Attachment 9.2

Assessment of the Economic Life of the DBNGP

January 2020

Dampier Bunbury Pipeline

1. Introduction

This attachment addresses the question of the economic life for the DBNGP system as a whole. This is not an issue that the ERA or ourselves have addressed previously. However, we believe that changes to the energy sector require a change in the approach to considering asset lives. In this attachment we outline our reasoning associated with this and the way in which we have calculated the economic life of the system as a whole. The energy sector as a whole is undergoing a rapid and fundamental transformation. While the costs of renewable energy remain (only just) more expensive than natural gas for power generation, and hydrogen is more expensive than natural gas for other uses like heat and chemical processes, the costs of these substitutes are falling rapidly.

Moreover, distributed technologies themselves can be located close to end consumers and can operate at a variety of scales, thus competing directly with natural gas transported over long distances. Therefore, it is possible to see how in the near future these technologies will be able to replicate the services provided today by natural gas; introducing uncertainty about the economic life of the DBNGP.

In the past depreciation has focused on sub-classes of assets with each sub-class given the same asset life from one regulatory decision to the next with no explicit consideration given for the overall life of the pipeline system as a whole. As an example, the significant looping of the DBNGP which occurred in the early 2010's will not be fully depreciated until 2082. Further capital expenditure (capex) related to pipelines (asset life of 70 years) incurred during the current AA4 period will not be fully depreciated until 2090, but, if this remains the life for that class of asset, by the end of AA5, the last asset will depreciate to zero by 2095; and so on into the future.

We have therefore undertaken analysis to explicitly consider the likely economic life of the pipeline system of the DBNGP as a whole in light of the changes to the energy sector in Western Australia. We have then assessed how this should be reflected in the calculation of the depreciation schedule for AA5.

Specifically, section two summarises the evidence that has necessitated the assessment of the economic life of the DBNGP, with a focus on technological and policy drivers in the energy sector. In section three we explain the approach we use to turn information on technological and policy drivers in the energy sector into a response now (before it is too late to respond) and detail the analysis we have undertaken to determine the economic life of the DBNGP as a whole.

The analysis demonstrates that the current implied economic life of the DBNGP as a whole is too long, and that a life up to 2059 is more appropriate. The analysis also shows what this means in the real sense of how we compete with renewable energy in the future as we shift from a binding regulatory constraint to a competitive marketplace; the 2059 end date is not a declaration of when the pipeline will be switched off. Rather, it is a date to use in the ERA model which will allow the DBNGP to make the switch to a competitive market efficiently and at lowest cost to our customers.

In light of the outcome of the above analysis, section four explains the need to act now (as opposed to delaying future regulatory review periods).

Finally, section five demonstrates how our proposal is consistent with the National Gas Rules.

2. The changing energy landscape

Technological change in the renewable energy industry and policy change affecting the wider energy industry are rapidly and fundamentally changing the nature of the sector and the role of the DBNGP within it.

The DBNGP transports natural gas from the places where it naturally occurs to the places where it is in demand. This business model is already being challenged by changes underway in the energy sector which were not even contemplated back in AA1 when the economic lives of our assets were first set, and which were arguably only barely on the horizon at the start of AA4 when those lives were last considered by the ERA. These changes are associated with rapid reductions in cost within the renewable energy sector (including storage) and policy measures to encourage decarbonisation. These forces have arisen at an Australian and global level.

In this section we outline the forces impacting our proposal and the implications for natural gas and the DBNGP including:

- policy drivers of change in Australia and globally; and
- progress in renewable and distributed energy technologies driving change.

2.1. Policy drivers of change

During the period when the DBP AA4 proposal was being submitted, assessed and approved (2014 to 2016), climate change policy in Australia was undergoing a period of significant uncertainty. The *Clean Energy Act* was repealed in 2014, completely removing the Commonwealth price on carbon which had been in place for two years from 2012-13 to 2013-2014. Furthermore, efforts to achieve an international agreement on climate change were floundering with the Paris Agreement on Climate Change not reached until December 2016. At a Commonwealth and state-level the only commitment to emissions reductions at the time was the Commonwealth commitment to reduce emissions by -5% on 2000 levels by 2020.

Since that time there is significantly more certainty as to the direction of change with global, national and state level commitments to reducing emissions rapidly.

The Paris Agreement committed all signatories, including Australia, to limit global temperature increases to well below 2°C and preferably limiting the increase to 1.5°C.

In Australia a number of policies are of particular importance in achieving this commitment:

- The Western Australian Government has adopted a commitment to achieving net zero emissions by 2050, and as of October 2019, every state and territory government has a commitment to achieving net zero emissions by 2050 or sooner.
- The Commonwealth has committed to reducing emissions by - 26-28% below 2000 levels by 2030.
- The Emissions Reduction Fund Safeguard Mechanism commenced operation in 2016, imposing emission baselines on designated large facilities with annual emissions over 100,000 tonnes. In Western Australia, the Safeguard Mechanism imposes a limit on the emissions of 119 facilities, including the majority of DBP shippers (and the DBNGP itself).
- The Commonwealth Renewable Energy Target is set to achieve 20 per cent renewable electricity by 2020, including a significant sum of renewable electricity generation in Western Australia.

- The Western Australian Government is currently considering further options for the State Climate Policy. The outcomes of this process are expected to be released in 2020.

In the short term, as a result of these policies, natural gas is likely to see relatively unchanged demand or potentially a small increase for a period of time as policy and asset owners shift away from coal for electricity generation. This is evident in our forecast of demand (Chapter 11), with an uptick in demand expected from 2023 with the retirement of coal-fired power at Muja. However, over the longer term, gas demand is likely to decrease as reflected in our forecasts; if the Western Australian Government meets its 2050 target, for example, our economic life out to 2059 is likely to be too long.

Over the longer term, tightening emissions standards will begin to affect natural gas too. While the changes that will take place in the energy sector remain uncertain, the direction of policy is clear. Governments of all persuasions in Australia are committed to reducing emissions in line with, or beyond, international commitments and expectations. The long term direction of policymakers is towards a tightening of emission standards.

To an even greater extent, it is policy change in other jurisdictions that matters, because WA is relatively small and a destination, not originator, for technological innovation. For example, if California or Germany mandate emissions standards, their markets being relatively large, firms there and across the globe will respond with innovation to meet their requirements. However, having developed new products, they will then seek to market them globally, including in Western Australia.

The response to this policy framework is very rapid technological change. Specifically the rapid adoption and deployment of renewable substitutes for natural gas; chiefly wind, solar, storage and green hydrogen. While government policies in Western Australia and at the Commonwealth level are driving the deployment of these technologies to some extent, action taken elsewhere has an even more significant effect in lowering their costs and improving their viability in Australia.

2.2. Renewable and distributed energy technologies as drivers of change

Renewable and distributed energy technologies (hereon in simply renewable technologies), can increasingly be considered substitutes for natural gas for two reasons: rapidly reducing costs and their potential for distributed application.

Unlike other rival energy sources to gas like oil or hydro-power,[1] renewable technologies can be placed anywhere there is access to wind, sunshine and water, and they can be produced at a variety of scales. This is significant for natural gas pipelines as it creates a competitive substitute at the source of demand.

[1] Nuclear power sits somewhere between oil, gas and hydro-power on the one hand and renewables on the other. Before a plant is built, it can potentially be built almost anywhere, but because the scale is so large, it will need to be built to maximise locational advantage in a very large market, necessitating a lot of transmission infrastructure. By contrast, renewables can be built at very small scales, and be distributed throughout a market.

When combined with various storage options, renewable technologies affect the DBNGP in three primary ways:

- wind, solar and storage as a substitute for natural gas in electricity generation;
- hydrogen acting as substitute for natural gas in industrial and mineral-processing including for heat and as a feedstock; and
- electrification and hydrogen as a substitute for natural gas used directly in residential and commercial applications (eg, heating, hot water, cooking).

As costs continue to decline, all of these substitutes have the potential to reduce demand for gas transportation and storage services on the DBNGP.

This section will outline:

- the economics of distributed generation and the market power of pipelines;
- the rapid cost reductions achieved to date and the implications for electricity and gas markets to date;
- the implications for the DBNGP to date; and
- the potential for future cost reductions.

2.2.1. Economics of distributed energy

Renewable energy technologies are inherently distributable (they can be placed anywhere there is sufficient sun or wind) and can operate at a variety of scales (from residential rooftops to utility scale). It is possible to see now, in the trends emerging in the marketplace, a future where these distributed renewable technologies replicate the energy services of natural gas at a lower price and in a competitive market.

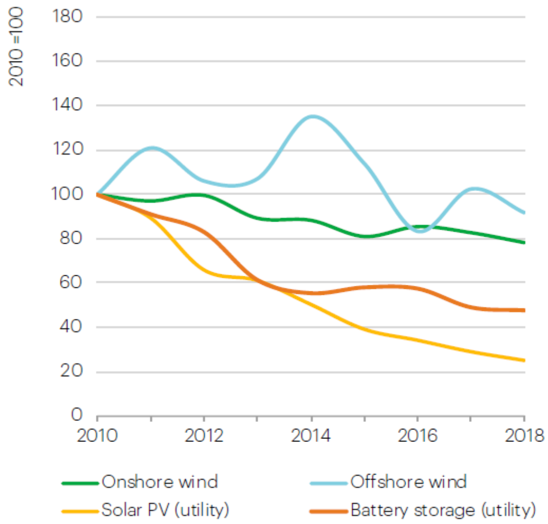
Once this future arrives, it will be the forces of competition from renewable energy and not regulation which influences our pricing and the services we are able to offer our customers.

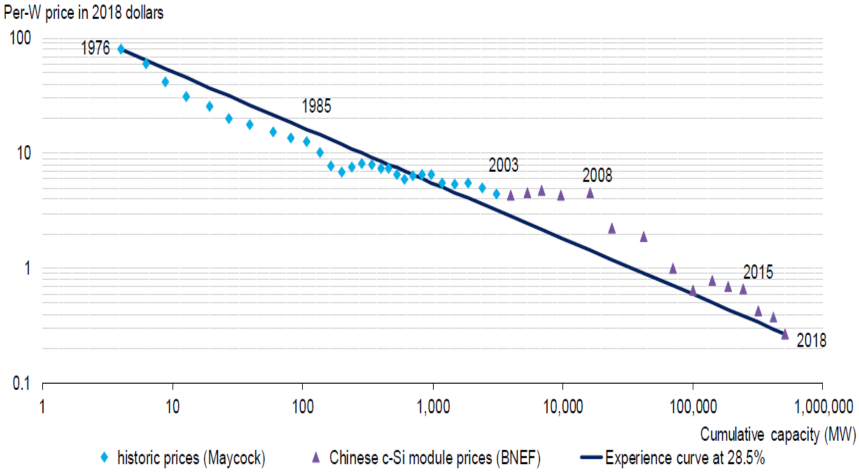
In particular, although hydrogen may theoretically be transported one day on the DBNGP, the economics of hydrogen are fundamentally different from those of natural gas because it too, just like wind and solar, is a distributable technology. This means that, absent of regulatory constraints, if the DBNGP transports hydrogen it becomes simply a method of arbitraging differences in sunlight and wind at the north and south of the pipeline.

At present, with high production costs for hydrogen, this arbitrage opportunity is larger than the regulatory tariff. However, as hydrogen production costs fall on average through time with scale and technological learning, the arbitrage opportunity will narrow substantially, to the point where it is smaller than a building block regulatory tariff. Thus, by the time that hydrogen makes sense as a fuel source for our shippers, that same low production cost will mean that regulation is no longer the binding constraint.

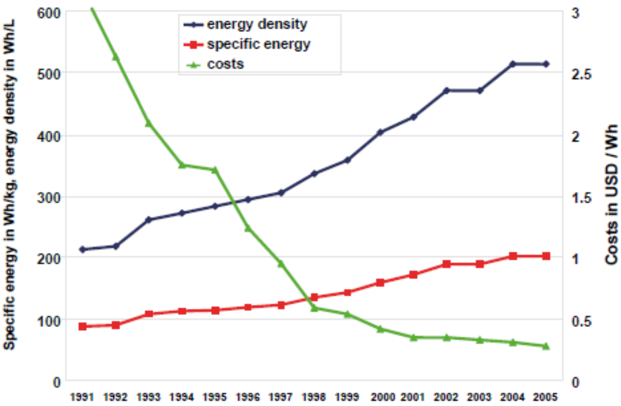
2.2.2. Cost reductions to date

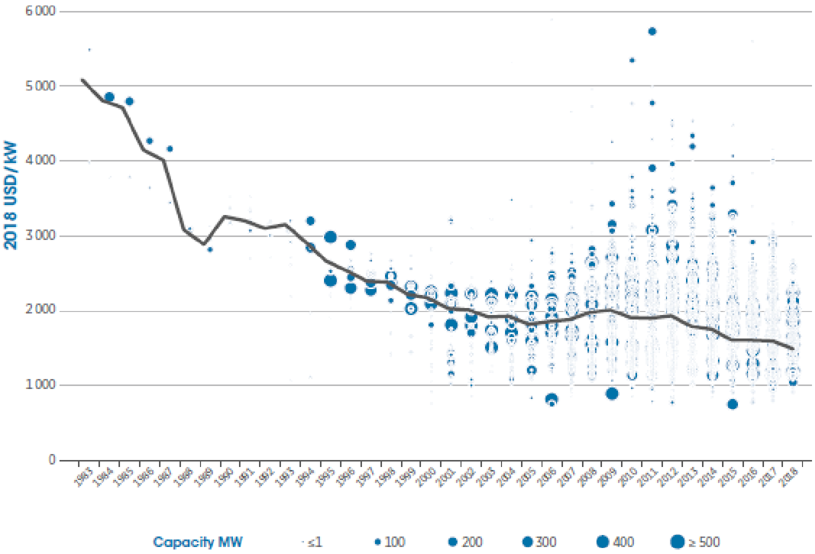
The cost of various renewable power options has been declining markedly in recent decades as shown in Figure 1.Figure 1: Declining





renewable costs

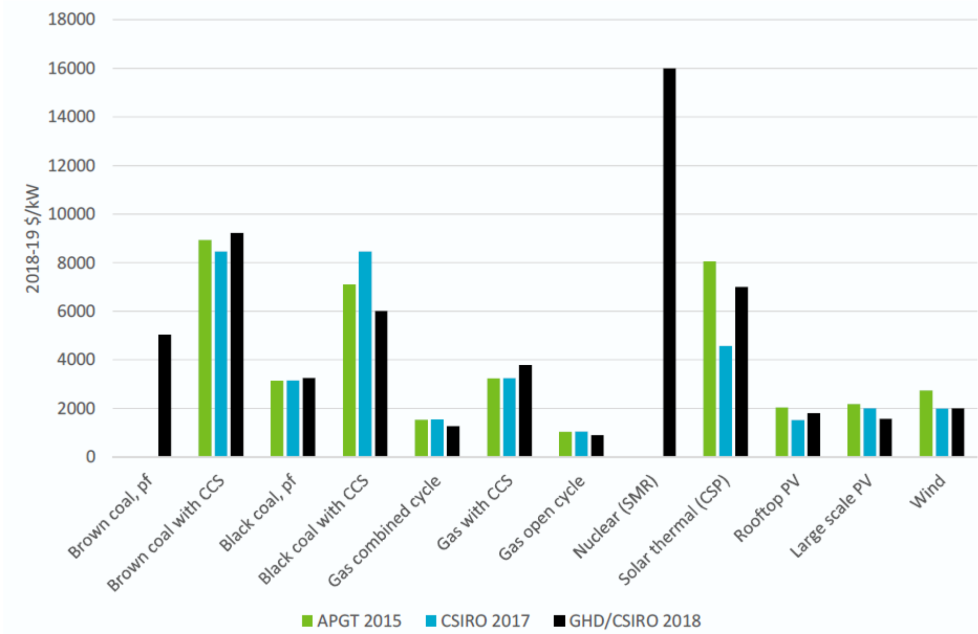




Note –clockwise from top left: Global investment costs index for renewables (from International Energy Agency, 2019, World Energy Investment 2019, available from www.iea.org/wei2019), long run declines in wind costs (from International Renewable Energy Agency, 2019, Renewable Power Generation Costs in 2018, available from https://www.irena.org/publications/2019/May/Renewable-power-generation-costs-in-2018), long run declines in US solar costs on logarithmic scale (from Business Council for Sustainable Energy, 2019, 2019 Sustainable Energy in America Factbook, available from https://www.bcse.org/factbook/), and long run battery energy density and costs (from International Renewable Energy Agency 2017, Electricity Storage and Renewables: Costs and markets to 2030, available from https://www.irena.org/publications/2017/Oct/Electricity-storage-and-renewables-costs-and-markets

The decreases in price have meant that renewables are now very close to traditional fossil fuels in cost and, in many cases, actually cheaper. This is shown in Figure 2, from a recent paper by the CSIRO for AEMO.

Figure 2: CSIRO comparison of different technology costs

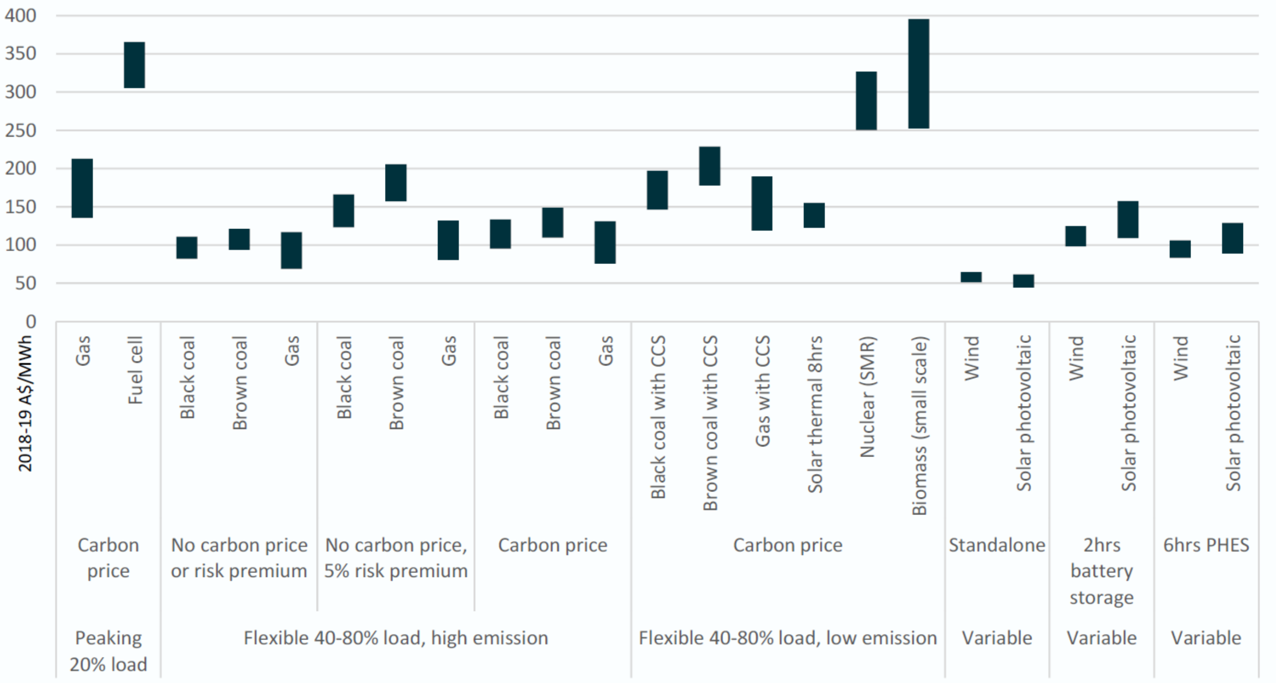


Source: CSIRO, 2018, GenCost 2018: Updated projections of electricity generation technology costs for AEMO, December 2018, p5, available from https://publications.csiro.au/publications/#publication/PIcsiro:EP189502

CSIRO have also looked at combinations of systems providing roughly comparable reliability. For renewables, they examine battery or pumped hydro storage if the system includes 50-75% renewables (2 hours storage) or 80-90% renewables (6 hours storage). The results of this analysis as a projection for 2020, are shown in Figure 3 below.[2] Note that renewables plus pumped hydro is already comparable to gas without a carbon price, whilst renewables plus batteries sit just above.

[2] The results are similar to those published by Lazard (see, for example, https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2018/) and also US results published by the Business Council for Sustainable Energy in the US (see p38 of their 2019 Factbook, available from https://www.bcse.org/factbook/)

Figure 3: CSIRO comparison of different system costs - 2020



Source: CSIRO, 2018, Ibid, p28

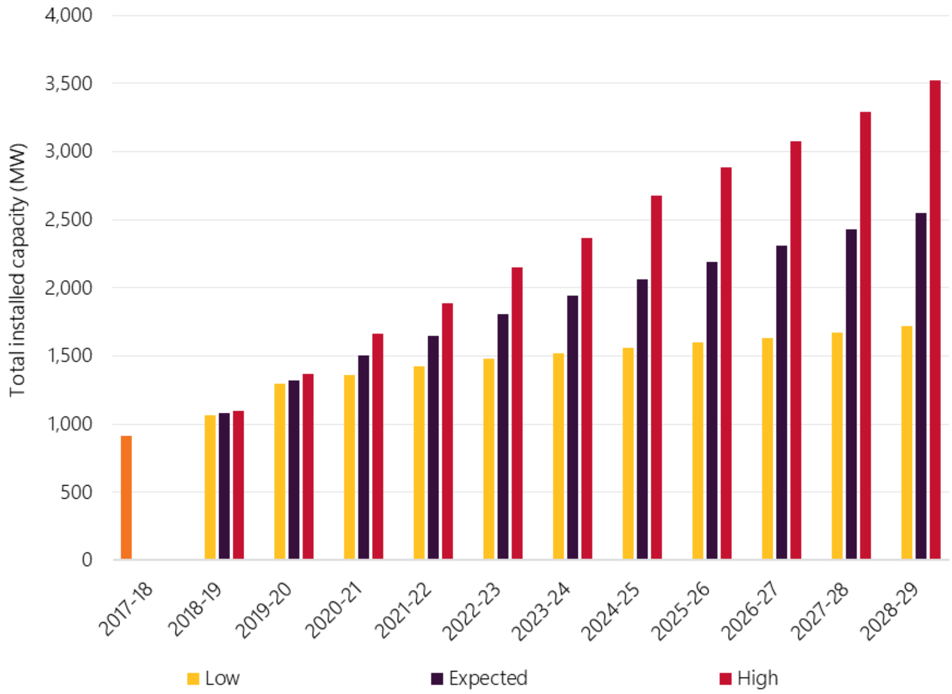
As the costs of renewables have come closer to the cost of conventional fuels, their prevalence in the generation mix has expanded.

Figure 4, Figure 5 and Figure 6 show this for Western Australia and Australia as a whole. In WA, behind the meter solar, currently with around 1000 MW of capacity is projected to be more than twice as large by the end of the next decade. Additionally, AEMO is projecting 980 MW of grid-scale wind, 250MW of grid-scale wind and solar and 150MW of grid-scale solar to enter the SWIS by 2021.[3] By comparison, there is 5789 MW of generation capacity in the SWIS at present, 513 of which is renewable power, and AMEO is forecasting around 3800 MW of peak demand through the course of the 2020s.[4] In Australia renewable electricity generation reaches 16% of the total in 2017-18. While in Western Australia the renewable proportion reached 15% by the spring of 2019 (according to the most recent data from AEMO; the average percentage for 2019 is 13%) of the total with almost no state-specific policy incentives in place and with an isolated grid. In South Australia, with stronger policies and a connection to the NEM to manage variability, the renewable proportion is close to 50% in 2017/18.

[3] Source: AEMO, 2019 Electricity Statement of Opportunities, June 2019, figure 4, available from https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM/Planning-and-forecasting/WEM-Electricity-Statement-of-Opportunities

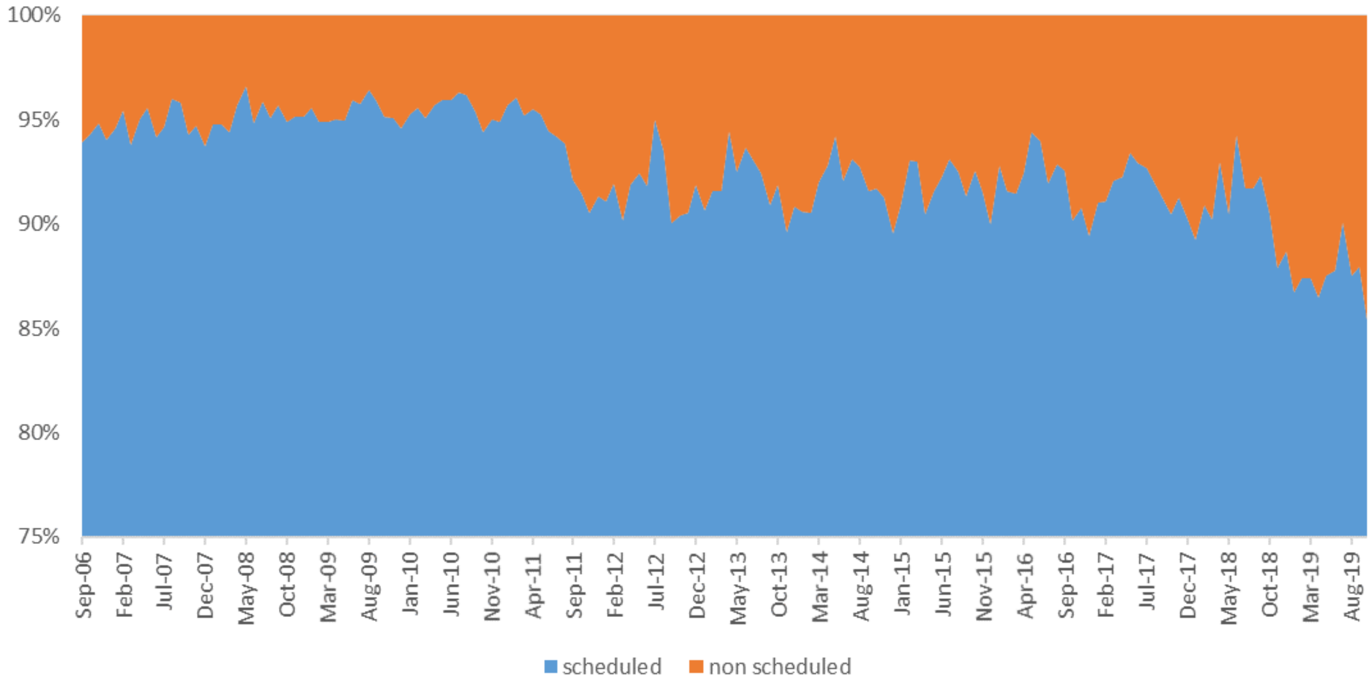
[4] Current generation capacity from AEMO website (https://www.aemo.com.au/Electricity/Wholesale-Electricity-Market-WEM) and forecasts are from the ESOO p5. Note that peak demand is fairly stable through the 2020s due to rising penetration of behind the meter PV.

Figure 4: Behind the meter solar PV penetration - SWIS



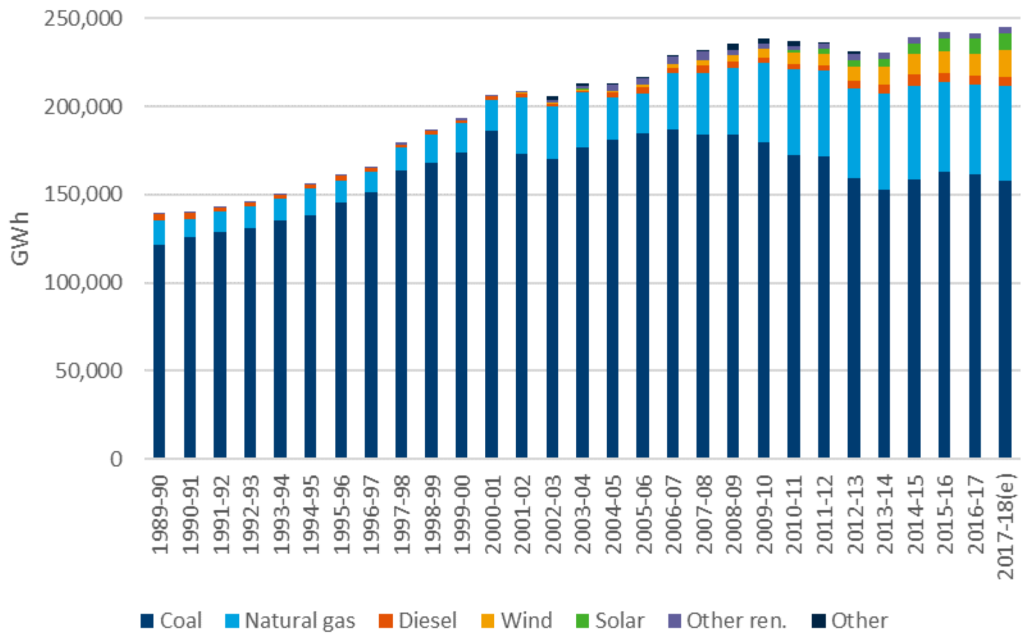
Source: AEMO 2019 Electricity Statement of Opportunities, June 2019, Figure 8

Figure 5: WA SWIS Scheduled and non-scheduled loads



Source: Load Summary data, available from http://data.wa.aemo.com.au/#load-summary (note that scheduled load is coal gas and distillate and unscheduled load is wind, (utility scale) solar and biomass

Figure 6: Electricity generation in Australia – 1989-90 to 2017-18



Source: Australian Energy Statistics Table O, available from https://www.energy.gov.au/publications/australian-energy-statistics-table-o-electricity-generation-fuel-type-2017-18-and-2018

The significant increases in new renewable electricity capacity and in turn output follow significant reductions in cost in recent years, for solar in particular, after decades of more gradual progress.

This is an important consideration; a ten percent drop in the price of solar circa 1990 would have made almost no difference to its market position vis-à-vis fossil fuels. However, a ten percent drop when solar is sitting just above fossil fuel (as with more recent history) is likely to have a very large effect on demand if it moves solar from being slightly more expensive to slightly cheaper than fossil fuels. This kind of non-linear relationship between cost and demand is an important part of the picture for the uptake of renewable energy sources.

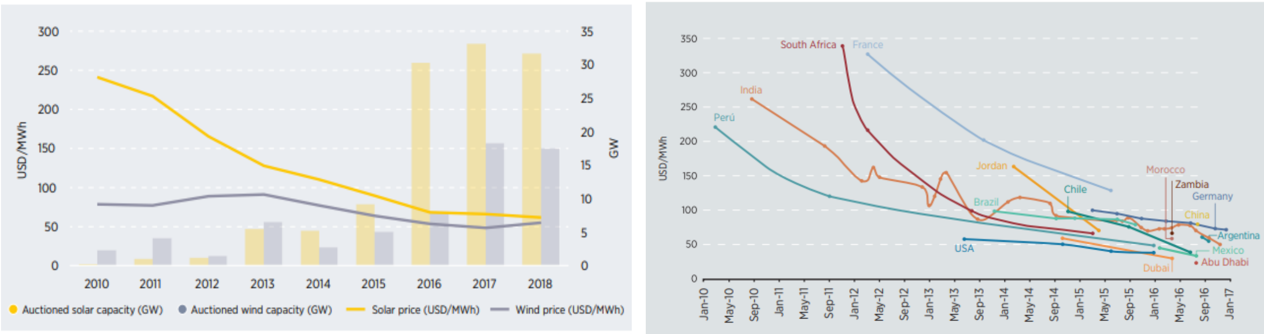
The impact of renewables is being felt in a wide range of sectors, not just electricity generation for grid consumption. Renewable technologies are increasingly important as energy sources for industrial and mining businesses; traditionally our most important customers from the perspectives of the volumes of gas used. Recent projects include for:

- Zinc production in Queensland (125 MW solar).[5]
- Steel production in South Australia (1GW solar).[6]
- Iron ore production in Western Australia (60MW solar).[7]

[5] Seehttps://reneweconomy.com.au/no-need-for-new-coal-sun-metals-formally-opens-solar-farm-in-george-town-26798/
[6] See https://reneweconomy.com.au/gupta-launches-1gw-renewable-plan-at-cultana-solar-project-67819/
[7] See https://www.fmgl.com.au/docs/default-source/announcements/1986209.pdf

More broadly, auctions for renewable electricity (which secure the lowest cost renewable electricity for a buyer of a specified quantity of energy) have seen prices fall and scale increase, as shown in Table 1 below. As a point of reference, the average wholesale price of power in the National Electricity Market during 2018 ranged from between $80 and $110 per MWh, significantly above the price achieved in many auctions.[8] This experience is also evident in international outcomes as seen in Figure 7.

Figure 7: Trends in global renewable power auctions (IRENA)



Sources: LHS: IRENA, 2019, Renewable Energy Auctions: Status and trends beyond price, p7, available from https://www.irena.org/publications/2019/Jun/Renewable-energy-auctions-Status-and-trends-beyond-price. RHS: IRENA, 2017, Renewable Energy Auctions: Analysing 2016, p20, available from https://www.irena.org/publications/2017/Jun/Renewable-Energy-Auctions-Analysing-2016

This kind of activity is already affecting demand for gas transport on the DBNGP. In particular, it is making demand more volatile as gas demand for electricity on the DBNGP respond to the peaks and troughs of renewable generation. When the wind is blowing and the sun is shining, demand for gas for electricity generation drops quite significantly, and peaks whenever renewables (we have relatively little storage in WA at present) cannot meet demand.

[8] See https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Data-dashboard#average-price-table

Table 1: Renewable energy auction results

Wind

Auction/scheme	Location	Capacity (MW)	Start date	Contract length (years)	Quote price ($AU/MWh)	Constant price ($AU/MWh
ACT Wind Auction 1, 2015	Coonooer Bridge Wind Farm, VIC	19.40	Mar-16	20	$81.50	$62
ACT Wind Auction 1, 2015	Ararat Wind Farm, VIC	80.5	Feb-17	20	$87.00	$67
ACT Wind Auction 1, 2015	Hornsdale Wind Farm, SA	100	Jan-17	20	$92.00	$70
ACT Wind Auction 2, 2015	Hornsdale Wind Farm, Stage 2, SA	100	Dec-18	20	$77.00	$59
ACT Wind Auction 2, 2016	Sapphire Wind Farm 1, NSW	100	Apr-18	20	$89.10	$68
ACT Next Generation Renewables, 2016	Hornsdale Wind Farm, Stage 3, SA	109	Oct-19	20	$73.00	$56
ACT Next Geneneration Renewables, 2016	Crookwell 2 Wind Farm, NSW	91	Sep-18	20	$86.60	$66
AGL, 2017	Silverton Wind Farm, NSW	200	mid-2018	5	$65.00	$61
Origin Energy, 2017	Stockyard Hill Wind Farm, VIC	530	2019	12	$50-60	$43-51

Solar

Auction/scheme	Location	Capacity (MW)	Start date	Contract length (years)	Quote price ($AU/MWh)	Constant price ($AU/MWh
ACT Solar Auction 1, 2012	Royalla Solar Farm, ACT	20	Sep-14	20	$178	$136
ACT Solar Auction 1, 2013	Mugga Lane Solar Park, ACT	13	Mar-17	20	$186	$143
ACT Solar Auction 1, 2013	Williamsdale, ACT	7	~2017	20	$186	$143
WA government, solar PV, 2012	Greenough Solar Farm, WA	10	Oct-12	-	$240 – LCOE	$240 (LCOE)
ARENA/NSW Government, solar PV	Nyngan Solar Farm, NSW	102	Jul-15	-	$180 (LCOE)	$180 (LCOE)
ARENA/NSW Government, solar PV	Broken Hill, NSW	53	Jan-16	-	$180 (LCOE)	$180 (LCOE)
SA government, solar thermal, 2017	Aurura solar thermal power plant, Port Augusta, WA	150	~2020	20	$75-78	$57-60

Source: https://theconversation.com/renewables-will-be-cheaper-than-coal-in-the-future-here-are-the-numbers-84433

2.2.3. Further cost reductions on the horizon

The sections above have outlined how progress in renewable energy technologies is already having an effect in real markets, and indeed for the DBNGP. The evidence that this transformation will continue is equally strong.

There are a large number of predictions about this available within Australia and internationally, and each year tends to produce a new range of forecasts showing lower projected costs than the previous year.

An important point to note in considering forecasts of the future is that most forecasts tend to be relatively smooth in nature; our own is no exception in this respect. However, actual change can be anything but smooth; the World Economic Forum suggests some caution in this respect because change, when it comes, tends to be highly non-linear in nature and subject to tipping points as substitutes move from being just above to just below the relevant price point.[9]

Although we have not taken this kind of non-linear approach to our own modelling, we believe it is a relevant consideration for our own industry over the timeframes we are looking at, and we suspect it renders many of the forecasts below, including our own, relatively conservative.

Within Australia, Figure 8 shows recent projections of renewable electricity generation costs to 2050 from CSIRO. In considering these forecasts it is important to note that they include a carbon price consistent with a "4-degree" increase in global temperatures; the Paris agreement commits signatories, including Australia, to aim for only 1.5^{o}C of warming, while state government commitments to achieve net zero emissions by 2050, including in Western Australia, imply much higher carbon prices.

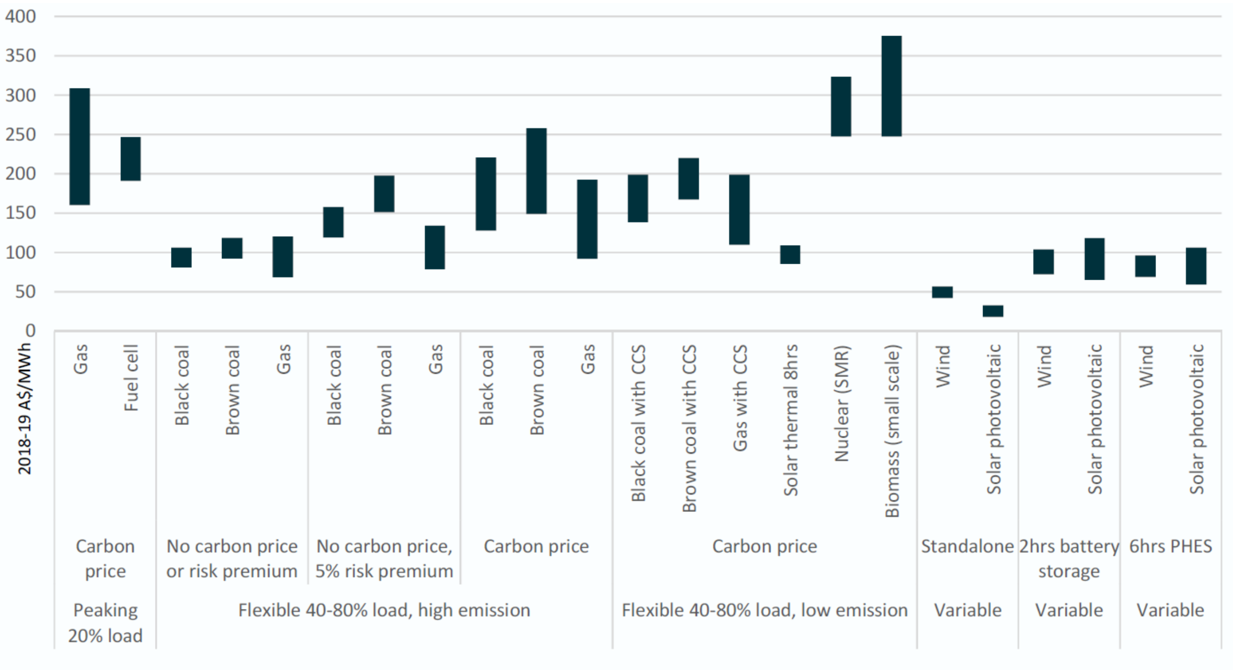
[9] See World Economic Forum, 2019, *The Speed of the Energy Transition: Gradual or Rapid Change?*, September 2019, available from https://www.weforum.org/whitepapers/the-speed-of-the-energy-transition

Figure 8: Projections of renewable electricity generation capital costs to 2050 (clockwise from top left: solar thermal (6-hours storage); large-scale solar; wind; battery)

Source: CSIRO (2018) Ibid, pp16-20.

This gives rise to projected "system costs", produced on the same basis as Figure 3 above, shown in Figure 9 below. By 2050 renewables plus storage is clearly the cheapest option.[10] As a point of comparison, ACIL Allen's expert report, provided in Attachment 9.3, suggests the cost of renewables (wind + solar + battery) will be between $72 and $135 per MWh in 2050, with $110/MWh in the central scenario; towards the upper end of the range suggested by CSIRO (and is, as such, another conservative assumption by ACIL Allen).

Figure 9: Forecast of different system costs - 2050



Source: CSIRO (2018) Ibid, p31

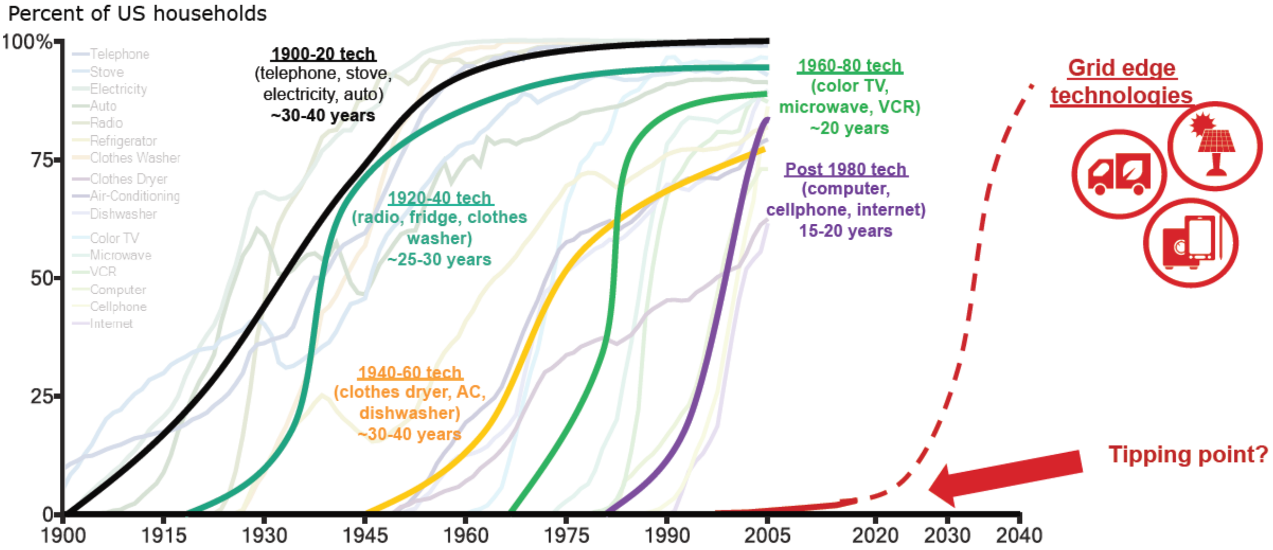
Globally the same trend, albeit more advanced, is obvious. We highlight two prominent forecasts of the global trend here.

The first, from the World Economic Forum in Figure 10, compares the amount of time it has taken various technologies to reach high levels of penetration amongst consumers and use this to explore how "grid edge technologies" (renewables plus storage in a distributed grid) might take to reach the same high level of penetration. It suggests we are on the cusp of a tipping point where the deployment of renewable technologies will increase even more rapidly.

Once such a high level of penetration is reached, the effect on demand for gas transportation services is likely to be profound, as these technologies represent direct competition (at least in electricity production) for a large part of the gas transportation market. Their conclusions are summarised in Figure 10 and highlight the 2030s as a key decade for transition.

[10] Note that the CSIRO is far from the most bullish on cost relativities between different sources of electricity. *Sustainable Energy Now* (see https://www.sen.asn.au/clean_energy_wa_study) and Lu, Blakers and Stocks (see https://www.sciencedirect.com/science/article/pii/S0360544217300774) believe that the SWIS could be converted largely to renewable supply for only a relatively small premium over the prevailing fossil-fuel costs by 2030

Figure 10: Forecast of penetration of grid edge technologies.

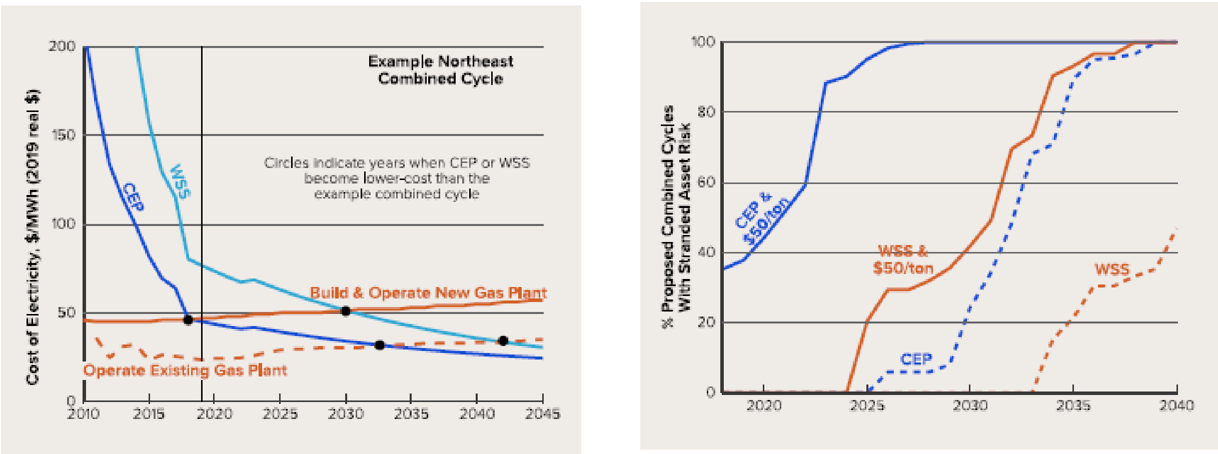


Source: World Economic Forum, 2017, The Future of Electricity: New Technologies Transforming the Grid Edge, p6, March 2017, available from *https://www.weforum.org/reports/the-future-of-electricity-new-technologies-transforming-the-grid-edge*

The second international forecast, from the Rocky Mountain Institute in the US models the impact of a "clean energy portfolio" (CEP) including wind, solar, storage, demand response and efficiency gains, and compares this optimised version of renewable costs with gas generation.[11] The results shown in Figure 11 demonstrate that new gas-fired generation is barely cost-competitive today with the CEP in the US (calling into question $70 billion of such investment proposed in the US through to the mid-2020s). Existing gas-fired generation (which must recover only its operating costs to go on operating) is unlikely to be competitive by the mid-2030s.

[11] See Rocky Mountain Institute, 2019, *The Growing Market for Clean Energy Portfolios*, available from https://rmi.org/insight/clean-energy-portfolios-pipelines-and-plants/

Figure 11: Optimised "clean energy portfolios" compared to gas-fired power generation.



Source: Rocky Mountain Institute, 2019, The Growing Market for Clean Energy Portfolios, pp 34 and 45, available from https://rmi.org/insight/clean-energy-portfolios-pipelines-and-plants/. The left figure compares costs and the right figure shows the proportion of generating assets predicted to become stranded. In each, "WWS" stands for "wind solar and storage" and represents the raw costs of renewables that have not been optimised into a portfolio along with efficiency gains and demand management. The dotted lines on the right-hand graph show outcomes without any assumed carbon price.

In a companion piece, the Rocky Mountain Institute also track how the impact of renewables on gas-fired generation is likely to impact US gas pipelines. This analysis suggest drops in throughput of between 20% and 60% for US gas pipelines, leading to price increases of between 30% to 140% in delivered gas prices as the fixed pipeline costs are spread over fewer transported units of gas.[12] As can be seen in Chapter 9 of the Final Plan, our proposal for amended depreciation results in a much smaller impact on prices today, highlighting the benefits of acting sooner.

The Rocky Mountain Institute's work serves to highlight that we face risk which may exceed even the most aggressive scenarios considered in this paper.

For example, Linn and McCormack have shown that, over the past few decades in the US, coal plants have been retired not because of environmental policy, but because gas prices (brought about by technological change in fracking) and electricity consumption have reduced.[13] The RMI work suggests that renewables may do the same thing to gas in the coming decades, as its costs reduce.

The evidence presented above is one of the motivations for our decision to revisit the question of the economic life in the context of the DBP and, in particular, to consider the life of the whole system rather than just of a sub-classes of assets. We describe how we do so in the following section.

[12] See Rocky Mountain Institute, 2019, *Prospects for Gas Pipelines in the Era of Clean Energy*, available from https://rmi.org/insight/clean-energy-portfolios-pipelines-and-plants/

3. The Economic Life of the DBP

Given the recent and evolving changes to technology in the renewable energy sector and emissions policy described above, we consider it appropriate to assess the economic life of the pipeline as whole, rather than looking solely at sub-classes of assets. Following that analysis, it is then appropriate to consider how any required change is given affect through the calculation of depreciation. This gives rise to the notion of a maximum life for individual asset categories, representative of the likely economic life of the system as a whole.

In this section we describe the analytic method used to determine the economic life of the system as a whole. This is the WOOPS model of Crew and Kleindorfer described below. We also describe the results of our analysis.

However, before describing this model it is important to note that our approach to dealing with future economic forces involves considering the depreciation building block and that this is not, in principle, the only way in which we could have addressed that risk. Other ways in which it could be addressed are covered in Box 1, which also makes it clear why we believe that the risk is most appropriately addressed using depreciation.

Box 1: Approaches to meeting the risk of future competition

We have decided to use an approach based upon depreciation to deal with the risks associated with future competition, but it is not the only approach we could have chosen. Had we chosen a different approach, we would need to asses that against the NGR. There are, in principle, three things the regulator could do:

- Change the WACC to allow for the increase in risk.[14]
- Allow an opex item that reflects the cost of insuring against the potential risk of asset stranding.
- Make appropriate changes to depreciation.

The first of these options is, we consider, not appropriate. The WACC is intended to provide an appropriate return for our debt and equity investors. As the ERA (and AER) have pointed out many times, the equity allowance is intended to cover the systematic risk borne by our equity investors. The ERA has suggested that this kind of asset stranding is not a systematic risk.[15] Thus, it would not be appropriate for the ERA to increase our equity allowance to cover this risk.

Debt, by its nature, does have an element of asset specificity. However, the way the ERA calculates our debt allowance, by considering a wide set of bonds with a similar credit rating, will not pick up the specific risk of our bonds because most bonds with that credit rating do not face this specific risk. Conceptually, an allowance could be added, but we do not see how.

We are also opposed to the use of WACC for another reason; it raises the cost to consumers and does so into the future. In the unlikely event that the ERA (or anyone else) could correctly quantify the risk, we would still be in a position of our consumers paying more for their gas transport than is the case at present, and doing so over the life of the asset. This is not the best solution to the problem.

In respect of adding an insurance premium to our opex, we are not intrinsically opposed to this. We are not aware of a specific insurance product we could purchase for this purpose, but we can see, at least in principle, how one might determine a self-insurance amount. However, we do not see how this could be done in practice with a great deal of rigour, and we have thus not put it forward. Also, as with the increase in WACC, it increases costs to consumers throughout the life of the asset, which again makes it a sub-optimal solution to the problem, even if it could be adequately quantified.

Making appropriate changes to depreciation provides for no additional cost recovery, and merely results in a change in the timing of when our invested capital is returns. Also, the competitive threats we are likely to face in the future have a direct consequence on our economic life, and depreciation is tied specifically to our economic life. A more detailed assessment of our approach against the requirements of the NGR is contained in Section 5.

[14] The CSIRO (2018), p24 note the practice of adding 5% to the WACC of coal-fired generation assets as a proxy for future asset stranding risks. Given that gas has less carbon intensity, and coal is likely to be stranded first, this would seem a little high at present, but would perhaps not be out of place in the future, when gas faces the same asset stranding risks that coal now faces.

[15] See, for example, Economic Regulation Authority, 2018, *Final Rate of Return Guidelines*, [196] and *Final Gas Rate of Return Guidelines Explanatory Statement* [292], December 2018, available from https://www.erawa.com.au/gas/gas-access/guidelines/gas-rate-of-return-guidelines. The latter paragraph cited specifically references solar power and

3.1. The conceptual framework of analysis

In this section we provide an overview of our approach to determining the economic life, making use of relevant information about the future growth of technology in the renewable sector, and emissions policy. The section is split into two parts:

- an overview of the theoretical "WOOPS" framework within which the issue is analysed;
- an overview of the model based on this framework and applied for the DBNGP.

3.1.1. The WOOPS framework

Our aim is to develop an approach which allows us to meet the competitive future which will eventuate once renewable energy reaches cost parity with natural gas without an "overhang" of assets which were efficiently incurred under a regulated environment but which might not be supported in a competitive marketplace and would thus be stranded. This is done within the modelling framework the ERA uses by choosing the economic life of our assets, which then drives how fast we recover our capital.

It is worth pointing out that, by choosing an economic life in a regulatory model, we are not necessarily suggesting that the pipeline will be "switched off" at that point in time. Rather, we are suggesting that the nature of our industry will change, and we are aiming to be able to recover our efficient investment (and no more) over the two regimes it will face; the regulatory regime of the present when the ERA sets our price and the competitive regime of the future when the price of substitutes is the binding constraint.

This exact issue is treated formally in a seminal paper by Crew and Kleindorfer, and we make use of their framework in our work.[16] The paper is part of a literature in economics on optimal schedules for depreciation, drawing much of its impetus from an earlier paper by Schmalensee.[17] In that paper, Schmalensee points out that, provided regulators set the allowed return on capital equal to the firm's actual cost of capital (that is, the rate of return guidelines are correct), then virtually any depreciation schedule will produce efficient prices.

Crew and Kleindorfer point out, however, that, amongst the many simplifying assumptions Schmalensee makes is a lack of technological progress, particularly amongst potential competitors to the regulatory service. Adopting an assumption of such technological progress makes a significant difference, as Daryl Biggar at the ACCC points out:[18]

> *A further piece of the jigsaw on depreciation/amortisation was suggested by Crew and Kleindorfer. This paper focused on the possibility of an external constraint on the ability of the firm to recover its costs in the future.*

---

competitive bypass (the ERA makes essentially the same arguments we make above), indicating quite clearly that these risks are not compensated in our allowed return on equity.

[16] 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

[17] See Schmalensee, R, 1989, "An Expository Note on Depreciation and Profitability under Rate-of-Return Regulation", *Journal of Regulatory Economics*, 1(3), 1989, 293-98. A later paper by Burness and Patrick (Burness , HS and Patrcik RH, 1992, "Optimal Depreciation Payments to Capital and Natural Monopoly Regulation", *Journal of Regulatory Economics*, 4, 35-501992) points out that the consequences of an allowed rate of return that is too high is a desire by regulated firms to delay depreciation (so they can earn extra profits on their RAB for longer) whilst the consequences of an allowed rate of return that is too low is a desire to depreciate more quickly, so that capital in the RAB can be deployed elsewhere to earn better returns for the risk level involved.

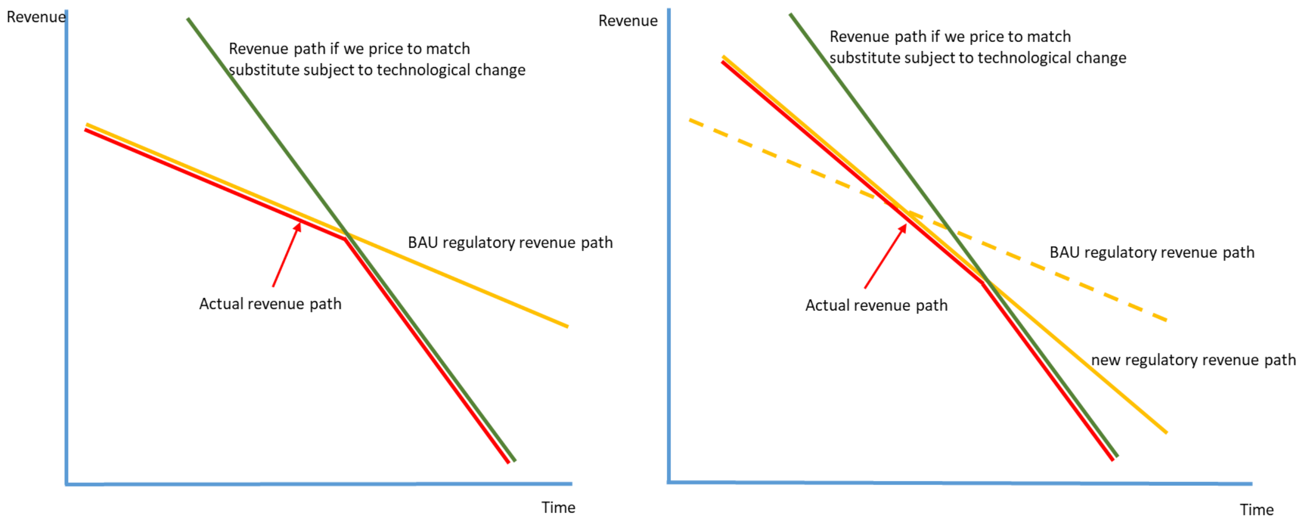
[18] See Biggar, D, 2011, *The Fifty Most Important Papers in the Economics of Regulation*, ACCC/AER Working Paper No. 3, May 2011, p21

> *Greenwald noted that the regulatory asset base could not increase above the present value of the future revenue stream for an unregulated monopolist. In the Crew and Kleindorfer paper, the present value of the future revenue stream for the unregulated monopolist is declining exponentially over time, perhaps due to forces of competition or technological change. This places a declining upper limit on the path of the regulatory asset base over time. The result, unsurprisingly, is that front-loading of capital recovery is essential if the regulated firm is to remain viable.*
>
> *In essence, when the regulated firm will be constrained by other forces in how much it can recover in the future, the regulator must take this into account in the present, and allow the firm a higher rate of depreciation. This is the origin of the tilted annuity concept used by some regulatory authorities in telecommunications regulation. Crew and Kleindorfer point out that traditionally there has always been a sense among regulators and utilities that problems could be put right "at the next rate case". However, they emphasise that this is clearly not always true. If some other constraint – such as changes in demand or technology – prevents the regulated firm from earning a normal return in the future, the regulator must take that into account in its depreciation policy today.*

The WOOPS model provides a framework to show how depreciation should be increased today (by shortening regulatory economic lives) in order to ensure that, given the competitive environment which is forecast to exist in the future due to technological change, the regulatory pricing schedule up to the point that this competitive market emerges is capable, when combined with revenues expected to be earned in the competitive market, to deliver sufficient returns to meet the efficient costs of the relevant investment.

The WOOPs model can be expressed diagrammatically, as in Figure 12.

Figure 12: The WOOPS model diagrammatically



The left-hand figure shows a "business as usual" regulatory approach whereby the regulator ignores technological change. The yellow line (marked "BAU reg price path") shows the regulatory revenue which would result through a standard building block model. The green line shows the revenue we would earn if we priced to match a substitute subject to a declining price due to technological progress; wind, solar, storage and hydrogen.[19]

The price of such substitutes is high now, but it falls faster than the revenue path under regulation. The red kinked line shows the actual revenue which the regulated firm can earn at a given point in time; governed by the constraints of regulation initially, and then by the constraints of competitors. Beyond the point of intersection between the yellow and green lines, the regulatory price will no longer be the effective constraint because we can no longer earn the allowed regulatory revenue but must instead price to meet the competitive market or suffer a significant loss in demand.

The right-hand side shows the regulator responding to this situation by increasing depreciation (compare the dotted "BAU regulatory revenue path" with the solid "new regulatory revenue"); the slope of the price path allowed by the regulator has increased, and the intersection point between the yellow and green lines has moved outwards in time. This leaves the regulated firm able to compete with the substitute product for longer under the regulatory regime, and thus improves the chance that it will be able to recover its efficiently incurred investments.

Note that the maximum slope that regulators can give the yellow line is that of the green line; if the yellow line is steeper than the green line, then this implies that the price under regulation is higher than that provided by the competitor, and regulation ceases to bind. This, then, is what motivates an early increase in depreciation; the longer one waits after the potential for a change in the market becomes apparent, the less likely it will be that the regulator can create a yellow line with a lesser slope than the green line. Ultimately, and as discussed in Section 4, this is not in the long-run interest of consumers.

Crew and Kleindorfer formalise this by determining a Window Of Opportunity PaSt (WOOPS) point, which is essentially the last point in time a regulator can act before the yellow line will have a slope steeper than the green line (ie, where the price set by the regulator is above the substitute price). We are less interested in the WOOPS point per se, as we are more concerned about what the regulator can do now than we are about determining when it can do nothing. Thus, rather than making use of the whole paper and finding the WOOPS point, we rather make use of the framework employed by Crew and Kleindorfer to allow for a formal treatment of the problem of choosing a change in depreciation to match a future competitive challenge.

[19] Assuming a sufficiently low elasticity of demand that higher prices would not lead to less consumption; for the purposes of illustration, this figure does not include such demand response effects. Note also that the straight line is for illustration purposes; in reality costs in the competitive industry could follow any pathway, left and right of the intersection point, and the model shown in Equation 1 would still allow us to choose the "right" intersection point by choosing the "right" depreciation schedule whilst we (or rather, the regulator) can control prices under the regulatory regime.

In a simplified world where there are no operating expenses and no future capital expenses, our approach gives rise to the following equation which sits at the core of our model:[20]

$$Z = \int_0^M e^{-rt}\left[\frac{Z}{T-K} + s\left(Z - \frac{tZ}{T-K}\right)\right] dt + \int_M^T e^{-(r+\gamma)t} P_0 X dt \qquad \text{(Equation 1)}$$

In this equation:

- *Z* is the RAB at time zero (that is, now)
- *M* is the intersection of the green and yellow lines in Figure 12.
- *e* is the exponent, so we are considering continuous time for the NPV calculations.
- *r* is the actual cost of capital for the firm (with *s* the allowed return on capital; these are the same number in the model we use, and are just differentiated here for clarity).
- *T* is the overall life of the asset, and *t* is a given point of time in that asset life.
- *K* represents number of years one brings forward the end of the asset life.
- γ represents technological progress for the substitute. Note that, in the exponent, this will mean that the price for this alternative at any point in time (P_t) will be lower than the price right now (P_0), and the larger is γ, the lower is P_t.
- *X* is demand; for energy in this instance.

The first integral represents the NPV of revenues (via the exponent) under regulation; up to the point in time M. Here, there are two components to the regulatory revenue in the square bracket; depreciation (or the return of capital) and a return on capital. If K were zero (so the left hand side of Figure 12), then depreciation would be Z/T; simple straight line depreciation to the original end life for the asset. Where K is positive, subtracting it from T results in bringing forward the end of the economic life of the asset and thus increasing depreciation. T-K, then, is the end of the economic life the asset and (T-K) minus the current date will give you the economic life of the asset in question.

In our case, T could be set at 2090, which is the start of AA5 plus 70 years; the life of the longest-lived asset we have and thus a suitable starting point. K might be 30, which would imply that the economic life of the DBNGP as a whole would end in 2060. Since AA5 starts in 2020, this means maximum economic lives are 40 years.[21]

The return on capital is found by subtracting the depreciation which has happened up until each time period (tZ/(T-K)) from the initial RAB (Z), and then multiplying this by the WACC (s), which is exactly how this component of the building block model works. The first integral is therefore a simplified version of the building block model, with the ability to change depreciation.

The second integral represents revenues under competition, which is simply the price at each point in time (P_t, as it is predicted today via $e^{-(r+\gamma)t}P_0$; with the negative power indicating a declining price), multiplied by demand at that point in time. We sum the two integrals and check whether or not they add up to the RAB today, Z. In a sense, we are checking that the area under the kinked red line in Figure 12 is equal to the RAB, and we do this by altering K in order that M will change.

[20] For those following the Crew and Kleindorfer paper, this is an expanded version of their Equation 9, with its various components as defined in equations 5 through 8.

[21] Note that Crew and Kleindorfer have only one asset. We have eight classes of assets, and essentially, this means running equation 1 across all eight classes, and then summing the results, before comparing that sum to the overall investment. For six of the eight classes, K is set at zero, and for two, it is positive.

It is important to note that the two integrals are linked only at the point *M*; they are otherwise completely independent of each other. This has an important consequence in respect of NGR 89(1)(d); the prohibition of double-recovery. At a particular *M*, the model starts by calculating the revenue which might be expected under competition from that point in time onwards. It then calculates the amount of revenue available under the regulatory regime up until that point and compares the sum of both of these to the efficient investment cost. At *M*, the asset still has positive value; one way to think about it is that the current asset owner operates the asset until the intersection point *M* and then sells it to another asset owner who re-purposes it to use in the competitive marketplace. If that sale price is too high, then the owner under regulation is effectively double-recovering depreciation as capital is returned once by the regulator and again in the sale price. However, this will show up by the right hand side of Equation 1 being higher than the left-hand side and the regulator can solve that problem (now), by reducing the depreciation schedule (reducing K, or lengthening the asset life) such that the RAB at point *M* is no longer higher than the NPV of what is expected to be earned subsequently in the competitive marketplace.

Note that *K* is re-assessed at each regulatory submission. Thus, if it turns out to have been too small in the past it can be increased and if too large, decreased. The key point for shippers is that, because depreciation only occurs once for each asset, once the RAB is decreased, it stays smaller.

Note finally that, since we have opex and maintenance capex to consider,[22] which Crew and Kleindorfer do not, rather than Z just being the RAB, we include in our modelling (detailed in Section 3.2 below) the NPV of expected opex (which is recovered in each year of the model) and expected capex (which is depreciated). We are thus making an assumption that a new entrant is effectively coming in to run the pipeline in an efficient manner, and considering how much money needs to be set aside in order to do so.

Thus, in the modelling detailed in Section 3.2, for the K implied by an economic life ending in, say 2070 (so if T=2090, a K of 20), an investor may have a RAB of $3.34 billion in December 2020 and need to put aside around $2.25 billion to fund future opex and around $760 million to fund future maintenance capex (assuming in so doing that the funds put aside would earn the real WACC and thus be able to fund the relevant activities).[23] However, if said investor would only expect to earn just under $6 billion in actual revenues, in NPV terms, once the forces of competition had acted, this would leave the investor roughly $500 million short of the efficient costs to be incurred to run the pipeline. Such an investor would clearly not make the investment in the pipeline system.

In order to implement our modelling approach, we have relied upon an expert report from ACIL Allen. In that report, ACIL Allen describe how they have developed a model based upon Equation 1 above, parameterised the key variable of technological progress and taken into account other

[22] Although the pipeline has a defined end date, we still need to invest; for example, in all of the assets with shorter lives, such as cars, computers and telecommunications equipment. Discussions with our engineers suggest that, over long timeframes, assuming the same (roughly $30 million per annum) capex per annum rather than, for example, attempting to work out exactly when each piece of larger kit might need to be refurbished or replaced is the best working assumption to make. It is certainly not the case, given that many of our larger users are affected not by gas prices per se, but rather the relative prices of gas and hydrogen (see discussion in Section 3.1.2) that capex would be linearly related to demand or RAB. One effect of our assumption of constant capex is a slight uptick in depreciation towards the end of the period; all capex made in period T-1 (ie – the penultimate year) must be depreciated in year T, along with half of the capex made in year T-2, a third of the apex from year T-3 and so on. In reality, we would expect the capex to be refined closer to the implied end date, and it makes only a very small difference to what we might otherwise choose to do now, because maintenance capex is itself so small compared to the RAB.

[23] These opex and capex numbers come from out modelling. Note that T=2090 reflects the AA starting in 2021, and the 70-year asset life of new investments as per the pipeline asset life used in AA4. Of course, T does not need to be set at 2090, but it makes a convenient starting point for understanding how the model works, and what K represents.

key factors which drive the analysis. We describe the work by ACIL Allen in the development of the model in Section 3.1.2 below, and then go on to describe the results obtained in using the model in Section 3.2. Section 3.1.2 also includes some instructions for use of the model, to assist the ERA when it does so.

3.1.2. An overview of our model

Our model is essentially an implementation of Equation 1, with the addition of opex and new capex noted above. In terms of Equation 1 above, the key term which captures technological progress amongst substitutes for the gas we transport is the γ term; a high γ implies a very rapid rate of technological progress and a low γ represents a very low rate of technological progress, noting that "progress" is defined in terms of how costs are reduced. Thus, all of the disparate information about cost-reducing technological progress is distilled into the term γ.

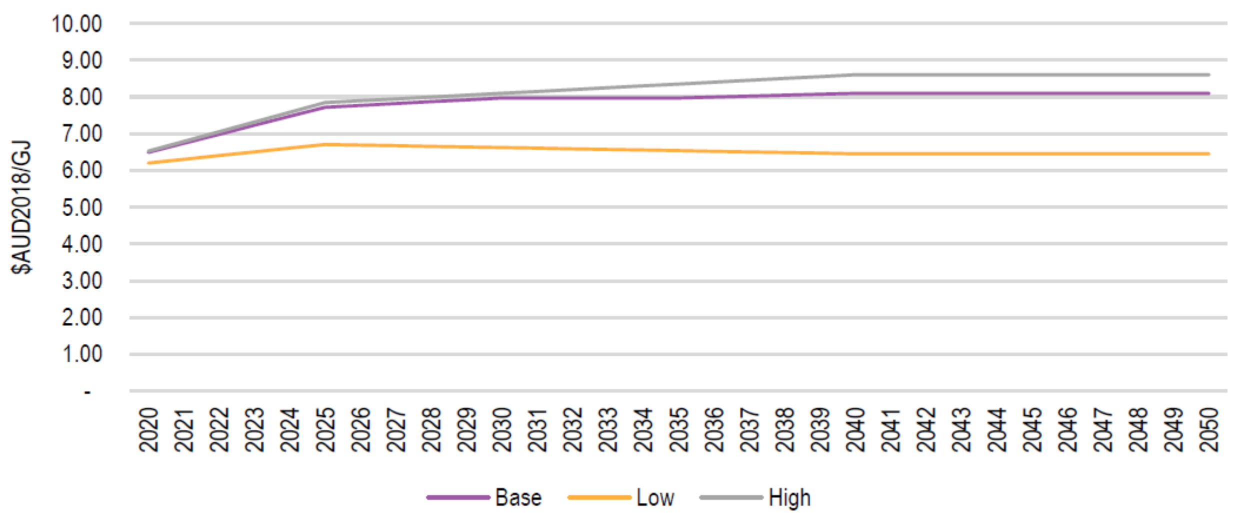
However, there are factors not captured in the Crew and Kleindorfer framework (or Equation 1) which we need to accommodate in our modelling to deliver reasonable predictions:

- changes in the price for natural gas in the wholesale market;
- different markets for the use of gas we transport; and
- the policy framework for greenhouse gas emissions.

Gas markets

In respect of wholesale gas markets, we make use of recent forecasts from the International Energy Agency converted into a WA LNG netback price. This gives rise to a low, medium and high gas price scenario. These are shown in Figure 13.

Figure 13: Gas price forecasts- ACIL Allen



Gas market segments

In respect of our shippers, we divide our market for gas transportation services into seven sub-categories, which are treated differently in the model, these are:

- alumina;
- gas for power generation;
- other domestic gas;
- chemicals;
- iron ore;
- nickel; and
- other minerals.

For gas for power generation (that is, in the South West Interconnected System - SWIS), we assume that the substitute is renewable power with storage. The modelling of the uptake of renewable power with storage is undertaken in ACIL Allen's "Powermark" model of the SWIS, described in Attachment 9.3. Demand for gas in the SWIS is shown in Figure 14.

Figure 14: Demand for gas within the SWIS

For the remaining market sectors above, we assume that the substitute is hydrogen produced at the point of production.[24] Some sectors only have hydrogen as a low/zero emissions fuel for heat or as a feedstock substitute (chemicals and domestic gas consumption). Other sectors, like Alumina, require both electricity and heat, and (currently) only hydrogen can provide the latter with low/zero emissions. In reality, different market sectors (and different firms within a sector) will likely use several different technologies to meet their energy needs.[25]

The practical effect of only considering hydrogen as a substitute is two-fold. Firstly, it makes the operation of the model simpler. Secondly, since hydrogen is currently higher cost than other renewables plus storage, and likely to be so through most of the period of analysis, assuming hydrogen as the substitute forestalls the crossover point, and injects a degree of conservatism into the modelling by extending the economic life of the DBNGP.

[24] As noted in Section 2.2.1, even if hydrogen is transported down the DBNGP, we would need to price at the cost of producing it local to the source of demand so, from a modelling perspective, this assumption makes no difference.

[25] The construction of the model includes an ability to manually change gas demand per sector and per annum which allows for this kind of granularity to be accommodated.

Note that for these other sectors, outside the SWIS, we do not assume that demand for gas falls as gas prices rise or emissions standards begin to tighten. This is because each of the relevant industry sectors is low on their international cost curves, and could sustain quite high gas price increases before they were no longer internationally competitive (see ACIL Allen report).

What happens instead is that, once the price of hydrogen is lower than the (delivered) price of gas, these users are assumed to switch from natural gas to hydrogen. The model does allow users to manually adjust down use of gas for our shippers to proxy a shipper becoming internationally uncompetitive, or reducing demand for some other reason, but we have not adjusted the model in this way for our simulations. Since doing so would, in general, raise prices for remaining shippers, the effect of making this manual adjustment would be to bring forward the crossover point. Demand for gas by other shippers is shown in [redacted]

[redacted]

Sector	Capacity (PJ/a)	Throughput (PJ/a)
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Emissions policy

In respect of emissions, we make use of three scenarios:

- Low: a reduction in carbon dioxide emissions by 2030 of 15% below 2005 levels and net zero emissions by 2080.
- Base: a reduction in carbon dioxide emissions by 2030 of 26% below 2005 levels and net zero emissions by 2070.
- High: A reduction in carbon dioxide emissions by 2030 of 45% below 2005 levels and net zero emissions by 2060.

The base scenario aligns with Australia's commitment under the Paris Agreements (see Section 2), whilst the high scenario aligns with the targets adopted by the Australian Labor Party at the lower end of the range recommended by the Climate Change Authority (40-60%), the statutory authority charged with recommending emissions targets.[26] The 15% scenario is effectively no carbon policy at all, as we have already met this target and the model records zero impact up to 2030.

Note that we have not implemented a target of net zero emissions by 2050, which has been adopted by the WA State Government and all other state and territory governments (see introduction). We could further amend our modelling to take this policy announcement into account, and the net effect of doing so would be to bring forward the crossover point, as our model shows use of natural gas,

[26] See https://markbutler.net.au/news/transcripts/insiders-15919/. Note also the comment that this would be required to meet targets of net zero by the middle of the 21st Century. And see http://www.climatechangeauthority.gov.au/files/files/Target-Progress-Review/Targets%20and%20Progress%20Review%20Final%20Report_Chapter%209.pdf

and hence net positive emissions, after 2050 in our base, or most likely scenario.[27] This is a key area where our modelling is conservative.

The way the emissions targets are given effect in the model is to use shadow prices. That is, an amount is added to the price of the relevant fuel (here natural gas) which has the effect of reducing demand for that fuel sufficiently that the relevant decarbonisation target can be met, without making any assumption about what mechanism is actually employed by policymakers to achieve that reduction.

In no way are we assuming that there will be a carbon price implemented in WA; the shadow price is simply a construct within the model which is used to give effect to whatever policy is actually used to induce emission reductions. Shadow prices are widely used in economic models for exactly this purpose.[28]

Post 2030, each shadow price is increased by the long run GDP growth rate (roughly three percent). This is known as the "Hotelling Rule" and is widely used in modelling such as this.[29] It reflects the idea that the efficient exploitation of a non-renewable and non-augmentable resource should be effected by increasing its price by the discount rate to maximise the value of that resource. Here it makes sense to use the expected growth rate of GDP as the discount rate to preserve inter-generational equity as, all else being equal, the consumption of future generations will be that of the present generation multiplied by the growth rate of GDP.

Technological progress for renewable substitutes

We turn now to the γ term; the rate of technological progress of renewable substitutes for natural gas. Although there are four substitutes (wind, solar storage and hydrogen) and each of them has their own γ, in the model we treat wind, solar and storage together (effectively producing a combined γ for them), as they are the substitute for electricity in the SWIS, and then treat hydrogen separately, with its own γ.

The starting price for hydrogen of $8.25/kg (inclusive of the commodity and storage) is derived from the CSIRO *National Hydrogen Roadmap*. In dollars of December 2020 and reflecting technological progress forecast in the roadmap between its publication and December 2020, this gives a range of $5.37-$7.26. The price for combined renewables plus storage is approximately $160/MWh, and comes from a variety of sources detailed in the ACIL Allen report.

Each of these prices is assumed to change due to "learning rates" (their γ), which is a percentage change in price from the previous year due to technological price and emerging economies of scale. Hydrogen, which is a relatively new technology, has relatively high learning rate in the first few years, before the rate declines to more modest rates in future decades. While batteries follow

[27] Note that, if the WA State Government policy had the intent of stopping at net zero by 2050 (so not actively removing carbon from the atmosphere) then there would be no need to apply the Hotelling Rule beyond 2050, as emissions standards would get no stricter.

[28] See, for example, Dreze, J & Stern, N, 1987, "The Theory of Cost Benefit Analysis", in Averbach AJ and Feldstein M, eds *Handbook of Public Economics,* Vol II, Elsevier, NH, 909-89, who define (p910) the shadow price as the impact on social welfare of the increase in supply of a given commodity.

[29] See, for example, https://treasury.gov.au/sites/default/files/2019-03/sglp-report.pdf, from which ACIL took this aspect of its approach. By way of comparison Covington, (see Covington, H, 2016, "Investment Consequences of the Paris Climate Agreement", *Journal of Sustainable Finance and Investment* 7(10: 54-63, available from https://www.tandfonline.com/doi/abs/10.1080/20430795.2016.1196556) suggests that meeting the Paris agreement will require a 4% per annum reduction in carbon emissions through most of the 21st Century. Cumulatively, this is a much larger increase than ACIL Allen uses.

a similar pattern, solar starts at a lower rate reflecting its greater maturity and wind starts at the lowest rate reflective of the fact that it is a fairly mature technology.[30]

The learning rates for hydrogen have come from the CSIRO *National Hydrogen Road Map* and have been extrapolated forward for future years by ACIL Allen, and the learning rates for renewables plus storage come from a variety of sources and ACIL Allen’s expertise in the sector.

Since the learning rates for renewables plus storage also reflect the amount of each of the three technologies needed to meet the level of demand for electricity in each year (in particular, lots of batteries need to be deployed early in the model as there are few in the marketplace at present), the shape of the learning curves through time is not smooth. For hydrogen, which is not an amalgam of three technologies, the curves are smooth.

The prices for hydrogen and renewables plus storage, given these learning curves under three different learning rate assumptions per technology are shown in Figure 15 and Figure 16.

[30] CSIRO (2018) pp44-8 also make use of the same kind of “learning rate” assumption that ACIL Allen use.

Figure 15: Hydrogen price scenarios

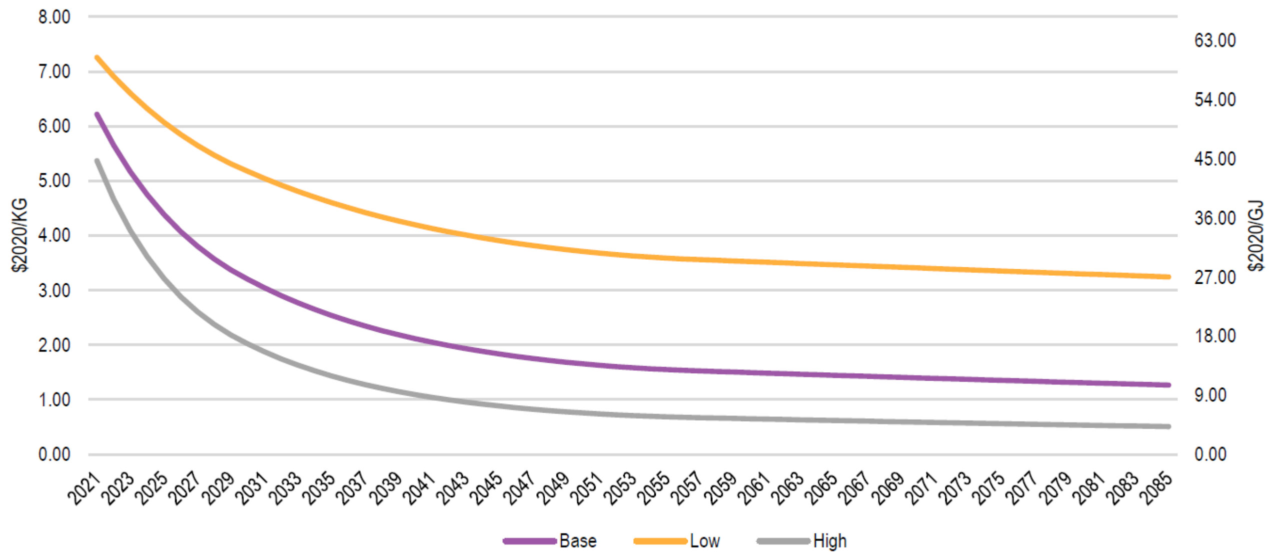
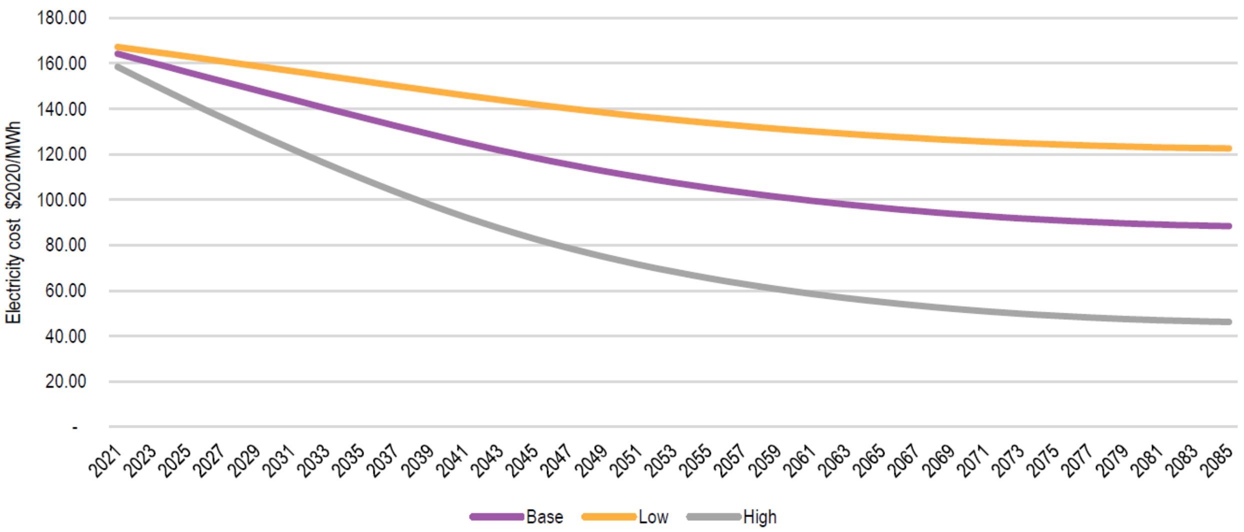


Figure 16: SWIS renewable price scenarios



Model outputs

All of the information above is used to establish the price of the substitutes for natural gas, and the price for natural gas itself (including transport – which is worked out following a standard regulatory building block model). The price for the substitute and the natural gas is then multiplied by demand, and this gives the competitive substitute proxy revenue and regulatory revenue.

Whichever is the minimum of these is then the revenue ascribed to the business. The revenue stream through time is then compared to the starting RAB and the opex and capex needed to keep the pipeline operational.[31] If the NPV of revenues is greater than the NPV of costs (including RAB), this indicates that *K* is set too high, and if the NPV of costs is higher, then this indicates that *K* is set too low.

Note that, in using the model, one does not choose *K* directly, but rather chooses the end date for the economic life of the asset (so *T-K*). This is due to the nature of the way the ERA's depreciation model works and in no way shape or form influences results.

Box 2: K or M?

From the perspective of the economic modelling of depreciation, our focus in Equation 1 is K (or T-K) as this is what determines the asset life cap and depreciation. However, as a business, our focus is on *M*, the date at which the regulated price and the price of competitors crosses over, and we face the discipline of the competitive market rather than the regulator.

Depreciation is straight line, and this means that *K* and *M* are linked geometrically. We might determine that a T-K equal to 2060 makes the left and right hand sides of Equation 1 balance, but what we are really interested in is the *M* of, say 2050 that is linked to that K. By choosing a *T-K* of 2060, we are not saying that we expect to be out of business by 2060 and will switch the pipeline off. What we are rather saying is that we expect to be under a new business environment, maybe selling hydrogen in a competitive marketplace, in 2050 and, given what we can predict now about the revenues we can likely earn in that marketplace (over whatever timeframe; our life in the competitive marketplace is not linked to K, which drives only depreciation in the regulatory setting), we need to make sure that we have recovered a certain amount of our investment under the regulatory framework by 2050 so we can be viable.

The ERA arguably has the same focus; it wants to make sure that we aren't recovering more revenue before 2050 than is absolutely necessary to enable us to be viable in the competitive marketplace. More broadly, it is arguably interested in when competitive pressures mean it no longer needs to regulate us than when a notional regulatory economic life tends to zero.

Thus, although K is the focus of our modelling, M is the focus of our business.

Using the model

Our model is intended not only to provide a basis for our conclusions in respect of the depreciation schedule, but also to be used by the ERA to explore the consequences of different approaches to depreciation and different assumptions about underlying economic conditions. We believe this aids transparency.

We have supplied the ERA with three spreadsheets which comprise our modelling tools:

- A "vanilla" version of the WOOPS model developed by ACIL Allen. This has the regulatory inputs in the "Capital base and reg revenue" tab, and the ERA can change the depreciation line manually in this tab, run different scenarios, examine revenues and compare these against the NPV of capex and opex (which it can also change itself manually in the same tab) which it also calculates manually.
- A "working" version of the ACIL Allen WOOPS model which we have actually used in our results below. We have not changed the fundamental structure of the ACIL Allen model at all, but have instead just automated some of the manual steps, in particular:

[31] For simplicity, we have set the tax allowance at zero, essentially assuming the ERA will provide us with no tax allowance. Since tax is merely cost reflective (rather than being an incentive item like, say opex) this does not distort the final result by much, and avoids the near impossible task of solving for tax through half a dozen regulatory scenarios for each simulation run.

  - We have linked the regulatory input in the "capital base and reg revenue" tab to a separate sheet (below) to allow changes to opex, capex and depreciation (in particular) to be done more flexibly.
  - We have added a few cells which calculate the NPV of revenues, capex and opex (and also set the inputs for these to zero after the asset has been fully depreciated, as relevant), adds them to the RAB and compares them to the NPV of the actual revenue stream.
  - We have changed the WACC assumption in the "inputs" tab to reflect our most recent value. This, as discussed below, makes little difference.
- A spreadsheet ("Extended RAB for Depreciation") with the regulatory inputs we have used included. This has the same structure as the ERA's own model when it comes to capex and depreciation (an opex line is also added, to keep all the information in one place), and has a function which allows users to change the end of the economic life in the model, as well as the flexibility to make changes to the size and nature of capex.[32]

We also provide the ACIL Allen report which summarises both the foundation of its model, and how the model works. Users have two choices methods for using the model:

- Use the "vanilla" model and do all of the work manually;
- Use the "working" version of the model and accompanying spreadsheet which automates just some of the tasks.[33]

Whichever approach the ERA takes, the basic process is the same:

- Choose the depreciation schedule by choosing a K (actually T-K).
- Choose the scenarios(s).
- Run the model, check the NPV of costs and revenues and, if they are not equal, return to step 1 with a different T-K.

As a final point, the ACIL Allen model (see the "results" tab, rows 114 and 115) records two versions of our actual revenue; one which assumes regulation will cease when the asset is depreciated to zero (row 115) and one which assumes it will continue (row 114). We use the former in our modelling, not because we believe regulation will cease, but because we wanted to highlight the consequences of depreciating too quickly as well as too slowly.

The "extended RAB for Depreciation" sheet sets all costs equal to zero once the asset is fully depreciated because this works better in the NPV calculations in the WOOPS model. If one uses Row 114, since it picks the lower of the regulated and competitive price, it will choose the regulated price as soon as the asset is fully depreciated. We will still get our investment back but, if depreciation is "too fast" (in the sense that the asset end date is in a year when the price of

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[32] For simplicity, we have assumed that the same capex we assume during AA5 (which is all stay in business capex; we have no expansion plans) continues through the whole life of the asset. The ERA could change this if it likes to, say, simulate adding a new compressor in the year the existing compressors come to the end of their current economic lives. We have not done this partly for simplicity and partly because it is the economic life we are trying to determine. Note also that, once one puts in an definitive end to the life of the asset as a whole, depreciation naturally ramps up at the end because, in the final year, all of the capex from the previous year, plus half from the year before that, a third from the year before that and so on, is depreciated to zero. In the penultimate year, it is half of the capex for the prior year, a third from the year before that and so on. And backwards it goes. This is not a function of the WOOPS modelling, but rather a consequence of making the asset as a whole end at some point in time, rather than assuming that the asset as a whole is essentially eternal (as the ERA's model currently does) and individual components within it come to the end of their lives and are replaced.

[33] It is worth pointing out that we could have asked ACIL Allen to make its model solve for K; the depreciation schedule which allows us to earn our capital back. However, this removes flexibility from the process, which we think is important to allow the ERA to explore the issue more fulsomely.

competitors is still very high), then the depreciation has essentially been too heavily front-loaded and we could have better served the interests of consumers with a longer set of asset lives.

If, however, row 115 is used, and depreciation is too fast, this shows up in the results as a very large positive NPV due to the assumption that we price at the level of our nearest competitor. This sends the right signal to the model user that the speed of money needs to be slowed down somewhat to better meet the long run interests of consumers, who are not served any better by depreciation being too fast as compared to being too slow.

This needs to be borne in mind when looking at the NPV results for very short asset lives; their large size is due to an assumption in the model that we would be able to price at the level of renewables when they are still high in price, and they are thus more a signal that the life is too short, rather than a signal of how much we would actually earn if lives were that short as we would still be under regulation in reality and there is no way the ERA would allow us to price at the level of substitutes if these were well above our costs. The converse is not true of negative NPV results from asset lives being made too long as these reflect prices that the regulator would actually let us charge in a building block model.

The ERA does not have to use row 115; row 114 works just as well, but users should be cautious of the issue in calculating NPVs and not depreciate the asset too quickly.[34]

3.2. Our conclusions from modelling

We now turn to the results of our modelling. We present our analysis into three scenarios:

- A "low" scenario, where gas prices are assumed to be low, learning rates for electricity and hydrogen are both assumed to be low and emissions standards are assumed to be set at their lowest level.
- A "base" scenario, where all of these variables are set at their middle or most likely levels.
- A "high" scenario, where all are set at their highest levels.

Table 3 shows the result of the application of Equation 1; that is a comparison with the actual revenue path predicted by the model given regulatory and competitive pricing (the right hand side of equation 1) and the cost of our business (the left hand side). A negative number means that the cost of our business over the economic life (in the model) of the assets is greater than the revenues we are able to earn and a positive number means the converse.

[34] This is not fixed by putting in opex post the asset being depreciated to zero. It is relatively small, and row 114 would thus choose the regulatory revenue stream under a fast depreciation schedule, meaning one would still miss the signal that depreciation is too quick.

Table 3: Comparing revenues with costs at different economic lives (NPV $million)

	Base Scenario	Low Scenario	High Scenario
2035	$11,456	$67,318	-$29
2040	$5,894	$51,627	-$935
2045	$2,779	$39,541	-$1,524
2050	$1,095	$30,164	-$1,973
2055	$322	$22,649	-$2,329
2059	$34		
2060	-$23	$16,500	-$2,579
2065	-$261	$11,608	-$2,789
2070	-$453	$7,745	-$2,968
2075	-$614	$4,706	-$3,119
2080	-$745	$2,273	-$3,245
2085	-$843	$333	-$3,341
2090	-$864	-$27	-$3,363

Since the "base" scenario represents ACIL Allen's assessment of the most likely set of future outcomes, we focus on the Base Scenario column. This suggests that 2059 (so K=31 if T=2090), which is the last year in which the NPV is positive, makes for a suitable implied end date for the asset as a whole, and thus we make use of this value as our most likely implied end date. This means that the maximum asset life is 39 years and thus pipelines go from 70 years to 39 and the BEP lease goes from 52 years to 39.[35]

Looking at the other two columns, it is clear that, if policy settings and learning are relatively fast, we are probably already too late in respect of making a change to depreciation; even setting K to 55 when T=2090, so depreciating everything to zero by 2035 would be insufficient to allow us to recover our efficiently incurred investments to date. This point is crucial; if our assumptions prove conservative, and we believe there is a good chance they are, we have no time to lose in adjusting our approach to depreciation. In fact, since the recently announced WA government policy of net zero emissions by 2050 is tighter than the emissions controls in the "High" scenario, which goes to net zero by 2060, there is a risk that we may already be late in changing our depreciation approach.

On the other hand if both policy settings and learning transpire to be very slow, then setting K at zero (or one, to avoid a negative NPV) would be sufficient, but this would still require a shift in the basic approach to depreciation from one where the pipeline system is implicitly assumed to have an indefinite life to one where it has a maximum; here K=5 would be sufficient.

As a final point, where the ERA sets very short economic lives, but emissions policy and learning are slow, the profits shown are very high. We do not imply that the ERA would ever allow us to earn profits at this level (or even that our shippers could pay these prices). These high values are a consequence of the component of the model which is intended to highlight the problems of

[35] Note that pipeline assets installed before 2000, and with an asset life out to 2055 in the regulatory model, make up around $1.3 billion, or roughly half of the asset value in pipelines in 2021. Almost all of the rest is comprised of looping and expansions which finished in 2012 and thus presently has an asset life out to 2082. The BEP Lease is worth around $18 million in 2021.

depreciating too quickly discussed at the conclusion of Section 3.1.2, and are not intended as an indication of actual profits.

3.2.1. Sensitivity Analysis

We also examine three different variants to the above set of scenarios by way of sensitivity analysis; a change in WACC, a learning focus, and a policy focus.

In respect of WACC, we examine a real pre-tax WACC of two and one of five percent. This compares with our main case where the real pre-tax WACC is 3.08% (based on the October post-tax nominal WACC of 4.31% used elsewhere in our modelling. The results are shown in Table 4.

Table 4: Comparing revenues with costs at different economic lives with different WACC values (NPV $ mil)

	WACC at 5%			WACC at 2%		
	Base Scenario	Low Scenario	High Scenario	Base Scenario	Low Scenario	High Scenario
2035	$7,786	$39,168	-$27	$14,345	$94,006	-$30
2040	$3,705	$27,677	-$721	$7,706	$75,260	-$1,086
2045	$1,621	$19,608	-$1,147	$3,789	$60,039	-$1,801
2050	$593	$13,901	-$1,450	$1,555	$47,588	-$2,374
2055	$162	$9,731	-$1,673	$477	$37,070	-$2,843
2059	$14			$56		
2060	-$14	$6,619	-$1,811	-$30	$28,000	-$3,196
2065	-$128	$4,361	-$1,919	-$395	$20,393	-$3,508
2070	-$213	$2,736	-$2,004	-$703	$14,063	-$3,785
2075	-$279	$1,570	-$2,071	-$972	$8,813	-$4,033
2080	-$328	$719	-$2,121	-$1,204	$4,384	-$4,252
2085	-$360	$100	-$2,153	-$1,388	$661	-$4,435
2090	-$367	-$8	-$2,159	-$1,431	-$54	-$4,478

Although the NPV values obviously change, there is no change in our overall conclusions in respect of the economic life. This is perhaps not surprising, as we are looking at relative costs in each year, and the only building block that will change year to year with WACC is the return on capital.

Although this is important now, by the time we get to the period in time when competitive prices have fallen to levels close to the regulated prices the RAB is relatively small, and thus the return on capital component is also relatively small.

For the learning focus, we set the gas price and the policy setting to the low assumptions, and then use the base and fast learning rates. For the policy focus, we set the learning rates and gas prices to low, and set the policy rates to mid and high. The results are shown in Table 5.

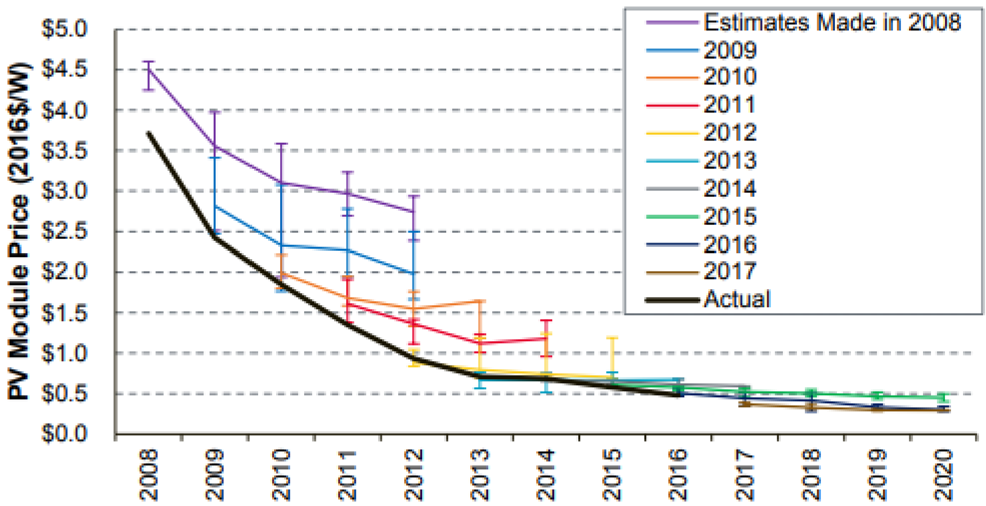
Table 5: Comparing revenues with costs at different economic lives - Learning and policy focus results (NPV $ mil)

	Low gas price low emissions and…		Low gas price low learning and…	
	Base learning	High Learning	Base emissions	High emissions
2035	$18,637	$2,383	$64,116	$56,527
2040	$11,715	$442	$48,677	$41,970
2045	$7,268	-$295	$36,914	$31,086
2050	$4,451	-$798	$27,713	$22,774
2055	$2,598	-$1,181	$20,566	$16,491
2060	$1,354	-$1,441	$14,949	$11,705
2065	$599	-$1,659	$10,510	$7,996
2070	$193	-$1,843	$7,003	$5,125
2075	-$16	-$1,999	$4,203	$2,935
2080	-$156	-$2,128	$1,998	$1,316
2085	-$256	-$2,224	$288	$175
2090	-$280	-$2,246	-$27	-$27

It is clear here that it is the learning rates which mainly drive results.

With this in mind, it is interesting to consider Figure 17, which shows predictions and actual price paths for solar power, just over the past decade or so.

Figure 17: Errors in forecasting solar power costs



Source: p11, Cole, W, Das, P, Donohoo-Vallet Main, T and Richards, J, 2017, 2017 Standard Scenarios Report: A U.S. Electricity Sector Outlook, October 2017, p11, available from https://www.nrel.gov/docs/fy18osti/68548.pdf

The point for our current purposes is that, although the ACIL Allen report represents the most robust forecasts we can make at present with the evidence available to us, it is almost certainly too conservative.

The remaining levers are gas demand and gas price. To explore the consequences of changes in these, we use the "Discrete Load Movements" tab in the ACIL Allen model to increase and decrease gas demand (capacity and throughput) by 25% and then adjust gas prices in the "Gas Price Projections" tab to 25 % above ACIL Allen's "high" scenario, and 25% below their "low scenario.[36] Note that the shift in demand is from the projections for AA5 and is "anticipated" in the sense that prices are set based on the changed demand rather than on the original demand. Both shocks are also on-off shocks. The results are shown in Table 6 below.

Table 6: Comparing revenues with costs at different economic lives - Changes in gas demand (NPV $ mil)

	25% decrease in demand	25% increase in demand	25% increase from high gas price	25% decrease from low gas price
2035	$9,058	$13,855	$5,600	$21,776
2040	$4,655	$7,133	$1,868	$13,951
2045	$2,183	$3,375	$382	$8,831
2050	$843	$1,346	-$215	$5,369
2055	$228	$404	-$620	$3,127
2058	$31			
2059	-$26			
2060	-$80	$14	-$889	$1,685
2065	-$313	-$230	-$1,112	$787
2070	-$505	-$424	-$1,299	$277
2075	-$665	-$585	-$1,457	$25
2080	-$797	-$717	-$1,588	-$123
2085	-$894	-$814	-$1,685	-$224
2090	-$915	-$836	-$1,706	-$247

The changes in demand have relatively little effect, essentially shifting the economic life backwards and forwards by one year. This is perhaps not surprising, as gas transport is only a small part of the delivered price of gas (only about a sixth at the outset, and falling through time as emissions controls operate via shadow pricing in the model) and thus even relatively large changes in demand do not change conclusions very much. Changes in gas price does change demand; a higher gas price brings forward the economic life (increases K) and a lower gas prices makes K smaller.

The sensitivity analysis suggests, if anything, that our economic life ending in 2059 is conservative. Demand and WACC make very little difference to results. Emissions controls alone also has a limited effect; although in the context of emissions controls, it is difficult to imagine a

[36] We have included the settings we used in both of these tabs as part of the "working" version of the model, and then changed the tabs mentioned above back to their original settings so that runs of the model by the ERA are not affected by this manual sensitivity analysis. To replicate our analysis, the ERA would need to manually enter our settings again. Note that, due to the construction of the model, demand in the SWIS cannot be changed in the "Discrete Load Movements" tab, but is rather set exogenously by ACIL Allen. This is discussed in their report at Attachment 9.3.

world circa 2050 where they are less stringent than they are today (unless we have solved global warming by then). The major drivers are technological growth and gas prices. If gas prices fall substantially then our economic life might be considered too short; the only scenario in the sensitivity analysis. However, one would need to consider the reason why such a fall in price occurs. If it occurs because there is a major increase in global supply of gas, then this points to 2059 being too early. However, if gas prices fall because of a major drop in demand occurring because consumers are shifting to cleaner alternatives then this is highly likely to be associated with the cost of renewable technologies falling faster than our base scenario. When this occurs, the sensitivity analysis suggests that 2059 is much too conservative.

We expect to update economic lives (K in the model) in future AA submissions as information about the future becomes available. However, with the information we have to hand at present, it appears clear that 2059 is a prudent and conservative first step to dealing with the likely impacts of future competition.

4. Why future cost reduction motivates action now

As the analysis above shows, there is a way for us to react, now, to the changes which can be forecast given information available about potential future outcomes for renewable power and its prices relative to gas. Nonetheless, the exact future for the energy sector remains unclear. We believe, however, not only that we can act now, but that it is better to act early rather than late for two reasons:

- the scale of the issue and the impacts delay will have on customers and investors; and
- the current interest rate environment.

We explore these reasons here.

Although regulators have dealt with the stranding of single assets they have yet to deal with whole systems or large parts of systems facing stranding. For an individual asset (for example, cast-iron mains for distribution networks), regulators have developed a practice of amortising remaining asset values over the following AA period. However, this approach would have significant consequences when assets are large relative to the system as a whole, by imposing significant costs on customers in a single AA period.

The approach will not work if the asset which risks stranding is either the whole asset, or a very large part of the capital base. In the former instance, those shippers who remain will face very high prices and in fact cross subsidise those who are able to substitute gas for other fuels early. In the latter case, there will be no shippers from whom the capital base can be recovered.

We therefore believe a more orderly transition is more in keeping with the long run interests of consumers.

As the Australian Energy Market Commission points out:[37]

> *"The concept of the 'long-term' recognises that there is an inherent trade-off between consumers today, and consumers in the future. Changes that may be in consumers' short-term interests may not be in their long-term interests if those changes undermine incentives to make efficient investments and operational decisions over time. For instance, making changes specifically to provide customers with short-term price decreases at the expense of enabling investors to recover a return on efficient investment will not be in the long-term interests of consumers if it results in generation retirement and power cuts that are more costly than the short term price savings."*

Academic evidence also suggests the potential high costs of delay as outlined in Box 3. Once a threshold of available information about the future has been reached, provided the reaction is one which can be undertaken with "no regrets" and can be flexible to future new information, it becomes more beneficial to the long run interests of consumers to act soon, and gradually. Furthermore, the National Gas Objective to promote efficient investment in natural gas services for the long term interests of consumers, suggests that rather than waiting until the last possible moment, and risking a chaotic transition, we should act today.

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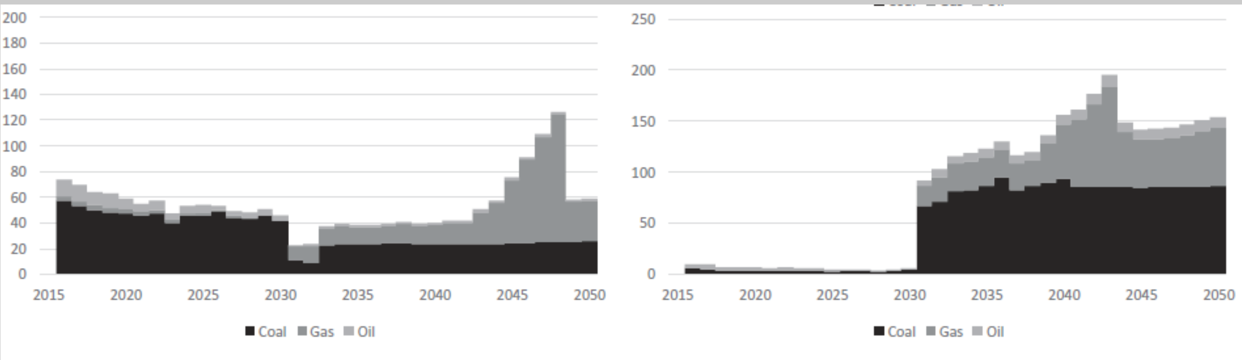
[37] AEMC, 2019, *Applying the Energy Market Objectives*, 9 July 2019, p5 (available from https://www.aemc.gov.au/sites/default/files/2019-07/Applying%20the%20energy%20market%20objectives_4.pdf)

Box 3: The costs of waiting for more information globally

Saygin et al (2019) have developed a bottom-up model of asset stranding in the power sector globally.[38] They consider two cases by which countries attempt to meet their Paris Commitments of a two degrees rise in global temperatures by 2050; one whereby each country, from today, replaces a retiring fossil-fuel generation asset with an equivalent renewable power source (Remap case) and one where countries wait until 2030 (Delayed Policy Action case). The figure below from the paper shows the difference in respect of stranded assets (in GW) with the Remap case on the left.



The difference is stark; starting now leads to stranding of about USD927 billion globally by 2050 (suggesting that this is already a live issue for the energy sector) but waiting until 2030 to start switching will result in USD 1824 billion in stranded assets. For Australia (including WA), the difference is even starker; USD 8.6 billion vs USD 48.3 billion; reflective of the age of some of our coal generating assets in particular, which are due for retirement in the coming decades.

Although the study does not focus on gas pipelines per se (see the Rocky Mountain Institute work cited above for work in the US on this point), a large part of our demand is power generation (SWIS plus our self-generating industrial and mining shippers) and thus we face the same kind of cost for delay. Certainly, it does not seem to be in the long term interests of consumers globally to impose a cost of around a trillion US dollars to wait until 2030 to start planning for a transition to renewable power, and nor would doing so likely pass the efficient growth of the market for reference services of NGR 89(1a) when other less tumultuous approaches are clearly open to policymakers.

The second point is an opportunity, rather than a reason. Interest rates are currently low; perhaps the lowest in millennia.[39] The added depreciation we propose compared to a business as usual case effectively means very little change from the regulated prices which have prevailed during AA4. Moreover, for future customers, since increasing depreciation now leads to a smaller RAB sooner in future and thus less return on capital, the balance between the increase in return of capital (compared to doing nothing on depreciation) and the decrease in the return on capital continues that stability into the future.

Just as it may be prudent not to impose a large upward price shock on consumers immediately where costs increase, but rather to stagger price increases in the interests of price stability, we believe that making use of the opportunity presented by the current low interest rate environment to effectively pay down the principle invested in our pipeline is a more prudent use of the low interest rate environment than a large price cut now which will not be sustained into the future.

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[38] See Saygin, D, Rigter, J, Caldecott, B, Wagner, N and Gielen, D, 2019, "Power Sector Asset Stranding Effects of Climate Policies", *Energy Sources, Part B: Economics, Planning, and Policy*, 14(4), 99-124, available from https://doi.org/10.1080/15567249.2019.1618421

[39] There are many web references to the work by Andy Haldane at the Bank of England that produced this arresting conclusion. See, for example http://www.svanecapital.com/perspectives/2016/4/29/negative-interest-rates. Far more detail on the relevant history (and a source used by Haldane) is Homer, S and Siller, R, 2005, *A History of Interest Rates*, 4th edition, John Wiley & Sons: Hoboken NJ.

5. Considering our approach to economic lives in light of the NGR

Depreciation is one of the "building blocks" which determine our allowed revenues. Our approach to depreciation was developed having regard to the requirements of the National Gas Law (NGL) and the National Gas Rules (NGR), specifically the Revenue and Pricing Principles,[40] and the provisions for depreciation.[41]This section considers the second part of our depreciation proposal in more detail against the NGL and NGR.

Box 4: The Revenue and Pricing Principles and Depreciation in the National Gas Rules

The National Gas Objective is:

> ***to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas***

Section 24, which expands on the objective into a series of "Revenue and Pricing Principles". These are:

(1) The revenue and pricing principles are the principles set out in subsections (2) to (7).

(2) ***A service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in—***

- ***(a) providing reference services;*** *and*
- *(b) complying with a regulatory obligation or requirement or making a regulatory payment.*

(3) A service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides. The economic efficiency that should be promoted includes—

- *(a) efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and*
- *(b) the efficient provision of pipeline services; and*
- *(c) the efficient use of the pipeline.*

(4) Regard should be had to the capital base with respect to a pipeline adopted—

- *(a) in any previous—*
  - *(i) full access arrangement decision; or*
  - *(ii) decision of a relevant Regulator under section 2 of the Gas Code;*
- *(b) in the Rules.*

(5) A reference tariff should allow for a return commensurate with the regulatory and commercial risks involved in providing the reference service to which that tariff relates.

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

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

Depreciation is covered specifically in the National Gas Rules, which sit underneath the National Gas Law, and specifically Rules 88 to 90. Of particular relevance, Rule 89(1) outlines the criteria governing how a depreciation schedule is established. These are:

(1) The depreciation schedule should be designed:

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

[40] NGL s 23, s 24

[41] NGR 88-90

5.1. National Gas Objective and Revenue and Pricing Principles

The NGO is to promote efficient investment in and operation and use of natural gas services in the long term interests of consumers.

NGL section 24(2) notes that service providers should be provided with a reasonable opportunity to recover at least the efficient costs in providing reference services, and complying with regulatory obligations. In the face of fundamental and rapid changes in the energy sector as outlined above in Section 2, maintaining the current approach to depreciation keeps in place a significant risk that service providers may not be able to recover the efficient costs of providing reference services, specifically the investment in the pipeline itself.

Furthermore, NGL sections 24(6) and 24(7) require that the regulator have regard for the economic costs and risks of over and under investment in, and over and under-utilisation of a pipeline. Again, the evidence presented above in Sections 3 and 4 suggests that absent our proposed approach, investment in and utilisation of the DBNGP is unlikely to be most efficient because the risks and costs to future customers will not have been sufficiently taken into account.

Finally amongst the revenue and pricing principles it is worth considering section 24(5), that a service provider should be provided with a return commensurate with the regulatory and commercial risks. In this regard we note that our proposals do not change the return provided to the service provider, they merely bring forward a return on our assets in time to address the risks as outlined above; our proposal remains NPV neutral.

On this basis we believe our depreciation proposals are in line with the National Gas Objective and Revenue and Pricing Principles.

5.2. Depreciation criteria

NGR89(1) outlines the criteria against which the depreciation schedule should be designed. In commenting on each of these criteria, the sections that follow outline how our proposal to consider the economic life of the DBNGP system as a whole is consistent with each.

5.2.1. NGR 89(1)(a)

NGR 89(1)(a) requires that the depreciation schedule be designed so that reference tariffs vary over time in a way that promotes the efficient growth in the market for reference services.

The proposed approach will increase depreciation from AA5, and the question is therefore whether this will affect the efficient growth of the market for reference services negatively, compared to a counter-factual of doing nothing.

Guidance in this matter has been addressed in the past by the Australian Competition Tribunal, who note:[42]

> *There is substantial agreement about what is required in terms of tariff paths to promote efficient growth in the market for reference services.*
>
> *The economic experts for both the AER and APA GasNet (PwC for APA GasNet and Frontier Economics for the AER) generally agreed that, subject to tariffs reflecting long-run marginal cost, recovery of any remaining costs*

[42] See ACompT8 (2013) [218]. Available from https://tinyurl.com/yxtq37hj. Note that, in the case in question, APA was seeking for a change in the AER's depreciation method. We are not seeking such a change, but rather just a change in economic lives.

> *should be so as to minimise distortion of demand. PwC states that efficient pricing entails ensuring that the marginal cost of consumption is signalled to consumers. To the extent that there are non-marginal (fixed) costs of supply, then these should be spread across consumers in a way that minimises distortion of consumption decisions.*

We note that depreciation is a fixed cost; it is the recovery of investment already incurred by the service provider. Thus, its recovery should be spread across consumers in such a way that it minimises the distortion of consumption decisions; in the language of the Tribunal above.

Shortening the economic life of the pipeline will increase depreciation now, because the same asset base is being recovered over fewer years. Whether this increase will distort consumption decisions over the life of the asset more than the level of distortion present in the current depreciation schedule depends on the price sensitivity of customers.

Most of our transport demand is accounted for by mineral processing customers who use the gas we transport either to generate their own electricity or as an input to their processes. These customers are primarily export focussed, being price takers in global markets.[43] ACIL Allen (see Attachment 9.3) suggest that most of our customers in this sector are towards the bottom end of the cost curve for their respective industry, and suggest that even quite large changes in gas transport prices would be unlikely to change their consumption decisions. This suggests that changes to depreciation would not distort the demand for reference services on the part of these customers whether such changes were up or down.

The remainder of our demand is accounted for by electricity generation in the South West Interconnected System (the significant majority of demand) and gas consumed in ATCO's distribution network (a very small component of our demand). Provided electricity generators using gas pass on any cost increase associated with transport to final consumers of electricity, one would expect both of these groups of customers to reduce their demand in response to a change in depreciation. How much they would change their demand depends upon their price sensitivity, but we note that our proposed approach results in very little change in prices from AA4 to AA5.

Estimates of the price sensitivity of current customers of gas and electricity are varied, but experts employed by the ERA and AER have suggested they are relatively low.[44] This means that a change in the depreciation schedule (up or down) would have a relatively small effect on their demand for reference services.

We cannot realistically quantify the price sensitivity for future customers because they do not yet exist. However, if the predictions of the various forecasts in Section 2 are correct, and in particular if renewables achieve price parity with gas or with electricity generated by gas (or both), then we can safely assume that price sensitivity will increase, perhaps dramatically. If there is no feasible substitute for a given good or service (as at present), price sensitivity is low because there is little opportunity to switch. However, the greater the feasibility of substitution, the greater the sensitivity, because of the opportunity to switch.[45] Thus, any change to the depreciation schedule will have a significant impact on demand by future consumers.

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[43] From an economic perspective, they earn "resource rents"; if their cost of supply is lower than the prevailing global price, they will supply as much as they physically can and will be unaffected by changes in the global market price but, if their cost of supply is above the global price, they will supply nothing.

[44] See Partington, G and Satchell, S, 2018, *Allowed Rate Of Return 2018 Guideline Review: Report to the AER*, 25 May 2018, pp4-7, available from https://www.aer.gov.au/system/files/Partington%20and%20Satchell%20-%20Report%20to%20AER%20Rate%20of%20Return%20Guideline%20-%2024%20May%202018.pdf

[45] Most of the activity of consumer brands and their advertisers is centred around reducing opportunities to switch by making a given good or service somehow "unique". This is somewhat difficulty to do when the good being sold is ultimately electrons or gas molecules.

The greater price sensitivity of future consumers relative to those of today is the driver of our proposals. We are changing the depreciation schedule such that more of the fixed cost of depreciation is being paid by current consumers with little price sensitivity and less is being paid by future consumers who have more price sensitivity. Allocating fixed costs in this way is well-known in the literature as being the least distortionary way to do so.[46] Therefore we consider this approach to be consistent with the requirements of NGR 89(1)(a).

5.2.2. NGR 89(1)(b)

NGR 89(1)(b) requires that the depreciation schedule be designed so that each asset or group of assets is depreciated over their economic life. This is satisfied by considering the system as a whole; if the DBNGP has an economic life out to 2059, it is difficult to see how any of its sub-assets could have a life beyond that. Of course, it may be that a compressor, say, could be taken out of the pipeline and used somewhere else, but this is a matter of it having a scrap value of greater than zero, not an economic life attached to the provision of reference services on the DBNGP (which is the economic life of importance here) past 2059.

Not only does our proposed approach address NGR 89(1)(b), but a failure to change the current regulatory approach of looking only at each asset class within a pipeline has the potential to fail to address this criteria. This is because failure to look at the pipeline as a whole would mean a regulator would be implicitly assuming that life to be indefinite, when it is in fact finite, and thus ignoring the fact that the sub-classes of assets that make up the pipeline may be shorter.

5.2.3. NGR 89(1)(c)

NGR 89(1)(c) requires that a depreciation schedule be designed so as to allow as far as reasonably practicable for adjustment in the expected economic life of a particular asset or group of assets. Our approach is amenable to changing economic lives as more information becomes available (one simply changes "K" in Equation 1 discussed in the next chapter). Indeed, the foundation of our approach is that economic lives should change more often than has been necessary in the past given changes in the energy sector, and we propose a way in which this might be done robustly.

5.2.4. NGR 89(1)(d)

Our proposal has no substantive effect on criterion (d) in that we are not proposing to depreciate any asset more than once. As outlined in the first part of our depreciation proposal, we have specifically undertaken the adjustment of asset categories to ensure existing and future assets are depreciated only once.

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[46] See Baumol, W and Bradford, D, 1970, "Optimal Departures from Marginal Cost Pricing" *American Economic Review*, 60(3), 265-83. A common objection to this way of allocating fixed costs is one of equity; customers with low elasticities of demand are often the poor, who have few other choices, and it thus seems unfair that they should pay more than others with more opportunities to switch. However, here, in shifting to a temporal perspective, we are not necessarily talking about different customers per se but, in many cases, the same customers at different points in time. Moreover, there may be a positive equity dimension. There are often concerns raised in the regulatory debate that, as richer customers avail themselves of alternate energy opportunities like rooftop solar, those without the capacity to switch are left with higher bills. The depreciation schedule we propose does not eliminate this risk but, by loading more of the depreciation on times when switching is harder for everyone because the substitutes are more costly, it leaves less of the RAB for the consumers who can't switch to pay in the future.

5.2.5. NGR 89(1)(e)

NGR 89(1)(e) requires that a depreciation schedule be designed to allow for the service providers' reasonable needs for cash-flow to meet financing, non-capital and other costs.

The transformation occurring in the energy sector as outlined in Section 2 above, suggests that without change in our depreciation schedule, there will be significantly more competition for energy services currently provided by the DBNGP. In order to respond to these challenges, and not impose unbearable costs on future consumers, an economic life for the DBNGP as a whole will help ensure that our needs for reasonable cashflows will continue to be met.