Attachment 6.1

Future of Gas Rationale and Modelling Approach

January 2025

PUBLIC

Dampier Bunbury Pipeline

1 Introduction

The purpose of this attachment is two-fold:

- It explains the rationale behind the approach we took to depreciation in the AA, with a particular focus on how changes in information from AA5 have driven our thinking. It also provides an overview of what we did, and our conclusions.
- It explains how the model we developed works, acting as a "manual" for its use. This is designed to assist the ERA in using the model itself to test our conclusions.

This attachment should be read in conjunction with Attachment 6.2, an expert report from CarbonTP that has informed our modelling and conclusions. The model itself is contained in Attachment 6.3. In respect of the current attachment:

- Section 2 contains an assessment of information we have used, including updated information from the same sources as we used in AA5, and new information, chiefly from CarbonTP. It also covers changes we have made to the modelling approach.
- Section 3 provides an overview of the modelling process we have undertaken, the lessons we have learned and the modelling results.
- Section 4 contains the model manual.

In undertaking our work, we have been mindful of the ERA's various decisions in respect of depreciation, in particular the standard and type of evidence it expects. There is no dedicated information paper, such as the AER *Regulating Gas Pipelines Under Uncertainty* paper, but the ERA has outlined its considerations, most recently in the ATCO Final Decision. These considerations, and our responses to each of them are summarised in Table 1.[1]

Table 1: ERA requirements and our responses

ERA Requirement	Our response
Reasonable opportunity to recover efficient costs	Our depreciation schedule seeks to manage overall risk levels to a reasonable degree,but does not seek to remove all risks. As more information becomes available in future periods, the approach will be revisited. ￼￼)
Intergenerational equity and efficient pricing over time	Our approach focuses on the effective price per GJ used to match customer experience, and avoids price shocks (see Figure 15 and associated discussion)
Financeability of investments for gas network services	Our approach maintains investment incentives by maintaining risk balances between ourselves and shippers as the market environment changes (see Section 3.1)
Supporting gas network utilisation and emissions reductions	Our approach promotes efficient network use by avoiding price shocks (see Figure 15 and associated discussion) and the role gas plays in supporting renewable power is a key part of our considerations (See Section 2.1.2)

[1] *See ERA 2024, Final decision on access arrangement for the Mid-West and South-West Gas Distribution Systems (2025 to 2029) Attachment 6: Depreciation, [113], available here, for the ERA's summary of its considerations, based on the National Gas Rules and National Gas Law. See also ERA 2024, Draft decision on revisions to the access arrangement for the Goldfields Gas Pipeline Attachment 6: Depreciation, [55]-[70], available here, for a similar discussion in respect of GGP.*

2 Updates to information and model

Depreciation in a changing energy market is not a simple "set and forget" part of the building block model but is something which needs to be continually re-examined as new information comes to light. This is due to a confluence of long lives and very large sunk assets in energy infrastructure which mean addressing issues associated with those assets without causing major impacts on customers requires time. However, a high degree of uncertainty and change in the energy market means that the environment in the energy sector is hard to predict except over relatively short timeframes. Both have consequences when determining depreciation. As the ERA points out:[2]

> *The ERA notes that any view on the economic life of an asset, particularly one with a possibly long technical life, implies a forecast and a level of uncertainty. Uncertainty does not prohibit the possibility of a change in economic life, nor does uncertainty remove the need to update forecasts to reflect the best available information. The standard of evidence for changing the outlook is not certainty*

For AA6, we have updated the information we considered in AA5. This includes both inputs to our modelling framework, and aspects of the modelling framework itself. We outline the source and nature of these updates in this chapter.

2.1 Updates to information

In this section, we update the information set we used to inform our approach in AA5, and explain how this led to a change in our thinking. There are three key areas:

- Updates to the particular sources of information we used last time. Key providers of forecasts, such as CSIRO and AEMO update their modelling regularly, and we have made use of their latest forecasts for this AA.
- A summary of the new information provided to us by CarbonTP, which is detailed in their expert report tabled at Attachment 6.2.
- A brief discussion of price forecasts, which have changed less than we thought they might have going into our work.

2.1.1 Updates to information from 2021

Our AA5 proposal was made a time when wind and solar had just spent a decade rolling rapidly down their respective cost curves and were reaching average costs comparable with fossil fuels. Many of our shippers had started pilot projects looking at ways of bringing renewable power into their production processes. At the same time, whilst WA did not yet have a legislated net zero target many jurisdictions, including at the Federal level, had significantly strengthened their net zero ambitions. In respect of regulatory practice however, the notion that economic lives might change was novel, with the ERA and ourselves being first movers in considering the issue around Australia.

Some specific points that we made about how the future might evolve included:

- After policy drift on decarbonisation at the start of AA4, policy direction at the start of AA5 had moved towards a much stronger decarbonisation stance including Federal Government

[2] *See ERA 2021, Final decision on proposed revisions to the Dampier to Bunbury Natural Gas Pipeline access arrangement 2021 to 2025, April 1 2021, [1512], available here.*

emissions reduction commitments to reduce emissions by 26-28 percent of 2000 levels by 2030 and the start of the Safeguard mechanism.[3]

- Renewable energy is fundamentally different to fossil-fuel generation because it can operate at much smaller, distributed scales, and manufacture power for both shippers and final consumers at the source of demand.[4]
- Over the previous decade, battery and solar costs had declined by 60 and 80 percent (respectively), with similar reductions in wind over longer timescales.[5]
- CSIRO data suggest that, in 2020, a renewable electricity system with batteries and pumped hydro storage was comparable in costs to one powered by gas, both with and without carbon prices and with and without carbon capture.[6]
- AEMO data suggested that rooftop solar represented roughly a fifth of total generation capacity in the SWIS (in MW), which it predicted would double by 2030. Grid scale renewables at the time served roughly 15 percent of demand.[7]
- Several minerals projects had started renewables projects with significant loads.[8]
- Prices for renewables auctions, both in Australia and overseas, had been falling rapidly and, in Australia at least, were at or below average prices in the NEM.[9]
- CSIRO forecasts from its GenCost publication show significant reductions in renewables costs with renewables systems (with 6 hours storage) moving from being just comparable with the upper bound of gas in 2020 to being at or below the lower bound of gas costs (even without a carbon price) by 2050.[10]
- Internationally, some predictions suggest that the 2030s will be when gas generators, even existing gas generators, cease to be competitive with renewable options.[11]
- AEMO Forecasts of future electricity demand had dropped by 20 percent over the time period from 2017 to 2020 based on the forecasts for the same years made at different times and it forecasts 74 percent of power in the NEM being generated by renewables in 2040 under its base case and 94 percent under its step change scenario, due to coal-fired generator retirement.[12]

Five years later, views of the future, though broadly similar, have changed in some important ways, which we discuss below. Before discussing updates to the information we relied upon in 2021, two key issues need to be borne in mind:

- In respect of policy, WA still does not have a net zero target legislated, but has developed policy statements around plans for decarbonisation,[13] and the Federal government has tightened several of its measures, most notably the Safeguard Mechanism which limits emissions from major emitters (like the DBNGP, and many of our shippers) via a tightening cap. This has already had an impact with the DBNGP being subject to a five year

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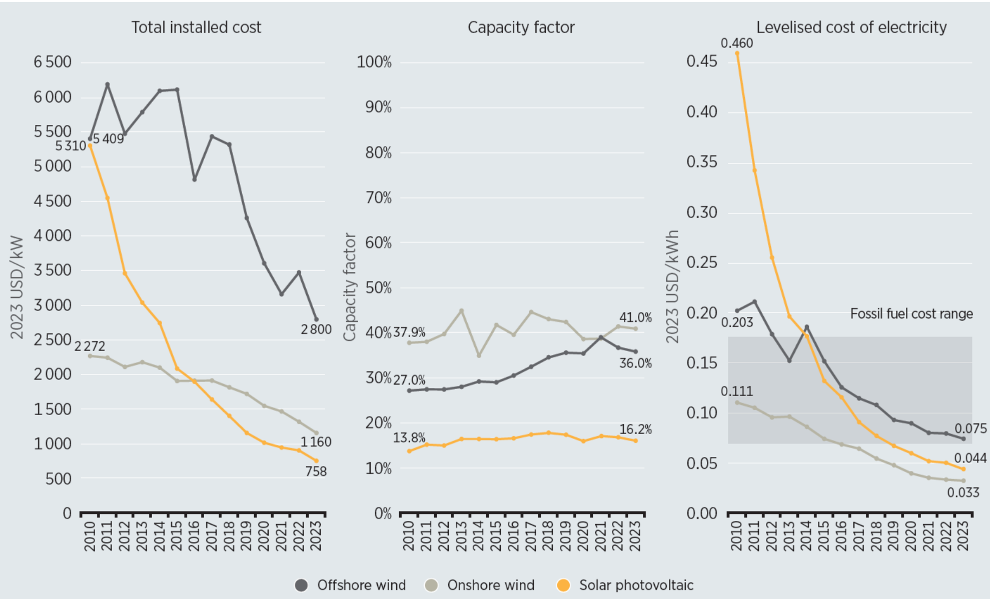
[3] *AGIG, 2020a, Assessment of the Economic Life of the DBNGP: Final plan attachment 9.2, January 2020, p2, available here*
[4] *Ibid, pp3-4.*
[5] *Ibid, p5*
[6] *Ibid p7; noting that the renewable system had, as a maximum, 6 hours of storage.*
[7] *Ibid, pp7-8.*
[8] *See Ibid, p9, with a further update provided in AGIG 2020b, Response to Draft Decision on Capital Base: Revised final plan attachment 9.7, October 2020, pp19-21, available here.*
[9] *AGIG, 2020a, pp10-11.*
[10] *AGIG, 2020a, p14.*
[11] *AGIG, 2020a, pp15-16. See also AGIG 2020b p17 for other studies which look at the relative costs of gas and renewables in a global context, and the net costs of switching from the perspective of the whole power system.*
[12] *AGIG 2020b, pp17-18.*
[13] *See, for example, the policy statements here.*

monitoring program with the Clean Energy Regulator. It may have additional impacts over the longer term.

- In the realm of regulation, changes to depreciation profiles for gas networks have gone from being novel to being a part of every decision on gas networks made since 2021. This has led to advances in methodology in assessing the need for depreciation.

With this in mind, we turn to an assessment of updates to the evidence we considered in 2021. One key issue is the cost of renewables, which have continued to fall over the past five years, but at a slower rate. This is shown in Figure 1. For wind and solar and Figure 2 for batteries.

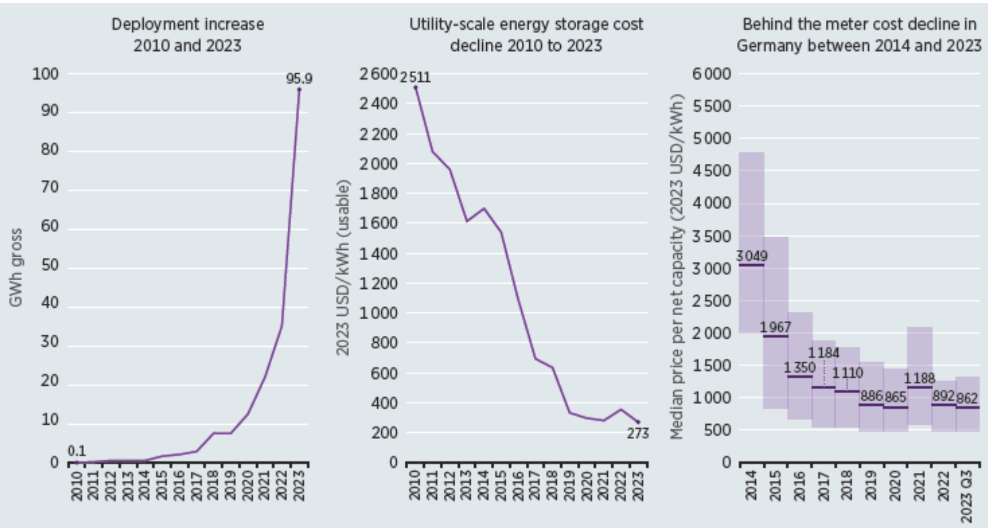
Figure 1: Renewables cost reductions



Source: IRENA 2024, Renewable Power Generation Costs in 2023, p38, available [here](#).

This is largely expected; costs cannot keep reducing at the same speed (according to IRENA – 2024, p103, solar costs have declined by more than 90 percent in Australia since 2010) over long periods for the simple reason that they must remain positive.

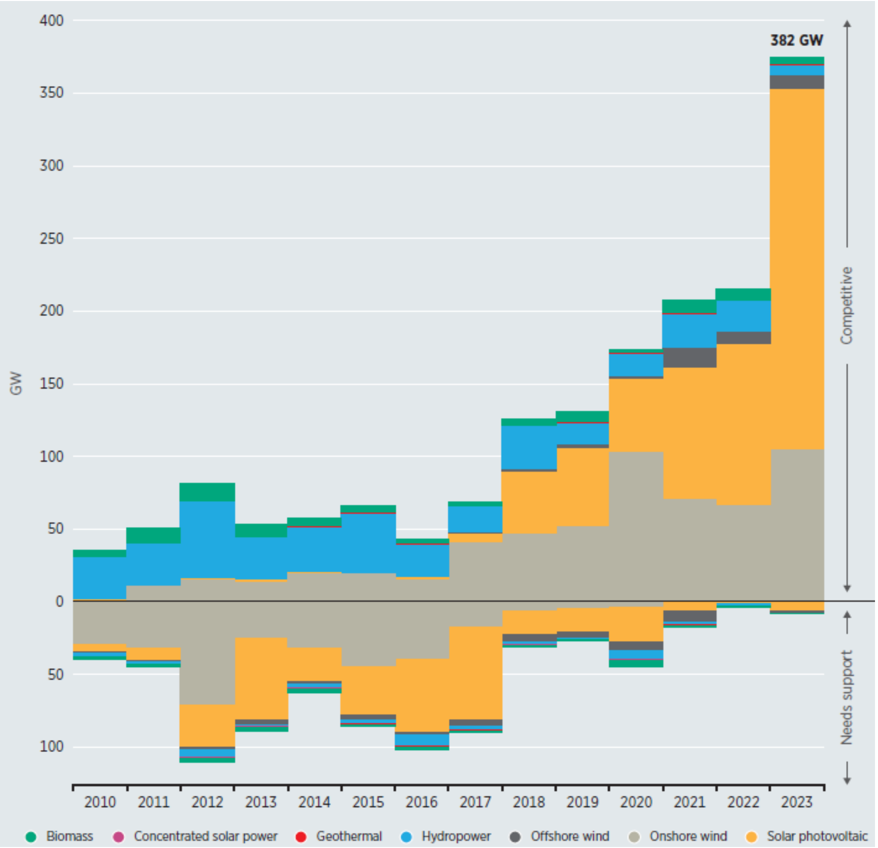
Figure 2: Global battery costs and deployment



Source: IRENA 2024, Renewable Power Generation Costs in 2023, p143, available [here](#). Note that the left and middle panel reflect global data, whilst the right hand panel reflects German data, but is still directionally similar to other markets

Not only have renewables fallen in cost, but IRENA believes they have fallen sufficiently for many to be deployed without requiring subsidies, as shown in Figure 3.

Figure 3: Renewables and subsidies



Source: IRENA 2024, Renewable Power Generation Costs in 2023, p42, available here.

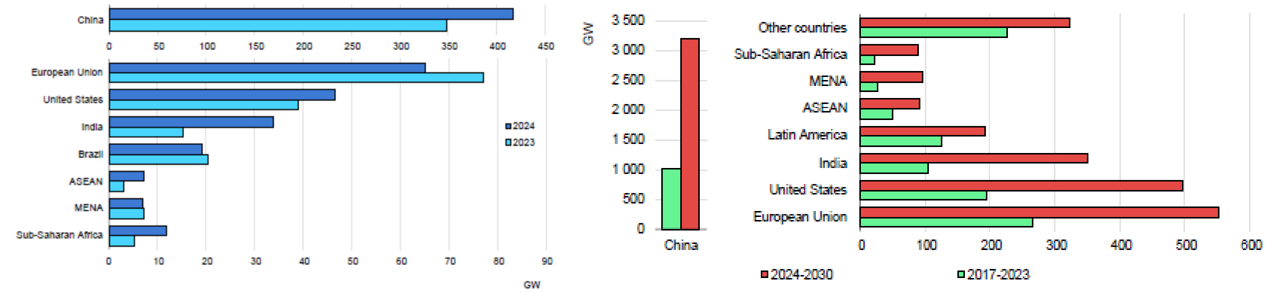
The fact that renewables can be competitive without subsidy ought to mean that subsidies are no longer widely used and that a more normal market for their supply should arise. However, neither appears to be the case yet, and does not appear likely to be the case for at least the remainder of this decade. This has important consequences for modelling and is worth exploring.

The International Energy Agency, in a recent publication,[14] suggests (p67) that some 84 percent of utility scale renewables growth over the next 6 years is policy driven, with market driven growth being only around 15 percent.[15] Australia is not specifically mentioned; it is included within the Asia-Pacific region, where market-driven growth accounts for 23 percent of renewables contracts.

However, even if the deployment of renewables in Australia were dependent entirely on market forces (which they are not), non-market based policy decisions by major players affect all markets, including Australia. For example, in China policy measures underpin some 90 percent of growth in renewables deployment, with administratively set fixed tariffs (effectively take-or pay contracts) for 15-20 years playing a major role (IEA, 2024, ibid, p68). This is already having a major impact on deployment of renewables, and is expected to continue to do so, as shown in Figure 4.

[14] IEA, 2024, Renewables 2024: Analysis and forecasts to 2030, available here.
[15] Policy driven initiatives include investment by state-owned utilities to meet targets, administratively set tariffs, government auctions for renewable power and tax credits. Green certificates, which are also often managed by governments, are classed as market driven, and make up slightly less than half of the 15 percent share of market driven approaches (see IEA 2024, ibid, p68).

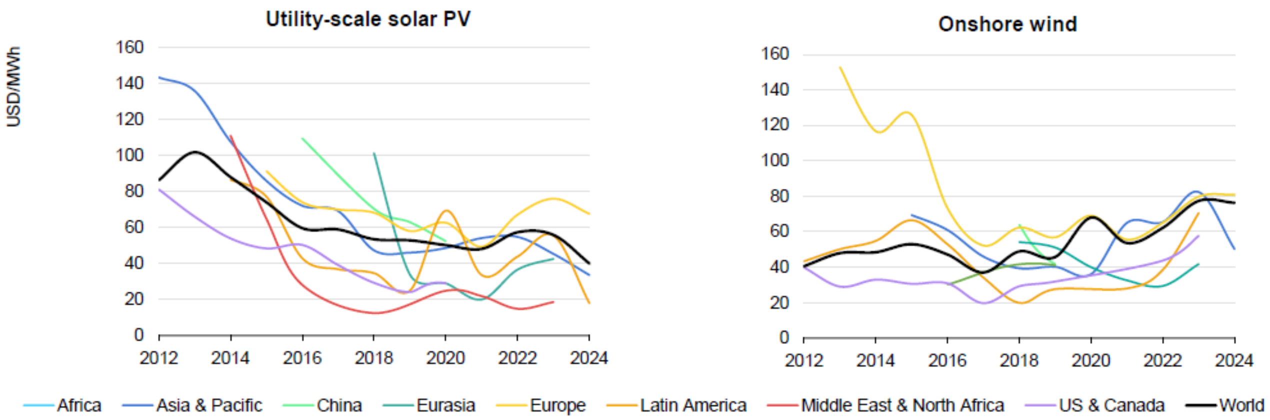
Figure 4: Renewable capacity additions current and projected.



Source: IEA 2024 ibid p30 (LHS) and 35 (RHS)

To achieve deployment on this scale, China has invested massively in manufacturing capacity causing global cell capacity to almost double in 2023 alone (IEA 2024 ibid p88-9). This growth is so fast that it has led to the closure of some USD 25 billion in projects that are no longer viable as technology changes, but is still expected to mean that manufacturing capacity is expected to run ahead of installations by some 40 percent in 2030 (ibid, p88). This has led to significant impacts on the profitability of renewables manufacturing, where net margins have been negative towards the end of 2024 (IEA 2024 ibid, p99) for solar and have only just turned positive for wind after nearly two years of negative margins (ibid p101). It has also led to significant reductions in capacity auction prices, particularly for solar, as manufacturers fight to recover at least some of their sunk costs. This is shown in Figure 5.

Figure 5: Capacity auction prices



Source IEA 2024, p75

Although capacity auction prices are falling more countries add non price components to their auctions to give effect to environmental and industrial policy goals (see IEA 2024 pp77-87); non-price criteria accounted for some 60 percent of awarded capacity in the first half of 2024. As the IEA reports, it can often be very difficult to predict the effect of non-price criteria, particularly in a general sense, because it depends very much on the detail of the relevant criteria. Trade policy, particularly policies designed to hinder the exports of Chinese-made solar cells can also have a significant effect on whether the impacts of what is going on inside China in respect of the balance between demand and manufacturing supply, and the rest of the world.

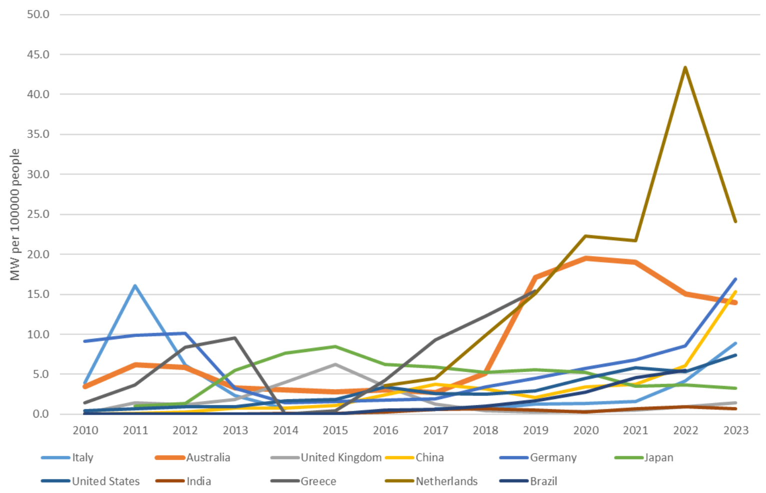
The IEA's discussion is global in focus, with only limited direct Australian evidence, and nothing which deals directly with Western Australia. However, even if WA's energy market was a normal competitive market (which it is not; witness the policy decision to retire coal), since we make none of the renewable equipment WA needs in WA, global forces matter in terms of both the price and the availability of renewable equipment. Actions by China and other major players will continue to have a major influence both on the price and availability of renewable power generating and storage equipment deployed in WA.

Australia has some key natural advantages when it comes to renewable power, in particular it is:

- At the bottom quartile for onshore wind costs (IRENA 2024 p77 and 79).
- The second lowest for grid-scale solar average costs (IRENA, 2024, p103), despite being the 6th highest when it comes to the cost of installing solar (ibid, p90)

It is unsurprising, therefore, that Australia has amongst the highest installed capacity of solar resources in the world, when measured on a per capita basis, as shown in Figure 6.

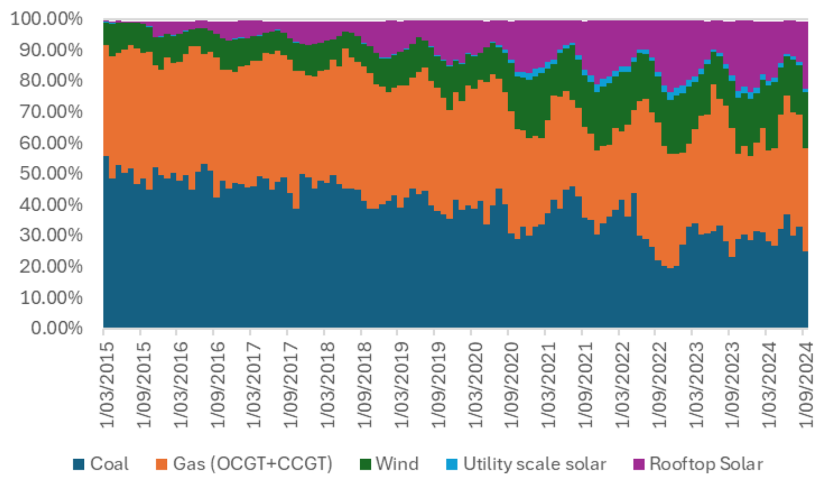
Figure 6: New solar PV additions (MW per 100,000 population)



Source: IRENA 2024, Renewable Power Generation Costs in 2023, p56, available here. Note – based on raw data

Wind has been a key (and growing) source of renewable power since at least the start of AA4. During AA5, a major emerging source of generation has been rooftop solar, from the now roughly half of WA homes which have solar panels installed.[16] This is shown in Figure 7.

Figure 7: Proportion of generation in SWIS 2015 to 2023

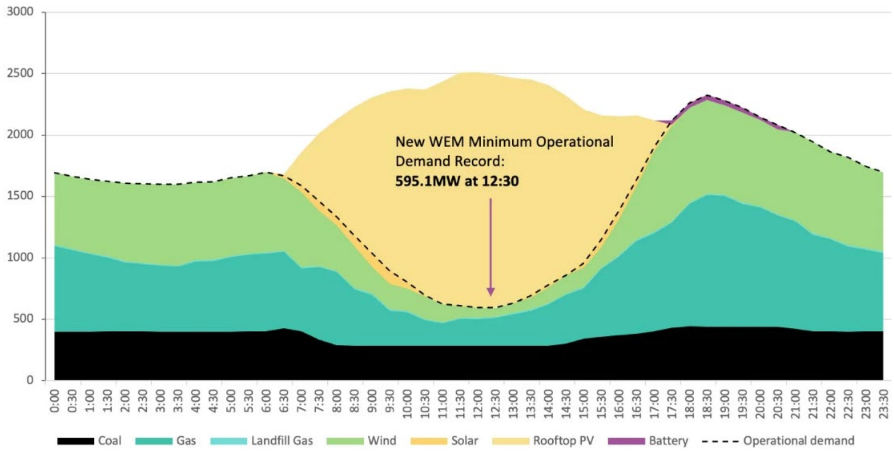


Source: Open Electricity data, available here

[16] *According to the Clean Energy Regulator, there were 515,505 houses in Western Australia with rooftop solar to their latest reporting date in 2024, whilst ABS data suggests there are 1,147,872 households overall in WA in 2021.*

Rooftop solar is now roughly on parity with both wind and coal-fired generation during the sunnier months, and much larger than utility-scale solar. In fact, rooftop solar has become so prevalent that it has become a potential threat to the electricity network; on four occasions during spring in 2022, the SWIS dipped below the minimum energy demand from the grid that the grid-scale generators could support, with a new low on September 2023 of 595 MW of demand, shown in Figure 8.

Figure 8: Minimum Energy Demand in the SWIS



Source: Western Power (available here).

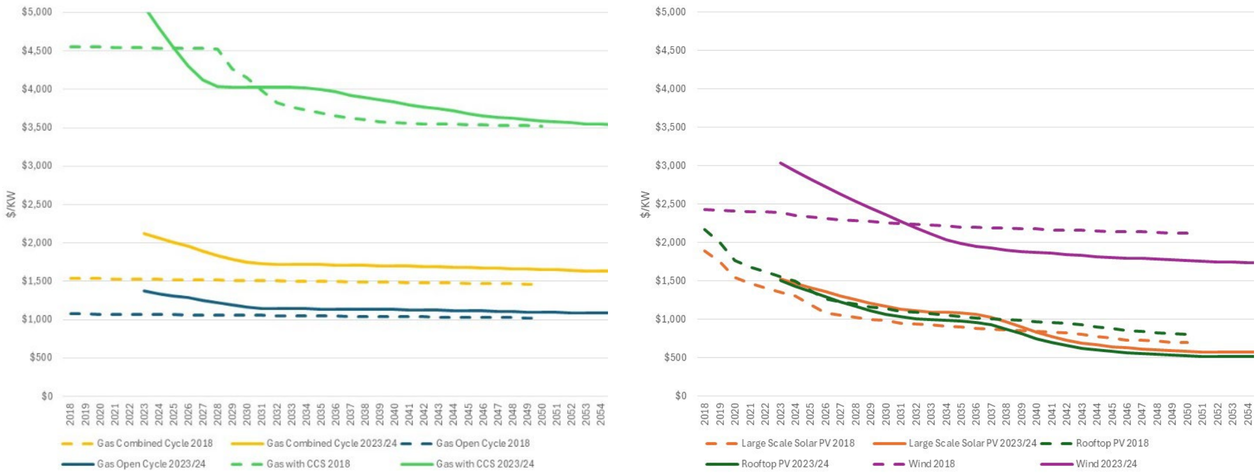
Minimum demand is a particular issue for the SWIS, as it is the largest islanded network in the world and cannot export power to or import power from other grids, like, say South Australia, which also has very high levels of rooftop solar generation. There are two solutions which come into play; using large scale batteries (which some commentators suggest can obviate the issue entirely) and activating the Emergency Solar Management protocol whereby AEMO can direct Western Power and retailers to effectively switch off rooftop solar units at times of stress on the grid.

It is the first of these two control mechanisms which has an influence on gas demand. To date, only some 11,500 households (see CER) in WA have both rooftop solar and batteries, and only 100MW of grid scale batteries are operational. However, future growth is projected to be substantial; in the case of grid-scale batteries, more than 1400 MW of additional battery capacity is due to come online by 2027 (see here, based on AEMO data) and AEMO's expected case from the 2024 ESOO suggests 1600MW of distributed battery capacity by 2033, up from around 67 MW today (see p 15 here).

This matters because these batteries, as they soak up midday solar power, cut into the peak evening load currently served largely by gas. Gas has shifted from providing base-load power throughout the day in the past, to more focus on evening peak-loads daily today and perhaps to less frequent "firming" power when neither renewables nor batteries are available in future. Precisely how this might play out in WA, with its various unique characteristics as an islanded network, is likely to be more clear at the end of AA6 than it is now. However thinking about this changing, much peakier role for gas has been a key part of our considerations.

We now turn from the present to an update of the some of the key Australian third-party forecasts we considered in 2021. The first of these is the CSIRO GenCost evidence which has been updated several times since 2021. Despite these updates, the GenCost long-range forecasts have not altered very much. Figure 9 shows the perspective of capital costs required for plant.

Figure 9: GenCost capital cost forecasts 2018 and 2023 (2023$/kW)



Source: Graham et al 2024,GenCost 2023-24: Final report, CSIRO, Australia, Appendix Table B.2 and Graham et al 2018,GenCost 2018: Final report, CSIRO, Australia, Appendix Table B.2 Available here.[17]

Non-renewable generation cost forecasts have increased slightly in the more recent forecasts, whilst solar costs have decreased. The drop in wind is more substantial towards the latter part of the forecast period but, given the time-scales and uncertainties involved, to say nothing of the fact that the assumptions underpinning 2023 scenarios have changed slightly from 2018, the drop is not a substantial difference. In particular, compare the size of the differences for wind in Figure 6 with the differences between forecasts and between forecasts and actual costs for solar during the 2010s shown in Figure 17 of Attachment 9.2 of our AA5 proposal (available here, p34) which are much more substantial.

In respect of average operating costs, proxied by the levelised cost of energy, the differences are even smaller from 2018 to 2023, shown in Figure 10. Whilst the lower bound of forecasts has dropped for renewables, by a quarter for wind and by 15 percent for solar by 2050, the lower bound has also dropped for gas; and upper bounds have shifted only slightly for both renewable and non-renewable sources.

Overall, in respect of relative costs between gas and renewable power, not much has changed since 2021 in respect of forecasts, particularly out as far as 2050; for all that current relative costs may have changed substantially.

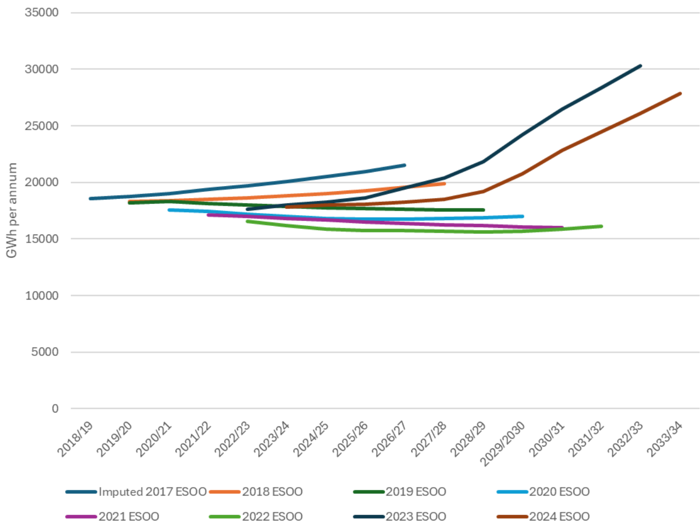
[17] 2018 data are from the "2 degree" scenario, and 2023 data are from the "Global NZE by 2050" scenario, and 2018 data have been adjusted by CPI to dollars of 2023. The 2 scenarios are not identical in assumptions, but appear to be sufficiently close for illustrative purposes. "Gas Open Cycle" is the average of small and large open cycle in 2023 and is what the CSIRO call "peaker" in 2018. The 2018 report does not distinguish between onshore and offshore wind, so we have assumed it is onshore wind, and compared with onshore wind from 2023.

Figure 10: CSIRO LCoE forecasts in 2018 and 2023 (2023$ per MWh)

Source: Graham et al 2024,GenCost 2023-24: Final report, CSIRO, Australia, Appendix Table B.9&10 and Graham et al 2018,GenCost 2018: Final report, CSIRO, Australia, Appendix Table B.3 Available here.[18]

The other major forecast we considered in 2021 was the forecast of deployment of different energy technologies made by AEMO in its ESOO and GSOO publications. These are informed by cost forecasts (indeed, AEMO and the CSIRO work closely together), which provide the basis for deployment choices. For several years ESOO forecasts have been trending downwards, but this changed in 2023, as shown in Figure 11.

Figure 11: AEMO ESOO forecasts for electricity demand in WA – 2017 to 2023



Source AEMO, various years Electricity Statement of Opportunity, available here[19]

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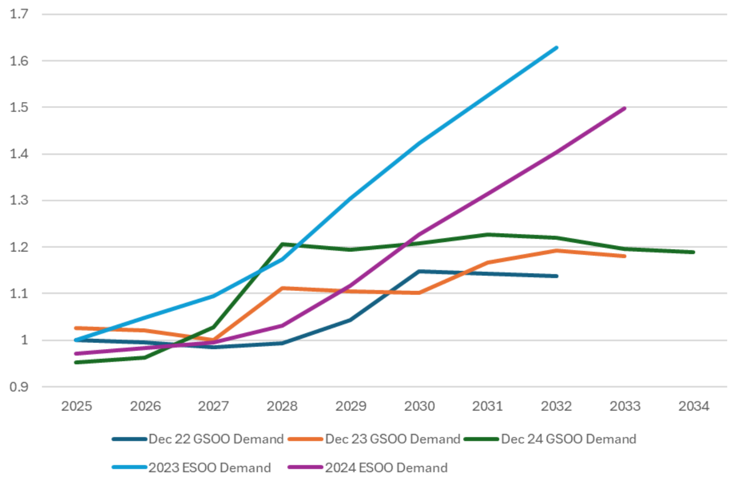
[18] *The 2018 GenCost report gives the background data for the LCoE calculations, so we apply the methodology shown in the 2023 report to the 2018 data. The costs from the 2018 report are adjusted by inflation to 2023 dollars, and we use the same discount rate as was used in 2023 to determine LCoE, so that the results are comparable and differ only in respect of changes in technology, rather than interest rates and inflation.*

[19] *These come from the "Consumption (or Operational) Demand Forecasts", in the appendices of each report. See, for example, p103 of the 2023 ESOO.*

The sudden change in trends appears to be due to a significant increase in forecasts of electric vehicle numbers, starting in 2023, when the uptake of electric vehicles assumed in forecasts increased significantly compared to 2022 (see 2023 ESOO, pp31-24, available here). Electric Vehicle projections seem to have fallen again in the 2024 ESOO (See 2024 ESOO, Appendices, p19, available here) and it is not clear how AEMO's view will evolve in subsequent years.

However, whatever is driving electricity demand forecasts, it is far from clear how much of that increased demand will be served by gas-fired generation. Figure 12 indexes the last three gas and two electricity demand forecasts by AEMO, with 2025 as the base year.

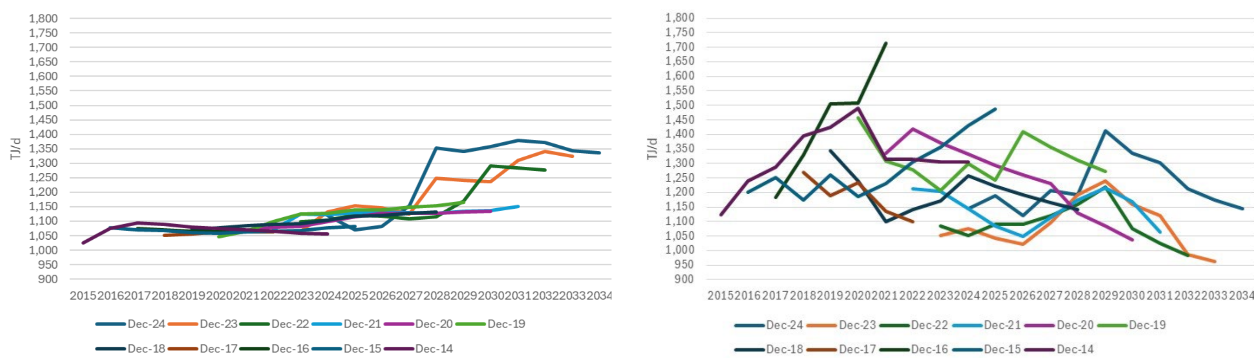
Figure 12: AEMO gas and electricity demand forecasts 2023 and 2024 – indexed



Source AEMO ESOO (available here) and AEMO GSOO (available here). In each case we have used the "base" or "expected" forecast, contained in the tables in the Executive Summary of each document and we have indexed gas to the 2022 GSOO and electricity to the 2023 ESOO forecasts for 2025.

If electricity demand is going to be some 50 percent higher by 2032 than it is forecast to be in 2025, and gas demand is only going to be some 15 percent higher, then clearly, something else is filling the gap; renewables and batteries, mostly, given assumptions about coal retirement. The is even more clear when considering gas demand and supply, as shown in Figure 13.

Figure 13: AEMO Gas demand (RHS) and supply (LHS) forecasts 2013 to 2023



Source: AEMO GSOO (available here). In each case we have used the "base" or "expected" forecast, contained in the tables in the Executive Summary of each document.

Demand forecasts tend to be relatively flat through most of the period, rising slightly in more recent years, due in part to gas replacing coal (in the SWIS and for some industrial users) as it is retired rather than being due to a rise in electricity demand.[20] Supply, however, is forecast to fall

[20] *See Chapter 13 for a summary of gas substitution for coal over the next five years, as part of AA6 demand forecasts.*

through the same period, and AEMO has been looking towards supply declines for most of the past decade. In fact, significant supply shortfalls of over 300 TJ/d have been forecast for the early 2030s.

CarbonTP (See Attachment 6.2 p40) notes that WA does not have an issue with gas shortages, per se, but with the fact that some 90 percent of the gas in the state is exported, and suggest that a successful gas reservation policy could act to keep demand and supply in balance without domestic prices rising to the level of LNG netback prices. Regardless, whether the gap is filled or not, it is clear from Figure 12 that, in AEMO's view, there is no direct link between electricity and gas demand going forwards, as there may have been in the past.

Finally, we noted in our revised proposal for AA5,[21] that a number of mining companies were beginning the process towards electrification, several of them with fairly large-scale plans. Much of this information came from a trade journal Energy and Mines (available here) which focuses specifically on the growth of renewable power in mining. Subsequent issues of the same journal note continuing progress towards electrification but note that, as the sector moves beyond the rush of first mover enthusiasm, progress has slowed a little, in particular:

- The October 2023 issue points out that many miners with interim targets at 2030 are beginning to realise that, with project planning factored in, they don't have very much time to meet their targets. The same issue also notes that competition for renewable plant is fierce, from outside mining as well, and that key parts of the mining production chain, like transport, are still in their infancy insofar as renewables are concerned.
- The March 2024 issue points out that batteries for storage can be challenging, not only because they have a relatively high LCoE, but because they can be very sensitive to heat, dust, altitude and other things common on remote mine-sites.
- The April 2023 issue points to WA government data which suggests that, as at 2022, renewables used in mining were equal to approximately one percent of the total electricity generation load, which gives an idea of the scale of the challenge ahead; particularly when the electricity load does not include transport, which is usually based on diesel. The same issue also points to supply chain issues and competition for resources.
- The October 2024 issue points out that, although whole of life costs (particularly when compared to diesel at remote sites) are low, the capital costs are high, which can constrain investment. It also pointed out (as do articles in many issues) that cultural change is needed, as is more learning on how to best change mining practices to take advantages of the opportunities and constraints posed by renewables, but it noted that, as renewables move from C-suite policy to hands on application, these lessons are being learned.

Similar sentiments are expressed in reports by "State of Play" (available here); an organisation which, like the *Energy and Mines* publication, has a strong focus on how renewable electricity can be made successful in the mining sector. That publication places a particular emphasis on cost and culture. In respect of cost, it notes that renewable power has very low opex, but its capex is very high, and this can make it challenging for smaller, less well-capitalised miners, operating shorter duration mines. The rise in interest rates since our AA5 proposal, has made this issue more important.

In terms of culture, State of Play notes that the mining sector has had relatively stable technology for some years, so much so that safety cases and contracting practices have developed around the capabilities of existing equipment; something which is hard to change quickly. Additionally, with renewable power (and electricity more generally), the optimal way to operate a mine

[21] See Attachment 9.7 pp 19-21, available here.

changes, and this can take time for miners to learn. The publication suggests that the second generation of electric mines will learn from the first, but that this takes time.

None of this means, of course, that the electrification mining and the use of renewable power in mining will not happen. Rather, its scale and speed may have slowed a little compared to industry views in 2021, when interest rates were very low, and all anyone had to base forecasts on were a handful of pilot projects which replaced only part of the energy load of some mines.

2.1.2 Views of CarbonTP

In forming our conclusions we have not relied solely on updates of information examined as part of our AA5 proposal, but have instead sought new information and advice, primarily from a group of expert consultants very familiar with the WA energy sector, CarbonTP. Their views are detailed in Attachment 6.2, and we provide a brief summary of them here. CarbonTP's general conclusion in respect of the DBNGP is that (Attachment 6.2 p14):

> *The role of the DBNGP will change over time, migrating from one of providing a stable supply of gas to industry with some baseload and peaker power generation, to one of ultimately providing access to gas to firm power generation. As coal retires the role of gas generation will become more of a baseload provider before progressively returning to filling in peaks in demand and troughs in renewables generation. This pattern will be driven by electrification of industry shifting energy demand from the DBNGP to the SWIS, with progressive penetration of renewables in the SWIS driving gas from a base load generator, replacing coal, to a peaker service. With the forecast electricity load growth, it is possible future peak demand for GPG may exceed the instantaneous capacity of the DBNGP to deliver, although overall utilisation (annual throughput) is expected to remain stable or decline.*
>
> *Without intervention the contribution of the tariff to the cost of gas delivered could increase, incentivising shippers to seek alternative solutions for energy and compounding the problem.*
>
> *Appropriately managed, the DBNGP will be an integral part of the energy transition for WA, providing reliable low cost access to gas from the North and Perth Basin to gas power generators serving the SWIS.*

In respect of the SWIS, CarbonTP note the policy decision to retire coal from the SWIS, which they suggest will create an upward bump for demand for the DBNGP in the early 2030s.[22] CarbonTP then note how, as it comes down its respective cost curves and is deployed, renewable power (including battery storage) will continue to grow, taking up an increasing share of total electricity supply. However, they suggest that growth is likely to be similar to the growth of the power market as a whole (and test faster growth rates), which means that gas demand stays relatively stable, in aggregate, through until around 2050.

There is, however, a key difference in demand for gas compared to the present. The basic issue is with the nature of renewable power. The fuel may be free, but overall costs rise sharply as the share of renewable power in the market rises. Consider solar power, backed up by batteries (other renewable power generation and storage mechanisms are similar). To capture daytime power demand, one must build a fleet of PV solar farms. However, if one then wants to serve the evening demand as well, after the sun goes down, not only does one need batteries, but one also needs more solar PV to fill those batteries, because the original solar PV farms are already deployed to serve daytime demand. If one then wants to cover demand on cloudy days, one

[22] *In the depreciation model, we assume a few years of slippage in respect of this policy (as has been the case with similar policies elsewhere). However, even if it followed the government's intended timeframe, this would not change our long-term conclusions in respect of depreciation.*

needs more batteries, and more solar, and so it goes on, with the marginal cost of renewable deployment rising sharply with the proportion of the market served by renewables.

This has been a key part of our thinking in respect of the longevity of gas transmission in a way that it was not in our analysis preceding AA5. There is a trade-off with renewable power; over time, its average cost is going down, but at a point in time, its marginal cost rises with its share of the energy market, and the two trends act against each other to produce whatever will be the final equilibrium for renewable power. In this context, gas is both a complement and a competitor to renewable power. Moreover, because gas increasingly operates at the time when renewables and storage cannot do so economically and serves the entire market demand at that point in time, the amount of gas delivery infrastructure does not change significantly with the rising portion of annual demand served by renewables.

The fact that gas plays an important role in respect of firming renewable power does not, however, mean that it is somehow "safe" from future competition. As renewable power takes up a larger energy share, and gas is used on fewer and fewer days (or hours in a day; the issues are the same), whilst annual payments from shippers to the DBNGP might not change very much, the effective transport price to a shipper for each GJ of gas actually used will rise substantially. CarbonTP provide some examples of this in their report. This makes gas infrastructure like the DBNGP susceptible to future competition from a (renewable) source of firming power, especially one which does not require a large amount of delivery infrastructure.

In respect of industrial customers, we asked CarbonTP to focus only on alumina refining and chemicals and gas processing, which reflect roughly a third and 10 percent (respectively) of demand on the DBNGP. Alongside gas for power generation in the SWIS, which is also roughly a third of our business, this represents more than three-quarters of our business, which was considered sufficient to chart a path forwards.[23]

For industrial customers the story is relatively simple; available options to move away from gas in both alumina and chemicals and gas processing production are both highly capital intensive and uncertain in respect of their viability, making a move challenging whilst the future is uncertain, even with government policy pushing towards decarbonisation. A shift from gas, therefore, happens only in situations where gas, electricity and carbon prices align to make it viable. Additionally, electrifying an industrial task does not mean all of that energy demand supplied by gas is lost to renewables; where a shipper is connected to the SWIS, because the SWIS still uses at least some gas for providing firming power as the share of renewables increases, there is a "bounce-back" of gas demand associated with electrification which ameliorates some of the initial gas losses (See MVR example Attachment 6.2 p24 and calcination example p27).

None of this is to say that our industrial loads will not electrify; depending upon relative prices of gas, electricity and carbon in different views of the future, they do. However, it seems unlikely, in the 25-year time horizon which CarbonTP have used, that we will lose all of our industrial load and, what load we do lose is ameliorated by gas for power generation increasing somewhat. This is something we explore in more detail in Section 3.2.

2.1.3 Input price changes

In both AA5 and in AA6, a key driver of the modelling is price, and therefore it is instructive to examine how prices change between each model in each assessment. We do so in Table 2. This is necessarily approximate, as the ranges are different in construction, but it gives an idea of how

[23] When we include gas for ATCO's network, whose demand we assume the ERA has covered in its assessments of long run demand in its decisions for ATCO, the total is above 80 percent. Note that future iterations of our modelling framework may extend the same approach we have followed to remaining market segments, but the work is time-consuming with large error margins, and wetherefore chose to focus on the handful of sectors which make up the major share of our demand.

much any change in our conclusions stem from changes in price forecasts. Note, in examining the prices shown in Table 2, that gas and electricity prices are wholesale prices (not delivered) and expressed in dollars of 2024. Note, importantly, that the electricity prices from AA5 were for a 100 percent renewable SWIS, whereas in AA6 the prices are a for a grid with a mix of renewables and gas.

Table 2: Gas, Electricity and Carbon Price Assumptions AA5 and AA6

	2025	2030	2040	2050	2060	2070
AA5 Assumptions						
Electricity low ($/MWh)	$171.40	$150.34	$113.62	$87.43	$71.24	$61.57
Electricity high ($MWh)	$194.90	$188.56	$175.68	$164.44	$156.16	$150.54
Gas low ($/GJ)	$8.42	$8.32	$8.11	$8.11	$8.11	$8.11
Gas high ($/GJ	$9.85	$10.17	$10.81	$10.81	$10.81	$10.81
Carbon low ($ tonne)	$29.83	$34.59	$46.48	$62.47	$83.95	$112.82
Carbon high ($ tonne)	$49.87	$57.81	$77.69	$104.41	$140.32	$188.57
AA6 assumptions						
Electricity low ($/MWh) (% gas)		$91.00 (41%)	$80.00 (33%)	$77.00 (29%)	$77.00 (29%)	$77.00 (29%)
Electricity high ($MWh) (% gas)		$96.00 (29%)	$108.00 (14%)	$110.00 (9%)	$110.00 (9%)	$110.00 (9%)
Gas low ($/GJ)		$5.00	$5.00	$5.00	$5.00	$5.00
Gas high ($/GJ		$13.00	$13.00	$13.00	$13.00	$13.00
Carbon low ($ tonne)	$62.00	$96.00	$117.00	$198.00	$198.00	$198.00
Carbon high ($ tonne)	$75.00	$105.00	$221.00	$420.00	$420.00	$420.00

The comparison of electricity prices can only ever be approximate, because it is not an apples-with-apples comparison, given that AA5 is for a renewables grid and AA6 is for a grid which includes gas. In particular, there is no linear relationship between the proportion of gas and the electricity price, because a renewable grid increases rapidly in cost as one gets closer to 100 percent renewables. However, broadly speaking, the electricity prices are generally forecast to be lower in AA5 than in AA6, but at the same time, gas prices, particularly once carbon prices are included, are also lower. Since it is relative prices which matter, the situation has not changed significantly since AA5, particularly over long-term forecasts. This is perhaps not surprising, since the CSIRO GenCost work informed our analysis in AA5 and AA6.

2.2 New aspects of the modelling framework

Just as information about our inputs changes, so too does modelling practice. Our approach in AA6 still follows the same basic approach of comparing options for our shippers and testing how changes to depreciation might change their gas demand through time, but we make three key changes in how we model.

The first of these is a far more granular and detailed focus on how shippers might change their source of energy. In AA5, we compared forecasts of the price of gas and substitutes (renewables where the end use of the gas was electricity and hydrogen otherwise) and, when the substitute was cheaper for the industry in question, it was assumed that gas demand for that industry went to zero. There was no consideration how a given shipper might give effect to changing its energy source.

In AA6 we focus explicitly on how a shipper might change its energy source, and the end use of that energy; what technology allows it to do so and what does the technology cost. This results in a much more granular and realistic focus to our analysis. It does mean that we have had to narrow our scope, as this approach is more labour intensive than our approach in AA5, but most of our demand comes from a handful of industries in any event.

The second change we make to the modelling framework is how depreciation is given effect. In AA5, we changed asset lives but did not change the shape of the depreciation profile (see Attachment 9.7 of our AA5 proposal, available here, for an account of this debate). Subsequent to our AA5 proposal for DBP, we undertook work for our Victorian distribution assets and developed an approach which allows us to also "tilt" the depreciation profile and give differing amounts of depreciation for a given asset in different years of its economic life.

We note that the ERA has subsequently endorsed the flexibility of a tilt approach in its decision for ATCO,[24] and that it has also allowed a change in straight line depreciation in the case of the GGP.[25] Our model in this proposal allows both a tilt and a change in asset lives to maximise the flexibility with which we assess depreciation.

The final change is one of focus. For AA5, we implemented the WOOPS model of Crew and Kleindorfer fairly literally and focussed on the revenues during regulation and under a period of future competition, seeking to equate these with our existing asset base (and capitalised future capex and opex).[26] In AA6, we focus instead on shippers and their prices. We are not attempting perfectly flat future prices paths; as the ERA points out, this is not necessarily desirable and is in any case impossible in a model which has feedback loops.[27] Rather, we focus on ensuring an absence of price shocks and, where feasible, a relatively constant relationship with the price of substitutes to gas.

The net effect of this change in focus is small; a price series which does not contain shocks and does not change its relative relationship with the price of substitutes through time is also one where our chances of maximising the likelihood of recovering our invested capital and not stranding any assets. In fact, it is precisely by making such a price schedule that we keep the risk balance between our investors and our customers roughly the same as the market environment changes. However, a focus on our shippers, rather than us, gives us a better ability to choose the depreciation schedule (where several may give similar results in terms of asset recovery) which best meets the long-term interests of our customers.

[24] *ERA 2024, Draft decision on revisions to the access arrangement for the Mid-West and South-West Gas Distribution Systems: Attachment 6 – Depreciation, 24 April 2024, [76], available here. See also Attachment 6 of the Final Decision, pp29-31, available here.*
[25] *ERA 2024, Draft decision on revisions to the access arrangement for the Goldfields Gas Pipeline: Attachment 6 – Depreciation, 25 July 2024, [67], available here.*
[26] *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.*
[27] *ERA 2024, Draft decision on revisions to the access arrangement for the Mid-West and South-West Gas Distribution Systems: Attachment 6 – Depreciation, 24 April 2024, [86] to [89], available here.*

3 Summary of Results

In this chapter, we provide an overview of the approach we followed to do our modelling, and some of the lessons we learned along the way which we think will help underpin future work on depreciation. In simple terms, the end product of our analysis is a conclusion that the approach we followed in AA5 still performs adequately when it comes to avoiding price shocks for our shippers and maintaining the risk balance between investors and customers as the energy market changes.

It may be possible to produce different depreciation approaches which perform better in the model, but the future is highly uncertain, and we are wary of committing a ludic fallacy, rather than adopting pragmatic and workable solutions. This is especially salient given what we must exclude from our model due to a lack of information. This we discuss in detail below.

The first section of this chapter covers what we did, how we did it and what we learned from our modelling exercise; even if the end result is no change from AA5, the reasons why are still highly informative for the future. It should be read in conjunction with Chapter 4, which is a manual explaining how the model works and is designed to allow the ERA to run the model for itself and check our work. The second section examines some sensitivity analyses which serve to show the prudency of the AA5 approach to manage risks we cannot model.

3.1 Our results and their drivers

In this section we summarise the analysis we undertook and the lessons we learned along the way to the results of that analysis. It should be read with the next chapter, which summarises how the model works.

Our modelling approach works by tracking both scenarios and simulations. Scenarios describe a mutually consistent set of drivers that make up a large "world view", and then we simulate gas, electricity and carbon prices within each scenario. The scenarios are summarised in Table 3.

Table 3: Schema of scenarios

Case	Base	Medium	Accelerated
Gridcog Scheme	Scheme 1	Scheme 2	Scheme 3
Domgas policy outcomes	Success	Partial success	Failure
Gas price mean value	Low ($5/GJ)	BAU ($9/GJ)	LNG netback ($13+/GJ)
Growth of renewables to 2049	6.5% pa	7.2% pa	7.6% pa

Gridcog is the software package used by CarbonTP to simulate outcomes in the SWIS. A key part of the "schemes" which it uses are the capacities of renewables and storage. This are shown in Figure 14.

Figure 14: Gridcog "schemes" and renewables

Further details underpinning the different schemes and scenarios are provided in Attachment 6.2. The key drivers examined, and allowed to vary within and through scenarios (see brackets) are:

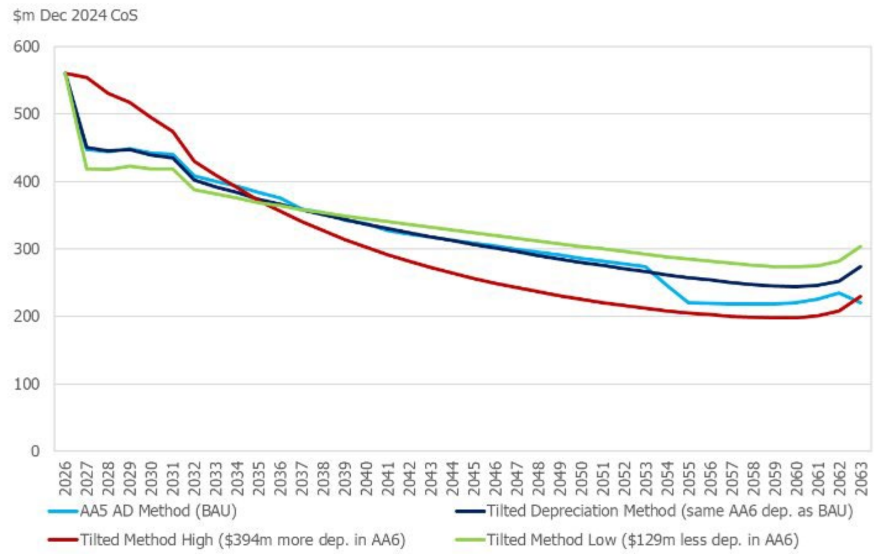
- SWIS electricity prices and projected consumption (scenarios)
- Wholesale domestic gas prices and projected consumption (scenarios and simulations)
- Global chemical prices per tonne (static input)
- Carbon prices per tonne (scenarios and simulations)
- Gas transport prices (output with feedback loop to project NPVs)
- Project capital costs and opex (static input)
- Gridcog gas dispatch output (scenarios).

For our shippers, we examine the particular options the largest of them (alumina, chemicals and gas processing and gas for power generation) have for decarbonisation and the costs associated with each option. Essentially, we look at how our shippers might behave given realisations of the drivers in the model and the options they have to act to change their gas demand. We then test different deprecation profiles within this framework.

Our aim in the modelling was to ascertain an appropriate depreciation schedule. That is, a depreciation schedule which allows our shippers to avoid price shocks. It is through a depreciation schedule such as this that we are able to maintain roughly stable risk allocation between ourselves and our shippers and the energy market changes around us. This is a crucial consideration; depreciation is a key tool for *maintaining* risk allocations and ensuring that additional risk does not fall on shippers or network investors as energy market conditions change.

A part of our search for an appropriate depreciation schedule that was not part of our approach in AA5 is the technique of using a "tilted" depreciation schedule. This was developed by us to model depreciation for our Victorian networks and accepted by the AER in a recent decision for these networks. A similar approach was used by ATCO in its recent AA proposal (see Section 2.2). An example of some of the different depreciation schedules associated with a tile to depreciation is shown in Figure 15. Figure 15 also shows the depreciation schedule currently built into our tariff model, following the ERA's decision for AA5, by way of a comparison.

Figure 15: Different depreciation tilts and their results



In Figure 15, we focus on the total cost of service through time, of which depreciation is a part. This is why the tilts are not smooth in early years, where the remnants of the asset recategorisation approach the ERA approved in AA5 still has a small effect. There are an infinite number of different tilt factors one can use, but Figure 15 illustrates the practical problem faced with using different tilt factors which has driven our decision to stick with the AA5 approach.

If we had evidence of a lot more risk in the future compared to AA5 we might choose a tilt profile like the red line in Figure 15, and conversely, we might choose something like the green line if we had evidence of a significant risk reduction. However, as discussed in Section 2.1.1, over the long run, our current information is reasonably similar to AA5 with similar uncertainties and risks as well. So the green line in Figure 15 would be in the wrong direction and the red line would place too much risk on shippers now. We therefore attempted to give a similar risk profile to the AA5 approach through most of the forthcoming decades using the tilt function represented by the dark blue line, but this increases risk in the 2050s; precisely when we do not want it to be increased.

The basic issue is that the tilt function is relatively simple, producing a single smooth curve. By contrast, because our AA5 approach can make use of an idiosyncrasy in our existing depreciation profile (the falling to zero of our pre 2001 RAB in around 2055), which has the effect of dropping risk at a time when doing so is particularly useful. This cannot be done with a simple tilt function.

As we worked on this and discussed it further with our experts, CarbonTP, considering in particular the nature of the WA energy market, a broader issue became apparent. A tilt function, like we used in Victoria and ATCO used in WA is particularly good when one can make use of the law of large numbers to deal with the incentives of a largely homogenous base of small customers, as occurs in distribution. However, it works less well in transmission, where there are a small number of large customers, with particular idiosyncrasies that, given the size of shippers, are enough to impact depreciation choices.

In a general sense, this suggests that a simple tilt function, which ignores the idiosyncrasies of the customers of a transmission pipeline, might miss important information. To include such information might be necessary, for example, to combine tilts with caps on asset lives, or to give the tilt function itself a piece-wise function rather than a single smooth function. More complicated tilt functions, however, raise a risk of over-fitting the model to the data one has and making poor out of sample predictions; of committing a ludic fallacy. Being mindful of this, before starting to create and test different, more complex tilt functions, we took the pragmatic step of simply checking whether our existing approach gives desirable results in terms of preventing price shocks for shippers. We report the results of this analysis below, but first we explain how our view of drivers and options changed as we worked through our analysis.

In terms of drivers, we found that two drivers, nickel and alumina prices, were less important than we thought they would be. In the case of nickel pricing, the domestic industry has already largely been priced out of the market by competition from Indonesia, and it seems unlikely to return to the importance it had in the past for the DBNGP in future. In the case of alumina, the opposite is true; the highest cost refinery, at Kwinana, is in the process of being mothballed already and, once it is removed, WA alumina refineries are sufficiently low cost that they seem unlikely to be priced out of global markets.

In terms of new industry drivers that might lead to increases in demand, the most feasible of them, green steel, sponge iron and lithium tend to have fairly short distance-weighted tariffs (particularly those in the Pilbara) and adding their load to the DBNGP, particularly under the current tariff structure, would not substantially change overall full haul equivalent loads. For this reason, although they are discussed by CarbonTP (See Attachment 6.2) we have not included them in the model. We have considered expansion of chemicals and gas processing, which does have an appreciable impact on full haul equivalent demand.

In respect of options for shippers, the number we thought would be feasible at the outset of our analysis got smaller as it became apparent that some were unlikely to ever be tenable. This was especially the case for electric calcining of alumina; information on the capital costs for this option suggest it is sufficiently high that only extreme combinations of electricity, gas and carbon prices will make it viable. CarbonTP also examine a number of other options which, in their view, seem unlikely to be viable as options for our shippers and discuss these in Attachment 6.2. In general, these were not tested in the model where it was clear that they would not be viable. The net result was a much smaller set of options that we thought would be the case, being:

- Mechanical vapour recompression for alumina.
- Expansion or otherwise for chemicals and gas processing.
- Different pathways for renewables in the SWIS.

One consequence of taking a much more granular approach towards options for shippers is that it allows one to look much more carefully at feasibility of different options, and this can often limit the scope of analysis in ways that are useful. This appears to be the case here.

At the same time as looking at options and drivers, we had to think carefully about what we are actually measuring when we looked at prices and shocks to them. Our shippers currently pay a capacity/commodity split of roughly 94/6.[28] That is, once they nominate a certain amount of capacity, in TJ/d, they must pay that same charge, every day, for the whole year.

In the event that demand is relatively stable, this doesn't matter very much; say an alumina producer running its plant 24/7 with a constant load. However, as noted in Section 2.1.2, in respect of gas for power generation, the tariff may hide the fact that the effective price per GJ used is rising with renewable penetration. For this reason, in our modelling for depreciation, we focus on the price per GJ used, and endeavour to choose depreciation schedules which avoid that from rising too rapidly, rather than focusing on reference tariffs or our revenues, both of which would miss a key signal.

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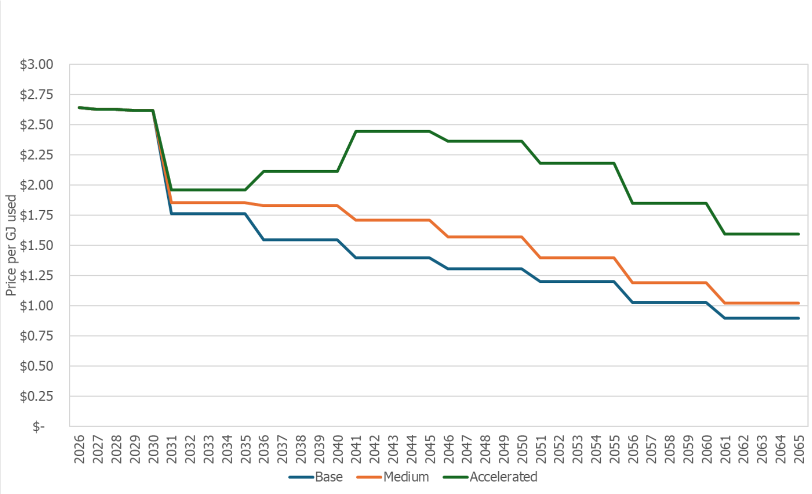
[28] *We make no assumptions in the model about different tariff structures. That would be a significant change, with lots of unforeseen consequences, requiring significant stakeholder consultation, so any model which is optimised to a tariff structure which does not exist risks giving impractical results.*

We now turn to our results. As noted above, the first depreciation schedule we tested using this metric of the price per GJ of gas used was our existing depreciation schedule from AA5. The results of this are shown in Figure 16.

Figure 16: Cost per GJ used with current AA5 depreciation schedule



In testing the depreciation schedule from AA5, we in no way pretend that it is perfect, or even the best that could be found using our modelling framework; this particular outcome was the result of pragmatism by both ourselves and the ERA in AA5. However, it fits what we are aiming for. That is, in the cases of the "Base" and "Medium: scenarios, from the outset, prices decline over time.[29] In the "Accelerated" case, prices do rise in the 2040s (this is due to the introduction of offshore wind, covered in Attachment 6.2), but never to the level seen in AA6, and they drop subsequently as demand expands.

We could, at this point, have started to explore more "bespoke" depreciation schedules, taking into account idiosyncrasies on the part of our shippers and the WA energy market as a whole to see if we could improve our results. However, if we have already largely achieved what we set out to achieve, and we are properly mindful of the risks of ludic fallacies in a very uncertain future world, it is not clear to us that further refinements add significant benefits. Moreover, the AA5 approach has support among stakeholders and imposing further change is only really appropriate to the degree that it is necessary.

This is an issue we will revisit for AA7, when new information is available. In particular, by the time AA7 starts, the 1400MW of planned grid-scale battery capacity (see Section 2.1.1) will have been operational for a number of years (as will the 1600MW of forecast distributed battery capacity with which households will increasingly seek to manage their own power needs). Additionally, coal retirement will have either happened or, if stalled, will be clearer in terms of its timing. This will be key information which can help us plan better.

We conclude this chapter with a brief analysis of some key sensitivities, and some addition of prudent judgement to the conclusions derived from our formal modelling to anchor conclusions about adding to or subtracting from the depreciation schedule developed in AA5.

3.2 Sensitivity of results and the prudency of longer asset lives

The results of the modelling in Figure 16 do not include any cases where:

[29] The significant drop at the start of AA7 is a combination of the effect of falling RAB and increasing demand in AA7, which is when we assume that coal retirements will start.

- A major shipper is ceases operations; or
- An economic substitute for gas for power firming emerges.

Both are conceptually similar in respect of their impact as both involve the loss of what is currently a major user of the pipeline, which would have a significant impact on shippers who remain. However, the nature of their likelihood through time changes, and drawing them out separately helps to illustrate this.

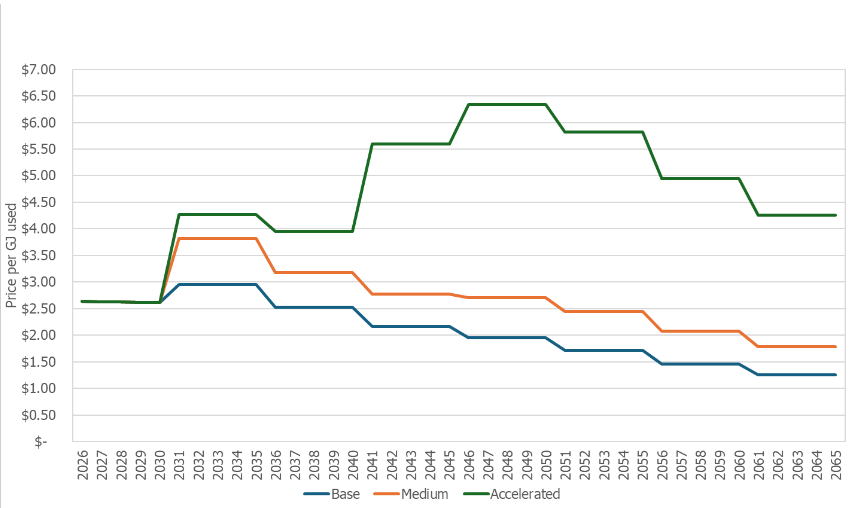
There are good reasons why the modelling does not include either of these possibilities; expert advice from CarbonTP showed little to no evidence for assuming a set of market conditions where a major shipper such as alumina might cease operating, nor much case for alternative (particularly renewable alternative) sources of firming power emerging prior to 2050.

However, the fact that such evidence is insufficiently strong to include in modelling does not mean that we should exclude it from our consideration as our model cannot reliably include all risks and still produce sensible results. For example, alumina producers may lose their social licence for mining in jarrah forest, or a researcher in a lab may be on the cusp of a major discovery in catalysts which is yet to be published (and thus known to experts like CarbonTP) but which might lead to low-cost renewable fuels. Both of these could have a major impact, but neither leads themselves well to modelling as we have essentially no information on their likelihood.

Our focus in examining these two possibilities is on consideration of whether the current AA5 approach of capping asset lives at 2063 results in too much depreciation. The analysis in this section does not change the conclusions of the modelling detailed above around Figure 16 that we do not need more depreciation more early than the AA5 approach gives. This is not due to the severity of the consequences of losing a major shipper or losing gas for power generation, but rather due to the likelihood of such an event occurring over the next 10-20 years.

We look first to the loss of a major shipper, and the impacts of this. For this assessment, we chose alumina refining. This is not to suggest that we believe alumina refining is likely to vanish over the next few decades, but rather to simulate what happens if it does. It is important to note that assuming alumina refining goes is very different from assuming that the current uses alumina refiners have for gas are electrified, which is something we do model. In the latter case, the SWIS takes up the load, and more gas is used in the SWIS for firm power (see Attachment 6.2 for details) to compensate for the larger electricity load. If alumina goes, so too does all of its gas demand. The results of the analysis are shown in Figure 17, where we assume that alumina vanishes at the end of AA6.

Figure 17: Loss of the alumina load



The consequences for tariffs of losing a load as large as alumina refining, are striking; in the Accelerated case, where renewables growth is fastest, prices (in terms of prices per GJ used) rise to over $6/GJ. This would doubtless have a major impact on remaining shippers, even if the model suggests that the pipeline would remain viable. In this instance, the model potentially understates the consequences of losing alumina. By construction, there is no economic alternative for gas for power generation, and mining part-haul shippers are not included in the model. It seems likely that, with such a large price increase, more shippers would move away from gas. In particular, if alumina was lost 20 years from now, rather than today, when the per GJ price of gas actually used by power generators was much higher due to increased renewables penetration, there would be a greater likelihood of one or more dropping gas for a substitute.

We now turn to gas for power generation. This has roughly the same share of full-haul demand as alumina and so, if we assumed that it was lost in its entirety in AA6, as we have assumed for alumina above, provided there were no subsequent losses of other shippers, the effects would be similar to those shown in Figure 17. The conclusion of this simple case would therefore be the same as for alumina noted above.

From a planning perspective, however, we need more than just the impact of a one-off event. What we need is to understand how likely that event might be through time. Even if we know almost nothing about the likelihood of an event at a point in time, understanding how that likelihood changes through time, which we can say something relevant for planning about, is useful. The impacts we discuss above might be immaterial if their likelihood was remote for the next 100 years, but this is not the case, as we now discuss.

Consider alumina first. Given the economics of alumina production and its position on global cost curves, we consider it unlikely that it would be economic forces (which we do model) that could cause the industry to fail, but it might fail if it loses its social licence. This kind of social or political risk is hard to model, but we might make a reasonable assumption that such a loss would be a random event, occurring with a low probability which is the same each year (this is simpler than assuming a trend in probability). Assume for the sake of argument that the probability of alumina losing its social licence in any given year is 1 percent. If this is the case, the likelihood that alumina would have lost its social licence after 50 years is about 40 percent.[30] Whilst we can say with confidence that alumina producers are unlikely to lose their social licence in, say, the next 10 years, the longer the period of time, the lower is our confidence.

Gas for power generation is quite different in this respect, because we can say more, at least in principle, about trends in the likelihood that a competitor for gas for firming power will emerge over time. This is because not only does the cost per GJ of pipeline capacity used increase as the frequency of use decreases with the rise of renewable power, but alternatives to gas in the provision of firm power that are renewable are likely to come down in cost through time as research leads to products which lead to commercialisation. This is not a certainty, of course, but with many hard to electrify sectors requiring carbon-neutral fuels, there is definitely a will, globally, to make the investments to underpin commercialisation.[31] In practice, this means that the risk of a substitute for gas for firming power is likely to rise through time, rather than remain constant; and this suggests that, over long time horizons, it is a riskier proposition than, say, the loss of alumina.

We do not know what the risk of substitution is now, or how it might be increasing through time, but a though experiment can still help in designing prudent depreciation approaches.

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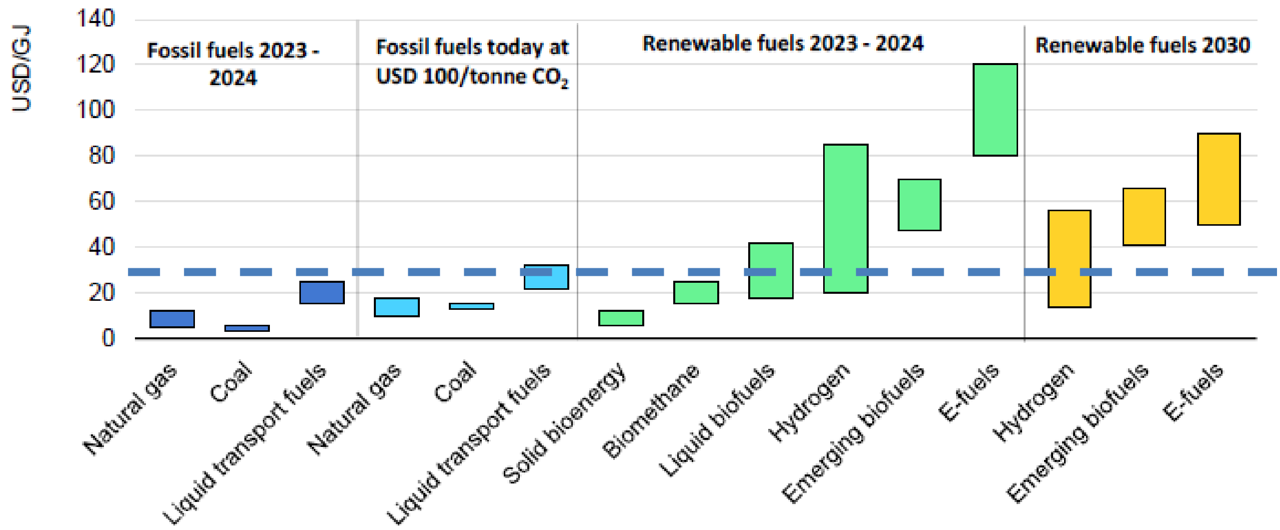
[30] If the risk of losing social licence is on percent per annum, the one-year probability of keeping said licence is 99 percent. The probability that the licence will remain after 50 years is $(0.99)^{50} = 0.6$. Hence the 40 percent chance noted above.
[31] We note that bio-diesel usage, although it is still small, is already large enough to be tracked as a distinct fuel by the Energy information Agency in the US (see here), due in part to policy initiative supporting its development in markets much bigger than WA.

Right now, whilst technically feasible alternatives to gas as a source of firming power that have zero emissions do exist, they tend to be expensive (see Attachment 6.2 for more details) and, in general, a long way from commercialisation at a scale necessary to supplant gas in the SWIS. However, consider an illustrative example reflective of a possible future. Carbon TP (Attachment 6.3 p18) suggest that, under the Accelerated scenario, only around 5 percent of electricity in the SWIS would be provided by gas. Following from the example provided by CarbonTP (Attachment 6.2 p17), for a given gas generator, operating only 5 percent of the time, the per GJ cost of gas transport is around $19/GJ, given a tariff in the model in 2060 of $1.00/GJ.[32] Under this scenario, CarbonTP assumes that the Domgas policy has failed, and that WA faces LNG netback prices of $17/GJ by this stage, which leads to a total cost for the shipper concerned of around $36/GJ. Consider this in the context of Figure 18, which provides renewable fuel cost projections today and out to 2030. For comparison, we assume that 1AUD=0.65USD, so AUD41/GJ becomes USD23.50.

Figure 18: Renewable fuel cost projections



** Source IEA, 2024, Renewables 2024: Analysis and forecasts to 2030, p130, available here*

Noting that the IEA values are current or out to 2030, which is more than 30 years of technological progress before we get to 2060, even considering a need to include all of the other delivery infrastructure for, say, liquid biofuels, could one say with significant confidence, that the cost ranges for renewable liquid biofuels would not reach parity with delivered natural gas by 2060 or so?[33] Could one say the same thing in 2070 when renewable penetration is likely to have increased, making the price per GJ of gas higher and further technological progress and scale economies in the production of biofuels (or e-fuels, or some technology not yet considered by the IEA)? We believe that, the further ahead in time one looks, the less reasonable is the proposition that a competitor for gas for firming power will not emerge.

Both the random event of alumina losing its social licence (the same analysis could be applied to any of our shippers) about which we can say little other than the probability of it happening is non-zero and the more trend-driven event of economical alternatives to gas for firming power

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[32] The price per GJ used in this scenario is $1.80. That is essentially an average over all shippers and all users, rather than for this particular example of a particular generator. Note that, if we had lost a major shipper first, the price might be much higher; both the tariff and the effective price of gas actually used.
[33] We note the views of CarbonTP in regards to alterative fuels, and the challenges they represent in Attachment 6.2, but consider that this does not mean that none of them will ever, decades after the timeframe examined by CarbonTP, emerge as an economically sustainable competitor to natural gas. That is not to dismiss the challenges, but rather just to note that motivated economic actors do find solutions, given decades.

emerging point to essentially the same conclusion; the longer is the time horizon, the less likely it is that key customers will remain. There is nothing special about the DBNGP in this respect; the moment one considers the possibility of a dynamic world for any piece of infrastructure, this conclusion logically follows.

This has two consequences. Firstly, a move backwards in terms of methodology, from the approach in AA5, to the methodology used in AA4 is inadvisable. Prior to AA5, whilst individual assets, a compressor station say, had finite lives, the implicit assumption was that the asset in question would be replaced like-for-like, but the pipeline as a whole would essentially last forever.[34] This, implicitly, assumes that shippers will last forever and that no economic substitute for the monopoly good will ever emerge. This assumption cannot be true, as discussed above, and points to a fundamental issue with economic regulation; it implicitly assumes monopoly power lasts forever when it does not. We expect this fundamental issue will become more apparent in time as electricity networks also realise that competition at some future point is conceivable; gas is merely ahead of the game in this respect.

Secondly, it suggests that, if a network (or its market power) is not eternal, then some form of regulatory approach which either caps lives or reduces asset exposure in coming decades is a prudent form of "insurance" against risks for both network owners and shippers who remain after major shocks hit demand on a pipeline, even where they cannot be quantified. This does not mean, of course, that a cap of precisely 2063 is the right answer but:

- It does produce, in the modelling we have undertaken, a declining price path across most scenarios, in the face of the risks we can model, which suggests it is not a particularly expensive form of insurance; and
- The nature of the lives of major, long-lived assets in the RAB at present, absent of a cap, would mean that the difference in prices today from a cap of 2063 versus one of, say, 2083, would not be substantial; and
- The information in Figure 18 suggests that the likelihood of a competitor for gas in its firming power role not emerging in, say, the 2070s is perhaps rather small.

For these reasons, we think that maintaining the AA5 approach, rather than rolling it back, remains a prudent approach until more information becomes available which might shed more light on the probabilities of events like those we have discussed in this section. This is an issue we intend to return to for AA7, when more information will be available.

[34] *If one had pipeline with a life of 50 years and compressors with a life of 20 years, and no other asset classes then, after 100 years, both would come to zero at the same time and the pipeline could end, but in reality, a simple common multiple analysis based on asset lives gives answers much longer than this; for some electricity networks, for example, it suggests a period of time longer than the time Aboriginal Australians have been in Australia before all assets go to zero at the same time and an investor could walk away with no unrecovered capital, rather than replacing all assets afresh. This is as near to forever as makes no practical difference.*

4 Detail on Approach and Model Manual

This section describes the modelling framework we have used in order to explore the question of appropriate depreciation during AA6. We cover the structure of the model, key model drivers and the instructions for how to run the model itself. This allows the ERA to replicate our results, and explore, as necessary, different solutions within the same modelling framework.

4.1 Detail on approach

The modelling approach is structured as follows with price path or transport tariff per GJ being the key output for future Access Arrangements up to 2066.

Tariffs are stylistically the cost of service divided by demand:

$$\frac{Forecast\ Cost\ of\ Service}{Forecast\ Demand}$$

For this reason two separate models are developed:

1) a long-run cost of service (LRCOS) model based on the DBP Tariff Model; and
2) a long-run demand (LRDEMAND) model developed based on the advice of Carbon TP

The long-run in the modelling context is each Access Arrangement up to 2066 with 1) at and annual frequency and 2) a 5 yearly frequency.

4.2 Long-run cost of service model

The LRCOS model is embedded within the DBP tariff model. The LRCOS model uses the cost and demand inputs for AA6 taken from the conventional tariff model. LRCOS output is *not linked* to the conventional tariff model, information flows only from the latter to the former. In particular AA6 demand is independent from the LRDEMAND model. All dollar inputs and outputs are real as at 31 December 2024.

Building block costs are modelled independently of demand for modelling simplicity. The only building block that should arguably be dependent of demand is system use gas, however, as this only represents around 4 per cent of costs keeping it constant for simplicity has little impact on the analysis in practice. This is shown in Table 4.

Table 4: Building block costs

Building Block Component	Long Run Modelling Approach
System Use Gas	Held constant at 2030 value
Operating Expenditure	Held constant at 2030 value
Depreciation	Modelled as long-run asset using conventional tariff model approach with an option to apply a tilted depreciation profile on long life assets.
Return on Asset	Held constant at 2026 WACC
Net Tax	
Tax	Inferred from tax payable on return on equity then converted to real dollars
Imputation Credits	50% of tax payable
Over Depreciation	Null

These components are summed to give the cost of service which each year is discounted by the real post tax WACC to get the present value of the cost of service at each AA start. This is the numerator in the calculation of the discount weighted average tariff (DWAT). The denominator is the sum of discounted demand output from the LRDEMAND model over the 5 years of each Access Arrangement (assumed constant over the AA).

A discount weighted average tariff is used to approximate the tariff calculation process to avoid the complexity of solving x-factors for tariffs in each future 5-year period.

4.3 Long-run demand model

This model focuses on key shippers who have material *distance weighted demand* which are full haul shippers in the south-west of Western Australia. Modelling effort is focused on gas consuming facilities that are subject to the greatest variability based on the long-run outlook for new projects that impact gas demand or increased utilization due to natural demand growth or substitution away from higher emission technologies. This is shown in Table 5.

Table 5: Industries and options for decarbonisation

Industry	Project/Demand Conditions Considered
Alumina	Mechanical Vapour Recompression & Electrified Calciners
Chemicals and gas processing	Green Hydrogen, Expansion of conventional Haber-Bosch process
Gas Powered Generation (GPG)	Retirement of Coal & ESOO Projections

4.3.1 Alumina and chemicals and gas processing

The alumina and chemicals and gas processing projects are modelled on a technical feasibility and NPV cost benefit basis factoring in the following ***drivers*** investigated in the Carbon TP report:

- SWIS electricity prices and projected consumption (scenarios)
- Wholesale domestic gas prices and projected consumption (scenarios and simulations)
- Global chemical prices per tonne (static input)
- Carbon prices per tonne (scenarios and simulations)
- Gas transport prices (output with feedback loop to project NPVs)
- Project capital costs and opex (static input)

Scenarios are set in the context of Domgas policy and dictate the most significant changes within the model by making relatively large changes to SWIS prices and electricity demand and wholesale domestic gas prices.

Domgas Policy Success is the base case and is characterised by the lowest penetration of renewables and highest use of gas under the lowest wholesale prices. Domgas Policy Failure is characterised by the highest penetration of renewables, notably offshore wind which eliminates some of the need for gas firming and thus transmission capacity. Partial success falls in between the two.

Simulation within the scenarios creates marginal variation in wholesale gas and carbon price projections based on variation around a time series model fitted to historical data.

There are a total of six scenarios, the three Domgas policy scenarios where one set is simulated using Reputex carbon price forecasts as the 'mean trajectory' and the other set using published Australian Energy Regulator carbon forecasts as the 'mean trajectory'.

The following drivers were excluded from the analysis:

- **Global alumina prices** were not considered because a) the decision to shut down the high-cost ageing Kwinana refinery has already been reflected in the 2026-2030 demand forecasts making the commodity price irrelevant and b) the remaining refineries are very cost competitive globally and so are assumed to be the last to leave the global market.

- **Nickel commodity prices** and technology because the decision to shut down the Kwinana nickel refinery has already been reflected in the 2026-2030 demand forecasts. Forecasting Australian nickel refining cost competitiveness globally was beyond the scope of the Carbon TP report.
- **Labour and industrial policies** affecting the cost of production and deindustrialization such as specialist immigration and industry subsidies were not considered because they are beyond the scope of the Carbon TP report. The impact of these would be more material than any other factor considered in our analysis, for example, if the Alumina industry were to close in WA transmission tariffs would roughly double in real terms. The impact of labour and industrial policies can easily be gauged in the modelling by deleting the load associated with a particular industry and observing the resulting tariff path.
- **New gas consuming industries** in the northwest of Western Australia were not considered because cases such as sponge iron, green steel and lithium have immaterial *distance weighted demand* and/or are too speculative for inclusion in the analysis. Only the expansion of the chemical and gas processing industry has been considered.

The last two points prevent the projected tariff path taking on extremities in either direction. Excluding de-industrialisation prevents an extremely high tariff projection while excluding speculative industries prevents an extremely low tariff projection.

4.3.2 Southwest Interconnected System gas powered generation

SWIS demand is modelled in two parts:

- Franchise load from shippers modelled
- All other demand

Modelled franchise gas powered generation load comes from electrified alumina mechanical vapour recompression (MVR) and chemical and gas processing plant expansion (AP3) which requires firming via flexible gas-powered generation when renewable energy is not meeting demand. The Parmelia gas pipeline is expected to net 8.8 TJ/d off the SWIS DBNGP transmission load through its connection to the TiWest cogeneration unit.

If MVR or AP3 are triggered as being feasible in a scenario's simulation it will add a firming requirement to SWIS gas powered generation, in megawatts which is assumed to be served via terajoules of *contracted* capacity on the DBNGP.

Despite low utilization, we assume capacity for firming is contracted 365 days a year to meet the AEMO fuel transport requirement because the model shows little spare capacity beyond 2030 to meet peak gas demand.

Carbon TP show the TJ/d of gas saved from conversion to MVR is roughly equal to the TJ/d of *capacity* added to the pipeline. The gas consumed or *throughput* to serve MVR throughout the year is 60 to 90 per cent lower due to the ability to use renewables throughout the year with corresponding emission reductions.

If triggered AP3 adds 5.6 megawatts of demand to SWIS gas powered generation demand (see this proposal, p3, to the EPA).

All other SWIS GPG demand is modelled using GridCog outlined in the CarbonTP report under three schemes that directly translate to the three scenarios outlined above; Domgas Policy Success, Partial Success and Failure. This demand is independent of transported gas prices and driven by ESOO demand forecasts under the assumption that gas will be dispatched, regardless of fuel cost, when renewables cannot.

SWIS per MWh prices are also determined by GridCog outputting the percentages of renewables and gas-powered generation which are used to produce a weighted average $ per MWh price which factors in carbon, transported gas prices and non-energy fees. These prices are used on a lagged basis to break circularity in the project NPV cost benefit analysis mentioned above. Further details are in the Carbon TP report.

4.4 Linking the two models

The NPV cost benefit analysis for alumina and chemicals and gas processing projects in the LRDEMAND model use transport tariffs calculated in the LRCOS model. A project under consideration in a particular year will use the prevailing (lagged) tariff from the last Access Arrangement in the NPV assessment because future tariffs are unknown.

This simplifying assumption avoids the need to simultaneously solve for both the tariff and project NPV in a given year. It is also realistic to assume that commercial decisions made in future periods would reference prevailing tariffs to forecast.

Unlike long run demand modelling in AA5, this model takes the realities of shipper size and gas consuming plant into account. By virtue of transport prices being around 20-25 percent of delivered gas prices and capital costs for plant like refineries being very high and sunk, transport prices have minimal impact on gas demand. The only exception to this is where a significant industrial load is lost, initiating a 'death spiral' where remaining shippers are allocated a much larger proportion of the cost of service.

4.5 Conservatism in assumptions

The modelling approach described above does not model dynamics of P1 and B1 shipper demand. It assumes that current contracted amounts remain unchanged and uses utilization of 87% which is much higher than P1 and B1 use. Using P1 and B1 historical and projected utilization would present the pipeline as being more at risk under even higher tariff and so the assumption we've adopted is conservative.

We seek to understand the impact of renewable uptake using existing diesel facilities as backup for P1 and B1 shippers who tend to be regional mining companies.

4.6 Model manual

The model consists of two main parts:

1. The long-run cost of service model to model costs over the long-run
2. The long-run demand model to model demand

4.6.1 Long-run cost of service model

The long-run cost of service model is a tab within the submitted ERA tariff model labelled 'Long Run CoS'. It links the long-run cost of service model to the long-run demand model as follows.

The rows highlighted orange in Figure 19 contain cells with green text that link to the demand output from the long-run demand model.

Figure 19: Demand output from long run demand model

Regulatory Period Year Days Project Year	AA7 2031 365 32	AA7 2032 366 33	AA7 2033 365 34	AA7 2034 365 35	AA7 2035 365 36	AA8 2036 366 37
166 **Load F/H Equivalent [TJ/day]**						
167 Capacity Reservation	845.000	845.000	845.000	845.000	845.000	845.000
168 Commodity	596.611	596.611	596.611	596.611	596.611	483.980
169 Total	1,441.611	1,441.611	1,441.611	1,441.611	1,441.611	1,328.980

The rows highlighted orange in the Figure 20 contain cells with black text which are the long-run cost of service model outputs, which in turn are used by the long-run demand model as inputs.

Figure 20: Long run cost of service model outputs

Regulatory Period Year Days Project Year	AA7 2031 365 32	AA7 2032 366 33	AA7 2033 365 34	AA7 2034 365 35	AA7 2035 365 36	AA8 2036 366 37
212 **Forecast Full Haul Tariff [$ /GJ/day] [$ 31/12/2024]**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
213 Capacity Reservation Charge	1.290	1.290	1.290	1.290	1.290	1.123
214 Commodity Charge	0.120	0.120	0.120	0.120	0.120	0.146
215 Full Haul Tariff	1.410	1.410	1.410	1.410	1.410	1.270
216 **Effective $/GJ**	**1.948**	**1.948**	**1.948**	**1.948**	**1.948**	**2.108**

AA6 prices and demand are not impacted by the long-run cost of service or demand model – they are modelled through the conventional method set out for the Access Arrangement process.

The AA6 prices established on AA6 demand feed into the long-run demand model as an 'initial condition' to set off the chain of demand response starting from 2031 which in turn influences prices for future years. ie price from the previous AA is used as a forecast to produce a demand response breaking circularity.

Other inputs for the long-run cost of service include capex and opex. The weighted average cost of capital and associated parameters is assumed to remain constant from the end of AA6.

Opex is input in the 'Long-Run CoS' tab rows highlighted in green below split between SUG and Other Expenses.

Figure 21: Opex inputs

Regulatory Period Year Days Project Year	AA7 2031 365 32	AA7 2032 366 33	AA7 2033 365 34	AA7 2034 365 35	AA7 2035 365 36	AA8 2036 366 37	AA8 2037 365 38	AA8 2038 365 39	AA8 2039 365 40
CHECK -- Cost of Service, Allowable Revenue [m$ 31/12/2024]									
56 **Cost of Service**									
57 OPEX									
58 Opex; System Use Gas	24.425	24.425	24.425	24.425	24.425	24.425	24.425	24.425	24.425
59 Opex; Other Expenses	105.700	105.700	105.700	105.700	105.700	105.700	105.700	105.700	105.700

For simplicity these values were assumed to be constant from the end of AA5, but can be freely changed to determine the sensitivity (or lack thereof) of results to opex inputs such as SUG that declines with demand.

Capex is input in the 'Long-Run Asset (AA5 Method)' rows highlighted in green below. Capex was assumed to be a recent 5-year average prior to 2022, where there is no expansion capex as per the outlook for the pipeline.

Figure 22: Capex inputs

AGIG, DBNGP Tariff Model
Long Run Asset (AA5 Method)

		AA7	AA7	AA7	AA7	AA7
Regulatory Period		AA7	AA7	AA7	AA7	AA7
Year		2031	2032	2033	2034	2035
Days		365	366	365	365	365
Project Year		32	33	34	35	36
240	Pipeline	0.527	0.527	0.527	0.527	0.527
241	Compression	2.775	2.775	2.775	2.775	2.775
242	Metering	5.470	5.470	5.470	5.470	5.470
243	Other Depreciable	2.760	2.760	2.760	2.760	2.760
244	Computers and Motor Vehicles	6.457	6.457	6.457	6.457	6.457
245	Cathodic/Corrosion Protection	5.209	5.209	5.209	5.209	5.209
246	SCADA , ECI And Comms	7.949	7.949	7.949	7.949	7.949
247	Building	0.317	0.317	0.317	0.317	0.317
248	Non-Depreciable	-	-	-	-	-
249	Cost of Raising Equity	0.746	0.746	0.746	0.746	0.746
250	Total	32.209	32.209	32.209	32.209	32.209

4.6.1.1 Tilted Depreciation

As discussed in 2.2 the long-run cost of service modelling includes an option to apply tilted depreciation. This is a tool that offers more flexibility in shaping depreciation so that tariffs are less prone to price shocks through equalizing changes in costs and changes in forecast demand over time. The switch is located in the 'Long-Run CoS' tab. The drop-down option circled in red below toggles between the 'AA5' deprecation method (currently selected) approved by the ERA and 'Tilt' which is the tilted method outlined in 2.2.

Figure 23: Choosing tilted depreciation

Regulatory Period		AA6	AA6	AA6	AA6
Year		2026	2027	2028	2029
Days		365	365	366	365
Project Year		27	28	29	30
22	Asset Account	Asset Method	AA5		
23	Opening Value	3,4[illegible]835	3,298.621	3,221.513	3,130.425
24	Capex	59.753	71.749	58.685	52.480
25	Depreciation	- 228.968	- 148.857	- 149.774	- 147.492
26	Asset Adjustment, Redundant Assets & Asset Disposal	-	-	-	-
27	Closing Value	3,298.621	3,221.513	3,130.425	3,035.414

If the tilted method is selected the option exists to shape depreciation in various ways through the 'tilt' parameter and 'End Life'. The Long Run Asset (Tilt) tab contains the asset base that calculates the tilted depreciation. The tilt parameter is shown below. The minimum value that can be entered is 0.0000001 or otherwise an error is returned. Higher values apply a steeper tilt, loading more depreciation into AA6 and less into future access arrangements inducing a declining cost of service over time

Figure 24: Tilting depreciation

Regulatory Period		AA5
Year		2025
Days		365
Project Year		26
Capital Base [m$ nominal]		
22	Tilt parameters	0.0000001

The End Life found in the 'Inputs' tab shown below *interacts* with the tilt parameter to change the shape of the depreciation profile. It is currently set to 2063 but can be removed by typing = "".

Figure 25: Pipeline end date entry

Regulatory Period		
Year ending (31-December)		
Days		
Project Year		
80		
81	Pipeline economic end date (year)	2063

4.6.2 Long-run demand model

The long-run demand model links to the long-run cost of service model to as follows. The rows in the 'Input-Output' tab highlighted orange in Figure 26 contain cells with green text that link to the tariff output from the long-run cost of service model.

Figure 26: Tariff Output from Long Run Cost of Service model

Input-Output	2026	2031	2036	2041	2046
Input					
Transport price (Capacity) per GJ	2.23	1.29	1.12	1.12	1.07
Transport price (Throughput) per GJ	0.11	0.12	0.15	0.19	0.18

The rows highlighted orange in Figure 27 contain cells with black text that link demand output from the long-run demand model to the cost-of-service model as described above.

Figure 27: Demand output link in cost-of-service model

1	Input-Output	2026	2031	2036	2041	2046	2051
191	Output						
198	Total Capacity		845	845	764	745	740
206	Total Throughput		597	484	374	378	365

The following inputs are input in the 'Input-Output tab pictured below:

Input-Output | SWIS GPG | CSBP Ammonia | Alumina | Carbon Price Model

- Scenario
- Wholesale Gas Price per GJ
- Carbon Price per tonne
- Scope 1,2 and 3 emissions for gas processing, transport, combustion and Haber-Bosch process.
- Technical feasibility for projects
- Project cost estimates
- Pinjarra Cogen assumptions
- Gas savings from electrification
- SWIS Carbon intensity
- Chemical prices and production costs
- Green hydrogen price assumptions per kg
- Shipper discount rates; and
- Initial Demand conditions

Of particular interest is the Scenario switch which allows switching between case 1, 2 and 3. This is shown in Figure 28.

Figure 28: The scenario switch

Input-Output	2026	2031
Input		
Case		3

4.6.2.1 SWIS/Gridcog Scheme Inputs

The remainder of the inputs derived from Carbon TP's SWIS modelling are entered into the SWIS GPG tab shown below.

Input-Output | SWIS GPG | CSBP Ammonia | Alumina | Carbon Price Model