest will be in more transparency around the price/GJ forecast. The 25% increase in total costs suggests a significant increase in price/GJ. We understand that the AGN network means that it can only purchase gas from one supplier.   We also expect to see declining volumes of UAFG as the integrity of the network is improved with the removal of 'leaky' cast iron and early version HDPE pipes. Fewer leaks should result in lower costs.

5. Capital Expenditure

Forecasting Process

AGN has outlined a four-step capital planning process in the Draft Plan (Draft Plan, Figure 8.2). Investment priorities are identified, having regard to Asset Management Plans, Risk Management Framework, regulatory obligations and projected network growth. Forecast costs are determined by either unit-rate estimates or non-unit-rate forecasts depending on the type of work to be carried out.

Q9. Do you support our approach to forecasting capex, including our approach to mains replacement in the next AA period?

CCP24 acknowledges that a robust capex planning process underpins the forecasts presented in the Draft Plan. We look forward to examining the details of the capex planning process in the Access Arrangement Proposal.

Capex Forecasts

AGN is proposing a 5% reduction in net capital expenditure for the next Access Arrangement Proposal, compared to the current period.

Table 8.1: Actual and forecast capex by priority ($million, 2020/21)

Priority	Current AA period	Next AA period	Drivers for change
Safety and reliability	375.5	387.4	✓ Start modification of transmission pipelines to allow inline inspection (ILI) ✓ Lower mains replacement program
Growing the network	194.1	159.9	✓ Proposed Mount Barker extension in 2020/21
Customer service	40.3	32.1	✓ Reduction in the number of periodic meter changes required
	609.8	579.4	

The headline capex details are shown in the table above with declines in spending for 'growing the network' of 18%, and 'customer service' of 20%. There is a 3% increase in proposed spending for the category 'safety and reliability', which in other settings would be regarded as replacement expenditure and network maintenance.

The Draft Plan lists eight "Capex drivers" within the three priorities for the next regulatory period, these being:

1. mains replacement
2. meter replacement
3. augmentation
4. telemetry
5. IT system
6. growth assets
7. other distribution system assets
8. other non-distribution system assets.

The focus of expenditure for each of these "drivers" is well summarised with three quarters of the expenditure being for mains replacement and growth assets.

Safety and Reliability

The mains replacement program at $292million is 50% of the proposed capital expenditure and will bring to an end a long-term program to replace the remaining cast-iron mains as well as replacing remaining first-generation high-density polyethylene (HDPE) pipes, which have not proven to be as durable as initially expected.

'Safety and Reliability' capex also includes expenditure on IT assets as follows:

- maintaining and upgrading current applications to ensure they remain current, fit-for-purpose and resilient to cyber threats - $18million;
- rationalising IT applications and infrastructure across AGIG - $8million;
- implementing an Asset Investment Planning Tool -$2million

In addition, this category includes a $2million replacement of SCADA and associated equipment.

Growing the Network

The 'growing the network' component of capital expenditure comprises 28% of total proposed expenditure. It comprises connection of 43,000 new residential and industrial customers, as well as augmentation of the network in both the north and south extremities. Augmentation is proposed to be 2% the total capital expenditure budget and centres on two augmentation projects, the building of a new high-pressure main and gate station at Gawler, to the north of the greater metropolitan Adelaide network to provide a connection with the SEA gas transmission pipe. The second project is to increase capacity in the southern suburbs of Adelaide.

Customer Service

The main expenditure under the 'customer service' category is meter replacement. In the current regulatory period 150,000 meters are planned to be replaced. The forecast is for replacement of 93,000 meters over the next AA period at a total cost of $19million, based on declined performance of historic meters and the need to replace them for improved safety and efficiency. The 'customer service' category also includes investment of $5million to deliver more customer services digitally.

Q10. Is there sufficient information to understand our proposals and the basis of costs included in our capex forecasts? Is there any other information that would assist in the assessment of our proposal?

Mains Replacement

The mains replacement program has been the subject of considerable consumer engagement and discussion and completing the program in the next Access Arrangement period aligns with customer expectations. We understand that this work will address important safety concerns, as well as diminish the rate of gas leaks in the network. It will also mean that the South Australian gas network would be hydrogen ready, should hydrogen be the future of gas for energy. We note the factors that are leading to a higher average cost forecast across the mains replacement program. Our understanding is that costs were increased in the current AA period due to the complexities of mains replacement works being undertaken in the Adelaide CBD. As this work is expected to be completed in the current AA period, we would expect there to be a reduction of cost forecasts in the next period. We expect that the various cost drivers will be outlined in the Access Arrangement Proposal.

Meter Replacement

It is not clear why the meter replacement rate has reduced significantly for the next period. For a customer base of 450,000, replacement of approximately 150,000 meters in every 5-year period would be expected, given the standard asset life of 15 years. We note that AGN has actively explored a rollout of smart meters with various customer segments and concluded that while there is some interest in smart meters there is not a strong community appetite for them, and so AGN's approach is to provide smart meters where requested at a cost to the customer. This approach has been supported in the engagement sessions that we have observed, however we did not observe discussion regarding the potential benefits of smart meters to consumers such as facilitation of monthly billing, or the reduction of meter reading costs. Efficiency of the meter replacement program is another area for elaboration in the Access Arrangement Proposal.

Growth

'Growth' is the most difficult driver to assess because of the uncertainty about the future of natural gas in a carbon constrained future, notwithstanding the commitment of AGN to green hydrogen as the long-term future, and their leadership in exploring hydrogen as a future fuel. All the same, investment in growing the network must evoke caution in a period of significant longer-term uncertainty. On the other hand, a significant part of the proposed 43,000 new residential and industrial connections we understand, will be occurring in Mount Barker, which has been the focus of research, engagement and planning throughout the current regulatory period, and which the AER has accepted.[3] At this stage we understand that the project has not been approved by the AGN/AGIG Boards

it is also understood that increasing customer numbers should improve network productivity and ultimately lower costs for all customers.

Forecasts of future demand for gas are also difficult in the current environment, so while the AGN demand forecasts are well explained, and considered in response to questions 18-20, we find it difficult to have a definitive view on this aspect of proposed capital expenditure at the Draft Plan stage and signal to the AER and to AGN, that we would expect this to be a topic of more scrutiny as the Access Arrangement Proposal is developed and subsequently analysed by the AER.

Augmentation

We note the proposal to invest $8million in a new high-pressure main and gate station to provide a new connection into the SEA Gas transmission pipeline in Gawler. CCP24 questions whether this is a prudent investment the event of a future hydrogen network. Firstly, we understand that there may be concerns relating to transporting hydrogen through steel pipelines[4], and secondly, we are unsure whether hydrogen supply will be provided via the traditional gas transmission network. We expect the business case for this project will elaborate on the implications of future gas supply options, and the potential for stranded asset risk.

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[3] https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/australian-gas-networks-future-capital-expenditure-determination-mount-barker-gas-network-extension>

[4] For example, see the discussion on embrittlement in high pressure transmission pipelines at p.51 in the December 2019 report to COAG Energy Ministers http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/nhs-hydrogen-in-the-gas-distribution-networks-report-2019_0.pdf

Telemetry & IT Systems

Details provided in the Draft Plan are insufficient to enable us to form a view on the investments described under these categories. We will review the business cases presented in the Access Arrangement Proposal with interest. For the IT System investments, we will also be keen to understand the business drivers, and cost sharing arrangements between AGN and other AGIG entities. Our expectations are that productivity improvements driven by IT investments will be reflected in future opex forecasts.

Other distribution system assets

The Draft Plan presents the rationale for inline camera inspection of early generation plastic piping, but not the basis on which the volume and cost estimates have been developed. We anticipate that more details will be available in the Access Arrangement Proposal.

We question the program of elimination of high-risk meters located in buildings and carports. CCP24 understands that consumer engagement prior to the current Access Arrangement period identified a lack of support for this program to be funded by AGN, rather revealed a preference for funding to be provided by the owner of each premise.

The Draft Plan is silent on the potential for developers to contribute to network costs through capital contributions, which would result in cost reductions for consumers.

6. Capital Base

The Draft Plan identifies that the closing capital base for the current AA period will be $1,793.7million, and the closing capital base for the next period is forecast to be $2,120.7million, an increase of 15.4% over the period. The 'Regulated Asset Base' per customer increases from $3986 to $4271, an increase of 7.1%.

We note that AGN proposes to use standard AER approaches to calculation of the capital base, and employs the 'year-by-year' tracking approach for calculating depreciation.

AGN proposes to bring forward $215million of depreciation over the next AA period to write off the value of assets that were removed from the network as part of the mains replacement program in the current period.

Q11. Do you have any comments on our proposed approach to adjust our capital base over the current and next AA periods, including how we have taken into account our mains replacement program?

CCP24 is concerned at the forecast growth in the capital asset base, when the business is facing an uncertain future due to questions about the feasibility of employing hydrogen as a replacement for natural gas over the next 20-30 years. This presents an increasing stranded asset risk for customers should the hydrogen solution fail to eventuate.

While we agree that assets removed from service should correspondingly be removed from the regulated asset base, we observe that $215million is a very large write off to take effect in a single regulatory period, with a resultant significant impact on prices. We have not observed any engagement with customers on this issue, although it is presented as one of 'intergenerational equity' for customers. We anticipate that engagement with customers on this issue will be a priority prior to finalisation of the Access Arrangement Proposal, involving a discussion of options for applying the depreciation over more than one regulatory cycle.

Q12. Do you consider the RBA-based approach will produce better forecasts to the inflation relative to the bond break even approach? Are there any other approaches to forecasting inflation that should be used / considered?

The issue around the best measure of expected inflation was the subject of an extensive review by the AER in 2017. That review focussed on two questions[5]:

(i) What method should we use to estimate expected inflation?

After examining a range of measures, including the bond break-even approach proposed by AGN, and used by the AER until 2008, the AER concluded that the existing RBA method:

> "… has the greatest strengths and fewest weaknesses and therefore provides the best estimate of expected inflation."

(ii) Does the regulatory framework deliver appropriate compensation for inflation?

The AER concluded that:

- Targeting the real rate of return is consistent with the National Electricity Rules
- The AER's approach does deliver this real return (aside from some minor and symmetrical deviations that do not affect our overall conclusion)

Following submissions from networks over the last 12 months, the AER has recently announced another review focussing on the same two questions as the 2017 review, plus a third:

(iii) should the regulatory framework target a nominal (ie nominal WACC) or hybrid (eg real equity/nominal debt) return?

With a timetable that has the AER publishing its final position paper by December 2020. We look forward to seeing the AER Discussion Paper in early May and subsequent stakeholder submissions to inform our response to AGN. If the review results in a simple change in the methodology for estimating expected inflation then any change will be incorporated into the AER's decision on AGN's 2021-26 AA. Any changes involving a rule change and the rate of return will not be incorporated in the 2021-26 decision.

The current RBA method gives an expected inflation rate of 2.34%. AGN has indicated that using their preferred measurement approach (bond break-even) would result in an expected inflation rate of 1.5%.

7. Financing Costs

AGN calculates the WACC according to the December 2018 binding rate of return guideline. This gives the following indicative WACC with gamma at the level set in the guideline.

[5] AER "Regulatory treatment of Inflation – Final position" December 2017 https://www.aer.gov.au/system/files/AER%20-%20Final%20position%20paper%20-%20Regulatory%20treatment%20of%20inflation%20-%20December%202017%20-%20Web%20upload.PDF

Table 10.3: Indicative AER Rate of Return and Gamma

Parameters	AGN Draft Plan
Return on Equity	4.69%
Return on Debt	4.73%
Overall Rate of Return	4.72%
Gamma	0.585

The actual WACC will be calculated in early 2021 as part of the AER's final determination.

The tax allowance is calculated according to the outcome of the 2018 tax review. This gives a zero tax allowance for 2021-26.

Q13. Do you have any comments on our approach to setting the financing and tax costs from the Draft Plan?

We agree with the approach taken by AGN.

In its discussion of setting the rate of return, AGN revisits arguments discussed in the 2018 Rate of Return review – that gas networks face greater systematic risk than electricity networks and hence should have a higher equity beta than electricity networks[6].

The argument is that given gas is discretionary (consumers can ultimately do without it), whereas electricity is essential, gas has a higher income elasticity of demand. Ceteris paribus this means higher systematic risk, though proponents agree it is difficult to quantify that higher risk is a specific adjustment to the beta. The NZ Commerce Commission decided on a 0.05 uplift to the asset beta applicable to regulated gas pipeline businesses in New Zealand.

This will no doubt be an issue in the 2022 review of the rate of return binding guideline.

Of interest in the context of this reset are the potential implications of this higher systematic risk on the 2021-26 capex plan. If systematic risk is higher and this justifies a higher beta, then why increase that risk with additional capex in 2021-26 before we have the data to indicate that hydrogen is economic?

[6] See for example the submission from the APGA on 12th December 2017 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-instrument-2018/initiation

8. Incentives

AGN currently operates with one incentive scheme – opex efficiency benefit sharing scheme (EBSS) in which the benefits of opex expenditure lower than the AER allowance amount are shared 70% to consumers and 30% to AGN. AGN propose that this continues.

AGN proposes two additional incentive schemes:

(i) Capital efficiency sharing scheme (CESS) - the benefits/costs of capex expenditure lower/higher than the AER allowance amount are shared 70% to consumers and 30% to AGN

(ii) Network innovation scheme – the current regulatory framework makes it difficult to invest in innovation because the CESS and EBSS schemes provide an incentive to reduce costs; this would be similar to the Demand Management Innovation Allowance Mechanism operating for electricity distribution networks.

On (i) the AER applies service performance measures to ensure that reduced capex spend does not result in reduced service levels. AGN is proposing similar Asset Performance Index (API) measures as their Victorian operations – SAFI, SADI and the number of reported leaks. The network's 30% share falls to zero if these measures fall below 80% of their respective targets.

AGN are consulting with their stakeholders on (ii) prior to launching across industry consultation process.

CCP24 comments

Q14. Do you support our proposal to maintain the opex efficiency benefit sharing scheme (EBSS)

Q15. Do you support our proposal to introduce a contingent capital expenditure efficiency scheme (CESS)? If so, are there any other matters you think should be incorporated into the CESS?

As the Draft Plan notes:

> "A key objective of the regulatory framework is to promote efficient investment in, operation and use of, gas distribution networks."

We consider that continuation of the EBSS and initiation of the CESS are consistent with that objective. We look forward to more detailed consumer engagement on the specific API metrics.

Q16. Do you think a network innovation scheme should be implemented? If so, what level of funding do you think should be allowed under this scheme? For example, $1per year ($2.5 million), $2 per year ($5 million) and so on? What type of projects should be in scope?

There is little doubt that the trend towards decarbonising energy markets and new emerging technologies including for more efficient network maintenance, mean that developing innovative approaches to a range of network issues and fostering innovation is an important part of future electricity and gas networks.

AGN has also identified that the Demand Management Innovation Allowance Mechanism (DMIAM) now applies to electricity networks to encourage innovation that will improve network productivity and support energy sector carbon emission reductions. There is logic to the argument that a similar mechanism should also apply to gas network businesses noting that arguably gas businesses are having to innovate (or wind down) more quickly than electricity businesses.

There is a prima facie case for an innovation allowance for gas network businesses however, there are some important caveats, namely:

- Any innovation expenditure must have a very high probability of providing benefit to customers of greater value than the cost.
- An innovation allowance would need strong support from customers, and ongoing engagement with them.
- Projects funded through innovation allowance should involve a range of stakeholders, where possible, including researchers, consumer interests and other businesses in the gas supply chain, and regulators.
- As with the DMIAM, the rules for gas innovation allowance should be standard across the NEM, and preferably nationally.
- Funding for gas innovation projects should be shared by the relevant gas network customers State and Commonwealth governments, researchers and the relevant renewable energy bodies.

We look forward to observing future engagement with customer and other stakeholder groups by AGN and encourage regular dialogue between the AER, AGN and other gas network businesses.

Q17. Do you think a Customer Service Incentive Scheme (CSIS) should be implemented?

It is recognised that there is current consideration of a Customer Service Incentive Scheme that has been proposed by AusNet Services electricity distribution business through its Customer Forum. The AER has conducted a formal process of consultation and analysis to consider this proposal. The outcomes may be relevant to gas network businesses.

We also observe that gas is a much more reliable network than electricity, due to its network being almost wholly underground, and so customer contact is less frequent for gas network businesses, though it remains important. It is also clear that the strength of AGN is that they have very high customer satisfaction scores, which have been measured regularly for the duration of the current regulatory period.

Consequently, we agree with the conclusion that AGN has reached on this question; “our conclusion is therefore that CSIS is not required to be applied for the next AA period”.

9. Demand

AGN use external experts, Core Energy & Resources, to forecast demand for three separate customer groups – residential, commercial (<10TJ/yr) and industrial – that reflect the haulage reference services to be provided over the 2021-26 AA period. These forecasts accord with the forecasting best practice guideline developed by the AER in 2013. Forecasts were tested with the SA Reference Group. In summary the demand outlook is:

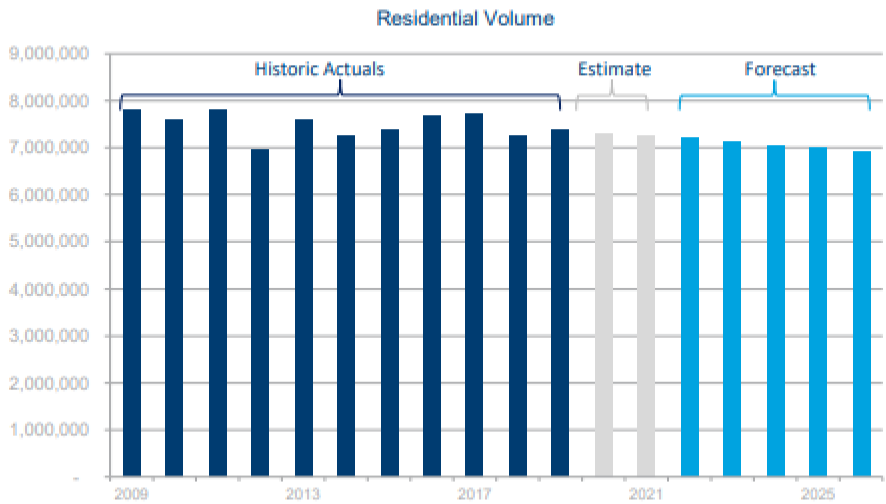
Residential	Falls by 1%/yr driven by higher wholes gas prices, increasing penetration of solar energy and energy efficiency
Commercial	Rises by 0.2%/yr driven by SA growth forecasts
Industrial	Falls by 1.3%/yr in response to higher wholesale gas prices

The build-up of the demand outlook for residential and commercial is similar - a combination of normalising historical data for weather and gas and electricity prices, forecasts of average consumption per connection and then forecast connections. The forecast for industrial customers was informed by survey responses for 10 of the current ~110 customers.

Q18. Do you consider our approach to forecasting demand to be reasonable?

As noted above, AGN utilise the services of Core Energy & Resources to assist in their development of demand forecasts across residential, commercial (SME'S) and industrial load, with the following demand forecasts for the period to the end of the next access arrangement.

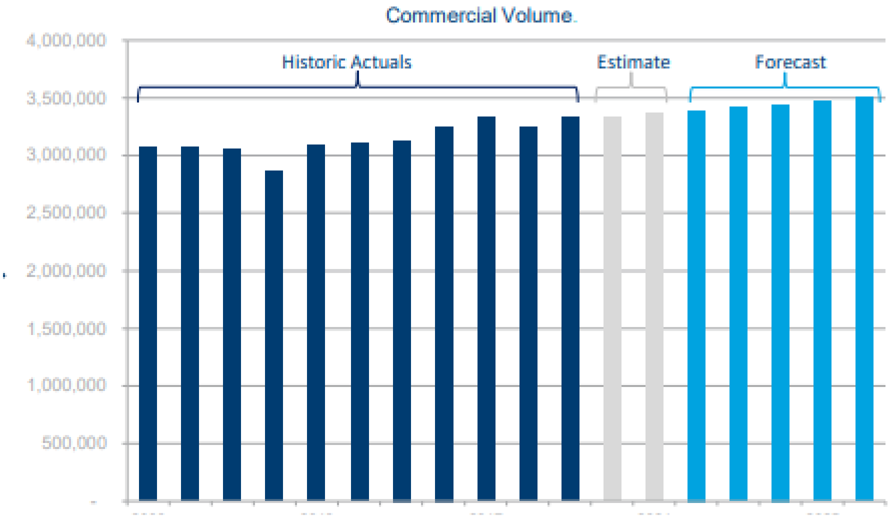
Residential Demand



Regarding residential demand the Draft Plan states:

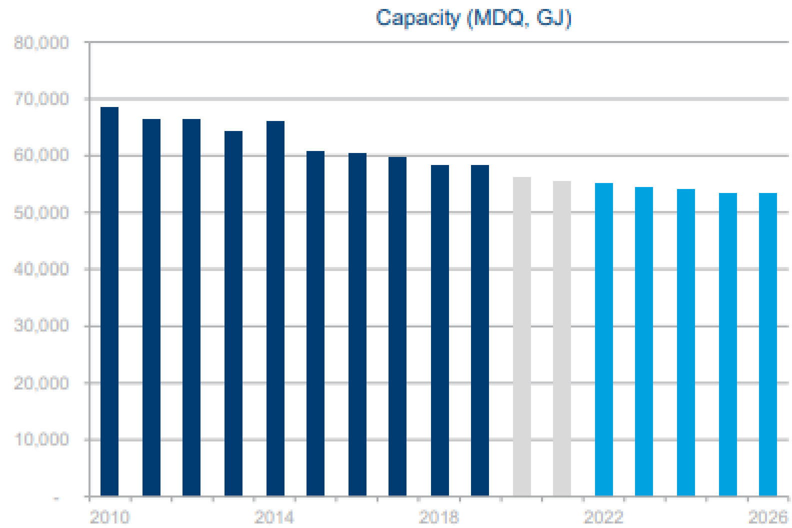
"This methodology results in residential customer number growth of 1.3% per year and residential consumption per connection decline of 2.3% per year resulting in an overall volume decline of 1.0% per year."

Commercial Demand



The Draft Plan states "This methodology results in Core's forecast for Commercial customer number growth of 1.1% per year and Commercial consumption per connection decline of 0.9% per year resulting in volume growth of 0.2% per year"

Industrial Demand



The analysis and Draft Plan included the following from Core:

"We conducted a survey of our largest Industrial customers to understand their business plans going forward, which informed Core's connections, volume and capacity forecasts

• Core forecasts the decline in connections based on both historical trends and our Industrial survey
• Core factors in international competitive, pricing and technological forces which drive efficiencies in consumption and hence capacity requirements

• This results in a decline in connections of 1.4% per annum and a decline in capacity of 1.5% per annum"

Our observation is that the analysis is thorough and has passed the "reasonableness test" from consumers with whom AGN has engaged.

We make two comments regarding forecasts for the AAP:

(i) We suggest that the apparent specificity of the forecasts perhaps belies a precision that is not reasonable for a forecast, and so it would make sense for there to be either a statement of probability about the accuracy of these forecasts or perhaps more usefully, they could be located within a range with some consideration then given to implications for AGN for both the high and the low forecasts from the range. This assumes that the forecasts given above are somewhere near the midpoint of likely ranges.

(ii) Regrettably the advent of COVID19 means that these forecasts may now be more optimistic than post-COVID forecasts will be, and so we are sure that AGN will give some consideration to this unanticipated change in circumstances.

Q19. Are there other factors we should consider in developing our demand forecast

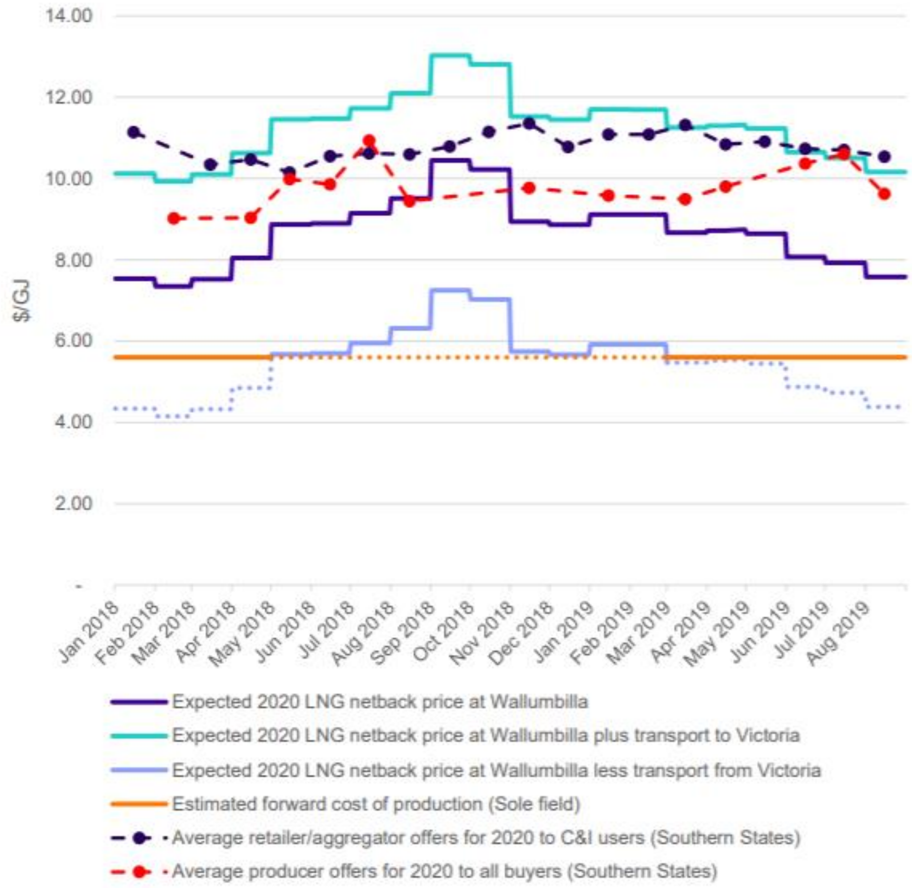
We consider that in a normal world the approach taken is both reasonable and robust. We expect that AGN will provide a view on this impact its June 2020 AAP and then January 2021 revised AAP.

Current events may provide a whole series of conflicting signals that impact own-price and cross-price elasticities eg lower economic growth, fall in prices of both electricity and gas due to demand destruction and lower international prices finally being translated into lower domestic prices for industrial customers; and a Government desire to increase local manufacturing in the medium term to lessen reliance on international supply chains.

The industrial demand forecasts presented show a 0.84% decline in annual consumption and a slight decline in the number of connections from 113 at the start of the period to 106 at the end of the period. While the proposed reduction in network tariffs will be welcome, the main concern for these users is the wholesale price of gas. If the recently published ACCC data on producer/retailer offers to C&I customers in Southern States up to August 2019[7] are indicative of offers to SA customers, then the falls in LNG netback are a long way from being passed on to domestic customers.

[7] See p. 61 https://www.accc.gov.au/system/files/Gas%20inquiry%20-%20January%202020%20interim%20report.pdf

Chart 2.4: Average of monthly gas commodity prices offered for 2020 supply against contemporaneous expectations of 2020 LNG netback prices (Southern States)[120]



In the absence of COVID19 impacts, this suggests industrial customers will struggle to survive where gas is a major input cost.

Q20. The South Australian Government has legislated to reduce carbon emissions by at least 60% below 1990 levels. Do you think this target will impact on gas demand over the next AA period, and if so, how should this be factored into the demand forecasts?

It is difficult to forecast impacts of carbon emission policy on gas demand for the next regulatory period particularly now that COVID / post COVID impacts are more likely to be dominant at least in the first half of the regulatory period.

However, we observe a close working relationship between AGN and the South Australia Government and that there is respect and understanding with both parties fully aware of the views of the other. We are also aware that the South Australia government has expressed strong support for exploring green hydrogen as a future gas fuel, and so we observe that there is close alignment between the South Australian Government and AGN on this matter.

Consequently, we are optimistic that whatever happens in policy terms, there will be a constructive and proactive relationship between AGN and the SA Government. It is our opinion, and opinion only, that South Australian Government emissions strategies are unlikely to significantly impact on AGN during the next regulatory period. We expect impacts more likely to be experienced in the 2026-31 regulatory period, by which time more should be known about the potential viability of hydrogen. This is discussed further in the Attachment, "Gas Futures: Considerations of Hydrogen Opportunities and Stranded Asset Risk".

10. Revenue and Prices

AGN affirm our experience that:

> "…affordability is the highest priority" (p.112)

Based on the building block revenue, the real price growth per year is shown in the following table:

Table 13.2: Proposed Price Path, 2021/22 to 2025/26 ($nominal, million)

	2021/22	2022/23	2023/24	2024/25	2025/26
Building Block Total Revenue (excluding ARS)	216.3	226.6	238.8	236.8	243.4
Smoothed Revenue	217.8	224.8	232.1	239.7	247.9
Real Price Path	-7.9%	1.2%	1.2%	1.2%	1.2%

The pricing is designed to align to the growth in the capital base to meet a "conservative" (p.114) view of the credit metrics the credit agencies require to maintain a long-term rating between A- and BBB+. The AER cost of debt calculation as part of the WACC calculation assumes the average borrowing costs of both these ratings. AGN says that the pricing in the Draft Plan:

> "…partially satisfies the thresholds required for a weighted average A-/BBB+ rating" (p.114)

If key parts of the Draft Plan are not accepted and these ratios are not met, then AGN proposes varying the inflation rate used in calculating regulatory depreciation and/or shifting capex to opex to allow earlier recovery of expenditure.

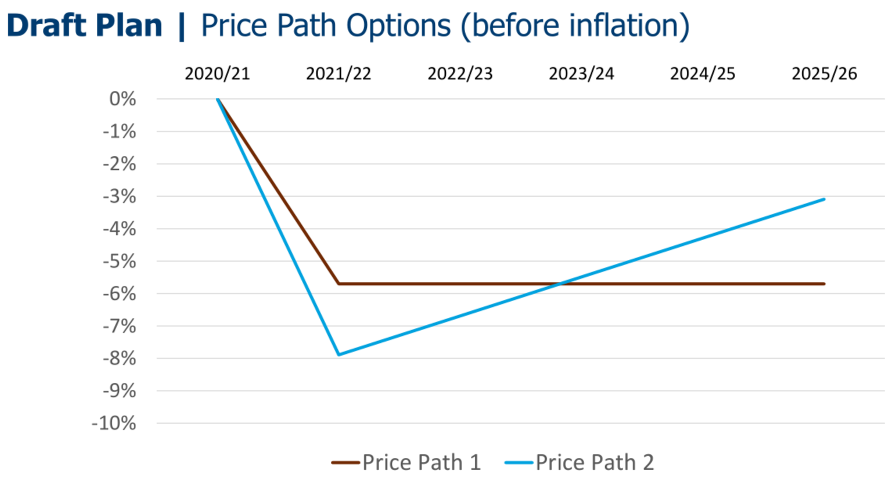
AGN supports continuation of the existing pricing structure for 2021-26:

- for residential and commercial customers, a fixed (25%) plus variable declining block tariff structure (75%); consumers have indicated a preference for a large variable component; and
- for industrial customers, a capacity based declining block tariff.

The declining block tariff reflects lower marginal cost of provision of higher gas volumes and promotes increasing asset utilisation to offset the general decline in gas consumption.

Q21. Do you support our objectives of maintaining stable credit metrics and aligning revenue with underlying costs in setting our proposed price path? Would you prefer an alternate price path, and if so, on what basis?

In engagement with the various Reference Groups in early April, AGN proposed two price pathways for 2021-26:



Price Path 2 is the one that is consistent with the key credit ratios. Involving the largest price fall in year 1, this path is traditionally supported by consumers and has been in AGN's consumer engagement. Price Path 1 is supported by SA gas retailers as it provides more simplified billing where prices are only changed in year 1. AGN argues that Price Path 2 also minimises any price rise in year 1 of the next 2026-31 regulatory period given it has a higher year 5 price in 2025/26.

Q22. Do you consider that explicit consideration should be given as to whether a pricing proposal provides sufficient cash flow to maintain the credit rating assumed by the AER in setting the cost of debt? If so, how do you think this assessment should be done – for example, by considering the credit metrics against levels assumed by ratings agencies? If an adjustment to prices is required, how should this be undertaken – for example, through changes in capitalisation and depreciation?

We consider that it would be useful for AGN to provide more detail in the AAP to justify the "conservative view" of the rating agencies measures of FFO to debt and FFO to interest cover.

<u>Additional comments</u>

CCP24 suggests that addressing the following matters will assist consumers' interpretation of the proposed prices and price paths.

(i) What has been the impact of falling WACC and tax allowance on prices?

In particular, it would be helpful to show:

- the standard waterfall chart showing the changes from current period revenue to 21-26 revenue – with major components – WACC, tax allowance, depreciation, opex etc.
- what the price path would have been with the same WACC and tax allowance as the current period.

(ii) Presentation of price changes

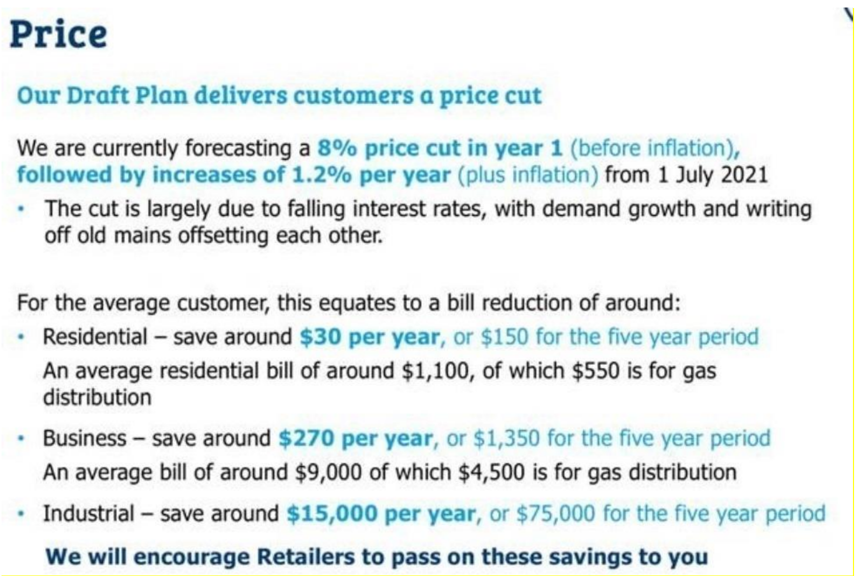
We find the presentation of the price path confusing in a number of aspects:

- Lines 1 and 2 in table 13.2 above are in nominal terms but line 3 is in real terms, but this is not clear in the table labels;

- The headline "8% real price fall" point is achieved by comparing:
  a) the nominal price on 30th June 2021 + the 2021/22 expected inflation rate (2.3%) with
  b) the nominal price on 1st July 2021

The price in (b) was 8% below the calculated price in (a). We don't think this is a transparent way of describing the price change. We prefer, particularly in the current environment of very low inflation, a simple comparison between the nominal price on 30th June 2021 and 1st July 2021. That is 5.7%.

The Phase 3 customer workshops in March used the following slide:



In this slide the price change on 1st July in percentage terms was combined with the average price change in nominal $ terms over the 5-year period which can be confusing. Two comparisons on the one slide are confusing.

(iii) Impact of a different expected inflation measure

It is worth noting that were AGN's preferred approach to measuring expected inflation adopted, the price fall in year 1 would be only 1.1% with no increases in the following years.

Q 23. Do you support AGN continuing to standardise terms and conditions across its network?

We acknowledge the leadership shown by AGN in convening and engaging on a regular basis with its Retailer Reference Group (RRG). CCP24 is not aware of any other network business that has a similar arrangement in place for engagement with retailers. We have observed discussions between AGN and the RRG on the terms and conditions of the Access Arrangement Agreement. Our expectation is that AGN will apply the advice it receives from its customer and stakeholder engagement, while complying with the National Gas Rules.

11. Conclusion

Q24. Is there anything that our Draft Plan hasn't considered that is important to you?

The question that we have raised with AGN that we suggest is under-presented in the Draft Plan is elaboration from AGN on its longer-term plans, for example for the period 2026 to 31. This is particularly with reference to the potential for hydrogen as the gas fuel because the current plans for the next AA are fairly clear: trial injection of hydrogen into the existing gas supply network up to about 10%, explore utilising hydrogen to replace unaccounted for gas and continue further research. If a hydrogen future is to be achieved, we assume that close to 100% hydrogen in gas mains would need to be achieved by about 2045. What is unclear is the staging posts from say 10% hydrogen in 2025 to 100% hydrogen in 2045. Given that other gas networks are already talking about accelerated depreciation of the gas network, a sense of the future beyond the 2021-26 Access Arrangement is pertinent.

We also think that the impact of Mt Barker on forecasts for future demand could be more explicit.

Q25. Do you have any further comments or feedback on our Draft Plan overall?

Leadership

CCP24 recognises the AGN leadership in Australian energy markets, including the pro-active consideration of hydrogen as a future fuel, CEO Ben Wilson now chairing the Energy Charter and active participation in a range of ENA committees and projects. While our focus remains on AA2021-26, the broader role that AGN is playing shapes the AAP and the consumer centred and pro-active culture that they demonstrate. The culture of AGN is one of believability and credibility which is why we think that the ambition of 'capable of acceptance' can be taken seriously.

The tough question

In discussing the future of hydrogen, CCP24 remains concerned that considerations about the stranded asset risk to consumers should hydrogen prove not to be economic has received insufficient attention to date. In response, CCP24 has developed the attached discussion paper "Gas Futures: Considerations of Hydrogen Opportunities and Stranded Asset Risk" to explore this issue in more detail, and prompt further informed discussion and actions regarding the potential risk mitigation strategies for consumers in this environment.

12. Attachment - Gas Futures: Considerations of Hydrogen Opportunities and Stranded Asset Risk

1. Introduction and Summary

This attachment arose out of CCP24's consideration of the potential stranded asset risk to consumers from an expanding gas network when Governments are moving towards zero net carbon emissions targets. ACT already has a legislated commitment to zero net carbon emissions by 2045[8]. Advice from AGN is that South Australia is expected to make a similar commitment over the 2021-26 AGN Access Arrangement (AA) period, also with a timeframe of between 2045 and 2050.

Within this context, the more we considered the issues, the more we began to focus on the wider suitability of the National Gas Law (NGL) and Rules (NGR) to meet the National Gas Objective in this policy environment. This Attachment has two objectives with associated recommendations:

Objective	Recommendations
(i) Given AGN is not proposing accelerated depreciation, how should consumers assess AGN's proposed $160m expansion capex where it has an asset life greater that the likely date of a zero emissions target?	Matters that AGN should consider including in the next stage of its consumer engagement to ensure its consumers are supportive of its approach
(ii) Examine at a high level the suitability of the National Gas Law and Rules to consider stranded assets in the changing Government policy environment	A holistic review by the AER of these rules to assess whether they are fit for purpose for the next 10-20 years

(i) AGN's proposed expansion capex given no consideration of accelerated depreciation in 2021-26

The AGN argument for not considering accelerated depreciation in 2021-26 is driven by a combination of:

- confidence that the gas industry will have a much better idea of the potential for 'economic'[9] hydrogen in time for the 2026-21 reset; and
- a preferred price path that provides for price falls in year 1 of each revenue period as a key part of retaining and increasing customer numbers; the large depreciation in 2021-26 from its mains replacement capital results in a lower RAB from 2026/27; this gives 'head space' to consider accelerated depreciation during 2026-31 and still provide a price fall in year 1 of 2026-31.

This led to our examination of the following question:

> *"Where a Government has, or is expected in the near future to, legislate a formal target of zero net carbon emissions (or similar) by a particular future date, should consumers support expansion capex where:*

[8] https://www.environment.act.gov.au/__data/assets/pdf_file/0003/1414641/ACT-Climate-Change-Strategy-2019-2025.pdf/_recache

[9] This Attachment refers to hydrogen being 'economic' when it is 'commercially mature' ie when it can be commercially viable as a substitute for natural gas for reticulated gas purposes without a specific subsidy or specific policy direction.

- *the assets have an expected asset life longer than that expected future date, and*
- *the alternatives to natural gas are currently not commercially viable and are not expected to be over the term of the reset period under consideration?"*

Hydrogen is a hot topic for Governments, energy industry players and particularly for gas pipeline owners. For Governments and energy industry players it is seen as a key part of achieving Australia's Paris climate change targets. For gas pipeline owners it is more direct – hydrogen is the key to their long-term survival.

So, understandably, AGN sees a bright future for gas and hydrogen. It does not want to be managing a network that is not expanding, and even potentially shrinking. AGN is committing to significant R&D expenditure to assess the potential for 'green' hydrogen. If successful this will replace natural gas and ensure a growing customer base with network assets fully utilised for the designed asset lives where they are beyond a zero-emissions target setting date.

We share the hope for a hydrogen future as potentially a key part of achieving the Paris climate goals. However, we must also actively explore the current reality that hydrogen is not yet a proven, cost effective energy alternative to 'natural gas' or electricity.

The most comprehensive current forecast of the hydrogen roadmap is in the National Hydrogen Strategy[10]. This Strategy concludes that it is very unlikely that hydrogen will be a competitor for piped natural gas before 2030. With this outlook, it is reasonable to assume, in the context of the 2021-26 AA that all *new market expansion* ('new') capex with an asset life of greater than ~30 years has the risk of part of the asset value becoming stranded.

(ii) Suitability of the National Gas Law and Rules to consider stranded assets in the changing policy environment

Consideration of the AGN specific issues led us to ask a broader question - are the NGR and NGL fit for purpose in a world of stranded asset risk from substantial Government policy change?

AGN's proposed expansion capital will be submitted and assessed according to r79, where the selection of the term of the NPV analysis may mean that stranded asset risk is not taken into account. The AER will also have to have regard to the National Gas Objective in section 23 of the NGL and the revenue and pricing principles in section 24 of the NGL that may be interpreted as allowing for consideration of stranded asset risk.

While we discuss a range of options to address the stranded asset risk consumers may face, we are not experts on rules interpretation. We do not know whether the objective of protecting consumers from unnecessary stranded asset risk can be achieved by a different AER interpretation and application of the current rules in an uncertain world, or whether it requires amendments to the rules.

[10] National Hydrogen Strategy November 2019 https://www.industry.gov.au/sites/default/files/2019-11/australias-national-hydrogen-strategy.pdf

This has led us to recommend to the AER that it undertake a more holistic review to consider whether the current NGL/NGR are fit for purpose for the next 10-20 years given emerging Government policy on zero emissions.

The current Jemena Gas 2020-25 AA for NSW has highlighted different interpretations of how the NGL and NGR apply to accelerated depreciation. Jemena's submission for accelerated depreciation was rejected by the AER in its Draft Decision[11]. Jemena's revised proposal and a report prepared by INCENTA[12] have argued that the AER's Draft Decision is an incorrect application of Rule 89 of the NGR and Section 24 of the NGL. The AER Draft Decision not to accept Jemena's proposal argued that there was insufficient evidence that stranded asset risk is occurring. Jemena's response is that a deferral of the decision only increases the adjustment required when the risk is recognised and it is too late for gas networks to respond.

While Jemena's proposal was to apply accelerated depreciation to all new capex with an asset life over 30 years, whereas our focus is on all new expansion capex with an asset life over 30 years, we consider that the range of views on the NGL and NGR supports our recommendation for a more wide-ranging review by the AER of the NGL and NGR.

We would suggest a similar argument from consumers' perspectives. Consumers, like networks, benefit from a clear and understandable regulatory framework. The longer a decision is delayed, the greater the likelihood that consumers will bear stranded asset risk and the greater the likelihood that that risk will be borne in inefficient and inequitable ways among different consumers. The risk of a 'death spiral' may be greater in gas compared to electricity because of the ability to substitute electricity for gas.

Finally, we would like to highlight and acknowledge the willingness and openness with which AGN has engaged with us as we have tested these ideas in respectful, sometimes robust discussions. We would also like to acknowledge the assistance of AER staff in helping us navigate the complexity of the NGL/NGR. The willingness to explore 'the tough questions' recognises evident willingness to seek the best outcome for customers.

2. The problem and the challenge

We agree with the AGN concept of 'economically stranded asset'[13] as described in the following example:

- If the residual value of an asset today is $1m and it has an expected remaining life of 50 years then the asset owner will receive that $1m over the 50 years with straight line depreciation
- However, if an assessment of its economic life is only 30 years, then recovery, in the absence of a move to accelerated depreciation, will only be only $0.6m
- So, $0.4m is the 'economically stranded asset'.

We recognise that an asset may move in and out of being stranded over its life.

[11] Note that this paper was written before the AER Final Decision was made for JGN
[12] INCENTA "Using asset lives to manage stranded asset risks" December 2019 https://www.aer.gov.au/system/files/JGN%20-%20Attachment%208.3%20-%20Incenta%20-%20Using%20asset%20lives%20to%20manage%20stranded%20asset%20risks%20-%20January%202020.pdf
[13] Correspondence with CCP24 8th April 2020.

The issue of stranded asset risk has a long history in regulatory economics[14]. It has been present for years as own and cross price elasticities, competition, technology changes or changes in Government policy mean past investments will reach a stage in their life when they will never be utilised to the level assumed in their original regulatory approval business case. This Attachment is concerned only with the last – where a stranded asset is the result of an exogenous Government policy change – here an actual or likely net zero carbon target.

We distinguish between three capex categories:

(i) Historical capex spent up to the end of the current reset period
(ii) Replacement capex proposed for 2021-26 to sustain existing connections
(iii) Expansion capex proposed for 2021-26 - both 'infill' where it is new connections in areas where gas is already available and 'augmentation' where it is expansion of the network to new regions/suburbs.

Our focus here is with (iii). We argue that the party which bears stranded asset risk associated with (i) and (ii) is set by the existing regulatory contract between network, consumer and the AER under the existing rules.

In one sense we are asking – does an exogenous change in Government emissions policy mean we need to consider a new regulatory contract which involves a different range of policy options and risk allocation?

Gas pipeline owners deliver a product that, unlike electricity, has a substitute – which is electricity. The gas network asset base components have very long lives. Getting back return *of* capital is slow. There can be substantial policy changes over the life of a 50-60 year asset that result in stranding risks to both asset owners and consumers, depending on the form of regulation.

The table below shows the standard asset lives used by AGN in its last AA together with their forecast RAB value at the beginning of the next AA period.

Asset Class	**Standard Life (years)**	**Projected opening RAB on 1st July 2021**	
		$m	%
Mains	60	1,300.0	73.3%
Inlets	60	197.2	11.1%
Meters	15	61.5	3.5%
Telemetry	20	3.2	0.2%
IT system	5	10.1	0.6%
Other distribution system equipment	40	199.0	11.2%
Other	10	1.6	0.1%
Total		1,772.5	100%

AGN: Standard asset lives and asset value

[14] Stranded asset considerations have been applied to railways, canals, telecommunications, for example and the literature for treatment of stranded assets has a history of at least 80 years, with Harold Hotelling one of the early economists to tackle the problem.

Developers/builders are making a decision on whether to connect gas on the basis of a range of factors eg building codes and incentives like free connections provided by networks. Buyers of these houses and units are then effectively stuck with gas for at least the life of the gas appliances.

The move by Governments to net zero emissions targets by 2045-2050 to meet Paris commitments is the most significant policy change to impact on gas networks in decades. Implementation can include changed building codes that no longer require gas connection[15] or potentially to ban new connections until there is economic zero carbon or carbon neutral gas.

Hydrogen (and to a much lesser extent biomethane) is seen as that gas. It presents the opportunity for gas network owners and consumers to avoid stranded asset risk and for network owners to guarantee the return of capital over normal asset lives.

While hydrogen is 'technically mature' (ie we know how to make it, transport it and use it), there are still a range of technical issues to be addressed eg (steel pipeline) embrittlement, blending and hydrogen appliances. The big industry challenge is around when it will be 'commercially mature' (referred to in this Attachment as 'economic' hydrogen) ie when will it be commercially viable as a substitute for natural gas for reticulated gas purposes without external subsidy or specific policy direction. Governments and gas networks are ramping up efforts to address these issues with a range of spending initiatives, some of which we comment on below.

The Commonwealth Government's National Hydrogen Strategy however suggests that it is very unlikely that pipeline hydrogen will be commercially mature prior to 2030. If hydrogen is proven not to be economic in 5-10 years' time, consumers may be suddenly faced with a gas network charge assuming an asset life of only a further 10-20 years rather than 50, as accelerated depreciation steps in. Slow recovery of capital suddenly becomes very fast as network charges increase significantly. In the context of a 'no regrets' decision framework, consumers may regret that their builder installed gas in 2022.

This raises an important issue for consumers in the context of AA reviews for regulated gas networks, including AGN. Under what conditions should consumers (both existing and those who are the beneficiary of the new connections) support capex on 30+ year life new connection assets - whether it be infill where there is an existing gas reticulation infrastructure or connection of new suburban/ commercial/industrial developments?

Should there be no new connections capex allowed until there is a clear pathway to economic hydrogen? Alternatively, under what conditions should consumers support this capex and take on the stranded asset risk if hydrogen proves not to be economic?

3. Some background

(i) Gas industry vision and Commonwealth Government Policy

The Australian gas industry published the Gas Vision 2050[16] in 2017. It[17]:

> "…highlights how gas and renewables can support each other to achieve a near zero carbon energy sector by 2050, including a decarbonisation pathway for natural gas beyond 2050."

[15] As in now the case in the ACT.
[16] https://www.appea.com.au/media_release/gas-vision-2050/
[17] https://www.australiangasnetworks.com.au/news-and-articles/advice/gas-vision-2050

The ENA/APGA Gas Vision 2050 published last October talks about[18]:

> "Our plan is to demonstrate the viability of these [hydrogen] technologies by the mid-2020s and then start reducing emissions in individual networks, with the objective of full conversion across the country to zero emissions gas in the longer term…Through these activities [various hydrogen related activities], it is expected that the cost of hydrogen will be competitive with natural gas within the next five to 10 years"

AGN describes its strategy of achieving a 'carbon neutral 2050 target' through[19]:

> "…Replac(ing) all natural gas in the distribution networks with hydrogen or biogas, resulting in near zero-emission fuel delivered by our network."

Hydrogen is expected to be the major contributor – either 'blue' (produced from methane or coal with carbon capture and storage) or 'green' (produced by electrolysis using renewable energy). While the Commonwealth Government recently announced the development of a National Bioenergy Roadmap through ARENA[20], this option is not considered in this paper as it is considerably behind hydrogen in terms of getting support to move to commercial maturity.

The recent International Energy Agency study on the potential for hydrogen around the world, concluded[21]:

> "The report finds that clean hydrogen is currently enjoying unprecedented political and business momentum, with the number of policies and projects around the world expanding rapidly. It concludes that now is the time to scale up technologies and bring down costs to allow hydrogen to become widely used."

In the Australian context, while hydrogen has all the benefits it has in any country eg versatile use across a range of energy and feedstock uses including replacing natural gas and firming renewables and providing a measure of liquid fuel security, it is also seen to have a great opportunity given Australia's potential vast low cost renewable energy resources. This, along with Australia's reputation as a stable investment destination with high skill levels, offsets the high cost of labour and the cost of water especially if desalination is required. Exports in the form of steel[22], ammonia or aluminium may be possible given the high transport costs for hydrogen.

The Finkel review laid the basis for the National Hydrogen Strategy that was adopted by COAG Energy Ministers in November 2019 with the Commonwealth, States and Territories rolling out various programmes to support pilot plants and R&D.

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[18] ENA and APGA " Gas Vision 2050 –
Hydrogen Innovation Delivering on the Vision" https://www.energynetworks.com.au/resources/reports/gas-vision-2050-hydrogen-innovation/ p. 1

[19] https://www.australiangasnetworks.com.au/gas-explained/the-future-of-natural-gas

[20] https://www.minister.industry.gov.au/ministers/taylor/media-releases/setting-path-bioenergy-future-energy-source

[21] IEA "The Future of Hydrogen" June 2019 https://www.iea.org/reports/the-future-of-hydrogen

[22] eg the recent Grattan report "Start with steel: A practical plan to support carbon workers and cut emissions" May 2020 https://grattan.edu.au/report/start-with-steel/

For example, in May 2020, the Commonwealth Government announced a $300m boost to the Clean Energy Finance Corporation[23] debt and equity funding to support the growth of a "…clean, innovative, safe and competitive Australian hydrogen industry." This will include funding to support ARENA's Renewable Hydrogen Deployment Funding Round[24] that will provide a $70m grant programme aiming to demonstrate the technical and commercial viability of hydrogen production using Proton Exchange Membrane (PEM) technology.

(ii) The South Australian Government policy context

There is a trend for State and Territory Governments to endorse some form of net zero carbon policy by around 2045-2050. Victoria's *Climate Change Act 2017* establishes a long-term target of net zero greenhouse gas emissions by 2050[25]. The ACT Government recently legislated a net zero emissions target by 2045[26]. The NSW Government has a 2050 net zero goal in its recently released climate change policy[27].

In South Australia, under the Climate Change and Greenhouse Emissions Reduction Act 2007[28], South Australia has a target to reduce by 31 December 2050 greenhouse gas emissions within the State by at least 60% to an amount that is equal to or less than 40% of 1990 levels as part of a national and international response to climate change[29].

The current Government has recently set an aspirational target of net zero emissions by 2050 and AGN has advised their expectation is that the Government will move to legislate this following publication of its formal Climate Change Strategy due in mid-2020. Although this may be delayed with COVID19, it seems reasonable to assume the target will be formally in place, if not before, then soon after the start of the 2021-26 AA period.

4. AGN is playing a leading role in this transition

AGN is playing a leading role in implementation of the 2050 Gas Vision shown by the following current examples:

(i) Pilot green hydrogen plant under construction in Adelaide – Hydrogen Park SA[30]

[23] https://www.cefc.com.au/media/files/cefc-welcomes-launch-of-new-300-million-advancing-hydrogen-fund/
[24] See https://arena.gov.au/knowledge-bank/renewable-hydrogen-deployment-funding-round/
[25] https://www.climatechange.vic.gov.au/reducing-emissions/emissions-targets
[26] https://www.environment.act.gov.au/__data/assets/pdf_file/0003/1414641/ACT-Climate-Change-Strategy-2019-2025.pdf/_recache
[27] See NSW Department of Planning, Industry and Environment "Net Zero Plan Stage 1: 2020–2030" March 2020 https://www.environment.nsw.gov.au/-/media/OEH/Corporate-Site/Documents/Climate-change/net-zero-plan-2020-2030-200057.pdf?la=en&hash=D65AA226F83B8113382956470EF649A31C74AAA7
[28] https://www.legislation.sa.gov.au/LZ/C/A/CLIMATE%20CHANGE%20AND%20GREENHOUSE%20EMISSIONS%20REDUCTION%20ACT%202007.aspx
[29] https://www.environment.sa.gov.au/topics/climate-change/south-australias-greenhouse-gas-emissions
[30] https://www.agig.com.au/hydrogen-park-south-australia

This is a 1.25 MW Proton Exchange Membrane (PEM) plant ie green hydrogen produced using renewable energy, at the Tonsley Innovation District. This $11.4m plant, due for completion in mid-2020 received a grant of $4.9m from the State Government. The hydrogen produced will provide a 5% hydrogen blend with natural gas for supply to ~700 residential and business customers in suburban Adelaide.

(ii) Australian Hydrogen Centre in Adelaide[31]

Established in late 2019, this $4.2m Centre received a $1.3m grant from ARENA. Its R&D work will cover studies on the technical, economic and regulatory hurdles for blending hydrogen into natural gas networks and support subsequent detailed feasibility and design studies to facilitate an investment decision. This will include trials of a 10% blend in three locations in SA and Victoria. The Centre will also have an important role in educating the community on the benefits of hydrogen. AusNet Services, ENGIE and Neoen are also involved.

(iii) Hydrogen Park Gladstone[32]

This $4.8m PEM plant has received a $1.8m grant from the Queensland Government. Announced in February 2020, hydrogen produced will support a trial from late 2021 of a 10% blend in the local Gladstone gas network including the first supply to industrial customers.

(iv) Use of hydrogen for unaccounted for gas

AGN is has consulted with consumers on their willingness to pay to use varying levels of hydrogen to replace unaccounted for gas during 2021-26.

(v) Participant in a tender for the supply of 10% hydrogen

In March 2020, AGIG, Jemena, Evoenergy and AusNet issued a joint tender for the supply of 10% hydrogen for their distribution networks in Queensland, NSW, ACT, Victoria and South Australia. This is ~10PJ/yr. Responses are due in June.

CCP24 understands that by 2022, AGN expects to have evidence on:

- The ability to safely and reliably blend up to 10% hydrogen and community/policy support for widespread blending of up to 10% by 2030;
- Some idea of the feasibility of 100% hydrogen on a very small scale, and potential plans for an all hydrogen new residential development, and a credible pathway to 100% hydrogen appliances; and
- Large scale blending projects under construction (tender referred to above).

By 2024-25 when consultation is underway for the 2026-31 reset, AGN expects that there would be:

- supportive State Government policy eg requirement to use hydrogen for Unaccounted for Gas (UAG), and
- a reasonable scale (10MW) PEM plant operating based on a large Government subsidy.

[31] ibid

[32] https://www.australiangasnetworks.com.au/our-business/about-us/media-releases/gas-groups-hydrogen-push-moves-into-queensland

5. What is AGN proposing in its Draft Plan?

AGN is proposing a total capital expenditure of $579.4m in 2021-26 of which $159.9m is "growing the network". This growth capex is 18% lower than the forecast $194.1m growth capex spend in the current period.

The Draft Plan assumes the Mt Barker extension capex expenditure starts in 2020/21 (~$25m of the total approved $33m in the current 2017-21 period) with connection of new customers over the 2021-26 period. In its application to the AER in June 2018 seeking an advance determination under r. 80, AGN pointed to the extensive public consultation it had undertaken in evaluating the extension. Its application, backed by submissions to the AER review, showed widespread community and stakeholder support for the project. In December 2018 the AER approved the project as conforming expenditure under the criteria set out in r. 79 of the NGR[33]. However, AGN has advised CCP24 that the project has yet to receive approval from the AGN Board.

We understand AGN's argument for expansion capex in general to be threefold:

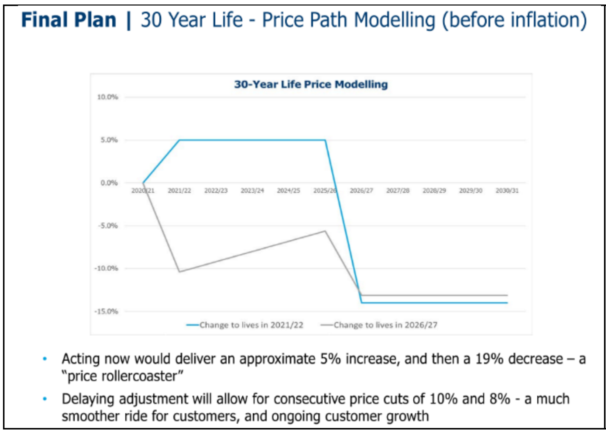
(i) it meets the conforming capex requirements under the NGR;
(ii) to not expand the network will mean the network will inevitably shrink and lessen the ability to deliver hydrogen in the future should it become economic, with the lack of expansion making the pathway to 'economic' harder given the smaller potential customer base;
(iii) it enables lower prices in 2021-26 as the new customers contribute to the shared network costs – if prices were to rise as a result of no new customers, then that would just hasten the end of gas.

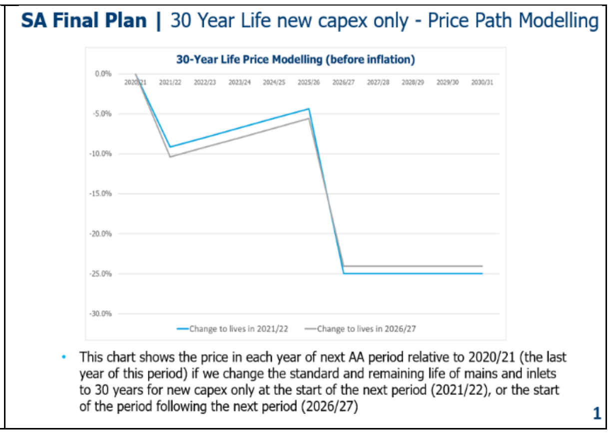
CCP24's understanding of AGN's position is that while they recognise some uncertainty regarding the use of hydrogen in the economy in the future, they are proposing expansion capex in anticipation of hydrogen becoming economic. We understand that AGN does not want to see a 'one time only' decision by the AER for the 2021-26 period closing off options for customers to use economic hydrogen in the future because expansion capex was not approved.

Further, AGN seeks to present a price path that provides for price falls as well as minimising large changes in prices. While the AA process limits the ability to set prices to the next AA period, AGN's actions in 2021-26 seek to influence the price in "Year 6," the start of the following Access Arrangement period. AGN has provided the following two figures to illustrate this point[34]. They both show alternative price paths over the next two AA periods depending on assumptions about the timing and level of accelerated depreciation.

[33] See https://www.aer.gov.au/system/files/AER%20-%20Final%20Decision%20-%20AGN%20-%20Mount%20Barker%20gas%20network%20extension%20-%2018%20December%202018_0.pdf

[34] Communication with CCP24 8th and 20th May 2020; note that while the price paths from 2021-26 are based on the Draft Plan and developments since then that will be incorporated into AGN's AA proposal in June, there are many simplifying assumptions behind the numbers for the 2026-31 AA period eg assumed the same average WACC of 4.37% as in 2021-26.





The starting point for both is AGN's current situation. Its mains replacement programme will be completed in 2021-26 and AGN are proposing a large increase in depreciation for 2021-26 reflecting full depreciation of past mains replacement capex. This means the RAB is much lower for 2026-32 period leading to the forecast fall in price on 1st July 2027 irrespective of the assumptions on accelerated depreciation.

The chart on the left is the price path over the next two regulatory periods assuming the asset lives of *all* assets in the 'mains' and 'inlets' RAB categories[35] are adjusted to 30 years from 1 July 2021. Instead of a price decrease of 10% on 1st July 2021[36] then a price decrease of 8% on 1st July 2027 without the adjustment (grey line), it would be a price increase of 5% on 1st July 2021 then a 19% decrease on 1st July 2027 (blue line).

The chart on the right is the price path over the next two regulatory periods assuming the asset lives of *only new* assets[37] in the 'mains' and 'inlets' RAB categories are adjusted to 30 years from 1 July 2021. The two price paths are, perhaps surprisingly, quite similar reflecting the smaller value of assets that are having the 30-year asset life applied.

AGN considers that the grey line in the chart on the left is the best-balanced price path of any of the four shown in the two graphs. Consumers prefer a 'smoother' price path – especially one that has price falls in successive AA periods and AGN is using the depreciation profile to help achieve this outcome. AGN considers that this price path provides the best opportunity for keeping existing and gaining new customers. It also allows AGN to focus also on the "year 6" price as it has "price space" to consider some form of accelerated depreciation from 1st July 2026, assuming external factors eg rising WACC, do not prevent this. Finally, this price path is seen to have a greater chance of retailers passing on the full impact of the tariff falls. The distribution tariff is ~50% of the delivered residential price of ~$65/GJ.

[35] From the table above this covers ~$1.8b; the $199m in the 'other distribution system equipment' was not included.

[36] While the Draft plan projected an 8% fall on 1st July 2021, this has now increased to 10% with a lower assumed WACC.

[37] Again only 'mains' and 'inlets'.

6. Some comments on the AGN approach

As we noted above, the 2019 Gas 2050 vision is that hydrogen will be '…competitive with natural gas within the next five to 10 years'. This section looks at the latest data from the National Hydrogen Strategy published in November 2019, and considers the methodology under the gas rules for assessing expansion capex.

(i) What are we forecast to know when, regarding the cost effectiveness of hydrogen?

Hydrogen is at or near the top of the technology readiness index but near the bottom of the commercial readiness index with small scale trials about to be underway[38].

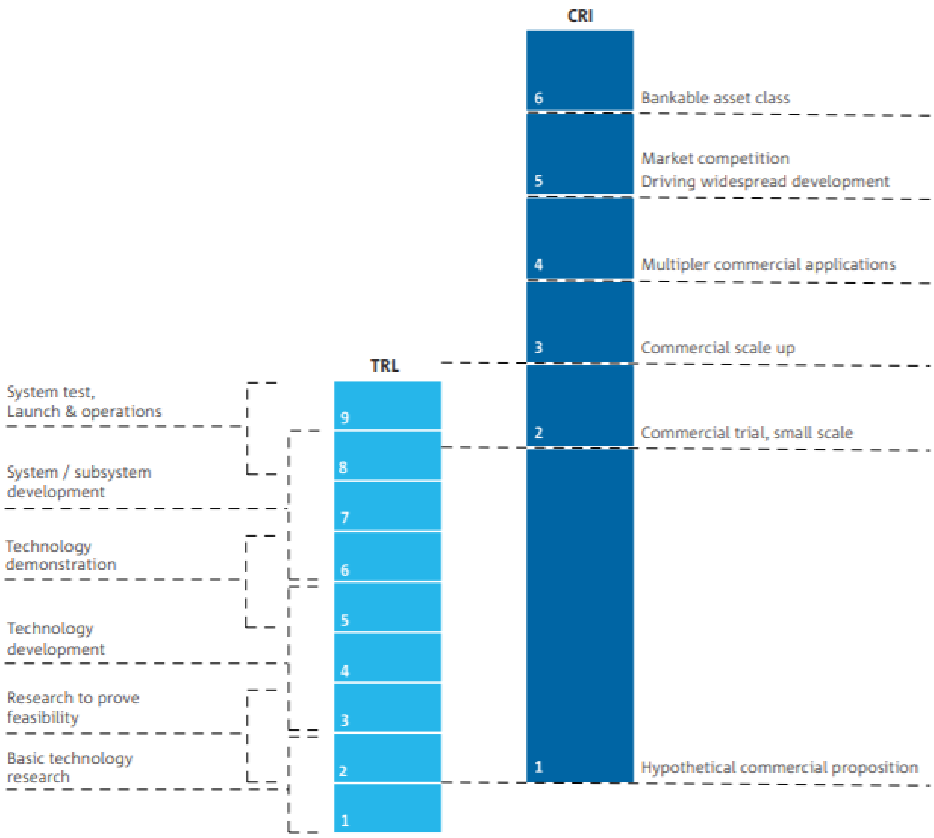


Figure 5. Technological and commercial readiness index[10]

[38] See CSIRO National Hydrogen Roadmap November 2019 p.5 https://www.csiro.au/en/Do-business/Futures/Reports/Energy-and-Resources/Hydrogen-Roadmap

Under the National Hydrogen Strategy, the "measures of success" for 2025 and 2030 are[39]:

2025

Clean hydrogen advances quickly	Clean hydrogen advances slowly
Hydrogen technology breakthroughs are occurring and uptake is driving cost reductions. Hydrogen scale is driving supply chain costs down rapidly	No or few hydrogen technology breakthroughs and there are minimal trials underway, meaning costs are not falling

2030

Clean hydrogen continues to advance	Clean hydrogen is falling behind
Hydrogen is cost-competitive compared to alternative fuel sources for some, if not most, hydrogen applications	Hydrogen is not cost-competitive and other technologies are the preferred low-emissions option in most, if not all, sectors

Hydrogen has different breakeven price points depending on its competing uses. Natural gas used for heating and domestic applications is one of the toughest places to reach that breakeven point. As shown in the table below, the estimated breakeven point for natural gas is ~$1.20/kg[40]:

Breakeven price points

This table shows the delivered prices hydrogen would need to achieve against competitor fuels.

Competitor fuel service	**Hydrogen breakeven price** ($/ kg H_2)
Drive 100 km using petrol (retail price $1.43/ L)[ii]	$13.31
Drive 100 km using diesel (retail price $1.50/ L)[iii]	$11.21
Deliver 1 GJ heat using natural gas (wholesale price approximately $10/ GJ)[iv]	$1.20

For comparison, the most recent comprehensive estimated costs in Australia from an ACIL Allen study in 2018 are as follows[41]:

[39] National Hydrogen Strategy op cit pp. 68-9
[40] Ibid p.xiv
[41] ACIL Allen "Opportunities for Australian for hydrogen Exports" August 2018 p. 30 https://arena.gov.au/assets/2018/08/opportunities-for-australia-from-hydrogen-exports.pdf

TABLE 4.1 HYDROGEN PRODUCTION TECHNOLOGIES AND COSTS IN AUSTRALIA

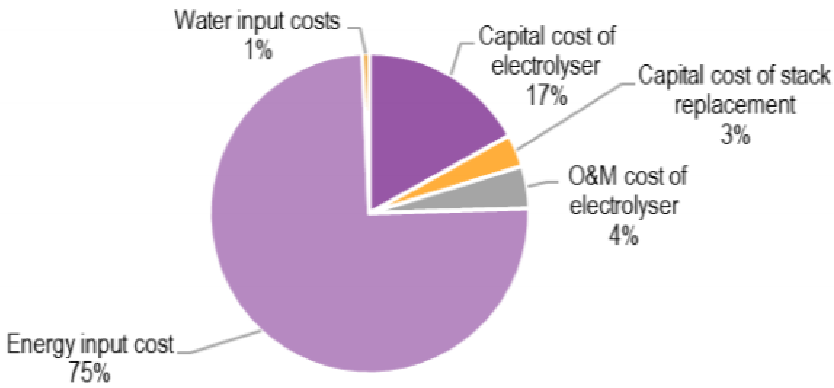
Technology	2018 A$/kg H_2	2025 A$/kg H_2
Proton exchange membrane (PEM) electrolysis	\$6.08–\$7.43	\$2.29–\$2.79
Alkaline electrolysis	\$4.78–\$5.84	\$2.54–\$3.10
SMR with CCS	\$2.27–\$2.77	\$1.88–\$2.30
Black coal gasification with CCS	\$2.57–\$3.14	\$2.02–\$2.47
Brown coal gasification with CCS		\$2.14–\$2.62

Note: CSIRO has reported 2018 as base case and 2025 as best case. PEM and alkaline electrolysis are based on grid-connected renewables with 93% capacity factor.

SOURCE: CSIRO 2018, NATIONAL HYDROGEN ROADMAP

ACIL Allen's analysis is that, given electricity accounts for such a large proportion of production costs[42] based on forecast 2025 capex, electricity needs to be ~3c/kWh to get to \$2/kg hydrogen[43]:

FIGURE 4.2 COMPONENTS OF HYDROGEN PRODUCTION COSTS IN AUSTRALIA



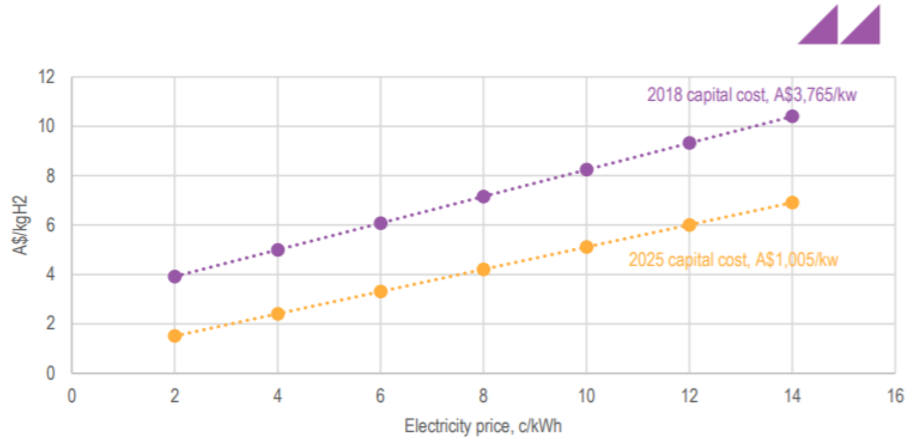
Note: Annualised cost shares. CSIRO has assumed 93 per cent capacity for renewable electricity.

SOURCE: CSIRO NATIONAL HYDROGEN ROADMAP 2018

[42] Ibid p. 34

[43] Ibid p. 35

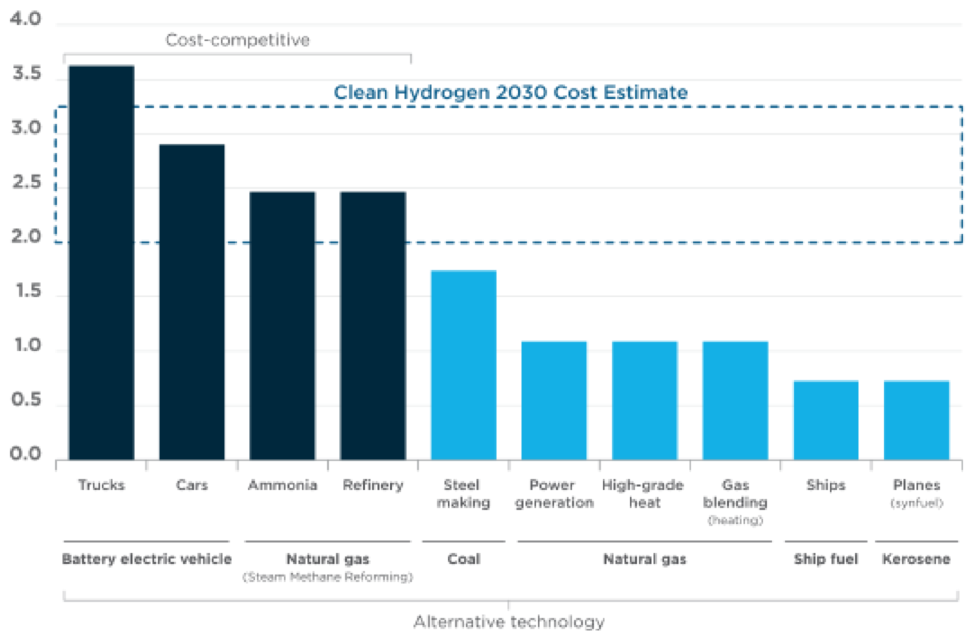
FIGURE 4.3 RELATIONSHIP BETWEEN RENEWABLE ELECTRICITY PRICES AND HYDROGEN PRODUCTION COSTS IN AUSTRALIA



SOURCE: CSIRO NATIONAL HYDROGEN ROADMAP 2018

Earlier this year the Commonwealth Energy Minster set up an advisory group led by Dr Finkel to advise on ways of getting to the very ambitious target of hydrogen under $2/kg[44]. While that price is likely to make it competitive for a range of uses eg long distance transport, motor vehicles[45] and ammonia, that price is not competitive with natural gas.

Figure 1.3 Breakeven cost of hydrogen against alternative technology for major applications, in 2030.



[44] See https://www.minister.industry.gov.au/ministers/taylor/speeches/keynote-address-ceda-future-direction-energy-technologies-event-sydney

[45] Daimler Benz recently announced that it is stopping development of hydrogen vehicles after 20 years of research because they were too expensive - electric vehicles were more promising; they will continue research on hydrogen for heavy vehicles; see https://electrek.co/2020/04/22/daimler-ends-hydrogen-car-development-because-its-too-costly/

This leads to a conclusion that, based on the National Hydrogen Strategy:

- hydrogen is unlikely to be a competitor for piped natural gas before 2030, and
- the discussion in 2024-25 leading into the 2026-31 revenue reset will be very similar to today – what risk should consumers continue to take on hydrogen development?

Based on this conclusion, continuing to invest in expansion capex in the 2021-26 period may not be consistent with a 'no regrets' approach, unless some of the policy options discussed below are considered.

(ii) Assessing the case for expansion capex

The regulatory framework for gas, developed at a time when gas prices were considerably below today's prices and climate change was much less of a public issue, is specifically designed to encourage gas consumption as an alternative to electricity, particularly through the conforming capex test in r 79. AGN will submit an expansion capex proposal that it believes meets the rule requirements – in particular the four grounds set out in r. 79(2) including:

> "(b) have an expected present value of the incremental revenue to be generated that exceeds the present value of the capex."

This allows an expansion of the network and increased customer numbers. Total network costs are then spread over a larger customer base and this results in lower prices to all – the denominator increase in customer numbers offsets numerator increase in capex/opex.

This mathematics assumes the asset is utilised for its full life. Yet this does not sit well in a world of net zero emission targets where the objective is reducing natural gas consumption, and expansion increases stranded asset risk if expansion asset depreciation profiles are longer than the zero-emissions target date. The increase in customer numbers does not offset the increase in the numerator under accelerated depreciation. Given the NGO refers to the long-term interests of consumers, the discussion of a lower price now cannot avoid a discussion of stranded asset risk, and a much higher price, later.

There also seems to be an inconsistency between the methods for assessing conforming capex and pricing the resulting network expansion. Following the AER's rejection of AGN's first Mt Barker application, AGN's second submission extended the NPV term from 20 to 30 years. This, even with the AER's constraining of residential demand growth to the first 20 years, gave the project the positive NPV required under the rules.[46]

The rules do not prescribe a term for the NPV analysis. Yet in calculating the price to be paid, AGN uses the asset life (much greater than 30 years) to set the price. This results in a lower price than would be the case if assets were depreciated over the same term as the NPV analysis. This, in turn, increases the probability of an economically stranded asset.

[46] We note that the AER undertook sensitivity testing on a -20% consumption combined with -20% penetration rate and the project still showed a positive NPV result.

7. What options might be considered to reduce consumers' exposure to stranded asset risk?

There are a range of measures that have been suggested as ways to address how the stranded asset risk around new expansion capex might be divided between the key stakeholders – Government, pipeline owners and consumers. We have grouped them in two categories:

(i) <u>Broader options outside the scope of this Attachment</u>

Direct Government investment eg subsidy, grant, low interest loan to support commercialisation

This is about taxpayers taking the risk on development of economic hydrogen to put in the pipeline.

Move regulation from a price cap to a revenue cap

Revenue cap regulation is more a tool for intra-period demand uncertainty, not asset stranding.

Increase pipeline Market Risk Premium as part of Weighted Average Cost of Capital

Gas networks often argue that they have greater stranded asset risk than electricity networks and hence should have a higher WACC. While this will no doubt be a matter discussed in the forthcoming WACC review, our view is that WACC is not a way of dealing with asset stranding which is a non-systematic risk. If hydrogen becomes economic subsequent to the AER allowing gas networks a higher WACC, it will be very hard for consumers to claw back the higher risk premium they have already paid.

Choose to move to being lightly rather than fully regulated

(ii) <u>Options we suggest be considered by AGN in its stakeholder consultation and the AER in its review of the NGL/NGL</u>

There are two sub-categories here:

(a) Limiting the level of capex going into the RAB in the first place

Ensure the incremental revenue test under r 79 explicitly takes potential stranded asset risk into account and is consistent with the depreciation rule

Ideally the incremental revenue test should focus on the economic life of the proposed assets. It is not clear that this is the current approach of the AER. Where a Government has or is expected over the AA period to have a zero emissions target then the period of the NPV analysis could be prescribed as no longer than the target year and then there would be no residual value in the model after that date. The depreciation rules refer to the economic life and this life should align with the NPV period. Currently there seems to be a misalignment between the two rules eg the Mt Barker NPV analysis under r 79 was for 30 years, but the majority of the spend will be on assets with a longer asset life – mostly 60 years.

If the AER in its Final Decision on Jemena's NSW Gas network confirms the Draft Decision and does not allow accelerated depreciation, it suggests networks are free to use economic lives longer than any expected zero emissions date. We are unsure how this accords with r74 which requires the best forecast or estimate to be used and to be arrived at on a reasonable basis.

Clarification of whether these proposed objectives require amendments to the rules or whether they can they be achieved by changing the way the AER interprets the rules is required.

Use of the speculative capex provisions under r.84

Under NGR r 84 AGN has the option of putting capex that does not meet the r79 test in a speculative investment bucket – effectively an unregulated asset. AGN had the option of doing that with Mt Barker, but chose to have it part of the RAB. As an unregulated asset, AGN would have been able to set a Mt Barker tariff according to what it thought the market could bear.

Generally, networks seem to favour inclusion in the asset base because it allows cross-subsidisation of the extension costs through postage stamp pricing across the whole network. AGN favours this option (see below) and this is how it is proposing to recover Mt Barker costs. The network does have the option in the future of meeting r79 and the asset coming back into the RAB with an NPV neutral outcome for the network[47]. Jemena's proposal to use that section for a component of the capex of a biogas project was rejected in the AER's Draft Decision[48]. In its revised proposal Jemena argued that their proposal was consistent with r 84[49].

AGN have responded saying that investors would be very unlikely to commit to lending for speculative capex provisions due to uncertain and / or delayed returns. AGN do own a number of Part 23 pipelines. In the Jemena situation, a significant proportion of the speculative capital is met by a grant, so Jemena investors are less exposed.

(b) Recovering the capex that is already in the RAB and who should pay for it

Accelerated depreciation with cost increase shared by all network users in postage stamp tariff

This is the conventional approach where the increased cost of accelerated depreciation on expansion capex is borne by all customers – it is just a matter of how this is calculated eg:

- Set at the start based on the asset life to the date of the zero emissions target, or
- Adjusted later if it becomes clear that hydrogen is not economic.

The former is likely to be preferable given the smoother price path. If say in 2030, hydrogen is shown to be economic then the tariff could fall to reflect the previously accelerated capital so far recovered and the now extended economic life of the asset in an NPV neutral way.

This is simple, but not efficient or equitable. We don't think it is equitable or efficient for an existing customer to subsidise the stranded asset risk of a new customer who connects to the gas network after a net zero emissions target has been announced, even if not legislated. We think it is efficient and equitable for all customers at Mt Barker to pay the efficient costs of their decision to connect and not be subsidised by other users.

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[47] Though consumers may object to this happening if the investment was made much earlier than reasonably necessary. They would be arguing for a delay to when WACC and indexation get applied.
[48] See pp 70-71 https://www.aer.gov.au/system/files/AER%20-%20Draft%20decision%20-%20JGN%20access%20arrangement%202020-25%20-%20Attachment%205%20-%20Capital%20expenditure%20-%20November%202019.pdf
[49] See pp.71-73 https://www.aer.gov.au/system/files/JGN%20-%20Attachment%204.2%20-%20Response%20to%20draft%20decision%20-%20Capex%20-%20January%202020.pdf

Differential cost based tariffs with users of expansion capex paying a higher price reflecting shortened asset lives

Consumers who benefit from the expansion capex pay a higher price that other pre-exiting consumers, given the shorter asset life of the expansion capex that is limited to the date determined by the zero emissions target.

The difference between this option and the previous one is that here consumer choice for supporting new connections and the network justification for new connections should be based on those new consumers paying the full cost of the new connection. There is no spreading of this cost to all other customers through a postage stamp tariff. Applying this approach to new customers in the Mt Barker expansion would mean they would pay a network tariff that reflects:

- their share of the existing shared network assets that the Mt Barker extension is connecting to (this covers historical capex and future sustaining capex and opex), *plus*
- the cost of the new Mt Barker assets based on the reduced asset life.

Again, if hydrogen was shown to be economic in the future, the tariff to Mt Barker customers would be adjusted as in the previous option.

The Draft Plan (p.115) proposes that the Mt Barker tariff will 'mirror' the Tanunda tariff ie be higher that other tariffs across the AGN network. We understand that the Tanunda tariffs R and C are higher reflecting the higher costs associated with connection of the region. AGN's Tariff D varies between the Adelaide region and other regions. Differential tariffs are quite common across jurisdictions and are important for equity and efficiency.

We do not see differential pricing creating confusion or complexity for retailers. They currently cope with a variety of electricity network pricing structures and have the choice of whether to market these to their customers. It is understood that Origin does not pass on the higher Tanunda tariff – but that is not a reason to not charge a retailer that differential tariff.

We recommend that the AER consider whether revenue and pricing principles on section 24 of the NGL already give it the flexibility to require cost reflective pricing eg Principles 3, 6 and 7:

> "(3) A service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides. The economic efficiency that should be promoted includes:
>
> > (a) efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and
> >
> > (b) the efficient provision of pipeline services; and
> >
> > (c) the efficient use of the pipeline.
>
> …

(6) Regard should be had to the economic costs and risks of the potential for under and over investment by a service provider in a pipeline with which the service provider provides pipeline services.

(7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a pipeline with which a service provider provides pipeline services."

Capital contributions/disconnection charges

This is an alternative to differential tariffs where consumers who benefit from the expansion capex pay either:

- an upfront connection fee to recover some of the higher costs (given shorter asset life), or
- a disconnection charge, or
- a combination of both.

The upfront connection fee provides a price signal that Governments implementing the zero-carbon target want consumers to receive. This could occur via a tightening of the incremental revenue test (where the customer needs to make a contribution to bridge the NPV gap) or pay for dedicated connection assets as with electricity connections. This may require a rule change to r 79 or maybe through the introduction of a connection fee as a new service – which also may require a rule change.

Given our view on the regulatory contract with existing customers, this fee would only apply to new connections. A disconnection fee may be seen as inequitable given the person disconnecting may not be the same person who made the original decision to connect. However, given as noted above, the decision to connect is more likely to be made by the builder than the consumer, a combination of connection fee and disconnection charge may be an alternative worth considering.

Such charges would need to offset the tariff so capital is only recovered once. And again, it would be adjusted if hydrogen is shown to be economic in the future.

Use the redundant asset provisions under r 85 and r.86

This rule gives the AER the option on removing assets from the RAB if they are no longer contributing revenue with a sharing between the network and consumers of the costs of removal. An example was the decision by IPART to remove the Moomba – Sydney lateral to Wollongong when the Eastern Gas Pipeline was completed. It can be used in the 'death spiral' situation discussed above when the network wants to remove assets to lower the price to encourage new customers and increased demand.

If at some time in the future the asset is expected to be able to earn sufficient revenue eg hydrogen becomes economic, then it can be rolled back into the RAB in an NPV neutral way that ensures the capital is only ever recovered once.

8. Conclusions

This Attachment has canvased many issues – some of which are directly relevant to AGN's AA, some of which relate more to the current NGL/NGR.

On the former we would encourage AGN to undertake comprehensive consumer engagement post AAP submission to explore the specific choices consumers are effectively being asked to make around expansion capex, including:

- how it impacts on price in 2021-26 and subsequent revenue periods, and
- how a lower price in 2021-26 might be offset with a much higher price post 2026 or 2031 if hydrogen does not prove to be economic as consumers convert to electricity and fewer gas consumers are left to pay for all assets – stranded or otherwise.

We have outlined a number of options that could be presented during that engagement process.

On the latter we recommend to the AER that it undertake a thorough review to consider whether:

- the current NGL/NGR are fit for purpose given emerging Government policy on zero emissions, and
- required changes can be achieved through a change in the interpretation and application of the existing rules or whether amendments are needed.