Attachment 6.1

Future of Gas and Depreciation - context and modelling detail

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Contents

1 Introduction

This attachment provides more detail underpinning the arguments outlined in Chapter 6, "The Future of Gas and Depreciation", with a particular focus on what the model is, how it works and the results which have been derived. It should be read in conjunction with Attachment 6.4 which gives the wider context of AGIG's strategic thinking about our future business, and the steps we are taking to be able to deliver renewable gas into the future. These steps are often much wider than is encapsulated by the regulatory framework.

Our modelling framework takes the forces we see driving our future and formalises them into a quantifiable framework so that the assumptions we make and their consequences can be transparently interrogated by the AER and indeed any other interested stakeholder who downloads our models from the AER website. In this context, the reader should keep in mind that:

- The narrative underlying the modelling is as important as the modelling itself. In an environment of rapid change and uncertainty, assumptions must be made and the reasoning behind those assumptions must be spelt out for all to see clearly. Models explain and test the consequences of assumptions, but they do not make the assumptions.
- Depreciation is not the only tool we can use to meet future challenges. Our framework shown here around balancing risk between networks and customers includes two additional elements, and other aspects of the AA proposal, such as the balance of opex and capex, also contribute (see Chapters 8 and 9 of the Final Plan).

The structure of this attachment is as follows:

- Chapter 2 provides an overview of potential medium term and longer-term futures, based on trends we can see now. The split into the medium and long term is not merely a convenience but underpins how we think about depreciation and the way in which the energy transition informs it.
- Chapter 3 outlines our framework for considering depreciation; essentially how the medium- and long-term pictures inform our depreciation approach and why this meets the requirements of the National Gas Rules.
- Chapter 4 outlines how we model depreciation. Since we have an extant model used in our recent Access Arrangement proposals for our Victorian networks (see here), we focus on changes to the model and why we have made them.
- Chapter 5 covers the results of our modelling; the amount number which we have included in our proposal for the change in depreciation we believe is appropriate.
- Chapter 6 provides a manual for our model to allow any interested stakeholder to run the model themselves and test our results. We believe that the ability of anyone to test a model, to change the assumptions and trace through the impacts of these changes on the final results in a transparent way, is crucial to the enterprise of determining appropriate depreciation.

Before we proceed with the detailed discussion of our modelling framework, we cover a small matter of terminology.

Box 1: Depreciation and "Accelerated Depreciation" – a note on terminology

In the past we, and others have used the term "accelerated depreciation" to refer to changes to a depreciation schedule. Up until around 2020, depreciation schedules had not changed in roughly 20 years, and the proposed changes in recent Access Arrangement proposals have involved an increase in depreciation compared to what would have been applied had methodologies not changed, either by shortening asset lives or by changing depreciation profiles. Since this involved more depreciation the term "accelerated depreciation" was meaningful.

Going forwards, we think that the term will diminish in usefulness for two reasons. Firstly, the relevant reference point in future will not be the situation pre 2020 but rather whatever was the most recent regulatory determination and it is not clear whether each new regulatory determination will necessarily mean more depreciation than would have occurred without a change in methodology. For example, in WA, having made a change to deprecation in 2021, our most recent proposal on depreciation is unchanged from the methodology followed in 2021 (see here). Are we still "accelerating" depreciation because we still follow an approach different to that which prevailed pre-2020 or is our depreciation schedule now not "accelerated" because we follow the same approach as in 2021, including the same asset lives? We can see the potential for confusion.

Secondly, the term may lend stakeholders to believe that changes in depreciation approaches are always those where more depreciation is required; see for example, the proposed ECA Rule Change (see here) which is focussed solely on the cases of greater depreciation. This may lead stakeholders to ignore cases like that for WA above and the role that changes in depreciation approaches that do not involve an increase can play. This would be exacerbated if changes to the National Gas Rules required the AER to focus only on cases where depreciation is required to increase. We believe that a better "regulatory mindset" is one of changes to depreciation (be they more or less), and that the relevant reference point is whatever decision was made at the previous AA, rather than harking back to a pre-2020 world which will become increasingly irrelevant.

This is an issue we discussed at length with the SARG and one on which we disagree; SARG still favours the term "accelerated depreciation" on the basis that we are asking for more depreciation than would occur with no change in our methodology. What we do agree on is the fact that it is the last AA, not the very first one where a network was regulated which is the basis point (SARG refer to this as being the point at which the "regulatory compact" has changed, as the NGR explicitly allows it to do). We also agree that we must outline to customers how depreciation has changed compared to the case if we had not changed some aspect of the methodology followed in the last AA and outline the reasoning for the change. We do both in this attachment.

2 The competitive future of the energy sector

In this chapter we outline how the energy sector might evolve, which produces the context behind our depreciation and modelling approach. The gas sector is going through generational change which will impact all energy networks and it is very difficult to predict how this future will ultimately look. We have aimed to reflect this in our approach.

We believe the future of the energy sector is a story in two parts. Over the very long term, we consider it is likely that networks will operate in a much more competitive market. Not between different networks or between appliances fuelled via different networks, but between a wide variety of players, many new to the industry. In particular, we believe that customers will be far more central to competition than they are now, by virtue of their having control over a key factor of energy production in a way that they have not had previously. For networks, it is less likely that regulation will drive most prices, and more likely that they will be driven by new competitive forces. Regulation in its current form may still exist and serve to protect some parts of the market where competition is weak, but market competition will likely play a bigger role in driving network pricing and behaviour.

Over the short to medium term, out to 2050, we see a future which is intrinsically similar to today; the nature of the gas in our pipes will change as renewable gas comes to the fore, but we will still be transporting gas used to heat water, heat homes, cook and to be used by our commercial and industrial customers in a manner similar to the way they use it today. Importantly:

- Regulation will still exist and govern our prices; and
- The competition that gas appliances face from electric appliances will remain (and may be influenced by government policies as well), and this competition will remain an important factor in our viability as the network carrying the gas for gas appliances.

We describe our views of this evolving future below. In Section 2.1 we cover the very long term, post 2050 where new forms of competition are more likely to dominate. Note that the choice of 2050 as the cut-off when competition is likely to be a greater driver is for convenience only; it is the fact that the future is likely to be much more competitive that matters, rather than precisely when this happens. We close Section 2.1 by looking at how a business in 2050, might be valued as a going concern dealing with competitive forces from that point forward, as this forms the starting point of our depreciation modelling in Chapters 4 and 5. Section 2.2 covers the next 25 years, up until 2050, when regulation drives our pricing, with a particular focus on consumer behaviour and how it informs our modelling. Section 2.4 concludes and discusses our consultation with customers and the AER on these points.

We note here that the assumptions underpinning our depreciation approach set out in this chapter are based on the context of the South Australian network, wider market forces in the energy market, current policy settings and renewable gas progress as a gateway to the future (see Attachment 6.4). The modelling to 2050, in turn, reflects our confidence in reaching that point and unlocking future opportunities. However, if policy settings changed or the future towards 2050 is materially different from these assumptions, then the outcomes would be different and likely require more depreciation.

2.1. The long-term competitive future

In this section, we discuss the long-term future of the energy sector and the forces which we think are likely to drive it towards greater, and very different, competition. The most important force comes from a change in the nature of consumers. This change comes from renewable power and storage. More particularly, because consumers will likely own renewable resources and storage, they will be able to exercise a degree of sovereignty over their energy in a way that has not been possible in the past. This gives rise to some very different competitive forces for energy networks.

One early example of this comes from expert advice supporting our depreciation model (See Attachment 6.3). In the past, resistive electric tank hot water systems have been poor competition for instantaneous gas systems because they are relatively inefficient and therefore costly to run.

However, a resistive tank electric hot water system which is powered by rooftop solar has essentially zero running costs most of the time, provided some restrictions on its use are accepted by the customer. This is a new and different source of competition for both electricity and gas networks. The source of the competition is not the appliance itself, but the ability of the customer to self-supply the energy which powers it. We have included this new form of competition in our modelling (see Section 5.1)

A second example comes from the AER's recent State of the Market Report (p257, here). The AER cites research suggesting that a house which is well-insulated and has rooftop solar can reduce its reliance on network supplied electricity to almost zero. Whether the modelling reflects how consumers with well-insulated homes will behave in future is something that only the passage of time will reveal, but to the extent the modelling is accurate it suggests that when consumers can supply their own power home design can act as a source of competition for networks. This obviously also has regulatory consequences as well if many homes behave in the way the modelling suggests, affecting the market power of all energy networks.

Both of these early examples are likely just the beginning as customers start to understand how to exercise their growing sovereignty over their energy supply and both they and new players in the industry look for new opportunities to serve customers. One key issue is that network costs tend to be roughly constant. This means that, to the extent that customers do self-supply some of their energy, the energy they source from networks, on a per unit basis, becomes exponentially more expensive. This unlocks new opportunities for competition as more expensive alternatives to network supply of energy become economically viable as the share of network-delivered energy falls.

Quite how this will play out over the longer-term is very difficult to forecast, because foundational change such as this tends to open up entirely new opportunities which have not existed previously. To explore the scale, if not the nature, of potential change, we looked in our consumer workshops at the land transportation sector, which has seen the emergence of consumer sovereignty over transport services through the rise of the automobile.

Roughly 250 years ago, if a person wanted land transport, he or she had the choice of walking, using a horse (or other beast of burden), using a cart or, in a handful of circumstances, to travel on a carriage. Transport was, by and large, self-provided, but in a way which was not particularly efficient, or rapid. During the 19th Century, first canals and turnpikes and subsequently (and much more extensively) trains opened up a much more extensive, efficient, convenient, rapid and cheap form of transport, as a service using third-party infrastructure owned by someone else. Land transport, of people and of freight, duly exploded over the course of the century. At the close of the 19th Century, the automobile was invented, providing consumers with a form of transport that was, in many cases, superior to trains, but which they could own; consumers gained sovereignty over their own transport, and the take-up was rapid, as evinced by these two photographs, taken roughly a decade apart, between 1900 and 1913 in the US.[1]

Figure 2-1: Cars displacing carriages 1900 to 1910

Sourced here.

The impact of the automobile extended far beyond transportation. It reshaped urban planning, as seen in the development of suburbs like Levittown (see here) in the US, designed around car use. Just as early car owners could not have imagined modern suburbs, today's solar adopters may not foresee how their grandchildren will use energy. Notably, the time between the rise of the car and the birth of the suburb was shorter than the lifespan of our longest-lived assets.

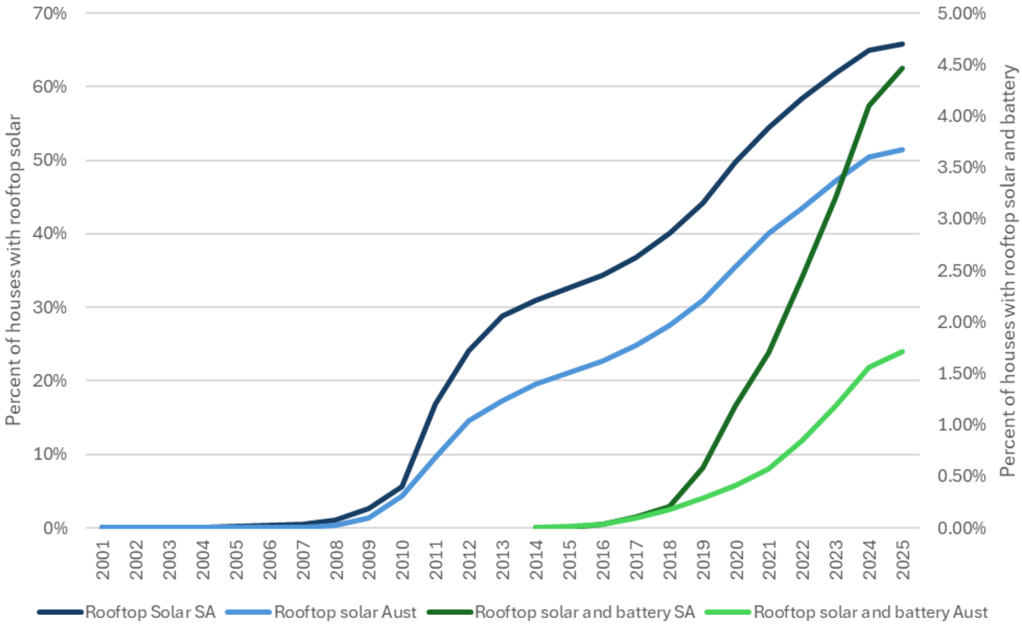
Two key lessons emerge from this analogy. Firstly, infrastructure evolves with technology. Cars required roads, but these were not funded or owned like railways. Similarly, future energy infrastructure may not be provided by today's networks. Secondly, legacy systems adapt. Railways didn't vanish, they found new roles; people don't use cars for every trip. The energy sector will likely feature a mix of sources, with consumer-owned resources playing a dominant role. Networks will need to adapt, much like trains did in the transport sector. With this over-arching theme of consumer sovereignty in mind, we turn to some of the other factors which sit around it, and which will drive our place in the energy sector.

2.1.1. Consumer-accessible renewable energy and storage

Consumer sovereignty in energy is a matter of the equipment they are able to access, and the cost of that equipment. In electricity, this means rooftop solar and batteries. In respect of both, South Australians have been enthusiastic participants, as shown in Figure 2-2.

[1] This is by no means unique; not even to the US, Australia and other similar countries. Roughly a century later, as Chinese consumers became wealthy enough to afford their own cars, the same kind of switch happened with similar rapidity, as the author had first-hand experience of in his wife's home-city of Qingdao.

Figure 2-2: Rooftop solar and battery penetration – South Australia and Australia



Source: Rooftop solar and battery statistics from the Australian Clean Energy Regulator (available here). Household numbers derived from ABS Cat no 8701 (2016 to 2022) and 8731 (pre 2016 and post 2022).[2]

Rooftop solar experienced an acceleration of uptake from about 2010 onwards, as costs fell and subsidies started to become widely available. By 2025, this has meant that roughly 65 percent of South Australian homes have rooftop solar installed. Batteries, which have taken longer to come down in price, are about a decade behind in terms of uptake, but are rising just as rapidly.

What happens next in terms of uptake depends on what happens next in terms of price. Rooftop solar itself is already significantly lower in price that electricity sourced from the grid, with the Australian Energy Council reporting an Levelised Cost of Energy of between $0.08 and $0.12 per kWh in Adelaide, compared to retail prices of $0.43 per kWh; roughly a quarter of the cost.[3] In its GenCost report for 2024/25, CSIRO forecasts the capital costs of rooftop solar will fall by two-thirds by 2050.[4]

Rooftop solar, however, only gives customers limited abilities to exercise sovereignty in energy markets because it only works during the day. This limits the uses customers can make of their generated power to uses they make of it during the day, and revenue they can earn from selling their excess power. Since most customers are not at home during the day, time-shifting is somewhat limited; one can set washing machines and dishwashers to run during the day or set the air-conditioner to cool the house ready for coming home, but evening uses of electricity cannot be covered by rooftop solar. Some houses with resistive electric water heaters can use their rooftop solar to provide very cheap hot water (discussed in Section 5.1) and those with electric cars that they do not use for commuting can use them for charging their vehicles. Other households are more limited. Further, although customers can earn feed-in-tariffs by selling their electricity to the grid, these are relatively small and getting smaller through time as subsidies are unwound, so available revenues are rather small. Indeed, precisely because of the rise of rooftop solar and the fact that it all produces power at the same time, electricity networks have sought powers to curtail rooftop solar supply when it can threaten the grid.

One way to increase energy sovereignty comes from being able to store rooftop solar in batteries, for use in the evenings when most of the energy use in a home occurs. The AEMC report in 2022 that the payback period for batteries reduced to less than their warranted life for the first time in 2022, which is the point at which they start to be economic for customers.[5] This is on the back of cost reductions of close to 90 percent since 2010 globally, which have been consistently under-forecast, as shown in Figure 2-3.

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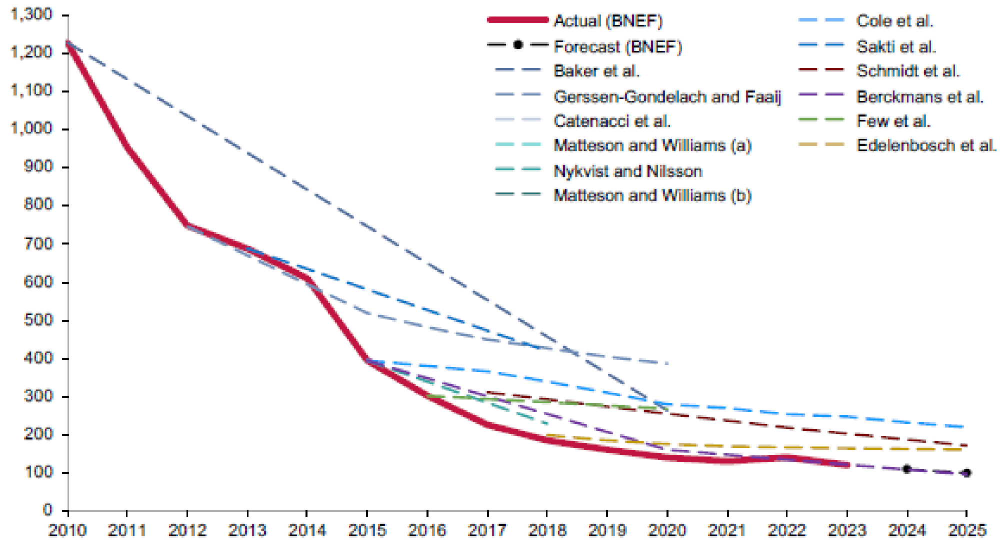
[2] The ABS publication 8701has numbers of houses from 2016 to 2022, whilst 8731 has house building approvals from 1983 onwards. The use of both series together, with a check for the time period 2016 to 2022 to confirm the accuracy of the method, allows one to reconstruct the total number of houses. Note that we consider only houses, and not other housing types, such as apartment buildings.
[3] Australian Energy Council, 2025, Solar Report: Quarter 1 2025, p12-13, available here. The different estimates are due to different discount rates, which range from ten-year mortgage rates of 5.08 percent to personal loan rates of 16 percent.
[4] Graham, P, Hayward J and Foster J, 2024, GenCost 2024-25: Consultation Draft, available here, p48
[5] As a reference point, the payback period for rooftop solar in Adelaide is around 2.5 years, according to the Australian Energy Council (here, p18) which is half of the warranty on the shortest-lived parts of a rooftop solar system and a tenth of the warranty on some solar cells (see here).

Figure 2-3: Battery cost reductions and forecasts – 2010 to 2023 (USD/kWh)



Source: Rocky Mountain institute, 2023, X-Change Batteries: The battery domino effect, available here, p17

The CSIRO GenCost report (ibid, Appendix Table B5 for a 4-hour battery) expects battery costs to fall by another half by 2050. This would improve significantly the ability of consumers to service more of their own energy demand, into the peak period (when electricity tariffs are much higher), and to exercise more sovereignty over their own energy.

Like electricity networks, gas networks will face competition from these forces, but gas networks themselves can act as batteries for the hours beyond which a battery can last. This makes them potentially both competitors and complementary to batteries; offering a different channel for the energy which cannot be self-supplied. Technically, this is possible to do today, with reciprocating engines and turbines at the larger scale, and fuel cells at the smaller scale.[6] The issue is one of economics; the relevant equipment must be available at a price which makes it economic. Two things, however, are important to note in this respect.

Firstly, current network electricity prices are not necessarily a good guide. Electricity network costs are essentially fixed, meaning that, if rooftop solar and batteries were providing 90 percent of a household's power, then the per kWh cost of the grid-delivered power that is actually used would be roughly ten times the current level. Options which are far from economic against grid-delivered electricity at current prices may be more economic if the amount of grid-delivered electricity falls to very low levels. Not all alternatives need a high fixed cost network to deliver an alternative; the IEA and IRENA, for example, report on technological developments of green liquid fuels.

Secondly, just as was the case for solar and batteries when they were at the top of their cost curves, the direction of future technological progress, and exactly what it will do to cost is uncertain; in respect of batteries, batteries had been used commercially for almost a century in 2010 and even lithium batteries had more than 20 years of development behind them and still Figure 2-3 shows how wrong predictions have been. In particular, progress in improving catalysts within fuel cells and electrolysers, so that they do not use as much precious metal, has been rapid. Some examples include:

- Zheng et al (2025) report an 800 percent improvement in producing hydrogen directly from sunlight (not via electrolysis) compared to existing methods.[7]
- Cha et al (2025) report on the development of a tuneable boron-doped cobalt phosphide catalyst which can potentially reduce the cost of electro-chemical production of hydrogen by half.[8]
- Kombargi et al (2024) report on a method to produce hydrogen using aluminium, sea water and coffee grounds that works sufficiently rapidly that hydrogen does not need to be stored as a fuel but can be generated as needed.[9]

[6] *See for example, this product, a combined heat and power unit which uses methane as a fuel and claims running costs half those of a diesel generator, with a third of the carbon emissions. We discussed other cases involving the use of combined heat and power units in our Victorian proposal (see here, p13). Other papers discussing the use of solid oxide fuel cells (which run on hydrogen or methane, or a blend of the two) are available here, here, here and here. There is a wide literature on this topic. Providers of reciprocating engines which run on hydrogen include Cummins and Caterpillar (among others), and hydrogen-ready turbines are already available from GE, Siemens and Wartsila (among others).*
[7] *Zheng H et al 2025, "Manipulating Electron Structure through Dual-Interface Engineering of 3C-SiC Photoanode for Enhanced Solar Water Splitting", Journal of the American Chemical Society, 147(17), 14815-23, available here.*
[8] *Cha DC et at 2025, "Tunable B-Doped Cobalt Phosphide Nanosheets Engineered via Phosphorus Activation of Co-MOFs for High Efficiency Alkaline Water-Splitting", Small, forthcoming, available here.*
[9] *Komarghi, A et al, 2024, "Enhanced Recovery of Activation Metals for Accelerated Hydrogen Generation from Aluminum and Seawater, Cell Reports Physical Science, 5(8), 102121, available here.*

- Liu et al (2025) report on a new, specially constructed catalyst designed for use in proton exchange membrane fuel cells used in heavy transport, which allows 200,000 hours of operation. For reference, the US Department of Energy has a target of 30,000 hours of continuous operation.[10]
- Sugano et al (2025) report on a new type of fuel cell powered by liquid sodium metal (a cheap and readily available substance) and air which has three times the energy of a lithium-ion battery of the same weight.[11]

There are many more examples in the relevant literature. In particular, the growth of AI, with its abilities to find patterns, makes it a particularly fruitful time for research which can improve the efficiency of chemical processes, like that in electrolysis and fuel cells. This article reports on one Australian example which produced a seven-fold improvement in the production of green ammonium. For this reason, predictions about the future involving renewable gases, and liquid fuels, which customers might one day be able to utilise to improve their energy sovereignty, are very likely to be completely wrong. This makes for a very challenging environment for all energy networks.

2.1.2. Renewable gas as a gateway

The main focus of this attachment, and of our modelling, is on the demand side; what services will our customers want and what will they be prepared to pay for said services. However, for gas businesses, there is also an important supply-side consideration, given the likely eventual transition away from natural gas; will renewable gases be available at a reasonable price and in sufficient quantities? This is a "gateway" question for us; without a shift to renewable gases, it is likely that our ability to continue to provide services into the long term will be much more limited. However, the availability of renewable gases do not solve all of our issues on their own because we will still face competition from other energy sources.

Progress in renewable gas cost and availability is summarised in Attachment 6.4, which also covers strategies we are engaged in to further this cause and initiatives from the SA Government, which is very supportive of renewable gases. It is important to note that we are neither alone, nor particularly important in respect of cost reduction in renewable gases. Both Europe and the US are investing heavily in renewable gas technology, supported by government policy initiatives designed to bring the industry forward.[12] Europe in particular has both climate-related and security related reasons to pursue renewable gases. Likewise, China, with its own net zero goals, has also invested heavily.[13] In all cases, where research leads to lower cost renewable gas, the relevant technology will be made available globally, and Australia can benefit. For reasons associated with both our own strategic initiatives and global initiatives, we are confident of the ability of renewable gas to be available at scale and at a competitive price. Further detail is provided in Attachment 6.4.

Box 2: Colours of renewable gases

There are many different ways to obtain renewable gases. In respect of hydrogen, these have been formed into colours. There are many such schemes, with slightly different labels. One such (see here, p16) is:

- Green hydrogen: electrolysis of water using renewable power.
- Pink hydrogen: electrolysis of water using nuclear power.
- Blue hydrogen: steam reforming of natural gas with the resultant CO_2 captured and used or stored elsewhere so that none is released into the atmosphere.
- Turquoise hydrogen: pyrolysis of natural gas producing pure carbon as a secondary output.
- White hydrogen: mining naturally occurring hydrogen. In this context, although nothing has been brought to market as yet, South Australia has significant potential for white hydrogen resources.

Added to these are grey, brown and black hydrogen which are produced from natural gas, brown coal and black coal, respectively, but without any capture of the waste CO_2. There are also new ways of producing hydrogen with zero emissions, using sunlight directly, using heat and using thermochemical and biological processes, which are under exploration in the laboratory but are yet to reach commercial exploitation (see here for a summary of some of these)

Biomethane (see here) does not have a colour scheme per se, but it can be sourced from biogas or from thermal gasification of solid biomass (where solid biomass is broken down into constituent gases in a low oxygen environment). The former is much more common, and biogas itself can be made from many sources, including:

- Biodigesters: where bacteria are used to break down organic matter (such as food waste, animal manure or crop residues) in a closed system.
- Landfill: where gas is captured from the decomposition of solid municipal waste as it decomposed in landfill sites.
- Wastewater treatment plants.

[10] *Liu, Z et al 2025, "Pt Catalyst Protected by Graphene Nano-pockets Enables Lifetimes of over 200,000 h for Heavy-Duty Fuel Cell Applications", Nature Nanotechnology, 20, 807–14, available here.*
[11] *Sugano, K et al, 2025, "Sodium-Air Fuel Cell for High Energy Density and Low-Cost Electric Power", Joule, 9(6), 101962, available here.*
[12] *Penttinen, SL, 2024, "Navigating the hydrogen landscape: An analysis of hydrogen support mechanisms in the US and the EU", Review of European, Comparative and International Law, 33(3), 397-411, available here has a summary of US and European initiatives with a focus on hydrogen. Sesini, M, Creti, A and Massol, O, 2023, "Unlocking and Supporting Renewable Gas in Europe: Policy insights from a comparative analysis", CEC Dauphine Working Paper, available here has more European-focused information covering biomethane and hydrogen. Detail on US biomethane support projects is available here.*
[13] *See the IEA, 2024, Renewables 2024: Analysis and forecast to 2030, available here which has detail on Chinese renewable gas policy (pp68-88).*

One remaining issue is the consistency or otherwise between depreciation and renewable gas. Some stakeholders have suggested that spending on renewable gas and increasing depreciation are inconsistent.[14] This, however, is incorrect, and predicated upon the misconception that our future is a binary case of renewable gas and everything remains as it is or no renewable gas and we go out of business. In reality, we will face competition regardless of the success of renewable gas, and this means we need to think about future prices, which are affected by depreciation choices made today. Depreciation and renewable gas are consistent; indeed, it would be pointless to pursue renewable gas and ignore future prices because we may that we open a gateway which leads nowhere because poor planning has left us priced out of the future and likewise, it would be pointless to pursue depreciation and ignore renewable gas as we may end up with nothing to transport at the low prices we can charge.

None of this means, of course, that we have licence to ask customers to bear any amount of renewable gas spending and any amount of depreciation; we need to test both to make sure they will deliver future benefits. And we do so. However, the notion of inconsistency is, equally, based upon a mistaken understanding of the potential future pathways the energy sector might take.

2.1.3. Treating the output problem of natural gas

Our focus as a business is on opening the gateway to renewable gas to ensure the supply side of our future sustainability, but this is not, at least in principle, the only solution. Methane leaks aside,[15] the climate change problem of natural gas is an output problem; when it is burned (or passes through a fuel cell), it produces carbon dioxide. Renewable gas is an input solution to this output problem, but it is also possible to solve the output problem by capturing the carbon dioxide as the natural gas is used, extracting the carbon, and re-using it. This is part of a "circular economy" where waste streams are re-conceptualised as resources for continued use.

The need to consider the potential for the re-use of CO_2 has been widely studied by, among others, the US National Academy of Sciences (here and here), the International Energy Agency (here) and the CSIRO (here). The carbon in CO_2 is a valuable commodity, able to be used as a chemical precursor in a wide variety of industrial uses. The key issue is the need to develop methods to effectively split the molecule which are economic and can deliver carbon at a lower cost than producing it from natural resources. This is an area of significant research.

De Luna et al (2019) ask what it would take for various different carbon capture technologies from an economic perspective, noting a need for renewable electricity prices to fall to US$0.04/kWh along with the need for improvements in some chemical processes, but notes the wide variety of opportunities to supply chemical processes that electro-catalysis of CO2 and water can provide.[16] Shin, Hansen And Jiao (2020) undertake a similar analysis of chemical precursors formed through low temperature electrolysis of CO2 finding that carbon monoxide and formic acid are already comparable with the costs of their conventional sources, whilst other chemical pre-cursors have further to go.[17] Kazemifar (2021) provides a wide-ranging techno-economic assessment of a number of different methods of capturing CO_2 from different sources.[18]

Newer research has focussed on different ways of capturing the carbon dioxide, mimicking the way nature operates in photosynthesis in plants,[19] bacteria,[20] or sped up geological processes.[21] Others focus on new catalysts to speed up chemical

[14] *The Brotherhood of St Laurence made this suggestion in a submission to our Victorian AA process in 2022 (see here, p17) and more recently, the JEC has made a similar suggestion in a submission to Jemena's NSW AA process (see here, p20)*
[15] *In South Australia, the AER reports (see here, p71), that unaccounted for gas (which includes much more than just gas leaks, see here) is roughly 1.5 percent of our gas transport volumes, and falling.*
[16] *See De Luna, P et al 2019, "What Would it Take for Renewably Powered Electrosynthesis to Diplace Petro-Chemical Processes?", Sceince, 364, available here.*
[17] *See Shin, H, Hansen KU and Jiao, F, 2020 "Techno-economic Assessment of Low Temperature Carbon Dioxide Electrolysis", Nature Sustainability, 4, 911-19, available here*
[18] *See Kazemifar, F, 2021, "A review of technologies for carbon capture, sequestration, and utilization: Cost, capacity, and technology readiness", Greenhouse Gases Science and Technology, 12(1), 1-30, available here.*
[19] *See Ahmad BIZ et al, 2025, "A Fully Light-Driven Approach to Separate Carbon Dioxide from Emission Streams", Chem 102583, available here. See also Prajapati A et al, 2022, "Migration-Assisted, Moisture Gradient Process for Ultrafast, Continuous CO_2 Capture from Dilute Sources at Ambient Conditions", Energy and Environmental Science, 2, available here*
[20] *Onyeaka, H and Ekwebelem, OC, 2023, "A Review of Recent Advances in Engineering Bacteria for Enhanced CO_2 Capture and Utilization, International Journal of Environmental Science and Technology, 20, 4635-68, available here.*
[21] *Chen Y and Kanan MW, 2025, "Thermal Ca^{2+}/Mg^{2+} Exchange Reactions to Synthesize CO_2 Removal Materials", Nature, 638, 972-9, available here*

reactions,[22] new membranes[23] to physically separate out the CO_2 and new solvents[24] and other materials.[25] Finally, some researchers look at the production of electricity with CO_2 as one of the inputs.[26]

Although the alternative of capturing the carbon dioxide which comes from using natural gas (or indeed biogas) does not form part of our strategies, we cannot predict how the future will evolve in respect of the costs and other impacts of technological developments. Directly treating the output problem of natural gas may become a climate mitigation strategy in future, and our networks may play a role. This might be in transporting natural gas for use, with the sources of energy demand treating the carbon dioxide outputs, or it may involve transporting the carbon dioxide produced by burning natural gas back to a centralised location for treatment. Or both.

2.1.4. Infrastructure re-use

A changing market structure and the potential for infrastructure to become obsolete is not a new issue, even to the gas industry. The key is how society responds to this risk. Perhaps the most wasteful way to respond is simply to close down the infrastructure and decommission it without giving any thought to potential re-use opportunities in a new economic or policy environment. It not only deprives some customers of ongoing value (as not all will stop needing the infrastructure at the same time) but also requires new infrastructure to be built—often at higher cost—to serve similar purposes.

Some infrastructure can remain useful for centuries, even as the societies that built them change dramatically. The Qanat irrigation systems in Iran, the Cloaca Maxima in Rome and the Grand Canal in China, all of which are roughly 2,500 to 3000 years old are examples of this.[27] These systems endure because water remains essential for drinking, sanitation, and transport, even if the nature of some of those tasks has evolved. Had these assets disappeared with their original builders, future societies would have faced the costly burden of rebuilding them from scratch.

In other cases, infrastructure can fall out use and then become relevant again. A good example of this is trams; Melbourne kept its tram network, whilst Sydney did not. More recently, Sydney has recreated sections of its tram network, to relieve urban congestion at great cost, with 12 km of light rail track costing some $3.1 billion; $1 billion more than originally budgeted (see here).

Infrastructure can also be repurposed. Disused railway lines have been converted into cycleways, leveraging their flat, direct routes into cities. While cyclists don't pay access fees like train passengers, society benefits through improved health, reduced congestion, and lower infrastructure costs compared to building new routes from scratch.

The gas sector is no stranger to adaptation and re-use of resources as the energy market changes. The first gas networks were developed for light, not heat; even in Australia, AGL is an acronym which means "Australian Gas Light Company". With the invention of the incandescent globe, this role was supplanted.[28] The initial response of the gas industry was to invent a better gas light, but over the longer term, the response was to invent new uses for gas. In the 1930s, this included, among other things, gas-powered fridges (see here), but the "killer app" which stuck was gas for cooking, which supplanted coal. At this stage, the gas was manufactured town gas, rather than natural gas and, in the UK, the system needed to be modified to meet peak demand on Sunday mornings when housewives were cooking the Sunday roast.[29] Subsequently, as much cheaper natural gas entered the system, gas was able to supplant coal (and nascent electrical appliances) for space heating as well.[30] In Adelaide, the South Australian Gas Company started providing gas light in 1865. By 1895, it faced increasing competition from electricity and from 1897 started to promote the use of gas for cooking, opening a showroom in King William Street in 1902 (see here).

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[22] *Ma, W et al 2025, "Encapsulated Co–Ni Alloy Boosts High-Temperature CO2 Electroreduction", Nature 641, 1156-61, available here.*
[23] *Hao, J et al, 2025, "Scalable Synthesis of CO2-Selective Porous Single-Layer Graphene Membranes", Nature Chemical Engineering, 2, 241-51, available here. See also Rufer, S et al 2025, "Carbonate/Hydroxide Separation Boosts CO2 Absorption Rate and Electrochemical Release Efficiency", ACS Energy Letters, 10(6), 2752-60, available here.*
[24] *Jiang, P et al 2021, "Techno-economic Comparison of Various Process Configurations for Post-Combustion Carbon Capture Using a Single-Component Water-Lean Solvent", International Journal of Greenhouse Gas Control, 106, available here.*
[25] *Shindel B et al 2025, "Platform Materials for Moisture-Swing Carbon Capture", Environmental Science and Technology 59(17), 8495-505, available here. See also Zhang, B and Kanoh, H, 2024, "Sodium Carbonate–Carbon Hybrid Material for Low-Energy-Consuming CO_2 Capture", Energy and Fuels, 38(13), 11927-35, available here.*
[26] *Pfieffer O et al 2022, "Life Cycle Assessment of CO2 Conversion and Storage in Metal–CO2 Electrochemical Cells", Journal of Industrial Ecology, 26, 1306-17, available here. See also Masoudi M et al 2025, "Ultralow Overpotential in Rechargeable Li–CO2 Batteries Enabled by Caesium Phosphomolybdate as an Effective Redox Catalyst", Advanced Science, forthcoming, available here*
[27] *In Australia, there are several pieces of infrastructure which are much older, including fish traps in Albany and in Victoria, which are at least around 7,000 years old. They have, sadly, largely fallen out of use.*
[28] *Electric light was not, initially, cheaper, and electric light was reserved for early adopters such as theatres and restaurants who made it part of the experience they were selling. Fouquet R, 2011," Divergences in Long-Run Trends in the Prices of Energy and Energy Services", Review of Environmental Economics and Policy, 5(2),196–218 (available here) provides an overview of the history of gas and electric light, and the decades it took the latter to supplant the former.*
[29] *See Forman, PJ, 2020, "Histories of Balancing Demand and Supply in the UK's Gas Networks, 1795-Present", Revue d'Histoire de l'Energie, 5, available here.*
[30] *See Hanmer C and Abram S, 2017 "Actors, Networks, and Translation Hubs : Gas central heating as a rapid socio-technical transition in the United Kingdom", Energy Research Social Science, 34, 176-83, available here*

Within the gas sector, as the switch was made from town gas to natural gas, there was no longer any need for the "gasometers"; the storage vessels which allowed manufactured supply to meet demand during peak times. Many of these, rather than being demolished, were re-purposed, become features in parks (in Brisbane, see here) and even housing (in Vienna, see here).

2.1.5. Gas use and network use

As gas demand evolves, it's important to recognise that changes in usage don't translate directly into changes in network utilisation. A 10% drop in gas demand could mean every customer is using 10% less gas, or it could mean 10% of customers have disconnected entirely. More often, the reality lies somewhere in between.

Several factors influence this dynamic. For example, many customers purchase reverse-cycle air conditioners primarily for cooling, but then use them for heating on milder days, reserving gas for colder periods. Others use both systems in tandem; gas appliances are more efficient for quickly heating a home, while air conditioners are more cost-effective for maintaining warmth. This hybrid approach can significantly reduce overall energy use.

Behavioural changes also play a role, especially during cost-of-living pressures. A German study found that households could cut natural gas use by up to 80% simply by wearing warmer clothing indoors.[31] Our own experience (see Chapter 13 of the Final Plan on demand) has shown gas usage decline even as connections grow. What is clear is that demand for gas and demand for a gas connections are two quite different things.

2.1.6. Potential impacts from policy

In the past, jurisdictions have explicitly favoured gas networks via policy with measures such as mandatory connection of new homes to the network. Such policy settings no longer exist, although the South Australian Government does have a policy framework which supports the development of renewable gas.

Other policy frameworks are more restrictive. For example, in the ACT, the government has banned all new gas connections and has a stated policy of net zero by 2045 which will effectively see the network closed by this date (see here, and also the Evo Energy proposal here, which is affected by this policy, and contains much more detail on its ramifications). In Victoria, there is no specific attempt to close the network down, but the Gas Substitution Roadmap (available here) has already seen a ban on most new residential gas connections and a requirement to pay upfront for new connections which are permitted, and has a proposal to ban most new gas appliances in homes (not finalised at the time of this document). In both cases, creating a sustainable business future is challenging.

Both Victoria and the ACT point to a key issue. Although markets can change quickly, because customers need to be convinced to make changes in behaviour, more gradual change (particularly for a key good, such as energy) is more likely. By contrast, policy can force rapid changes in behaviour. It can therefore be a much more destabilising force.

As part of our analysis, we include analysis of the consequences of a new connection ban, but do not look at the consequences of more extreme policies. Were such policies to be implemented, we would seek to re-open our AA. We consider this to be a reasonable compromise; seeking to react to a policy proposal which has been ruled out by the current Government (see Attachment 6.4) is likely to lead to prices for customers which are higher than they otherwise need to be.

2.1.7. Potential roles for gas networks within this future – beyond renewable gas

In examining potential long term future roles for the gas network (beyond the 2050s), two things are clear from the outset. Firstly, predictions made today will likely be wrong. Secondly, in addition to new uses, some existing uses will remain; some residential customers will keep using gas due to personal preference, and commercial and industrial customers may still find gas an economic and important option. Even though some current uses may remain, they will likely be priced differently (matching market forces rather than being driven by regulatory models) and the cost structure of the business will likely change with more opex and less capex, to better match commercial risk profiles in these competitive markets.

In respect of new market opportunities, we see three potential gas-related opportunities which may arise:

- Distributed electricity generation.
- Transport network support.
- Other gas transport, such as carbon dioxide.

[31] *See Huckerbrink D, Finke J and Bertsch V, 2023, "How User Behaviour Affects Emissions and Costs in Residential Energy Systems: The impacts of clothing and thermal comfort", Environmental Research Communications, 5, available here. We are not aware of similar work in an Australian context, and the authors do not convert the scientific measures of clothing warmth into something simple for a layperson to understand, but the results do suggest a fragility in heating demand to economic conditions; wearing a jumper indoors is not much of an imposition for a customer.*

Distributed generation essentially involves using the gas network as a battery. It could involve either burning the gas (in turbines or reciprocating engines) or using fuel cells, noting in the latter case that a solid-oxide fuel cell can run on methane as well as hydrogen but that other forms of fuel cells, such as PEM fuel cells, require pure hydrogen.[32]

At present, electricity networks are facing localised issues of network constraint as other sources of distributed generation, like rooftop solar, become more popular. One solution to this is to strengthen parts of the electricity network to deliver power when rooftop solar is not active. Another is to provide localised storage, like community batteries. A third is to use the gas network and local-scale gas generation to provide electricity grid support when it is needed. This is discussed in Section 2.1.8.

Further down the scale, commercial operators, such as shopping centres, who are already using their roof-space to generate renewable power, may look to own power generation assets, to backup their rooftop solar supply, or for emergency backup when the electricity grid fails. Hospitals, in particular, which require 100 percent reliability, may find that the gas network plus their own local generation is cheaper than an "electric only" option which delivers the same reliability, such as a feeder line from a different part of the electricity grid.

Finally, depending upon cost reductions in fuel cell technology (see Section 2.1.1), individual households wishing more sovereignty over their own energy supply may find it more cost effective or desirable to back up their rooftop solar using the gas grid as a battery, rather than batteries they own themselves. Alternatively, they may pair their own batteries with a smaller fuel cell to cover extended periods when their rooftop solar is unavailable to charge the batteries, rather than buying a lot more batteries.

These three forms of distributed power are presented above in order of potential adoption (in our view of the relevant technology) but increasing use of the gas grid.

A second use is from the transportation sector, with gas used for refuelling fuel cell vehicles. This may involve industrial facilities which use fuel-cell vehicles on site (such as warehouses, where fuel-cell powered forklifts are already considered economically viable compared to electric alternatives (see, for example, here), or delivering gas to what are now petrol stations for consumer vehicles powered by fuel cells. In such cases, local filtering means that the grid itself need not be delivering pure hydrogen, so long as the hydrogen can be extracted at the source of demand. In the latter case, it does not mean that what are now petrol stations would serve only fuel cell vehicles or only electric vehicles; there is no reason why both may not be served. Indeed, in the latter case, depending upon location and local electric networks constraints, the refuelling station may find it more economical to generate its own electricity on-site than to pay the network costs for reliable electricity delivery. In this manner, it would be acting like a commercial business using the gas grid as a battery, discussed above.

The final use derives from the discussion (see Section 2.1.3) around treating the output problem associated with natural gas; that is capturing its carbon dioxide waste and treating it to re-use the carbon in a circular economy. To the extent that this is done centrally, the gas network could be a carrier of waste carbon dioxide back to a central location. Note that this does not imply, necessarily, that the network would be delivering natural gas for use by customers, and then effectively hauling away the waste; the carbon dioxide could come from any source. Nor is it necessarily incompatible with other gases, like hydrogen, in the pipes, given appropriate filtering technology.

The three uses above all relate to the networks still carrying some form of gas. Parts of the network may also be re-purposed for other uses. The HDPE pipes are insulators and are thus not suitable for the undergrounding of high-voltage lines, which generate too much heat. However, they may be a cheaper option than a dedicated underground power network for local, lower voltage networks. Note that this need not involve networks which are owned and operated by SAPN; in some instances, local groups of customers seeking to share their excess renewable power in a community scheme (or a new market player doing the same on a commercial basis) could use unused local gas networks for the purpose. Another, similar use could be for fibre-optic cables (see, for example here and here) to provide fibre to the home in areas where the NBN is currently only delivering fibre to the node.

2.1.8. The value of AGIG circa 2050 as it looks forward to a more competitive future

Since our approach is predicated upon the energy market being driven by competitive forces, we need to establish the value of the business once competitive forces start to operate. This requires us to choose a date when competitive forces are likely to emerge, and to establish how our behaviour might change post that date. In respect of the date, we choose 2050, which is far enough from the present to encompass a fair deal of market evolution, as customers work through roughly two more cycles of appliances.

To estimate the value of the gas network beyond 2050, we adopt the perspective of a financial analyst operating in that future competitive market. This analyst would assess potential revenue streams from both existing and new services, subtract the associated costs (including recovery of the remaining regulated asset base, or RAB), and calculate the net present value (NPV) of the resulting profit stream.

[32] Note that this does not mean that the gas mix needs to be pure hydrogen in our pipes; filters can remove hydrogen from the fuel stream for use, putting other gases back into the pipeline for use by other shippers (see, for example the research programme investigating this at the Future Fuels CRC here, and two of the papers from this programme here and here). This is not cost effective yet but may be from the 2050s. The point is that different tasks do not necessarily imply a balkanised gas network with each gas only travelling in part of the network.

The cost assumptions used in this valuation reflect what a competitive business would likely incur. In total expenditure (totex) terms, these costs are comparable—or slightly lower—than those of a regulated network, as assets are more heavily utilised. The business would also favour opex over capex and only pursue opportunities that recover capital within 20 years. Given the higher risk profile of a competitive market, we apply a competitive weighted average cost of capital (WACC), proxied by the WACC used by the ERA in Western Australia for its Benchmark Reserve Capacity Prices (see here, p18).

While both costs and revenues are uncertain, for the purposes of the modelling we have deliberately taken an optimistic view of future revenue potential over the longer term. This reduces the amount of depreciation required leading up to 2050, following which the forces of competition will be much more at play. We believe it is appropriate for the first application of our risk-balancing framework to err on the side of apportioning more value to the competitive future—. As more information becomes available, future estimates of post-2050 value will evolve in both size and timing.

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

For revenues from residential customers, we take one of the model runs where the network still has customers in 2050 (this model run has 250,000 customers, about half the current number), and we assume that over the following 15 years, customers gradually leave until only a residual set of gas preferring customers remains. To proxy how many customers this might be, we look at wood heating at present; a technology which is more costly for most customers and has been overtaken (twice; one by gas and then later by air-conditioning) by more modern technologies for the majority of customers. Wood currently serves about 15 percent of household energy needs and so we assume that, in the long term, 15 percent of households maintain a residential gas connections.[33] We also assume that the number of households in SA grows by the levels forecast by the ABS (ABS Cat No 3236.0, available here).

To determine revenue, we take the current cost of heating, cooking and hot water for an all-electric home (the electric options in our consumer choice model) based on the 2023/24 current SAPN Default Market Offer price (see here p6), adjust it downwards based on appliance efficiency improvement assumptions in our model, and upwards by the AEMO index for residential electricity prices[34] to get a 2050 price that gas needs to beat in 2050. This is then multiplied by the number of households using gas.

For commercial customers, we use the proportional per household residential energy cost decrease outlined by the process above (so 2050 household electricity cost divided by 2025 cost), multiply it by our current gas revenue per commercial customer and then multiply this by the number of commercial customers in the relevant year. We assume that all commercial customers stay on the network, and we assume they grow by the forecast of SA household disposable income in its "Step Change" scenario.[35] For industrial users, we assume they can sustain a charge 50 percent higher than they do at present (we use the average annual revenue per residential customer), that all remain on the network, and that the number of customers grows by gross state product in the same AEMO scenario. The reason for using household disposable income for commercial and gross state product for industrial is that the former is a better fit to the growth of the local final consumption market (a restaurant catering to people in Adelaide, for example) whilst the latter is a better proxy for the growth of the local economy, which uses the outputs of our customers as its inputs.

In all three cases, most notably in industrial and commercial customer cases, we have likely erred on the side of optimism about the future competitive marketplace. However, as noted above, given where we are now in terms of the energy transition and the fact that our framework is new, we consider this to be a better option than an intentional slant towards pessimism. The NPV of the revenue from these services is roughly $1.2 billion over 50 years, which is a little higher than the value of the residual residential service above.

For electricity generation at the large scale, we have, for other work internal work, looked at sites on the transmission pressure (>1000kPa) components our network which intersected with major electrical substations and land packages large enough and suitably located for gas-fired generation. This includes with enough space for some local gas storage, to cover peaky demand. One such site exists in Salisbury. It is physically large enough to support almost 10 GW of generation, but AEMO reports only 3.5 GW of new gas fired generation capacity is required for the NEM.[36] Optimistically, we assume that SA could capture 1/3 of this, or 1 GW of capacity, which would require 10 TJ/hour of gas when it is running and the ISP suggests that such gas fired generation, in

[33] Based on the Australian Energy Statistics from DCEEW, available here. Research by CSIRO (Romanach L and Fredericks H, 2020, Residential Firewood Consumption in Australia, p40, available here) suggests around aa quarter of South Australian homes use firewood; slightly higher than its share in energy use.
[34] From the 2024 ESOO and its Forecasting Assumptions Workbook (available here)
[35] Also from the 2024 ESOO and its Forecasting Assumptions Workbook (available here)
[36] AEMO, 2024, 2024 Integrated System Plan for the National Electricity Market, p69, available here.

support of renewable power, would run for around 5 percent of the year.[37] If we assume that onsite storage is provided, the gas demand could be met with a capacity reservation of 12,000 GJ MDQ, for which we assume the power generator would pay the same as industrial customers do today.

For smaller scales of self-generation, we make use of earlier AGIG research, undertaken for the ENA Energy Networks 2024 conference (available upon request) which looked at different options for a household going off (electricity) grid now using half-hourly electricity consumption from a number of households and the iHOGA software package to model cost effective ways to meet a given demand pattern with different energy sources. For one Adelaide house, which had gas space and water heating, the simulations suggested that an option with rooftop solar, batteries and a small solid oxide fuel cell could, over a 25 year time horizon, reach self-supply electricity costs with roughly the same levelised cost of energy as relying upon the electricity grid.[38] The fuel cell in this set-up only ran for a very small number of hours, demanding 1GJ per annum of gas.

To work out what could be charged for the gas transport, we took projections of renewable gas prices and volumes from ACIL Allen for 2050,[39] and current retail margins in South Australia from the AER State of the Market report.[40] We then assume that households will pay a delivered price for gas that is price matched to electricity (see discussion above). The gas transport charge, in this instance, is the difference between the delivered price minus the wholesale renewable gas price and the retailer margin.

For commercial customers, using data from the SAPN 2025-30 Forecast RIN (see here Tab 3.4) suggest that small commercial electricity use is roughly three times residential electricity use, we assume that commercial users using a fuel cell as a backup will consumer 3GJ/annum in gas. Not all commercial customers are similar enough to a home user for this to be relevant (a factory using electricity to power motors, for example, will be very different, but a retirement home might be similar). To capture the proportion which are likely to be similar we look at ABS data of business numbers per industry class (ABS Cat no 8165.0) which is available down to the 4 digit level, and make a judgement call on which industry classes are likely to be, from an electricity use perspective, reasonably similar to a house when they are a small business (essentially, businesses unlikely to include a lot of electrical machinery), which is roughly 2/3 of the total. We then multiply the gas transport charge determined in the same way as for residences by the number of premises each year and then by 3.

The self-generation assumptions are fairly loose, but the numbers involved are not large; commercial and residential customers have an NPV of roughly $15 to $20 million each, and large-scale generation is $27 million. In these instances, if fuel cells or some other technology progresses significantly faster than batteries in terms of cost reduction (or, for batteries, their discharge time) then the market is likely to be larger. This is one area in particular that we would expect to change in forecasts made in future AAs and may offset some of the optimism in forecasts for traditional network uses above. Owing to a lack of data, we have not sought to quantify the other potential opportunities discussed in Section 2.1.7.

2.2. The next 25 years of status quo – demand side

We view the next 25 years as a transitional phase; long enough to encompass two full appliance replacement cycles (approximately 15 years each) for customers who joined the network in the past five years. For the first replacement cycle, we expect many customers will stick with their current appliance types, assuming no major price shifts. Appliances typically fail one at a time, and replacing like-for-like is often the simplest option. By the second cycle, however, customers will have spent a decade in a changing energy landscape and one increasingly shaped by national policies favouring electrification. Trends such as declining gas use for space heating may also become more pronounced. As a result, we expect the second appliance decision to carry a much higher risk of customers switching to electric alternatives.

Beyond that point, we do not attempt to model customer behaviour. It's not that we believe gas (renewable or otherwise) will be abandoned, but rather that we lack sufficient data or confidence in long-term behavioural trends beyond the second appliance cycle. This means that over the next 25 years, we anticipate a familiar form of competition—gas versus electric—but with increasing intensity. For residential customers (who account for roughly 80% of our revenue and are the only group modelled explicitly), each appliance decision—for cooking, hot water, and space heating—will involve weighing upfront costs, running costs, and non-cost factors such as convenience or preference.

Further details about assumptions for each appliance are contained in the model manual, contained in Chapter 6.

[37] *AEMO 2024 ibid.*

[38] *We examined three different houses; a family of four in Adelaide, a single person household in Adelaide (both dual fuel) and a fully electric family home in Melbourne. The aim was not representativeness, but rather to explore the concept. The single person home did not use enough electricity and the all-electric home had usage patterns that made self-supply less economic (early morning showers are a particular issue).*

[39] *See ACIL Allen 2024, Renewable Gas Target, Report for APGA and the ENA, 16 Feb 2024, pp7-9, available here.*

[40] *See AER, 2024, State of the Market Report, p246, available here.*

2.3. Conclusions about the future and customer views

Our customer consultation process focused heavily on the background information discussed in this chapter, with all of the drives covered to some extent and the transport example in particular used to illustrate the potential scale of future change resonated strongly with customers. Our two sessions dealing with depreciation were almost 6 months apart and we saw reasonably strong recall from the first to the second session. We also had good engagement on the "big picture" approach.

As part of the first consultation sessions, we also outlined how network businesses like AGIG differ from competitive businesses, and the process of adaptation which would be required if and when much greater competition comes about. We covered not only what might need to change in a regulatory sense but focussed on how competitive and regulated firms operate differently, with different risk profiles. We covered depreciation and its role in adaptation, including the modelling, in the second sessions, the results of which are summarised in Section 3.3.

The South Australian Reference Group (SARG) were more aware of the "big picture" of change in the energy sector. A key point of concern for them was less the demand-side picture painted in this chapter and the one following, but rather the supply-side picture and how we could be confident we ought to be that the "gateway" of renewable gas would be reached. For this reason, we held a deep dive dedicated to this topic and have covered it in more detail in Attachment 6.4.

3 Framework for considering depreciation

In this chapter, we outline our framework for considering the use of depreciation to meet the future we have described in the previous chapter. This has two parts:

- Where depreciation sits within the overall toolkit we have under regulation to meet the future.
- How to model the amount of depreciation we need.

In Section 3.1 we cover the National Gas Rules requirements, and outline how we think our "stable risk balance framework" (the toolkit alluded to above) meets these requirements. We compare this briefly to other proposed approaches currently before the AEMC. In Section 3.2 we cover the process for determining the appropriate depreciation amount via modelling.

3.1. The National Gas Rules and depreciation

The National Gas Rules outline how we are supposed to determine a depreciation schedule. The relevant clause from the Rules, which outlines the criteria we are required to follow, is summarised in Box 3 below.

Box 3: National Gas Rules and Depreciation

Rule 89 covers the design of depreciation schedules, and requires that:

(1) The depreciation schedule should be designed:
  a) so that reference tariffs will vary, over time, in a way that promotes efficient growth in the market for reference services; and
  b) so that each asset or group of assets is depreciated over the economic life of that asset or group of assets; and
  c) so as to allow, as far as reasonably practicable, for adjustment reflecting changes in the expected economic life of a particular asset, or a particular group of assets; and
  d) so that (subject to the rules about capital redundancy), an asset is depreciated only once (ie that the amount by which the asset is depreciated over its economic life does not exceed the value of the asset at the time of its inclusion in the capital base (adjusted, if the accounting method approved by the AER permits, for inflation)); and
  e) so as to allow for the service provider's reasonable needs for cash flow to meet financing, non-capital and other costs.

(2) Compliance with subrule (1)(a) may involve deferral of a substantial proportion of the depreciation, particularly where:
  a) the present market for pipeline services is relatively immature; and
  b) the reference tariffs have been calculated on the assumption of significant market growth; and
  c) the pipeline has been designed and constructed so as to accommodate future growth in demand.

89(2) is rarely much of an issue at present, at least for existing networks, as very few have assumptions of significant market growth associated with them. This could change, of course, where networks seek and gain new markets for renewable gas.

The National Gas Rules allow for changes to depreciation schedules to ensure prices continue to promote the "efficient growth in the market for reference services"; which may involve either expansion or contraction of services. This flexibility is important when external market conditions introduce new risks or dynamics not previously considered. If depreciation does not reflect these changes, prices may become inefficient; either too high or too low, leading to over- or under-consumption of services.

However, the National Gas Rules also require that changes be "reasonably practicable." This prevents abrupt shifts that could destabilize the market. For example, if depreciation had been held constant for too long, a sudden correction could cause prices to spike and demand to collapse. This concern is captured in the "WOOPS" framework developed by Crew and Kleindorfer.[41] The AER addresses these issues in much more detail in its Regulating Gas Pipelines Under Uncertainty paper (available here).

Some commentators, (see, for example, the AER's summary of ECA view in its Jemena decision, here, p10) have suggested that a change in depreciation is almost synonymous with a transfer of risk to customers, and for this reason requires a large number of guardrails around any change. However, this misunderstands the situation. When the National Gas Rules were first established, the notion that the market power of any energy network could vanish in the face of competition from emerging technologies and opportunities for customers was simply not part of the debate. Customers benefited from this because, with a view of essentially eternal monopolies who faced little competition, asset lives were set very long, network lives were effectively made infinite, and customer prices were much lower than they would have been had regulation been given a finite life from the outset. Circa 2020, this began to change, as various stakeholders started to realise that market and other forces might mean that gas networks in particular (we would argue that all energy networks face similar risks) might face future competitive forces whereby regulatory prices might no longer drive business or customer behaviour. This early realisation culminated the AER discussion paper alluded to above.

[41] *See Crew, M and Kleindorfer, P, 1992, "Economic Depreciation and the Regulated Firm under Competition and Technological Change", Journal of Regulatory Economics, 4(1), 1992, 51-61, available here*

Therefore, the situation is not one of a risk which has always existed being shifted from networks to customers, but rather a new risk, which has not been perceived before, which needs to be considered for allocation between customers and networks. There are a number of ways this new risk could be addressed: Keep the level of risk faced by customers constant and require networks to bear all of the new risk:

- Keep the level of risk faced by networks constant and make customers bear all of the new risk.
- Share the risk between networks and customers.

The National Gas Rules require efficiency as the driving consideration. There would only be a handful of situations in a marketplace where the most efficient response would be for one party to a transaction to take all of a new risk when it arises; sharing risk is a far more common market response. It is also not very practical. Forcing networks to cover all of the risk without explicit compensation via the WACC would make capex riskier and mean that network operators would instead seek opex responses, which tend to be more expensive. To the extent that this does not cover all of the additional risk, the prices to customers will not cover the risk, and they will consume too much gas transport services, loading up problems later when the risk crystalises into consequences. Forcing customers to cover all of the risk would just mean more of them would leave earlier than is optimal, bringing forward any adverse consequences which might occur if and when competition does materialise.

We consider the best approach is a balance, with the new risk shared between networks and customers, as a competitive marketplace would do. In fact, we think that the goal ought to be, as markets change, to maintain a stable balance of risk between networks and customers, to keep incentives and efficient action consistent through time, as the environment changes.[42] We think that this can be given effect through the use of a three-part conceptual framework whereby:

- A network operator, seeing a decline in demand, looks to new sources of demand which are sustainable in any future competitive marketplace, to fill the now available capacity, in just the same way as a competitive firm would do. Regulators, recognising the benefits of competition to the long run interests of consumers, support this.
- Customers of currently regulated services (whether the customers themselves are existing or new), seeing that not all of the costs previously incurred to provide their services could be recovered though new markets or into a competitive future, where reasonably practicable, seek to cover the balance before competitive forces have a greater impact
- Customers, realising that growth in regulated services cannot always be assumed, no longer impose costs on each other as they enter or leave the energy network; instead paying all costs attributable to their own use themselves.

The first two of these points cover risk between a network and customers as a whole and the latter covers risks between customers; in particular the externalities they can impose on other customers from their actions.

In practical terms, the three points mean together that, if a network has a RAB of $1 billion now, and an assessment of a competitive future circa the mid-2040s suggests its forward-looking value from the mid-2040s is $500 million, then it could seek to recover $500 million from its regulated customers before then (or enough such that the RAB by the mid-2040s is $500 million, given the need for maintenance capex) rather than all of its outstanding RAB from consumers of currently regulated services. However, before recovering this amount, the feasibility of doing so ought to be modelled to make sure that the prices are sustainable amongst customers. Finally, to reduce the higher costs that remaining customers face if customers leave, new customers should pay their connection cost up-front (and not make any risks larger by their actions) and departing customers should likewise not leave any costs behind to be socialised.

We are aware of rule change proposals currently before the AEMC which seek to address issues of risk that these points address. We do not think a rule change is necessary but a change in the way risk is balanced and how depreciation schedules may be considered at each relevant review would be more in the long run interests of consumers than the current set of pending rule changes. We discuss this at the close of this section, but first we unpack each point above in more detail.

The first point means that regulators ought to be able to consider new market opportunities, where these are reasonable, rather than just focussing on currently regulated services as a means for networks to recover their invested capital.[43] If it did not, this would be more protection than available in a competitive market where companies routinely re-deploy assets where they can to new markets as old markets become less viable. However, in making, or assessing any case in respect of new business opportunities, hypothetical or merely possible opportunities should not be included, but rather only those with some reasonable chance of viability. This could be considered as a corollary of "reasonable opportunity of recovery" in The Revenue and Pricing Principles (National Gas Law 24).

The second aspect is more easily implemented without causing any conceptual issues with the NGR; indeed several networks (including AGN in Victoria) have made and had accepted arguments on increasing depreciation after consideration of customer effects; albeit without considering the first part of the framework above explicitly (which in fact makes the task a little easier). It is

[42] *Note that a "stable balance of risk" need not imply an even split between networks and customers but rather means that the new risk is allocated to maintain the overall risk balance which existed previously. The framework is conceptual, rather than pointing towards an exact numerical balance, which has not been calculated previously and is thus not available as a reference point.*

[43] *The ERA, 2021, make a similar point in their Final Decision for our DBP asset in Western Australia (see here, [1524]), and the US Supreme Court, also made a similar point in the Market Street Railway case of 1945 (see here).*

this aspect where modelling is especially important, because it can help understand the extent to which more depreciation is "reasonably practicable", by explicitly and transparently assessing customer reactions to price changes. Just as it would be unreasonable not to test the amount of future risk a network is taking on when new business opportunities in the first stage, it is unreasonable not to test the risks to customers in terms of their potential consequences. Note that this has nothing to do with notions of "fairness" or "equity" but is rather a practical concern; a regulatory price which customers will not pay is a price which will not be charged.

The third aspect of the framework above is directed at risk-sharing between customers; although we note that a potential new connection charge (or at least, a means of financing new connections capex outside the RAB) will make the need for additional depreciation smaller, and lead to lower price effects for customers as a whole (see Section 5.2).

Economically, a gas network is a mix of public and private costs. The gas meter and the line connecting a property to the gas main in the street are deliver benefits just to that home. By contrast, a gas main serving a whole suburb delivers benefits to the whole suburb. Under ordinary circumstances, the public parts of the network would have their costs shared among all users and individual customers would pay for the parts that are provided just for one customer. It has not happened in the past in gas because gas networks were growing, and, given their high fixed costs, recovering the costs of connection through network tariffs reduced the costs of network entry contributing to lowering the average cost for all users as the number of users increased.

Once a risk emerges that the benefits new customers bring in terms of lowering average cost emerges, the case for moving away from a more standard beneficiary pays framework weakens, and consideration needs to be given to issues such as the following:

- New customers who enter the network should perhaps pay an up-front connection charge, as there is a reasonably high risk that they may depart the network before the cost of their individual services and meters have been recovered from them, meaning that others will bear an externality from their decision to leave the network.
- Existing customers who depart the network before the cost of their individual services and meters have been recovered in theory ought to pay any unrecovered costs associated with them, rather than leave them to be recovered from other users, as this imposes an externality on other users.
- Where the network incurs direct costs to remove an existing connection safely, this should be recovered from the customer who leaves the network, rather than socialised across all users, creating an externality.

Approaches such as these would not prevent prices from rising as customers leave, as the network is more than the sum of these private costs, but it will at least eliminate that part of any price increase that is caused by customers imposing externalities upon each other. We note that the first of these points (up-front connection charge) is already imposed in Victoria and is subject to a proposed Rule Change before the AEMC filed by the ECA (see here). We have not proposed any such charge for our South Australia networks at this stage, as implementation involves more issues than the economic ones elucidated here and we did not consult with customers on this, but we assume in our modelling of depreciation that such charges are imposed from the subsequent AA (ie 1 July 2031) onwards (see Section 5.1).

In relation to the third point, we believe the AER's current approach is not sustainable in this respect (See Chapter 7). We note that the JEC also has a rule change which, among other things, seeks to prevent the AER from socialising costs in this way (see here).

The second point, despite its theoretical nicety, is likely to prove difficult to implement in practice, particularly where a house has been connected for decades, and potentially across several owners, so that the person being asked to pay the charge is not the one who sought the connection in the first instance. To address this issue, in our depreciation proposal, we propose that any additional depreciation ought to be applied to the "Inlets" asset class, which covers service pipe running form the main to customer's property, rather than the "mains" asset class which is similarly long-lived.

3.1.1. ECA and JEC proposed rule changes

There are currently several proposed rule changes pending before the AEMC, from the ECA and JEC. Those relating to connection charges and disconnection charges we discuss above.

The ECA also proposes an additional rule change dealing with depreciation (see here). In respect of the ECA depreciation rule change, we consider that our framework outlined above represents a better way forward to deal with the relevant issues. This is because:

- So far as we can tell, the ECA Rule Change proposal provides no method, even in principle, to establish how much asset risk should be borne by networks and how much by consumers. The AER would therefore need to develop approach risk allocation if the ECA rule change proposal is accepted.
- Our approach is more amenable to taking into account the differences in the environment of different networks at a point in time (the policy landscape facing Evo Energy in the ACT versus AGN in SA for example) and through time, in transparent and robust manner. A "one-size-fits-all" approach is unlikely to reflect the different circumstances networks face.
- Rather than a negative focus on losses and sharing risk, our approach is based around a more positive focus of working together to seek out new opportunities and adapt to a changing environment, for the benefits of customers and networks.

For these reasons, we believe our framework is better for the long-run interests of consumers than current alternatives. We do not believe that a rule change is necessary to implement it, as we consider that the current form of NGR 89 can accommodate these changes to regulatory practice.

3.2. How we bring market developments into considering depreciation under the NGR

Our approach to depreciation makes use of a five-stage approach, which may be summarised as follows:

- We start with an asset value that we think is credible at the start of the period of competitive market forces (assumed to be 2050 for the purposes of the modelling).
- We look at the current RAB, and future required capex to meet the needs of customers now and into the future.
- We look at the difference between those two numbers and check to see whether this can be recovered without changing the current depreciation schedule. If it cannot be, we increase depreciation until it is.
- We test, using our formal model of consumer behaviour, whether the price increase caused by changing depreciation will cause customers to leave prematurely, effectively meaning we will not be sustainable until 2050.
- If no, we stop, if yes, we keep testing until a reasonably practicable depreciation schedule is found.

The first step is discussed in Section 2.1.8, where we outline how we take the perspective of an analyst circa 2050 looking forward to a competitive future and the business value (not RAB) she would determine from her analysis. As discussed in Section 2.1.8, this value is roughly $1 billion. This therefore forms the goal towards which action during the period up to 2050 is directed.

The second step looks at the RAB we have now (roughly $1.8 billion in the model) and the capex and opex we need to make to keep the business operating over the next 25 years (note that there is no restriction on capex lasting only to 2050). The third step looks at the delta between where the RAB is in 2050 and where the competitive business needs to be, and the fourth step then proposes and tests (against consumer reaction to resultant prices) amounts of depreciation which can bring the delta to zero. The fifth step then essentially repeats the whole process.

It should be noted that the second, third and fourth steps are, in practice, implemented together as we operate our model on simulations, and each simulation run involves different prices (of things other than network charges) which gives rise to different customer reactions and different customer numbers.

Our approach is a direct implementation of the first two steps of our stable risk-balancing framework discussed in Section 3.1. We first ask what new business opportunities the network might support in a future competitive marketplace. The RAB is reduced down to a point that enables the business to be competitive in that market and recover the RAB through that future market. We then take the remainder and test whether customers of currently regulated services can in fact cover the remaining costs; whether the price schedule resulting from any depreciation profile is "reasonably practicable". We bring the third step of our framework into the modelling by explicitly testing cases where new connection charges are made, and cases where they are not; generally, the former provide better price outcomes than the latter. Further detail on the modelling is provided in Chapter 5 for the results and Chapter 6 in terms of a manual explaining how the model works.

4 Modelling changes to depreciation

This chapter introduces the consumer choice model used to simulate how consumers respond to regulated pricing through to 2050, as outlined in Chapter 3. While the model builds on the one developed for Victoria, it is applied differently here (see Section 4.1.1). Given the similarities, readers may find it helpful to review our Victorian proposal for additional context (see here and here for more detail).

Section 4.1 explains the core structure of the model and highlights the key changes from the Victorian version. Section 4.2 discusses the technical challenges in capturing consumer behaviour, particularly in a data-scarce environment where assumptions are necessary. We explain these assumptions to support transparency; an essential part of our approach and a principle we have emphasised in discussions with customers.

4.1. Model basics

The consumer choice model operates by first using a regulatory building block model to determine the annual gas transport price. This, combined with wholesale gas prices and other components like carbon pricing, produces a delivered gas price for residential customers. The consumer choice model then evaluates two key decisions. First, for customers in the "appliance choice set," it determines whether they will choose gas or electric appliances for space heating, hot water, and cooking, based on projected lifetime costs. Second, for existing gas users outside this set, it estimates gas consumption based on price and elasticity. The appliance choice has the greatest influence on the model's outcomes. The resulting gas volumes, influenced by appliance choices and usage levels, are multiplied by the gas price to calculate annual revenue. These connection and consumption outcomes are then fed back into the building block model to update the price forecast for the next year. This iterative process continues annually until either all customers have transitioned away from gas or the year 2050 is reached.

Depreciation changes are introduced through a tilt function in the building block model and tested within the consumer choice model. Adjusting depreciation can help manage risk by shifting capital recovery to periods when gas is more competitive with electricity. This typically means moving recovery earlier, which results in smaller price increases and encourages more customers to remain on the gas network. As fixed costs are spread across more users, future prices are lower than they would be otherwise.

The model is run multiple times using @Risk to simulate a range of input values, such as gas and electricity prices. This generates a distribution of "stopping times"—the points at which the network ceases operation due to full electrification. If adjusting depreciation increases the number of scenarios where the network remains viable to 2050, it supports business sustainability.[44]

4.1.1. Changes from our Victorian model

In developing the model for this Access Arrangement, we introduced several key changes from the Victorian version. The most significant is the introduction of a 2050 cut-off. Unlike the Victorian model, which assumed the network would continue operating indefinitely under the same regulatory conditions until all customers exited, this model limits its scope to 2050. We do not model the network's value or operations beyond that point. While future versions could incorporate new business lines or competitive market dynamics, doing so would significantly increase complexity. For this proposal, we have chosen to keep the model focused and streamlined. Additional operational changes to the model are outlined in the following sections.

Removing the S-Curves

In the Victorian model, to proxy the choice of a new appliance, we used a S-curve (see here, p55). That is, the likelihood that a customer (or alternately, the number of customers ready to choose new appliances) would choose electricity over gas is an increasing function of the difference in the net present value of the lifetime cost of each choice, and the cumulative function slopes upward in a S-shape. This is a commonly used way in which to capture change from one product to a substitute when there are lots of different contributors to making the change other than just price.

To support analysis of policies like connection bans or new connections capex not entering the RAB, the model uses the same S-curve approach we used in our Victorian AA proposal for new connections. This allows for a gradual decline in new connections as NPV falls, rather than an abrupt stop as would occur under certain circumstances with a discount rate approach.

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[44] When using the model, one needs to exercise care in cases where there are a lot of stopping times many year prior to 2050. The RAB value in 2050 is reported regardless of whether the business remains a going concern. If the business fails, the RAB is typically below the $1 billion target. In cases with many failures, less depreciation is needed to manage RAB growth. However, that low depreciation result is not an indication of success, as the business fails early. When running many simulations and looking at overall results, this does not matter, but, when looking at a single simulation, one needs to look at both the additional depreciation and the year the business fails in the model.

An issue is that there are very few data with which to parametrise the S-curves, and the tuning parameters are difficult to interpret in a meaningful way.[45] We dealt with this in Victoria by discussing reasonable shapes for the curves with the AER for each of the scenarios we used, but this was largely a judgement call by us and the AER.

For existing customers making choices about new appliances, we use a discounted NPV approach, where all such customers will switch if the benefits of doing so outweigh the costs. We seek to reflect the same information that would usually be reflected in an S-curve through the choice of discount rates we use. Here there is a comprehensive literature on consumers making choices which is more adaptable to our circumstances, which has in fact been deployed by others, such as the European Union (see below) in a context similar to ours.

The relevant literature starts with a paper by Hausman which looks at purchases of air-conditioners of differing quality levels and price by customers.[46] By looking at actual purchasing decisions, Hausman uncovers the discount rates consumers are employing to compare the running cost savings of more efficient models with their higher up-front costs. These discount rates were much higher than those commonly used in financial analyses of running cost savings and came to be known as the "implicit discount rate". Subsequent papers during the 1980s found similar results,[47] and a literature developed looking at the "energy efficiency paradox" or "energy efficiency gap" which is a different way of looking at these high implicit discount rates.[48]

A large literature also developed seeking to decompose these discount rates into different elements. Schleich et al consider that three factors drive higher discount rates:[49]

- Preferences – customers have preferences for risk, loss and taking on debt which may lead them to disfavour larger capital investments.
- Departures from economic theory – such as bounded rationality or information asymmetry which may preclude "rational" decisions from being made; and
- External factors such a lack of access to finance which may preclude customers from making choices which they would make if they could.

The European Union has developed its PRIMES model to understand how consumers make choices, among other things in respect to energy appliances.[50] As the reports summarise, a key distinguishing factor between different implicit discount rates is socio-economic factors, with lower socio-economic groups having higher implicit discount rates; a reasonably consistent finding in the literature. The reasons are not difficult to see, as these are the groups for whom higher up-front costs will weigh more heavily in decisions. Although there are many rates we could use, we choose the ones used in the 2021 version of the EU publication, which range from 12.8 percent for higher socio-economic groups up to 14.1 percent for those from lower socio-economic groups.

Allowing early shift away from gas

In the Victorian model, the length of time a customer used an appliance was fixed at 15 years, and it was only at the end of 15 years that a customer could join the set of "appliance choice set". This meant that, even if prices rose substantially during the 15-year period, customers might reduce gas volumes, but they did not replace their gas appliances early in response to increasing price. This is not realistic; if the price of gas delivered reached $10,000 a year, and a new electric appliance could be had for $2000, one would expect the customer to bring forward purchase of the new appliance. In a modelling sense, what this mean was that the model tended to favour depreciation profiles which brought forward too much depreciation into the next period, as customers were artificially inelastic.

We dealt with this issue in Victoria by agreeing with the AER a regulatory price cap; essentially, if the price for gas transport rose higher than 1.7 times the current price, the AER would disallow the price increase, and the year in which that occurred was taken as the year the network failed due to unsustainable prices. This had the effect of reducing the tendency of the model to favour early

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[45] Even in the literature, there are few studies which we could credibly apply to the particular type of switching we are attempting to model. For example, this paper does empirically derive S curves for solar cell adoption in Queensland, but the maps it ultimately derives as it classifies customers are difficult to interpret in respect of what characteristics customers might share, and hence how we might adapt them to a South Australian context.

[46] See Hausman, J, 1979," Individual Discount Rates and the Purchase and Utilization of Energy-Using Durables", The Bell Journal of Economics, 10(1), 33-54, available here

[47] See Kim B and Sims C, 2016, "Why is Energy Efficiency Such a Hard Sell?", Howard H Baker Centre for Public Policy White Paper 1:16, available here, and Singh, M and Bahinipati CS 2024, "The Implicit Discount Rate, Information, and Investment in Energy-Efficient Appliances: A Review", Ecology, Economics and Society 7(2), 11-28, available here, for a review of this literature. It is also covered in the EU paper cited below.

[48] See Giraudet LG and Missemer, A, 2023, "The History of Energy Efficiency in Economics: Breakpoints and Regularities", Energy Research and Social Science, 97, available here, for an overview of the literature.

[49] Schleich J, Gassman X, Faure, C and Meissner T, 2016, "Making the Implicit Explicit: A look inside the implicit discount rate", Energy Policy, 97, available here. In subsequence papers, the authors seek to quantify the contribution each of the factors they posit makes to the implicit discount rate; see for example,Schleich J, Gassman X, Faure, C and Meissner T, 2023, "Making the Factors Underlying the Implicit Discount Rate Tangible", Energy Policy, 177, available here

[50] The various reports can be found here and here. The most recent report, published in 2021 has a very detailed summary (see pp159-174) on the debate around implicit discount rates leading ultimately to the rates which the EU has chosen. This summary includes both a literature review more comprehensive than the one presented here, and links to many more of the relevant papers in the literature.

depreciation and delivered reasonable results in terms of the amount of depreciation allowed, but the cap itself was a judgement call, and somewhat arbitrary, rather than reflecting customer behaviour.

To account for gas disconnection prior to the end of appliance life the fixed 15-year life assumption was converted to a formula that reduces the appliance life to proxy disconnection prior to end of life. The formula depends the difference between retail electricity and gas price inflation over the past two years. If retail gas prices are persistently increasing faster than electricity prices over a certain percentage threshold, the formula will start reducing appliance life below 15 years. There is currently no data to inform this threshold so it has been simulated as a large range between 0 and 500 per cent growth.

Once the set growth differential threshold has been crossed, the reduction from 15 years reduces at a set percentage rate or 'sensitivity' 5 times the inverse of the inflation difference. This figure has been chosen as a high starting point assuming that once the threshold has been crossed, relatively large numbers of consumers start leaving prior to the end of appliance life.

5 Model results

In this chapter, we outline the results of our modelling process. Recall that we are not seeking an "optimal" amount of depreciation but rather a "reasonably practicable" amount which will allow the business to remain sustainable into the longer term, without producing prices which drive customers away in the meantime.

Section 5.1 covers the setup of the model. Section 5.2 covers headline results. Section 5.3 provides focuses on long term customer price outcomes. Section 5.4 shows the impacts of waiting until the next AA before we implement change the approach to depreciation. It is important to note that our results are based on simulations across a wide range of input values, rather than fixed scenarios. As such, sensitivity analysis is embedded within the simulation process, rather than presented separately.

5.1. Model setup

The key parts of the model are what we assume for appliance prices, what we assume for relative electricity and gas prices and what we assume for opex and capex. Appliance prices vary in each of the broad cases we study, but otherwise (except where policy intervenes) vary only through time by a single level of technological progress per appliance. Opex and capex have two regimes; one where gas prices are favourable relative to electricity and one where they are not (to reflect the fact that we would plan our opex and capex mix differently if gas prices were broadly favourable compared to where they are not). Electricity and gas prices also have the same two broad regimes and are simulated within each of these two broad regimes. We also simulate the degree to which customers who still have working appliances choose to switch appliances early.

We model four policy cases, within this context:

a) **Case 1:** assumes no policy barriers to gas and includes new connections in the RAB. Customers consider the full upfront cost of electric alternatives like reverse-cycle air conditioners. This is the most favourable case for the business.
b) **Case 2** also assumes no policy barriers but excludes new connections from the RAB. Here, customers are assumed to purchase reverse-cycle air conditioners for cooling, so the heating function is treated as having zero marginal cost.
c) **Case 3** builds on Case 2 but assumes no new customers join the network, either due to policy bans or lack of demand.
d) **Case 4** mirrors Case 2 but adds a $2,231 subsidy for electric hot water systems, making it the most challenging scenario for the business. [51]

Within *each* of the four policy cases, we have three fuel price and appliance bundles:

I. **Bundle 1:** Gas-favourable prices, with electric alternatives being heat pump hot water systems and reverse-cycle air conditioners.
II. **Bundle 2:** Electricity-favourable prices, with the same electric alternatives as Bundle 1.
III. **Bundle 3:** Electricity-favourable prices, but with rooftop solar and resistive tank systems for hot water, and reverse-cycle air conditioners for heating.

Bundle 1 is most favourable to the network, while Bundle 3 is the least. When combined with Policy Case 3 or 4, Bundle 3 creates a scenario where gas loses both its upfront and running cost advantages, even without an explicit connection ban.

We note a minor logical inconsistency between space heating being treated in the policy cases and hot water systems being treated in one of the bundles. However, the way we lay out our results (see below) means that all of the relevant boundary cases are considered. The demarcation came about due to the process we took in setting up our modelling cases.

5.2. Headline results

Within the cases and bundles outlined above, we tested the effectiveness various amounts of depreciation has on reducing the probability of ceasing to be a going concern prior to 2050. In our headline three amounts of accelerated depreciation were tested:

1. No additional depreciation – only regulatory straight-line real depreciation using standard asset lives is applied. This generally does not lead to the RAB reducing to $1 billion by 2050, except in simulations where few new customers emerge.
2. Targeted additional depreciation – with the target being the amount required to get to a $1 billion regulated asset base by 2050 under the electrification scenario and policy setting.
3. High additional depreciation - $150 and $270 million as tests of how more depreciation lowers risk.

Probabilities were generated by simulating 1000 random draws of wholesale gas and retail electricity prices which is the key source of risk within our modelling framework. Table 1 provides an overview of the results. The second column shows the amount of

[51] *The amount of the subsidy was chosen because this amount is enough to start causing significant switching; recalling that the use of discount rates rather than S-curves causes tipping points.*

depreciation required in each combination of policy case and fuel and appliance price bundle to get on average (across all simulations) a RAB of $1 billion remaining in 2050. So in Policy Case 2, Price Bundle 2, with $77 million in additional depreciation, one would, on average, get $1 billion in RAB remaining in 2050. However, as discussed in Section 2.2, there no guarantee that the business will make it to 2050 (if there was, then a test of consumer response would be meaningless). Column 3, therefore, captures this. So in Policy Case 2, Bundle 2, with $77 million in additional depreciation 23 percent of simulation runs suggest that the business would not make it to 2050, because the price changes caused by this additional depreciation would be too high. As suggested in Section 4.1, the additional depreciation amount and the percentage of cases making it to 2050 can be linked. That is, one might see a very low number in column 2, which suggests that very little additional depreciation is required, but if this is combined with a very high percentage of cases where the business does not make it to 2050 in Column 3, then all the model is really picking up is that the business fails relatively early, so the RAB grows by very little. This is not a desirable outcome and is the reason why we show both the depreciation amounts and the likelihood of failure before 2050. The remaining three columns show the likelihood of getting to 2050 with zero, $149 and $272 of additional depreciation during the next AA. This provides an indication of how increasing depreciation can improve the likelihood of remaining in business.

Table 1: Headline results – additional depreciation and pre-2050 risk

	Amount of additional depreciation to get to $1billion by 2050	Proportion of sims stopping short of 2050	Proportion of sims stopping short of 2050 with no additional depreciation	Proportion of sims stopping short of 2050 with $150 mil additional depreciation	Proportion of simuls stopping short of 2050 with $270 mil additional depreciation
Policy Case 1					
Price Bundle 1	879	1%	0%	0%	0%
Price Bundle 2	150	26%	26%	26%	24%
Price Bundle 3	132	37%	43%	36%	30%
Policy Case 2					
Price Bundle 1	272	0%	0%	0%	0%
Price Bundle 2	77	23%	23%	23%	22%
Price Bundle 3	67	39%	41%	34%	29%
Policy Case 3					
Price Bundle 1	285	0%	0%	0%	0%
Price Bundle 2	77	38%	41%	36%	35%
Price Bundle 3	72	54%	61%	49%	41%
Policy Case 4					
Price Bundle 1	356	13%	12%	12%	12%
Price Bundle 2	127	35%	42%	34%	29%
Price Bundle 3	121	36%	41%	35%	29%

Under Policy Case 1 high amounts of additional depreciation compared to other policy settings are required to reduce RAB to $1 billion by 2050 because new connections grow the regulated asset base more quickly and depreciation are essentially working against one another. This is suggestive that additional depreciation is better paired with not including new connections capex in the RAB, so there is a practical reason to make this change to new connections capex as well as a principled reason as per our framework of keeping risk balances stable (see Section 3.1).

Policy Case 2 shows the situation when hew connections can still happen, but their capex is not entered into the RAB. Here, the amount of depreciation required to reduce the RAB to $1 billion by 2050 is much smaller as depreciation and new connections are not working at cross-purposes. Policy Case 3 also has no new connections capex entering the RAB, but this is because there are no new connections. Here, the amounts of depreciation are similar to Policy Case 2, but the risk of not reaching 2050 is elevated. This is suggestive that a policy setting which precludes new connections entirely, rather than letting the market decide is much riskier for customers who remain on the network. If one compares column 6 in Policy Case 3 with column 3 in Policy Case 2, it would take roughly four times as much additional depreciation to reach the same level of risk of not making it to 2050 with a new connections ban as it would without such a ban. This is indicative of the scale of the cost of a connections ban.

This is suggestive that additional depreciation alone may not be the best policy, as one is effectively adding to the amount of RAB which needs to be recovered by rolling new connections into the RAB. When conditions in the short to medium term (up to 2050) are favourable to gas, the number of new connections grows most rapidly, effectively storing up problems if future shocks are likely.

A hot water appliance subsidy for low to medium income households (see Policy Case 4) creates the challenge, even when gas prices are relatively favourable (Pricing Bundle 1). A $2,231 electric hot-water appliance subsidy stops many new customers connecting and makes early switching for existing customers economically attractive. Here $70 million of additional depreciation, sufficient in Policy Cases 2 and 3, would be insufficient; doubling the amount of additional depreciation would lower the risk by about 5 percentage points but we would need to roughly quadruple it to drop the risk below 30 percent.

Effectiveness of Additional Depreciation

Table 1 shows a subset of potential amounts of additional depreciation. To get a more holistic picture, we show the entire range of additional depreciation amounts, plotted against the risk of not reaching 2050, from zero through to $1.4 billion (which would effectively reduce our RAB to zero during the next AA.

Figure 3 shows Price Bundle 3 is the highest risk scenario and where additional depreciation is most effective. Depreciation is particularly effective under a new connection ban as RAB/building block costs are rapidly reduced in line with demand. Treating new connections as ARS is particularly effective in reducing risk, both with and without hot water subsidies.

Figure 5-1: Effectiveness of depreciation under Price Bundle 3

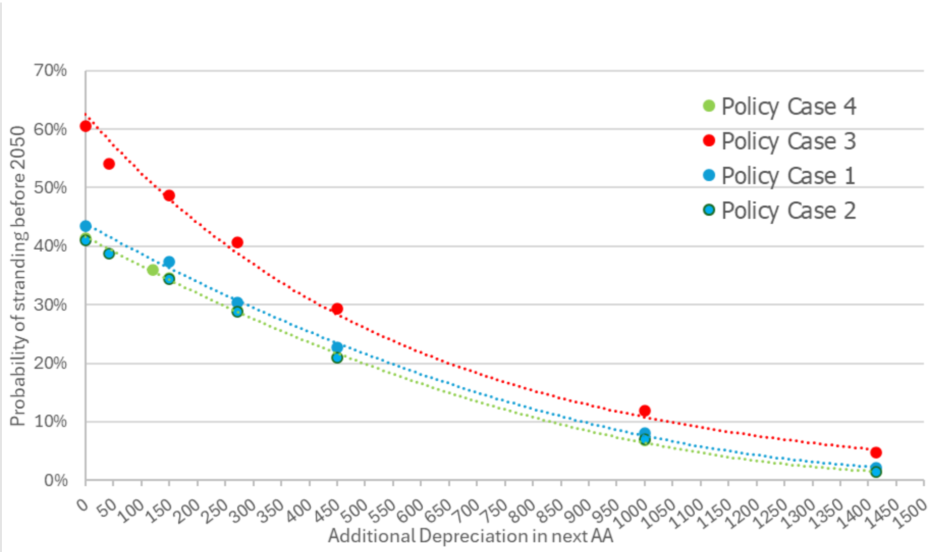


Figure 4 shows Price Bundle 2, which is less extreme than Price Bundle 3; shown by the curves intersecting the y axis at lower values. Additional depreciation is particularly beneficial where hot water subsidies are introduced in tandem with new connections capex not entering the RAB (Policy Case 4) as this helps offset the loss of total customer base resulting from subsidy. Under Policy Case 3, where new connections are banned, no new customers are added to share fixed costs and depreciation is less effective.

Figure 5-2: Effectiveness of depreciation under Price Bundle 2

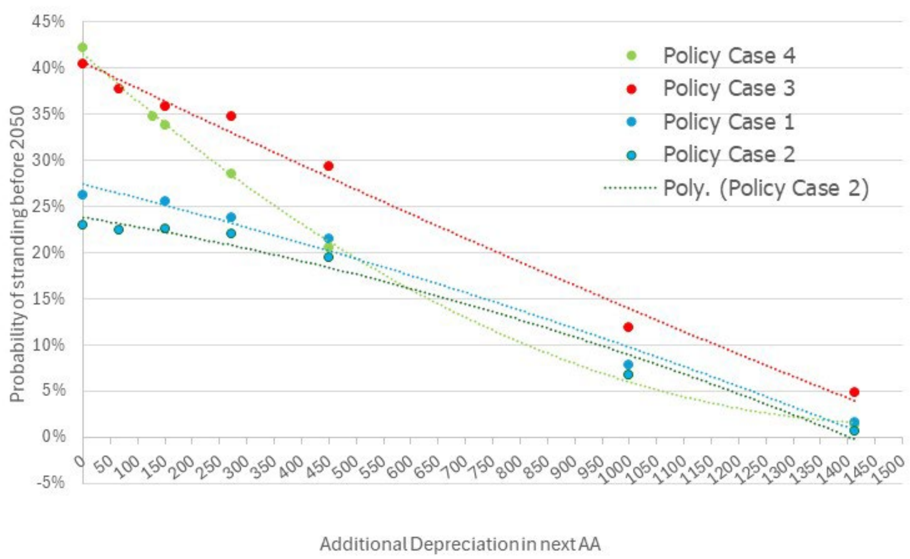
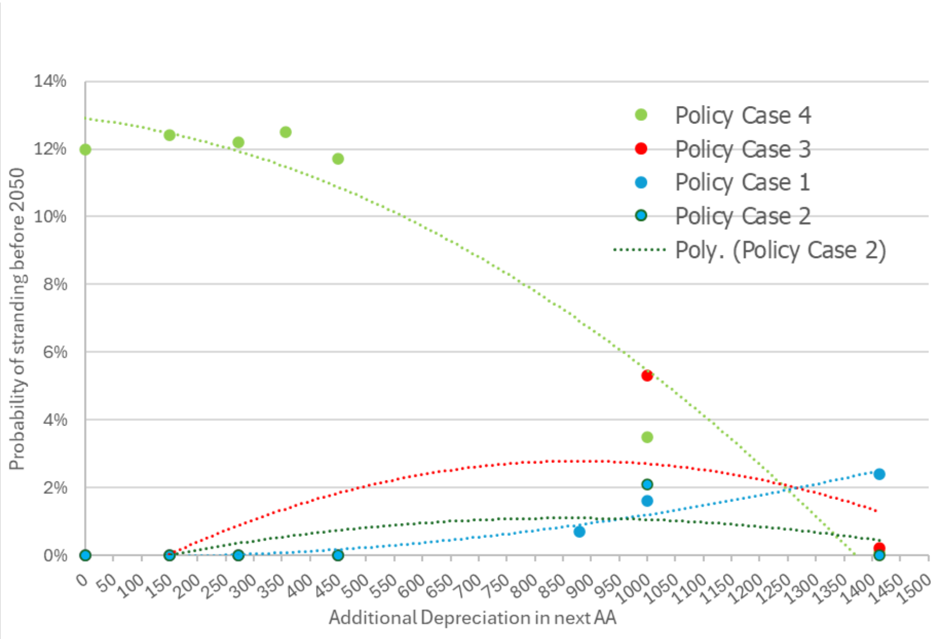


Figure 5, which corresponds to Price Bundle 1, shows that even under relatively favourable gas appliance and running cost conditions, hot water subsidies still pose a significant risk.

Figure 5-3: Effectiveness of depreciation under Price Bundle 1



The light green trend line rises to 12 percent, reflecting the erosion of both the existing customer base and new connection growth. The blue trend line in the base case continues to slope upward, indicating increasing risk as new connection capex combined with very high depreciation start to trigger price related death spiral effects. However, scenarios that exclude new connection capex—help mitigate this risk by stabilising or reducing the asset base. Overall, the ability to share costs across a growing customer base is a key determinant of business viability and the level of depreciation required. This ability depends on the competitiveness of gas and gas appliances for heating and is heavily influenced by policy choices around new connections and subsidies.

5.2.1. How we think this result meets our reasonableness criteria

From all of the assessments outlined above, we choose an amount of additional depreciation equal to $70 million as the most reasonable, model-supported amount of additional depreciation. This brings the RAB down to a level we consider can be supported in a future competitive market (roughly $1 billion) in the cases where new connections capex is not included in the RAB post 2031 or where we have no new connections. It would not be enough if new connections were included in the RAB, or if there were large subsidies on hot water systems, and it would not be enough if prices remained favourable to gas. However:

- Not including new connections capex in the RAB is valuable from the perspective of managing risk between customers and lowering the imposition those entering the network under a changed market or those leaving impose on other customers in any event. It is also an additional tool to reduce future risk exposure and arguably should be considered alongside additional depreciation for future AA periods.
- The South Australian government has not instituted large subsidies designed to push people away from gas hot water systems, so reacting to a policy this extreme at this juncture would be premature.
- If we really were certain price conditions were likely to remain favourable to gas into the long term, we might reconsider our long-term future more favourably, and so basing our depreciation considerations around this particular scenario alone has some issues in terms of logical consistency.

We note that $70 million is not a complete solution to ensure that the business is able to survive until 2050, and that risk could be reduced further with more depreciation; particularly in the price bundle cases which are less favourable to gas. Rather, $70 million represents the lower bound of what could be considered reasonable from a risk reduction perspective, if we are aiming for a RAB of $1 billion by that time. At this juncture, we consider that this minimal depreciation ask, alongside the optimistic view of the post 2050 business value (see Section 2.1.8) is a reasonable trade-off between current and future consumers.

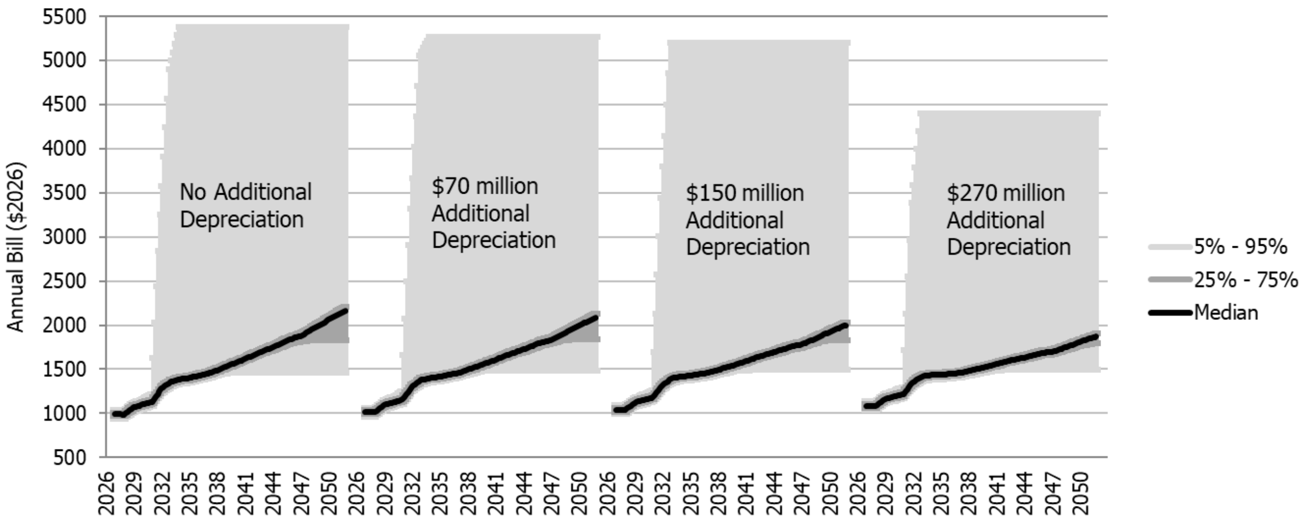
5.3. Long run customer price outcomes

The discussion above focuses primarily on the "reasonable practicability" aspect of the amount of depreciation; essentially whether the amount of depreciation will result in a high risk of customers leaving the network. As we discuss in Chapter 3, we consider this important as a way of determining whether an approach to depreciation is reasonable. However, of importance to customers is the long run price consequences of adding more depreciation; a model might say that customers desert the network in only a handful of situations, but if the price increases in the situations where they do not leave the network are excessive, this is unlikely to be attractive to customers.

In an economic sense, the issue is one of customer sunk costs.[52] That is, someone who has just installed a new hot water system, for example, is unlikely to switch from gas to electric just because prices of gas and electricity have changed a little because the relevant decision is between a gas appliance which requires no additional spending on one hand, and an electric appliance which needs to be bought anew on another. For such a customer, gas and electricity prices may need to be quite different before the appliance switch is made. By contrast, a customer whose gas appliance has just broken down or is near then end of its life may be more susceptible to a difference in relative fuel prices.

Below we outline the consequences for customers in the two more damaging sets of price outcomes, Bundles 2 and 3 under Case 1 policy settings; where there is nothing particularly aimed at gas networks from a policy perspective, as is the case currently in South Australia. We focus not just on the "central" or median results but on all simulations of prices, because although the median expected prices do decline a little with additional depreciation, the key benefit for customers is a reduction in the upper tail risk of prices; that is, when price combinations move against gas, the risk that this causes very high price impacts on customers declines.

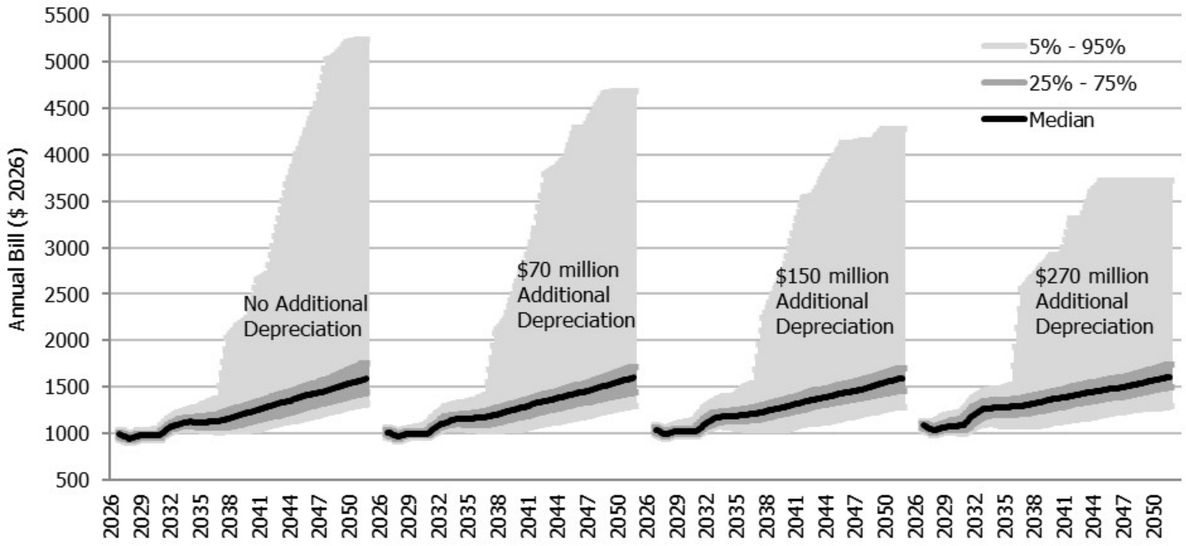
Figure 5-4: Bill impacts of depreciation – Price bundle 3



Under Price Bundle 3 higher amounts of additional depreciation reduce the extremity of bill outcomes and median bill growth over time. High exposure to risk comes on as early 2032. The impact of increased depreciation in the early years is shown by the black line intersecting the $1000 line with no additional depreciation then moving up slightly as amounts are increased up to $272 million. This increase is small compared to the change in the median bill trajectory and corresponding reduction in bill risk shown by the grey area.

[52] *See Biggar, D, 2009, "Is Protecting Sunk Investments by Consumers a Key Rationale for Natural Monopoly Regulation?", Review of Network Economics, 8(2), 128-52, available here. The Productivity Commission also debates aspects of this view here.*

Figure 5-5: Bill impacts of depreciation – Price bundle 2

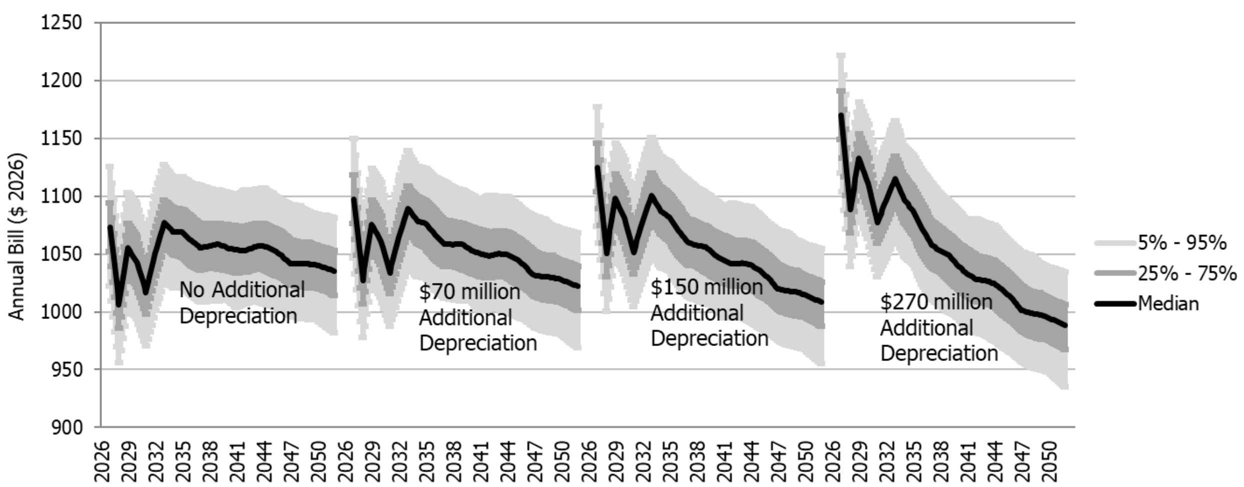


Price Bundle 2 is a less risky scenario than Price Bundle 3 because high risk is encountered six years later (2038) and comes on more gradually at around $500 lower. Again, higher amounts of additional depreciation reduce the extremity of bill outcomes and median bill growth over time. The benefit of increased depreciation in this scenario is mainly in the corresponding reduction in bill risk shown by the grey area, although bill growth is slightly tempered over time.

A key concern is the impacts of customers leaving on vulnerable customers and industrial customers whose gas load is hard to electrify. The focus of our modelling is on residential customers, but the proportional increases in bills are roughly indicative for industrial customers as well. The $72 million of additional depreciation represents a little over 2 percent of bills for residential customers over the next 5 years. Whilst customers are buying a reduction in median bills in future years with this bringing forward of depreciation which is a little bigger than the cost imposed next period, what they are really buying is a reduction in risk of very poor outcomes in price, which might be worth in excess of ten percent of (much higher, in extreme situations) bills.

To round out the discussion, we consider the situation in Price Bundle 1, which is most favourable to gas prices.

Figure 5-6: Bill impacts of depreciation – Price bundle 1



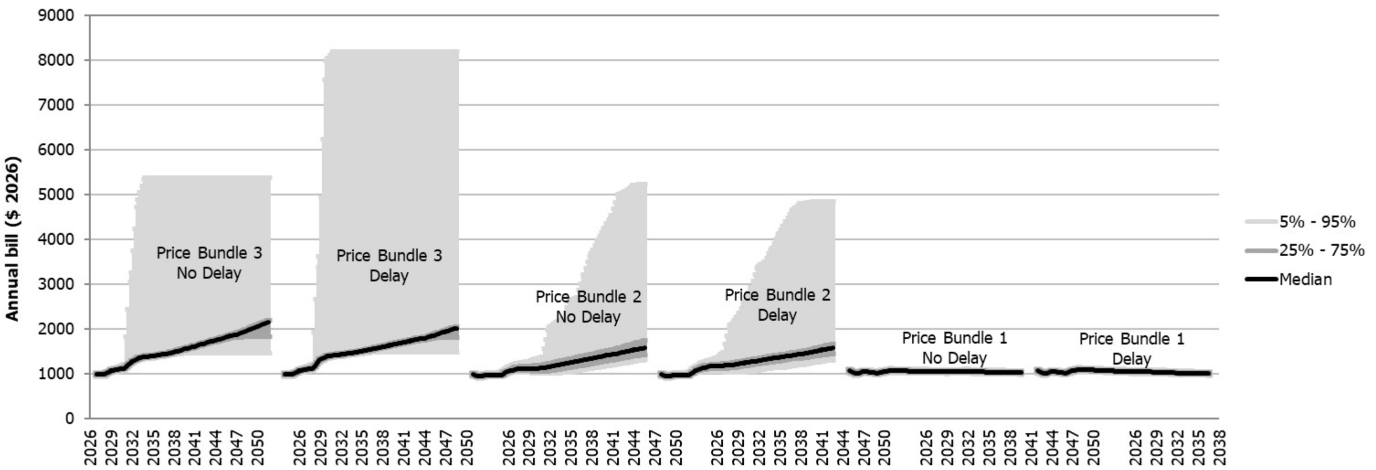
Price Bundle 1 shows risk levels with additional depreciation remaining virtually unchanged. Additional depreciation increases the average retail bill in the next AA in the order of $25 ($72 million additional depreciation) to $100 ($272 million additional depreciation). Higher depreciation results in bills declining further over time. However, it does not have the same impact in respect of risk as occurs in the other two price bundles.

5.4. The impacts of waiting

Figure 9 shows the average annual retail bill impact of delaying $70 million of additional depreciation from the upcoming South Australian regulatory period to the one after. The time series of retail bill observations is calculated the same way as outlined in the bill impact section above.

The first two graphs show that under Price Bundle 3 delaying depreciation produces a much greater spread of bill outcomes slightly earlier than applying additional depreciation in the upcoming regulatory period. The next two graphs show under Price Bundle 2 delaying depreciation has less of an impact, and in last two graphs delaying depreciation makes no material difference under Price Bundle 1.

Figure 5-7 : Impacts of delaying depreciation



Since Price Bundle 1 is the only situation favourable to gas, we focus on the other two price bundles to understand the impact of waiting. Here, it is clear that waiting can contribute to significant additional risk (the upper bound of the light grey range). For this reason, we consider that acting now is prudent.

The idea is similar to buying insurance: delaying the purchase is beneficial if the insured event never happens, but risky and costly if it does—leaving one unprotected. In this case it is both the gas distribution business and customers with gas appliances left more exposed to worse consequences.

6 How to use the model

6.1. Background

The Future of Gas Modelling framework is based on the Crew and Kleindorfer (1992) concept of the window of opportunity for capital recovery.[53] The basic premise is that there is a limited time for regulators to take remedial action to ensure capital recovery when a regulated firm faces the risk of competition and technological change in future. If timely action is not taken there is no alternative, but for the company to fail to recover some of its assets. In addition to losses suffered by the firm there are likely to be losses suffered by consumers in the form of higher future tariffs and service quality reductions as the firm seeks to partially address losses and some customers leave the network.

The Future of Gas modelling framework applies the window of opportunity for capital recovery concept under explicit assumptions. These assumptions are that technological change in electrical energy and appliances, and climate policy, result in electrical appliances becoming a substitute for natural gas and gas appliances over time. This is built on the model developed as part of our Victorian AA proposals (see here).

This chapter provides an overview of how the model works to assist stakeholders wishing to replicate our work or explore the consequences of making different assumptions in the model.

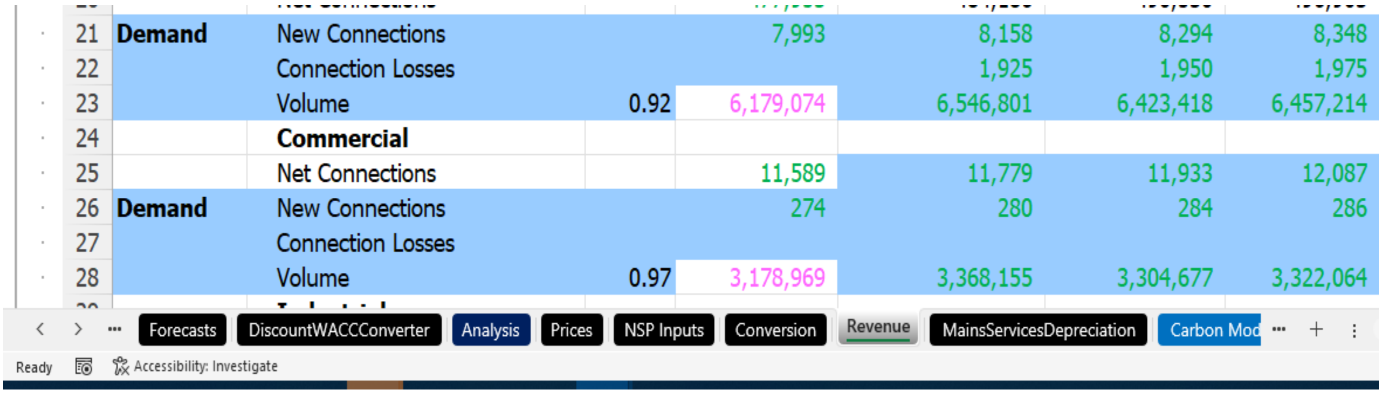
6.2. The model

The model we use for the future of gas work consists of two key components; a demand model and a building block model.

6.2.1. The Demand Model

A model of demand for gas connections and volumes (**Demand Model**) out to 2050. The dynamics of this model are primarily driven by upfront appliance cost and running cost differences between electricity and gas appliances. Running costs are a product of appliance energy consumption and retail energy (volumetric) tariffs. Retail gas tariffs reflect regulated gas distribution charges calculated by the building block model.

The demand model is summarised in the light blue columns of the 'Revenue' tab as picture below:



21	**Demand**	New Connections		7,993	8,158	8,294	8,348
22		Connection Losses			1,925	1,950	1,975
23		Volume	0.92	6,179,074	6,546,801	6,423,418	6,457,214
24		**Commercial**					
25		Net Connections		11,589	11,779	11,933	12,087
26	**Demand**	New Connections		274	280	284	286
27		Connection Losses					
28		Volume	0.97	3,178,969	3,368,155	3,304,677	3,322,064

New connections, connection losses of existing customers and volumes per connection shown in the blue shaded cells above are modelled in the three tabs below respectively:

[53] *See Crew, M and Kleindorfer, P, 1992, "Economic Depreciation and the Regulated Firm under Competition and Technological Change", Journal of Regulatory Economics, 4(1), 1992, 51-61, available here*

6.2.2. The Building Block Model

We have developed a gas distribution cost and pricing model (**Building Block Model**) which emulates the AER Post-Tax Revenue Model out to 2050 except on a pre-tax real annual (instead of 5 year) basis for modelling simplicity. The model employs the ability to front-load capital recovery through a variety of options such as 'tilting' depreciation on the opening RAB, shortening the weighted average remaining life on the opening RAB and shortening asset lives.

Building block cost calculated using the building block model are summarised in the revenue tab in bold green below:

Costs					
Building Block Cost		$ 259,723,587	$ 202,750,327	$ 214,762,991	$ 235,310,569

CCConverter | Analysis | Prices | NSP Inputs | Conversion | Revenue | MainsServicesDepreciation | Carbon Model - Distributi

The calculations behind this model are in the 'RAB & BuildingBlock' model tab:

Building Block	PV	2026	2027	2028	2029
R on K		57,666,824	61,461,991	64,781,933	67,625,020
R of K		59,010,570	65,742,810	71,717,912	77,234,173
Opex		86,072,933	87,558,190	98,810,723	99,653,296
Cost of Service	**$5,149,267,042**	**202,750,327**	**214,762,991**	**235,310,569**	**244,512,489**

Carbon Model - Distribution | RAB & BuildingBlock | OpexCapex | Depreciation Graphs | RAB Graphs | Sheet1 | Sheet3 | Sheet5

In turn this tab depends on opex, capex and depreciation modelled in the 'OpexCapex' tab and 'MainsServicesDepreciation' tab.

6.2.3. The Future of Gas Time Series Model

The Demand and Building Block modelling work together within the revenue tab to model gas distribution network tariff out to 2050 in the 'Revenue' tab in orange highlight below (**Future of Gas Model**):

	Price	*Note will not match PTRM X-factor as this real model and		
Prices	Residential Fixed (daily)	0.32	0.25	0.24
	Residential Volumetric	23.60	19.11	18.02
	Commercial Fixed (daily)	0.67	0.52	0.51
	Commercial Volumetric	11.77	9.23	8.71

NSP Inputs | Conversion | Revenue | MainsServicesDepreciation | Carbon Model - Distribution | RAB & BuildingBlock | OpexCapex | Dep

The Building Block Model passes tariffs from the end of the previous access arrangement to the Demand Model which uses this price to calculate running costs over the appliance life. The Demand Model then uses this cost to calculate new connections, disconnections and volumes for this first year of the new access arrangement which are then passed back to the Building Block Model.

The Building Block Model then uses this demand information to produce a forecast of the second year's demand and costs which are used to calculate the second year's tariffs. These tariffs are again passed back to the Demand Model which calculates demand information in the way aforementioned for the second year of the access arrangement. This process continues for the third year and so on to produce a gas distribution price and demand path out to 2050.

6.2.4. Inputs

There is a large array of other inputs not mentioned in the process above for simplicity of exposition. For example, electricity retail tariffs, gas network opening RAB and weighted average remaining life, capex/opex schedules, appliance efficiency and real growth in upfront appliance costs, customer discount rates, historical connection and disconnection rates.

As intuition would suggest, the paths of relative energy prices are the key driver of outcomes. As an extreme example, if electricity became free, holding everything else constant, we would expect to see fewer connections and large losses in gas network customers. Conversely, if we saw rapid increases in electricity prices we would expect to see more connections and fewer losses. More importantly, since our customers are also electricity customers and face the only the variable cost of their decision to switch from gas, it is variable or volumetric charges which really matter. This is an important consideration; the overall cost of the electricity network might be rising, but if all of that rise were loaded onto fixed charges (say to counteract the impacts of rooftop solar on the viability of network businesses), the incentive for individual customers might still be to change appliances, potentially raising total energy system costs still further. There are many forecasts of overall energy system costs in South Australia, but understanding how tariff structures in electricity might evolve is less well understood.

6.3. Using the model

The starting point in using this model is to understand there we have three fuel price and appliance bundles:

I. **Bundle 1**: where fuel prices favour gas and customers are assumed to use heat pump hot water systems as the electric alternative for water and reverse-cycle air-conditioners are the alternative for space heating.
II. **Bundle 2**: where fuel prices favour electricity and customers are assumed to use heat pump hot water systems as the electric alternative for water and reverse-cycle air-conditioners are the alternative for space heating.
III. **Bundle 3**: where fuel prices favour electricity and customers are assumed to use rooftop solar plus an electric resistive tank system (see Section 2.1) as the electric alternative and reverse-cycle air-conditioners are the alternative for space heating.

ACIL Allen developed electricity and gas price paths that were consistent with favourable and unfavourable scenarios as part of our Victorian AA proposal (see here), and we have updated these to suit the South Australian context as discussed below. It is important to note that these are not the only price paths consistent with the settings, which are relative, rather than absolute. We also run simulations on these price paths to randomly 'shock' them based on deviations observed in historical wholesale gas and electricity price paths.

We now turn to an example of using the model.

The basic intuition of model use is that cells which are coloured green are those which the user can input data. The 'Analysis' tab below is where the settings are changed from one price bundle to another and depreciation within the AA is increased by increasing the 'Tilt' parameter.

DiscountWACCConverter | Analysis | Prices | NSP Inputs | Conversion | Revenue | MainsServicesDepreciatio

Price Bundle 1 is labelled "Scenario 3" in the model, Price Bundle 2 is "Scenario 2" and Price Bundle 3 is "Scenario 1".

Assumptions	
Standard Asset Life	60
Focus Date (end of WARL on opening RAB)	2074
Focus date applies to next AA capex?	No
Resulting RAB @ focus date	-
BAU RAB @ focus date	
Additional Depreciation in next GAAR	-
Additional Depreciation in GAAR after next GAAR	-
Delay	No
Scenario	2
Tilt	0.00088887

When the tilt parameter is set to 0.00088887 additional depreciation in the upcoming gas access arrangement is zero. The tilt parameter has a limit where additional depreciation starts to plateau as the parameter approaches 1. For practicality only values between 0.00088887 and 0.8 should be entered.

To test the impact of delaying depreciation skipping the next access arrangements the 'Delay' setting should be set to 'Yes'. Note that a given 'tilt' value will take on different dollar depreciation values if delayed until the next access arrangement.

Policy settings including, connection bans, treating new connections as ancillary reference services, appliance subsidies are set in the 'SIMS' worksheet of the model shown below.

SIMS | Analysis | Revenue | Prices | NSP Inputs

Connections as ancillary references services can be set to 'Yes' or 'No' in the following cells within this worksheet:

Connections as ARS?	**No**

Subsidies for various appliances (as a dollar amount) and income groups can be entered into the following green rows within the 'SIMS' tab:

Subsidy/Rebates	
Low income	
Cooking	$ -
Hot Water	$ -
Room Heating	$ -
Space heating	$ -
Medium Income	
Cooking	$ -
Hot Water	$ -
Room Heating	$ -
Space heating	$ -
High income	
Cooking	$ -
Hot Water	$ -
Room Heating	$ -
Space heating	$ -

A connection ban can be set by entering the value '1' into the following green cells which are set to zero as default:

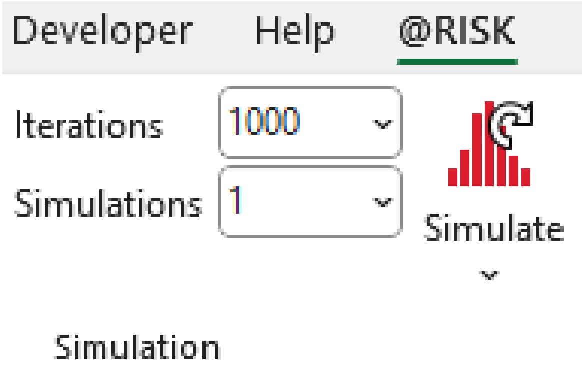
Residential Network No new connections	0	0

Once the desired amount of additional depreciation has been reached by setting the tilt parameter, it can be tested by applying simulation.

The following variables are simulated within the model:

- Wholesale gas prices, with the mean model based on ACIL Allen forecasts from our Victorian AA proposal scaled to match updated wholesale gas prices across 2024 and simulated variance based on a time series model fitted to historical actual wholesale gas price data.
- Retail electricity prices with the mean model based on ACIL Allen forecasts from our Victorian AA proposal scaled to match updated averages of retail electricity plans in South Australia across 2023/2024 and simulated variance based on a time series model fitted to historical actual retail electricity price data.
- Price difference threshold – the percent difference in the two year rolling average in electricity and gas price growth triggering customers to disconnect from gas before their appliance has reached the end of it's life following a continuous uniform distribution between 0 and 5. The lower this number the lower the customer's tolerance to persistent differences in gas and electricity price growth (See Section 4.1.1.2).

When the desired depreciation tilt is chosen each scenario can be simulated using the @RISK ribbon, entering the desired number of iterations within a simulation, then pressing simulate shown below.



When the simulation is finished the results of the outputs can be inspected. The outputs in our analysis examined include:

- **Compromised Asset Date;** ie when business cashflow becomes negative
- **RAB at 2050;** the value of RAB left outstanding at 2050
- **$ per GJ network charge;** the price path of the variable charge up to 2050

The first two variables can be found in the 'Analysis' tab:

Compromised Asset Date	**2100**
RAB @ 2050	**1,699,705,161**

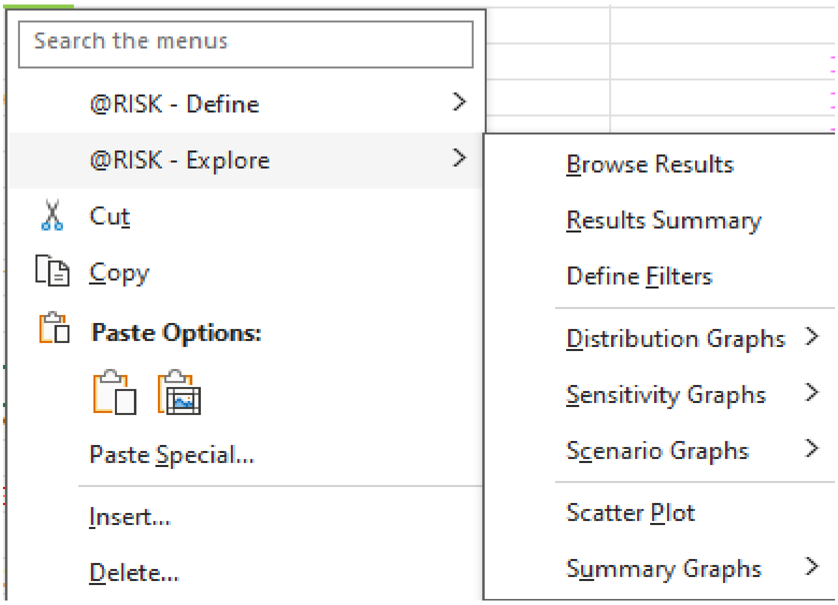
ew Connections | Existing Connections | Forecasts | DiscountWACCConverter | SIMS | Analysis

The dollar per GJ network charge is in the prices tab:

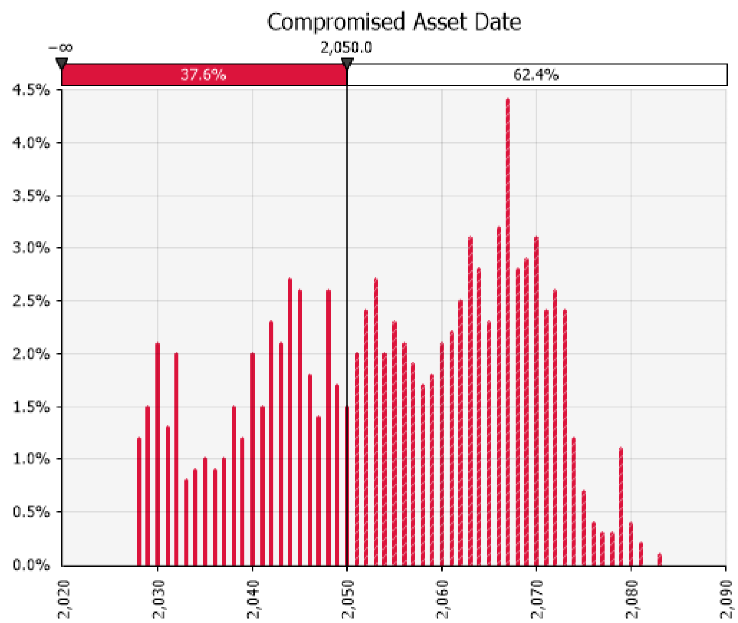
Highlighted in bold below:

Year	2024	2025	2026	2027	2028	2029	2030
Gas retail price ($/GJ)-residential	55.86	64.59	62.78	59.94	64.04	61.78	59.33
Electricity tariff ($/kWh)-residential	0.415	0.390	0.421	0.477	0.476	0.482	0.432
Gas service charge ($/day)-residential	0.793	0.793	0.761	0.751	0.781	0.784	0.775
Gas price % change-residential	193.7%	15.6%	-2.8%	-4.5%	6.8%	-3.5%	-4.0%
Electricity price % change-residential	77.1%	-6.1%	8.0%	13.4%	-0.3%	1.4%	-10.4%
Gas price index			1.000	0.955	1.020	0.984	0.945
Electricity price index			1.000	1.134	1.130	1.146	1.027
AGN fixed charge $/day	0.319	0.319	0.287	0.277	0.307	0.309	0.301
AGN $/GJ	23.601	23.601	**22.129**	**20.453**	**23.156**	**23.527**	**22.797**
Retail fixed charge $/day	0.793	0.793	0.761	0.751	0.781	0.784	0.775
Wholesale $/GJ	16.892	25.615	25.286	24.122	25.516	22.882	21.161
Reconciling amount $/GJ	15.369	15.369	15.369	15.369	15.369	15.369	15.369
Retail gas price $/GJ	55.862	64.585	62.784	59.944	64.042	61.779	59.328
	55.862						
Starting Point	0.658	0.658	0.658	0.658	0.658	0.658	0.658

Right clicking on these cells after performing a simulation brings up the option to explore results shown below:



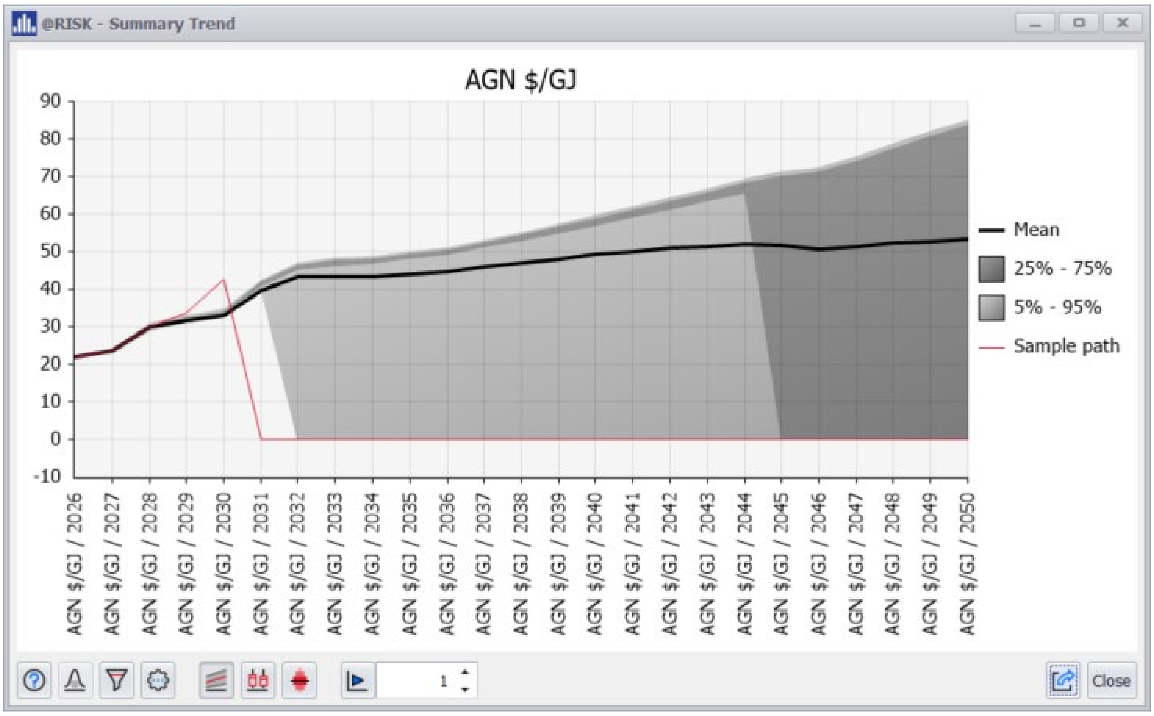
Browse Results gives a view of the distribution of simulated results for example those shown below:



Statistics	
	Compromised Asset D...
Cell	Analysis!C43
Minimum	2,028
Maximum	2,083
Mean	2,054.877
90% CI	± 0.704
Mode	2,067
Median	2,056
Std Dev	13.530
Skewness	-0.2618
Kurtosis	2.0234
Values	1000
Errors	0
Filtered	0
Left X	−∞
Left P	0.0%
Right X	2,050.0
Right P	37.6%

The percentage highlighted in red is of particular interest because it reports the probability of the asset being compromised prior to 2050 under the selected scenario with the chosen amount of accelerated depreciation. Note that the model itself has the flexibility to go beyond 2050 as the date where the new competitive marketplace starts is desired.

Highlighting a time series of results, such as those bold highlighted in the prices tab shown above, then clicking **Summary Graphs > Summary Trend** shows a time series with confidence interval bands:



These analytical tools will allow anyone with access to the model to replicate the results produced in our submission.