ACIL ALLEN

18 August 2023

Report to APA

A two-ship repair solution:

Assessment of market and consumer benefits

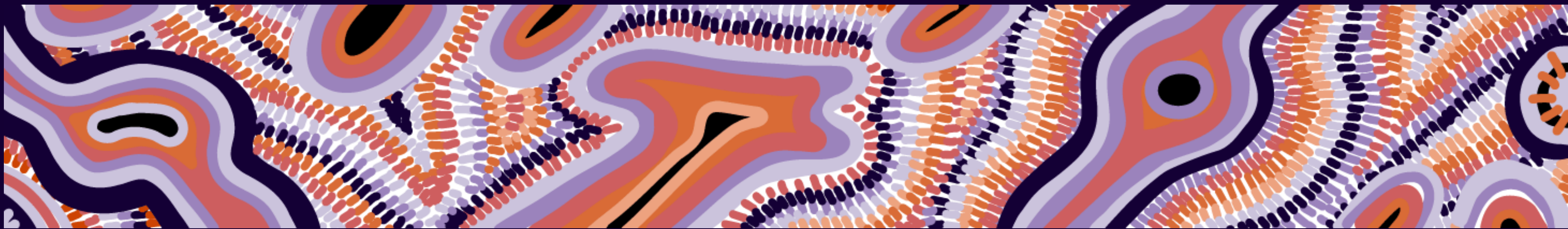
About ACIL Allen

ACIL Allen is a leading independent economics, policy and strategy advisory firm, dedicated to helping clients solve complex issues.

Our purpose is to help clients make informed decisions about complex economic and public policy issues.

Our vision is to be Australia's most trusted economics, policy and strategy advisory firm. We are committed and passionate about providing rigorous independent advice that contributes to a better world.

ACIL Allen acknowledges Aboriginal and Torres Strait Islander peoples as the Traditional Custodians of the land and its waters. We pay our respects to Elders, past and present, and to the youth, for the future. We extend this to all Aboriginal and Torres Strait Islander peoples reading this report.



Goomup, by Jarni McGuire

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Introduction

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APA is the owner of the Basslink interconnector connecting the National Electricity Market regions of Victoria and Tasmania. Basslink is a HVDC transmission line that is 390 km long, connecting to the 500 kV transmission system at Loy Yang in Victoria and the 220kV transmission system in Georgetown in Tasmania. Most of the interconnector length (290 km) is subsea across the Bass Strait.

Basslink operates under a revenue contract with Hydro Tasmania until 30 June 2025. APA is currently working on converting Basslink to a regulated asset.

Submarine HVDC transmission lines have a higher rate of historical failure than land-based transmission lines. When a submarine HVDC cable fails, locating and repairing the fault is more complex and time consuming than for an overland cable, because the cable lies on the sea floor at depths of 50 metres or more.

Basslink has suffered three significant outages since commissioning in 2005 as follows:

— a six-month outage from December 2015 to June 2016

— a ten-week outage between March and June 2018

— a five-week outage in August to September 2019

Repair of a Basslink fault requires a specialist ship to respond and identify the location of the fault at sea. The ship then needs to return to port to be loaded with specific equipment for the repair and then return to the location of the fault to undertake the repair.

APA has the option of paying annual fee, to get priority access to a second ship to assist with repairs, in the case of a Basslink fault. The second ship reduces the expected mean time to repair because the second ship can be loaded with repair equipment and reduce the amount of time lost in travelling to and from the location of the fault. As no two ships have identical capabilities, the second ship may also have better capabilities to undertake the repairs in adverse weather conditions, further reducing the expected time to repair the cable.

ACIL Allen has been engaged by APA to assess the benefits where APA takes action to reduce the repair time for a Basslink fault by paying an option fee for priority access to a second ship.

This report sets out the outcomes of market modelling to assess the market and consumer benefits of a proposed two-ship repair solution compared with a single-ship repair solution. The report is structured as follows:

— Chapter 2 of this report describes the methodology that has been used to estimate the market and price benefits.

— Chapter 3 discusses the outcomes of the electricity market modelling we conducted to estimate the market and price benefits.

— Chapter 4 discusses the underlying assumptions that were used to model the National Electricity Market. The assumptions we have used are based on ACIL Allen's April 2023 Reference case.

Methodology

2

This section discusses the methodology we used to assess the market and consumer benefits of the proposed two ship option fee.

2.1 Modelling approach

To assess the market and consumer benefits of the proposed two ship option fee, we have used our off-the-shelf April 2023 Reference case as a baseline scenario. This Reference case reflects a medium outlook on the National Energy Market with modelling out to 2050. The Reference case has been developed using our proprietary electricity market model, *PowerMark*.

For the assessment we have used the Reference case results over the five years of Basslink's proposed first Access Arrangement (July 2025 to June 2030). As an outage might occur close to the end of the Access Arrangement, we have included modelling through to the end of June 2031 to capture the time required to repair a fault.

Where a Basslink outage occurs, Tasmanian generation is unable to export to the mainland regions and mainland generators are unable to export to Tasmania.[1] These constraints result in changes in generation dispatch compared with the unconstrained case. They also result in changes in spot prices for electricity traded through the market.

The Reference case includes Basslink operating under normal conditions. The Basslink outage was modelled by setting its capacity for both imports and exports to zero MW (Basslink Outage scenario).

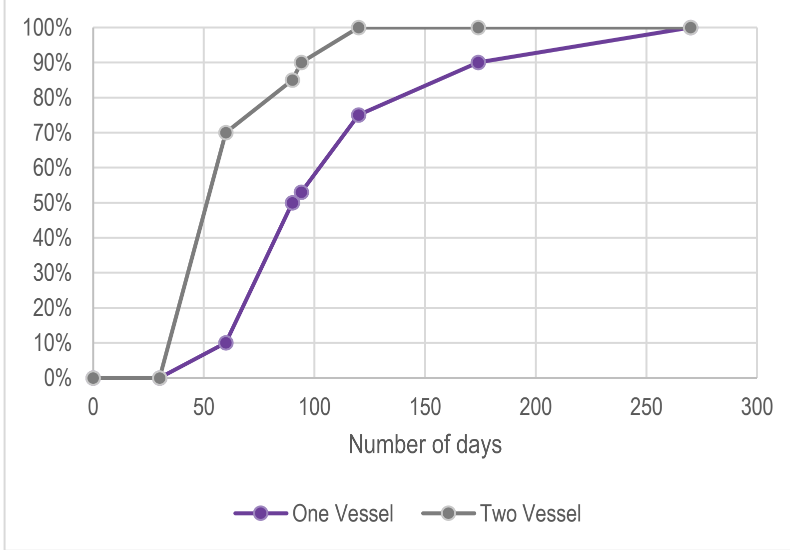
The difference between the Reference case and the Basslink Outage scenario is used to estimate the change in market and consumer benefits following a Basslink outage.

[1] Once Marinus Link is commissioned, these constraints have limited impact on Tasmanian imports and exports.

APA provided a cumulative probability distribution for the time required to repair the Basslink interconnector under a one-ship and a two-ship option as shown in Figure 2.1. We have calculated the loss in market and consumer benefits under a one- and two-ship option by multiplying the cumulative probabilities that were provided, by the change in market and consumer benefits after a Basslink outage for each point on the distribution.

Since we are unsure of when the outage might occur, we have applied the cumulative probability distribution of the one- and two-ship option using a sliding window approach with the outage start incremented a month at a time. This allows estimation of the change in market and consumer benefits for the one- and two-ship options for a Basslink outage occurring in each month over the period financial year 2026 to 2030.

Figure 2.1 Cumulative probability distribution of certainty of repair versus time



Source: APA

2.2 Calculation of the RIT-T – Market benefits

The standard market benefit test under the Regulatory Investment Test – Transmission (RIT-T) measures the present value of the change in market benefits (consumer surplus less the producer surplus) for the condition being considered. A full RIT-T includes an assessment of the change in resource costs plus competition benefits.

Resource costs include:

— fuel costs

— fixed and variable operating and maintenance costs

— capital costs (associated with investment in new generating plant).

Competition benefits occur where a change in the producer-consumer surplus is driven by changes in participant bidding behaviour because of the condition being considered.

The Basslink Outage scenario modelled involves a change to interconnector availability for relatively short periods. Therefore, the Reference case and Basslink Outage scenarios use the same entry and retirement schedule. Therefore, there is no difference in capital and fixed operating costs between the two scenarios and no change in competition benefits. The market benefits assessment is only based on changes in fuel and variable operating and maintenance costs.

We have calculated the market benefits of generators in the NEM by multiplying the short-run marginal cost of generators by their respective generation. The short-run marginal cost includes the variable and operating cost of generators, as well as the fuel costs of these generators

2.3 Calculation of Consumer benefits

The proposed annual payment to facilitate access to two ships is an operating cost and would be passed through to Market Customers under the current cost recovery arrangements. A Basslink outage will cause a change in spot prices in both the Tasmanian and Mainland regions. The change in spot prices would also be expected to be reflected in forward contract prices.

As a regulated interconnector, Basslink costs would be shared by Victorian and Tasmanian customers. Market customers will be disadvantaged by any increases in spot prices in both the Tasmanian and mainland regions. Therefore, reducing the length of a Basslink outage potentially benefits these consumers by increasing the consumer surplus.

We have assessed consumer benefits through the aggregate changes of cost of energy transacted in each NEM region. The cost of energy is determined by multiplying the Regional Reference Price (RRP) by the demand in each half hour for each region of the NEM.

2.4 Modelling variations in weather, plant outages and renewable energy

The Reference case provides a single point estimate of the market and customer benefits. It is preferable to determine distributions of benefits. Using the Reference case and the Basslink Outage scenario, we undertook stochastic analysis by varying demand (based on weather), plant outages and renewable energy generation inputs. The demand variation is based on using different historical weather years to determine demand. Renewable energy is also varied by matching it with each historical weather year. Plant outages are varied using randomly determined outages across the year, consistent with plant forced outage rates.

The stochastic analysis is based on running multiple simulations of the scenario by varying the demand, plant outage and renewable energy inputs. In this case, we used 10 weather years and five NEM-wide plant outage scenarios to create 50 different simulations. The weather years and outage scenarios were chosen to provide a reasonably unbiased distribution of results.

We then took an average of the 50 simulations to estimate market and consumer benefits for the Reference case and the Basslink Outage scenario. The difference in average market and consumer benefits have been reported in the next chapter. We have also provided graphical distributions of the difference in market and consumer benefits.

3

Results

This section provides the results for the difference in consumer and market benefits associated with reducing a Basslink outage by using a two-ship option to undertake repairs.

The timing of Marinus Link affects the calculation of consumer and market benefits because, once commissioned, it mitigates the impact of any outage at Basslink by providing an alternative path for inter-regional flows. The Reference case assumes Marinus Link is operational by January 2029. We have included a sensitivity for a delay in Marinus Link commissioning to July 2030.

3.1 Consumer Benefits

Figure 3.1 shows the consumer benefits for a two-ship repair solution for Marinus Link being operational in January 2029 and July 2030. We have estimated that the combined average savings of a second ship option in TAS and VIC reaches a maximum of $2,500 million in December 2025.

The top figure shows that during a Basslink outage, the savings of deploying a second ship are very similar between 2025 and 2028 but are close to zero from 2029 onwards (following Marinus Link commissioning). The bottom figure shows that the delay in Marinus Link results in customer benefits extending to the end of the FY 2030.

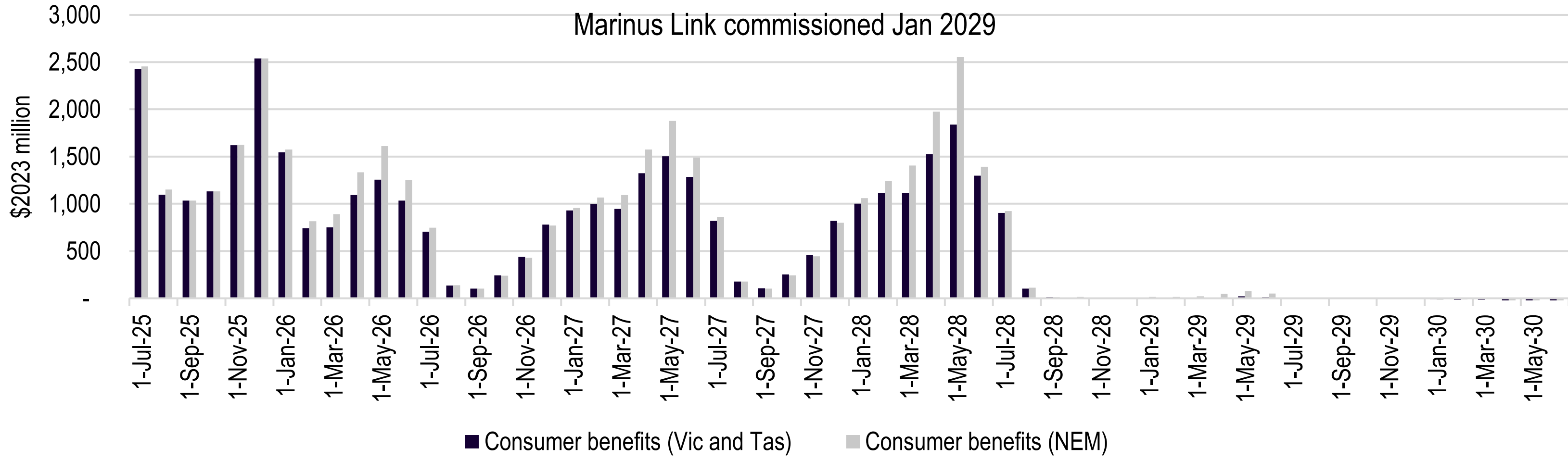
There is a seasonal aspect to the results with the period January to June greater than the July to December period. After the first twelve months, results peak in May, reflecting the outage period covering the winter period in each year.

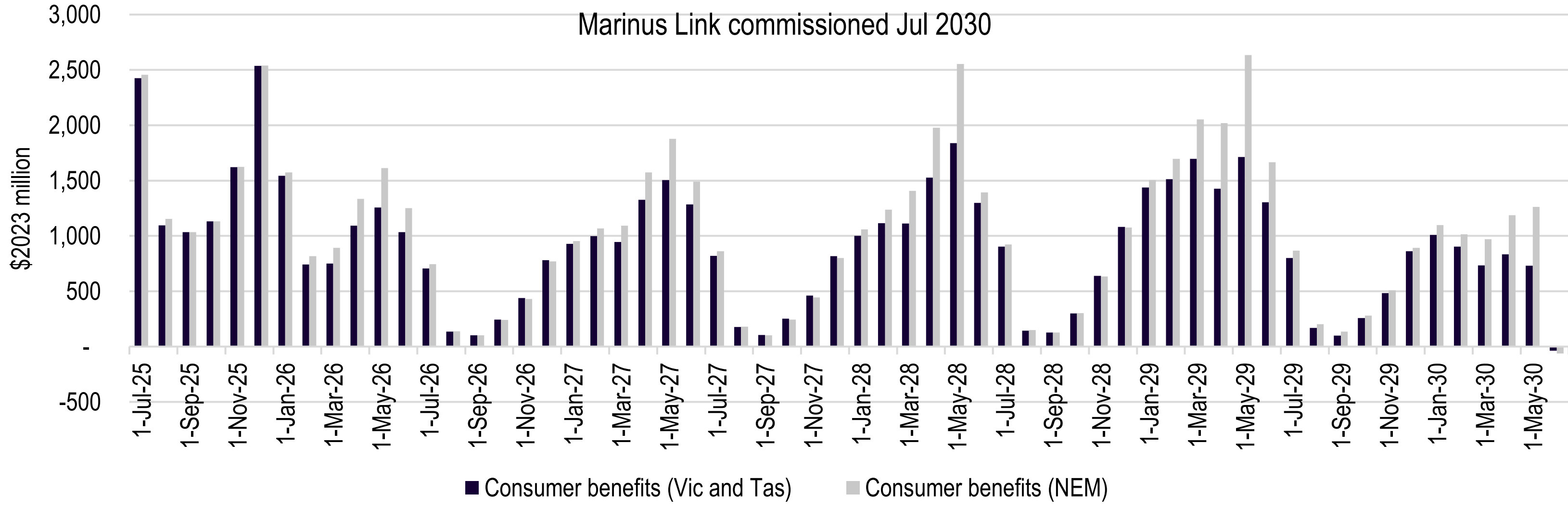
As discussed in Chapter 2, the consumer benefits are calculated by multiplying the hourly demand by the hourly RRP. The average RRP in each state is projected to decrease during the five-year period, because of government policies supporting renewable capacity and increased interconnection between the five NEM regions. The demand in the NEM is expected to rise, driven by developments like the electrification of the gas network and the increased uptake of electric vehicles. Since prices are decreasing and demand is rising, the consumer benefit of having a second ship during a Basslink outage does not change much over the period considered.

Figure 3.2 shows the range of projected consumer benefits expected based on the simulations used (demand, outages, and renewable generation). The maximum projected consumer benefit is around $18 billion for Victorian and Tasmanian consumers and around $30 billion for the NEM in 2028. The minimum results in a cost to consumers of around $4 billion for Victorian and Tasmanian consumers and around $6 billion for the NEM in 2030.

From the Victorian and Tasmanian consumers' perspective (who would pay for Basslink, including the second ship option fee),the expected benefits of the two-ship option are significant.

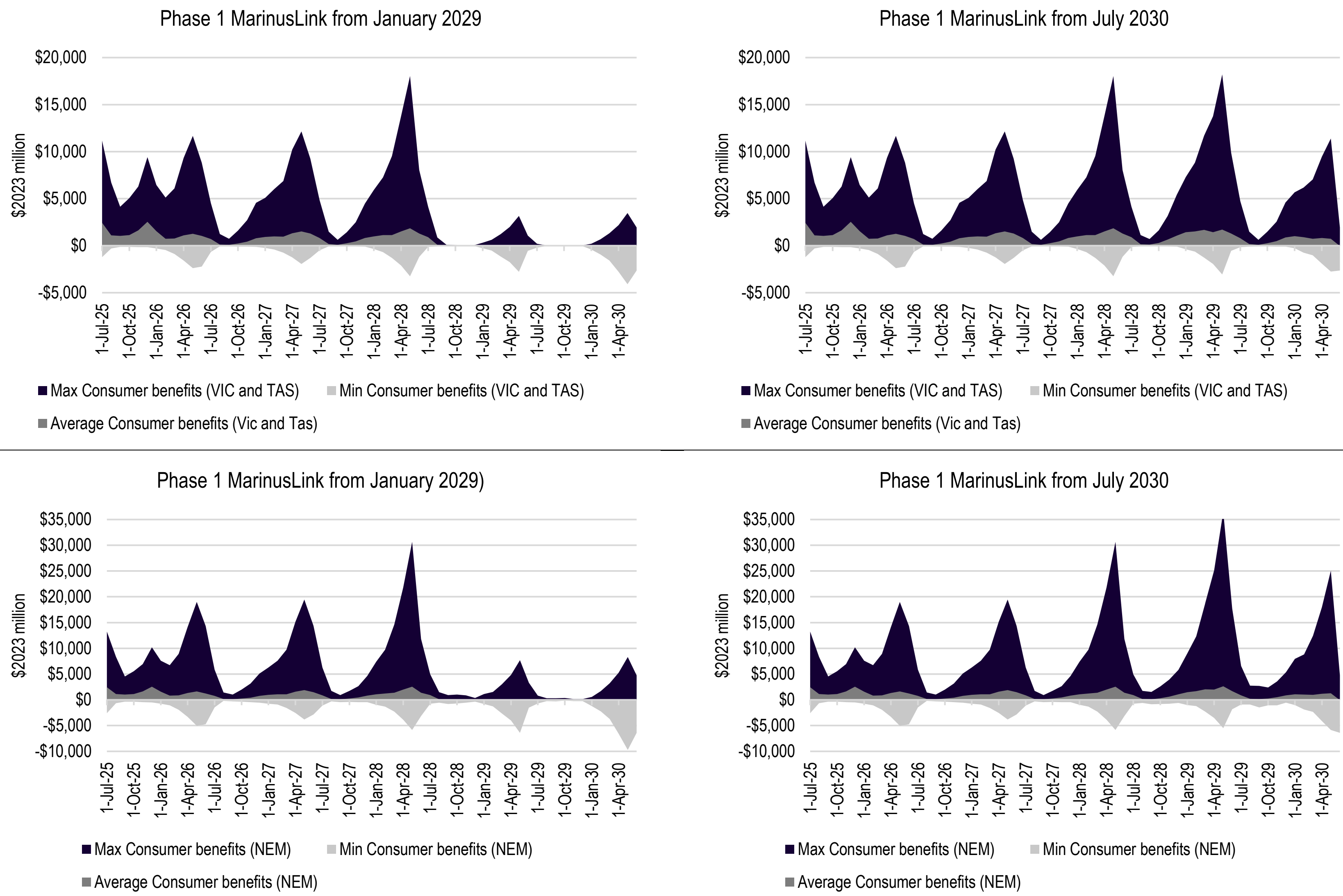
Figure 3.1 Two-ship repair solution - average consumer benefits





Source: ACIL Allen

Figure 3.2 Range of consumer benefits based on 50 simulations



Source: ACIL Allen

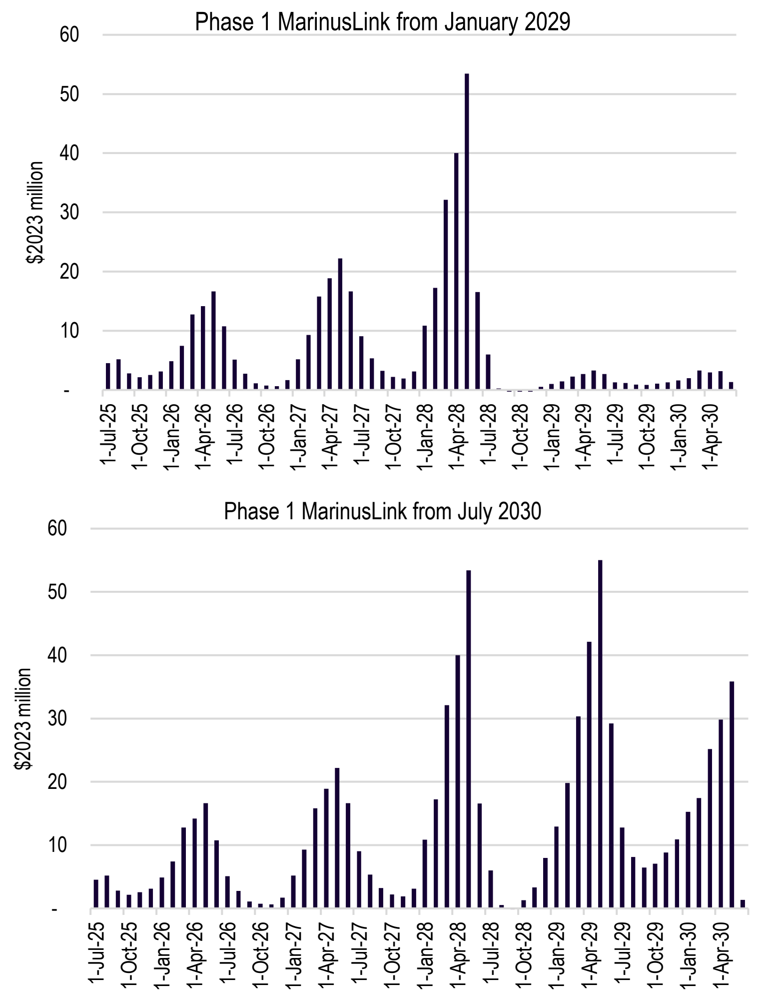
3.2 Market Benefits

Figure 3.4 provides an overview of the market benefits of the two-ship option. Like the consumer benefits, the market benefits follow a seasonal pattern with higher market benefits between March and June of each year. This is driven by more demand for electricity during the winter period, which is captured by Basslink outages commencing over that period. After the entry of Marinus Link in January 2029, the market benefits fall away substantially.

In 2026 and 2027 the market benefits range from $1 to $22 million depending on the timing of the Basslink outage. From 2028 the market benefits increase. Projected market benefits reach a maximum of $53 million for an outage commencing in May 2028.

Where Marinus Link Phase 1 commences in January 2029, market benefits fall away after Marinus Link is commissioned. Where Marinus Link commissioning is delayed until July 2030, market benefits reach a maximum of $55 million for a Basslink outage commencing in May 2029. Significant projected market benefits continue through to a Basslink outage occurring in April 2030. As there is little difference in repair times for a one- and two-ship solution for the first 60 days of a Basslink outage, market benefits fall away for a Basslink outage from May 2030, as Marinus Link is available from July 2030.

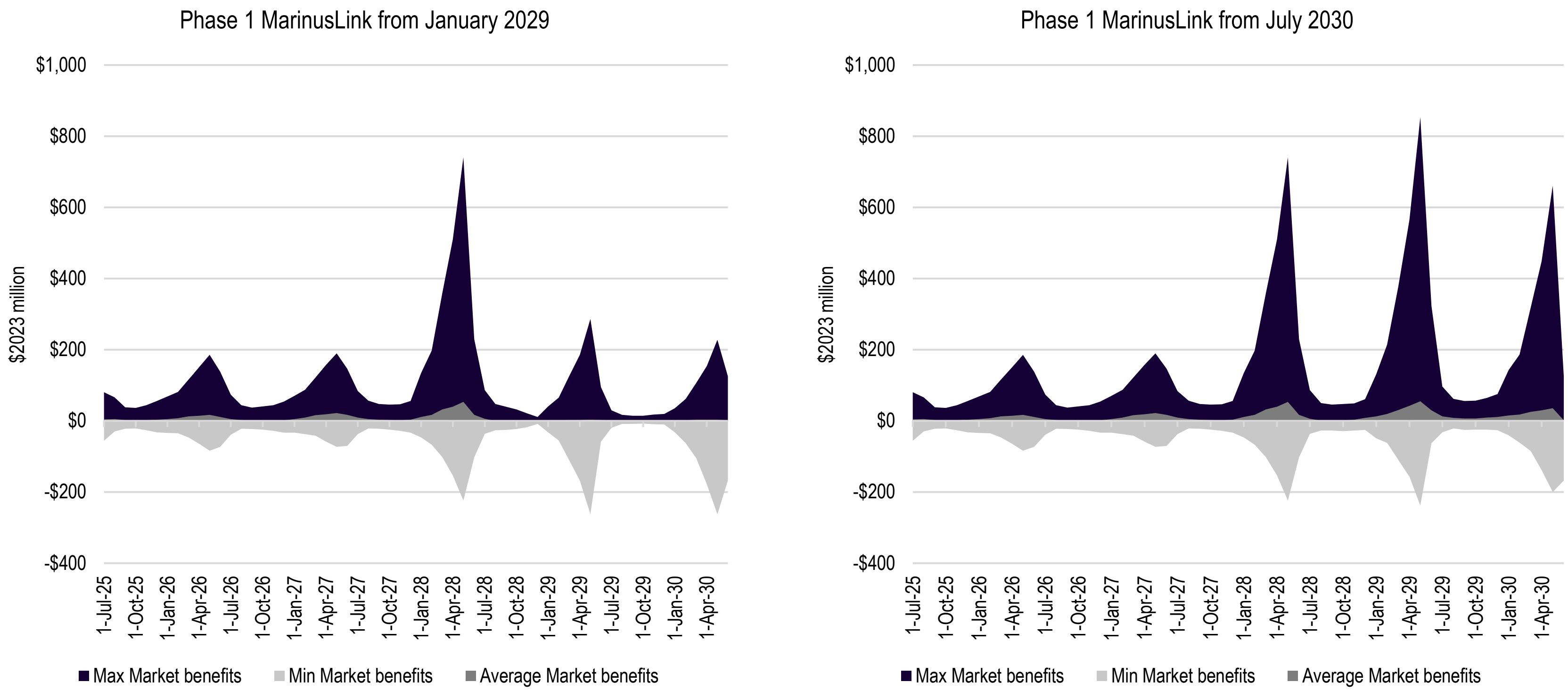
Figure 3.3 Two-ship repair solution - average market benefits



Source:

Based on the 50 simulations, the projected range of projected market benefits are between -$262 and $740 million where Marinus Link is commissioned in January 2029. Where Marinus Link is delayed until July 2030, the range of projected market benefits are between -$237 and $853 million. The range of market benefits are shown in Figure 3.4.

Figure 3.4 Total range of market benefits in the NEM based on 50 simulations

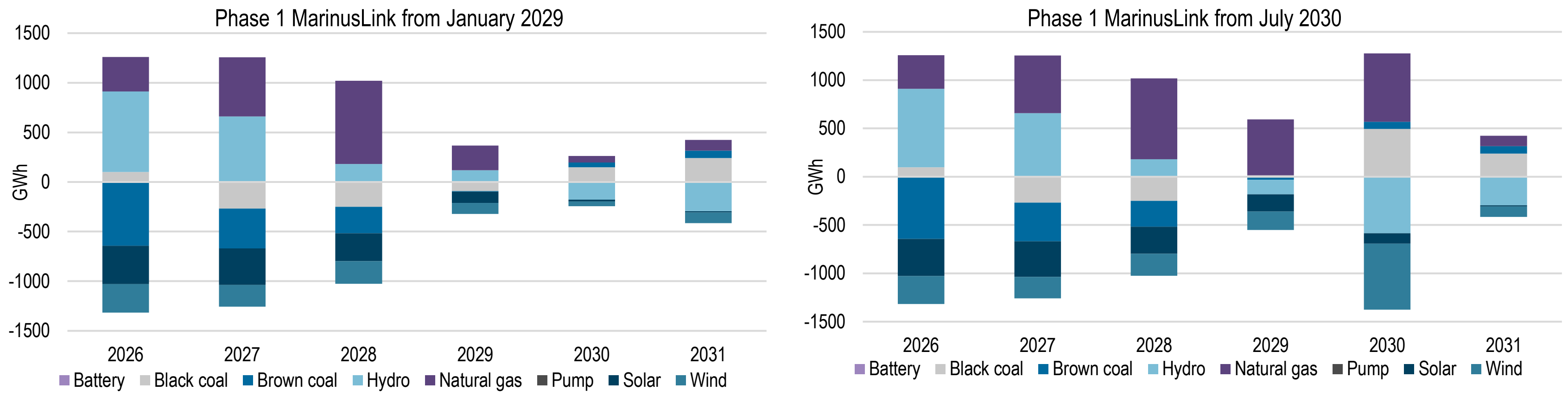


Source: ACIL Allen

To understand the change of savings in resource costs over the five years, it is important to look at the change in generation mix in the NEM during a Basslink outage. Figure 3.5 shows the NEM-wide change in generation mix during a Basslink outage. The chart represents the change in generation mix of the median simulation of all 50 simulations in terms of market benefits.

The chart shows that through 2028 wind, solar and brown coal generation is replaced by hydro and gas generation. After 2028 wind and hydro generation is replaced by gas and black coal generation.

Figure 3.5 Change in NEM-wide generation mix during a Basslink outage – median market benefits (GWh)



Source: ACIL Allen

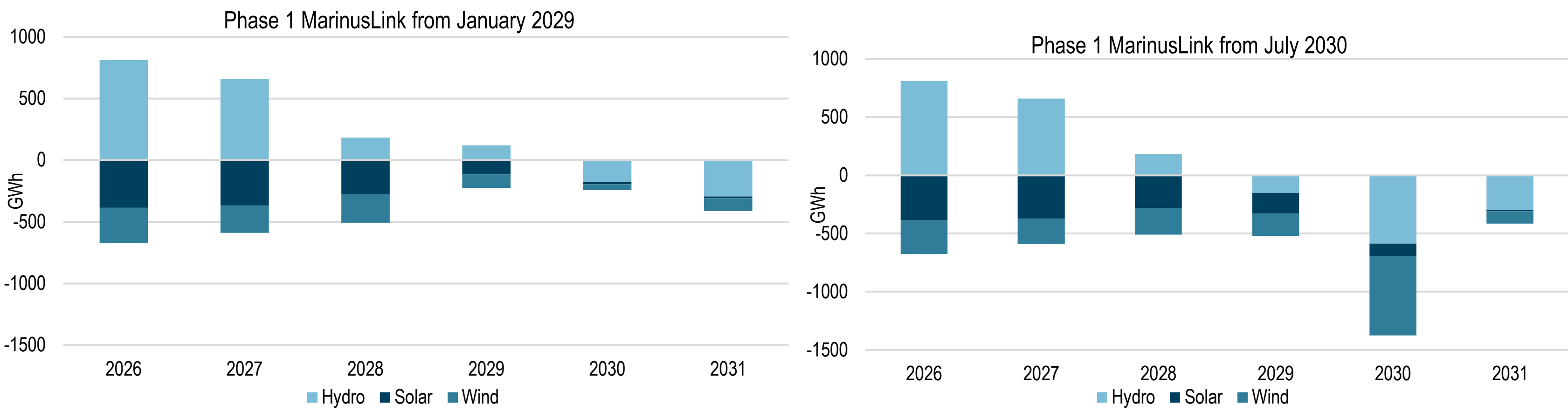
The changes in generation mix over the years are strongly influenced by coal closures and large transmission system upgrades in the NEM during this period.

This modelling assumes that Snowy hydro 2.0 and the interconnector VNI West will be operational from July 2028. As a result, there is increased generation flow between Victoria and New South Wales from July 2028 onwards. From July 2029 the interconnector QNI Medium is assumed to become operational. This increased interconnection means more black coal can flow from Queensland to New South Wales. When there is a Basslink outage Queensland black coal is available to meet demand in NSW and hence New South Wales black coal can meet demand in the rest of the NEM. Therefore, we find that from 2030 onwards black coal increases in both Queensland and NSW, with a Basslink outage.

Marinus Link is assumed to enter from January 2029 onwards for the Basslink Outage scenario and July 2030 for the sensitivity. We project that an outage of Basslink has little impact on the change in dispatch in Victoria once Marinus Link is commissioned. However, a Basslink outage results in a decrease in hydro and wind generation in Tasmania in both the scenario and sensitivity.

To understand how these changes in generation mix have impacted the savings in the projected market benefits we estimated, some specific fuel types have been analysed in greater detail. Figure 3.6 shows the change in renewable generation during a Basslink outage by renewable energy source. Hydro generation is projected to replace wind and solar generation in 2026 and 2027. From 2028, renewable generation shows a net reduction with the increase in hydro not offsetting the reduction in wind and solar. Renewable energy is generated at a short-run marginal cost of zero-dollars. The higher resource costs in the period between 2026 and 2028 can therefore not be attributed to a change in renewable energy.

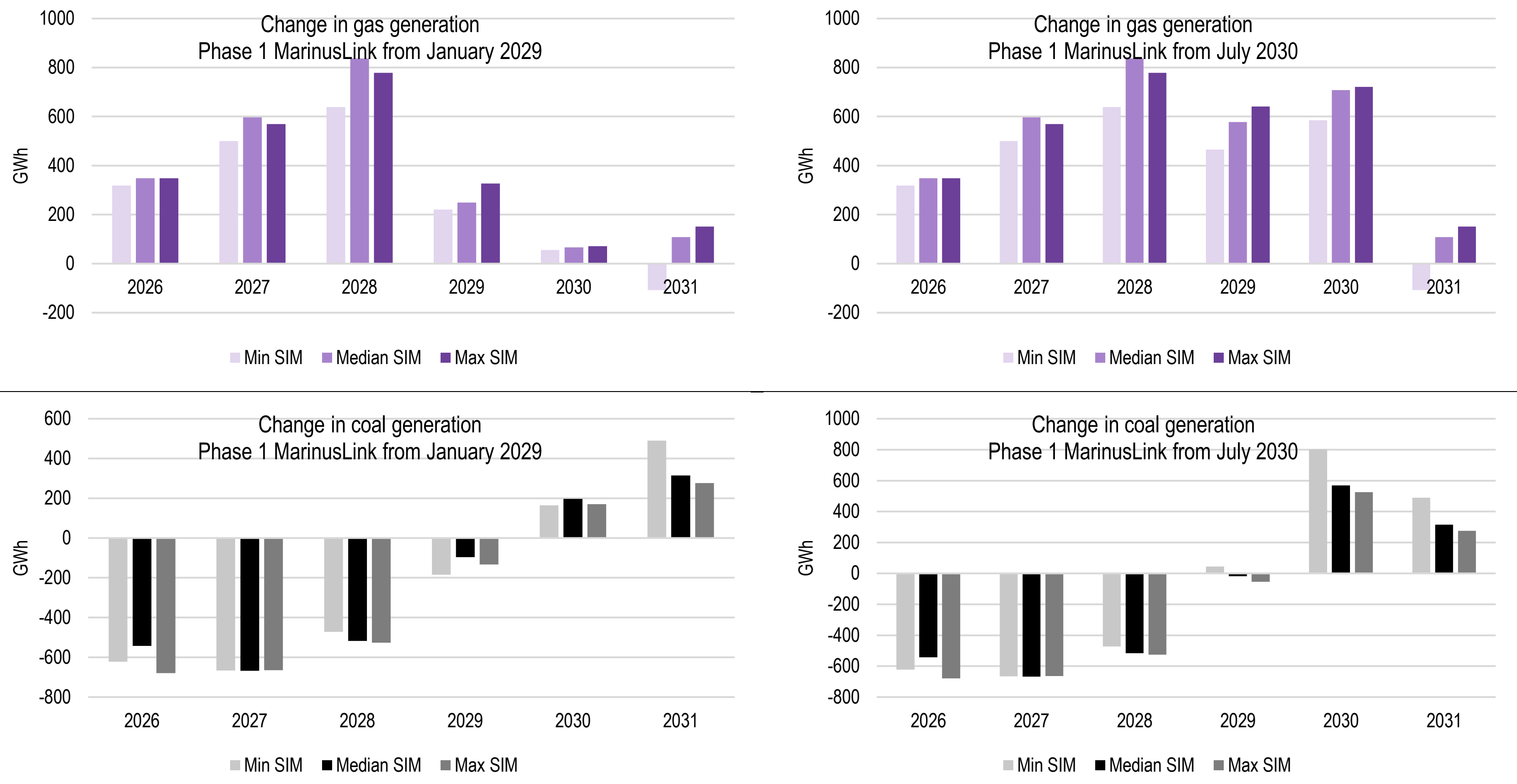
Figure 3.6 Change in NEM-wide renewable generation mix during a Basslink outage (GWh) -median simulation of market benefits



Source: ACIL Allen

Figure 3.7 shows the change in gas and coal dispatch for the Basslink outage scenario and the Marinus Link July 2030 sensitivity. In all simulations, gas generation increases. In the period 2026 to 2028 there is a strong decrease in coal generation. Since the short-run marginal cost of gas generation is significantly higher than coal generation, this results in a net increase in resource costs. Therefore, a two-ship repair solution which provides faster repair gives higher market benefits than a one-ship repair solution.

Figure 3.7 Changes of gas and coal generation during a Basslink outage for minimum, median, and maximum market benefit simulations



Source: ACIL Allen

4

Assumptions

4.1 Introduction

This Chapter sets out the underlying assumptions for the modelling of the April 2023 Reference case, which was used as a baseline scenario to assess market and consumer benefits.

The Reference case assumption set drives the Reference case modelling outcomes. Relying on the Reference case modelling results without considering the underlying assumptions can provide a false understanding of the potential range of future market outcomes.

The PowerMark modelling used to develop the Reference case simulation, requires single point estimates for each input assumption used in the modelling and for each hour modelled. The assumption set represents ACIL Allen's estimate of the central or most likely case, for each input assumption used, at the time that the modelling was undertaken.

In developing the Reference case assumptions, ACIL Allen has undertaken enquiries on a reasonable endeavours basis in establishing the input assumptions used. However, the level of confidence in these estimates vary depending on the availability and quality of the data on which they are based.

Therefore, ACIL Allen has philosophy of providing a high degree of transparency about the assumptions that are used in the Reference case modelling and the various methods by which assumption estimates are made or derived.

4.2 Macro assumptions

Inflation and foreign exchange assumptions are used in the escalation of nominal input costs for generators (fuel, variable O&M, capital costs for new entrants etc.).

The Brent crude oil price and the Newcastle FOB coal price are used as input assumptions to models used in developing ACIL Allen's gas and coal price projections, respectively.

Inflation

ACIL Allen undertakes the market modelling in nominal terms and therefore uses an explicit inflation assumption to escalate cost inputs relative to this index. Inflation is measured as the change in the Consumer Price Index (CPI) on an annual basis. The assumption used throughout is 2.5 per cent per annum, which corresponds to the mid-point of the Reserve Bank inflation target range.

Foreign exchange rate

The Australian dollar is a commodity currency that tracks reasonably closely with commodity prices in the long term. It rises and falls as commodity prices strengthen and weaken. Over the last ten years, it has traded mainly in the range of 0.70 – 0.80 AUD/USD with a median value near the middle of this range.

It has been assumed that the Australian dollar is held constant throughout the projection period, at 0.75 USD/AUD, the midpoint of the above range and close to the long-term average.

Brent crude oil price

The domestic gas market is linked to the international market through the LNG export plants in Gladstone. As a result, movements in global oil prices have had an important influence on domestic gas prices.

The principal pricing model for LNG contracts in the Asia Pacific region is oil-linked pricing based around the Japanese Customs-cleared Crude (JCC) price, a close proxy to the Brent crude price.

Fluctuation in oil prices has a direct flow-on effect to the price of LNG produced in Australia because most long-term LNG contracts (including those written by the three Gladstone LNG projects) have a formulaic link to the JCC oil price.

The brent crude oil price is assumed to converge from current levels to USD$79/barrel by the mid-2020s and remain at this level in the long-term.

The brent crude price was an important influencer of domestic gas prices until the introduction of the gas price cap and mandatory code of conduct in December 2022. Under the price cap it is expected that this relationship will still exist, however the price cap and mandatory code of conduct will limit the effect of international markets on the domestic price outcomes.

Export coal price

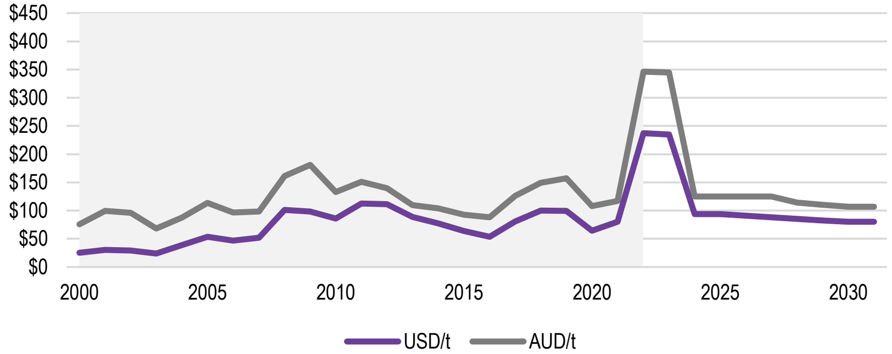
The Newcastle Free on Board (FOB) price for thermal coal is an important consideration in the price formation for all new coal contracts in New South Wales and for some in Queensland. The FOB is used for these plant for all times except while the price cap of $125/tonne is applied. The projection of this prices is used to establish coal export parity netback prices for Run of Mine (ROM) coal at each location from which power stations source coal. The ROM coal prices are then used to establish coal prices to power stations, taking into account local transport and handling costs.

Export prices declined dramatically during the second half of 2019 and early 2020 as supply growth outpaced demand – returning coal prices to levels more reflective of the marginal cost of supply. Since late 2020 export prices have increased in response to stronger Asian demand, driven by the region's economic recovery after the impact of COVID-19 and geopolitical factors. China's ban of Australian coal from late 2020 meant alternative sources of supply were needed to meet China's increasing demand. While embargoed Australian coal was mostly sold into alternative markets, constraints caused by the embargo increased inefficiency in trade and put upwards pressure on prices. Indonesia has been a major beneficiary (although in recent months, the Indonesian Government has reduced exports to satisfy domestic requirements), but coal has been sourced as far away as South Africa and Columbia.

Most recently, the war in Ukraine and embargo of Russian trade is putting additional pressure on thermal coal markets. Supply from some producers was voluntarily curtailed in 2020 in response to the low export prices, while a number of weather events also impacted coal supply chains, resulting in a tighter thermal coal market. More recently, domestic reservation policies have been invoked (for example, Indonesia) placing further pressure on supply.

The Reference case assumes that export coal prices will peak at USD 306/t in real terms in 2022-23, and then falling over time to a long-term marginal cost of supply, assumed to be USD 80/t (real 2023) terms by FY 2030. Export coal prices are then assumed to remain at this level for the remainder of the projection horizon.

Figure 4.1 Assumed Newcastle FOB prices ($/tonne, real 2023)



Source: www.Indexmundi.com and ACIL Allen

4.3 Electricity demand

Regional annual energy and peak demand are important inputs to the Reference case. PowerMark models the segment of the market to be satisfied by the NEM, that is, by scheduled and semi-scheduled generation. This is the underlying or so-called native demand less embedded and non-scheduled generation. Embedded generation includes rooftop solar PV and small cogeneration and other generation systems that are located inside customer premises. Non-scheduled generation are small generation systems (usually less than 5MW) that do not participate in the NEM central dispatch process.

In developing the demand projection for the Reference case, the starting point was the AEMO projection of regional summer and winter peak demands and annual energy published in the Final 2022 Integrated System Plan (ISP) by the Australian Energy Market Operator (AEMO) in December 2021. The demand projection is based on the Strong Electrification scenario and the 50 per cent probability of exceedance (POE50) level peak summer and winter peak demands.

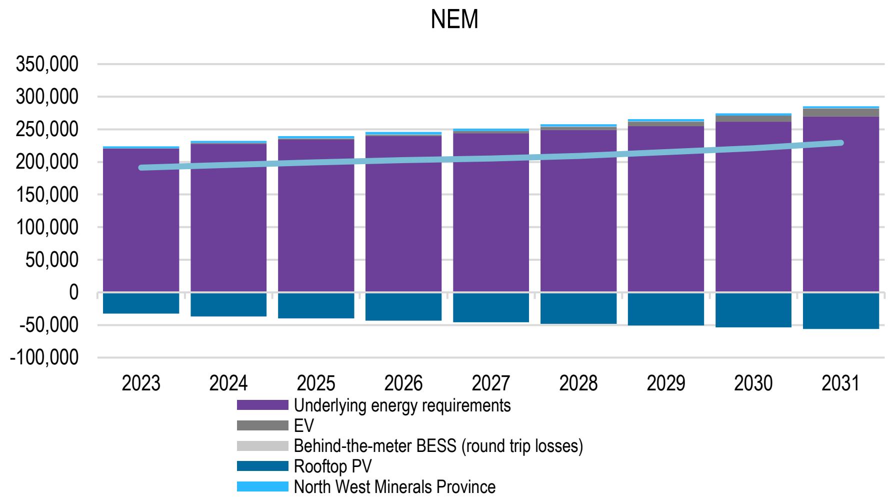
ACIL Allen made the following adjustments to AEMO's demand projection:2

1. ACIL Allen has undertaken and adopted its own projection of the uptake of rooftop solar PV and behind-the-meter storage for both the residential and commercial sector, which are internally consistent with other assumptions (such as exchange rates, capital costs, network tariffs etc.) adopted in the Reference case.
2. ACIL Allen has also undertaken and adopted its own projection of the uptake of electric vehicles. In addition, we are using our own charging profiles in our modelling.
3. ACIL Allen has included extra load from the North West Minerals Province in Queensland.

4.3.1 Energy requirements in the NEM

The resulting NEM-wide energy requirements are shown in Figure 4.2.

Figure 4.2 Assumed NEM energy requirements (GWh, gross)

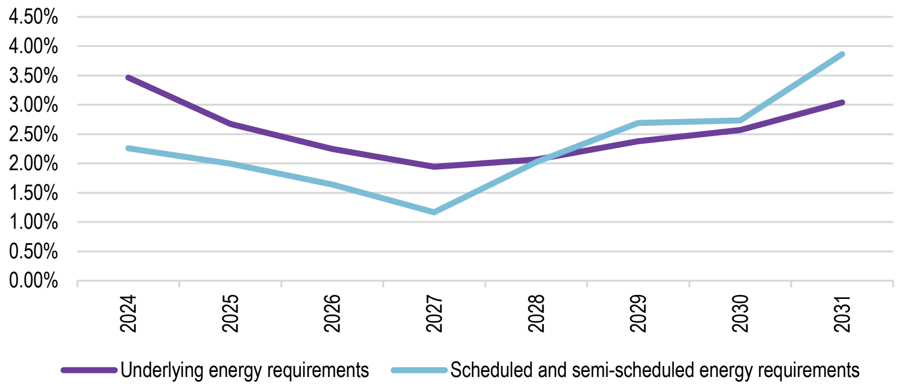


Source: ACIL Allen

2 ACIL Allen also deducts an estimate of significant non-scheduled generation from AEMO's operational demand forecast to arrive at a scheduled and semi-scheduled projection (the segment of the market supplied by the NEM).

There is a strong growth in energy requirements from around 2025 onwards as a result of growth in EV uptake and electrification of gas appliances and some industrial heat applications. Rooftop PV uptake shows a steady growth as well but does not offset the overall NEM-wide growth of scheduled and semi-scheduled energy requirements. By 2030 NEM-wide scheduled and semi-scheduled demand reaches a growth rate of 3.9 per cent as shown in Figure 4.3.

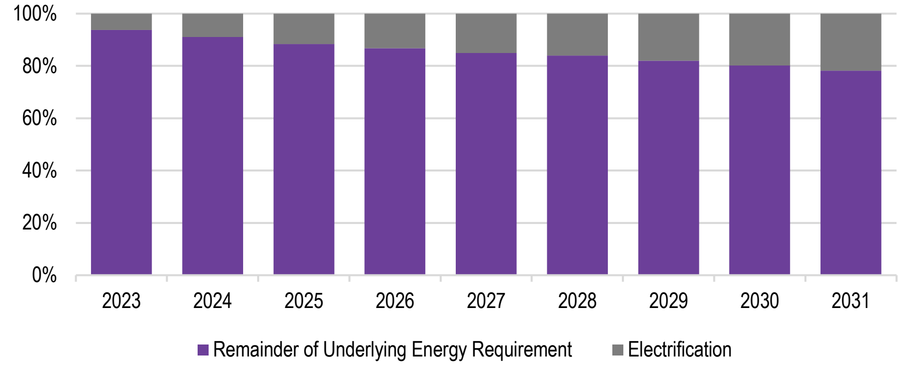
Figure 4.3 Annual year on year growth in assumed NEM energy requirements (%)



Source: ACIL Allen

The continued increase of underlying energy requirements is partly attributed to an increasing rate of NEM-wide electrification. Figure 4.4 shows demand from electrification as a percentage of total underlying demand, rapidly increases over time.

Figure 4.4 Percentage of electrification as part of total underlying energy requirement



Source: ACIL Allen

Peak demand typically occurs in the summer months in all regions of the NEM except for Tasmania. However, the conversion of natural gas appliances for heating, hot water and cooking to electricity, results in higher demand during winter, particularly in Victoria.

The aluminium smelters in the NEM are assumed to continue their operations per AEMO's Central scenario forecast.

4.4 Renewable energy policies

In September 2022, the Climate Change Bill 2022 passed the Senate, which legislates the Federal Government's target of 43 per cent reduction in greenhouse gas emissions from 2005 levels by 2030, and net zero by 2050. Each year, the Government releases economy-wide emissions projections to measure progress towards its 2030 target. The September 2022 quarterly update show that emissions in the year to September 2022 were 21 per cent below emissions in the year to June 2005.

The Large-scale Renewable Energy Target (LRET) has been fully subscribed since September 2019. In the absence of additional national energy policies, state and territories developed their own targets of net-zero emissions by 2050. In October 2021, the Commonwealth government announced a national net zero emissions target by 2050.

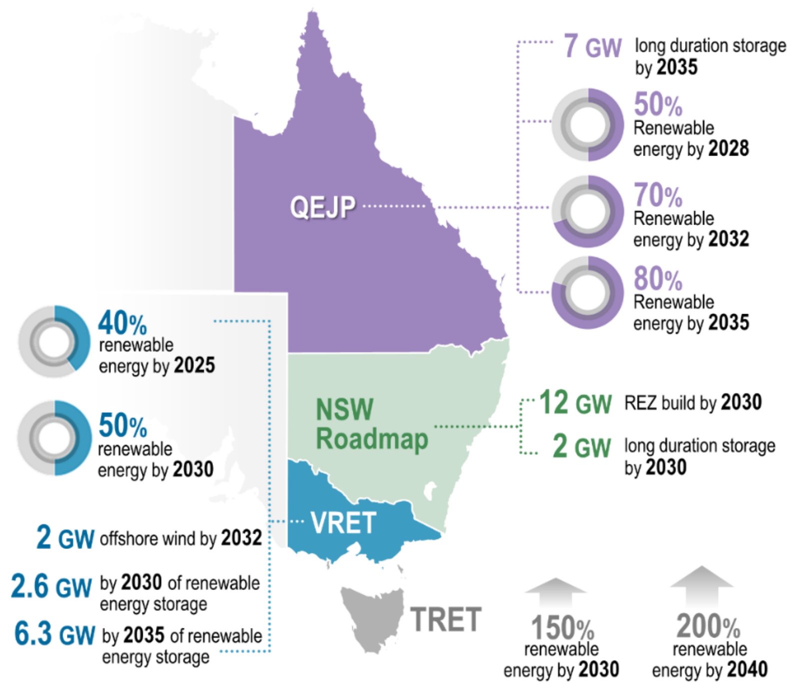
To achieve the various net zero objectives, each jurisdiction is implementing policies with most focusing their efforts in the electricity sector, where available technologies and abatement costs are considered to provide the most cost-efficient and least challenging abatement opportunities3 in the short-term. The electricity sector currently accounts for about one third of Australia's greenhouse gas emissions.

In 2020, a number of states legislated new renewable energy policies. Tasmania legislated ambitious renewable targets of 150 per cent by 2030 and 200 per cent by 2040 (TRET). New South Wales legislated their Electricity Infrastructure Roadmap (the Roadmap).

These renewable energy policies are in addition to Queensland QRET and Victoria's VRET. Both states have recently updated these targets to accelerate its renewable energy ambition and provide targets beyond 2030.

3 Comparatively, abatement in other sectors such as agriculture and transport is more challenging and will take time to implement.

Figure 4.5 State renewable energy policies included in Reference case



Note: South Australia has indicated an ambition of 100 per cent net renewable energy generation by 2030 in their Climate Change Action Plan (2021-2025). However, it is not yet clear how the state intends to deliver on this target.
Source: ACIL Allen

There has also been a particular focus from the state governments of New South Wales, Queensland and Victoria to support the development of Renewable Energy Zones (REZ) as set out in AEMO's Integrated System Plan (ISP). The development of these zones is expected to assist in the achievement of the various renewable energy targets.

The following sections cover the current renewable energy policies which affect the NEM along with a discussion of ACIL Allen's modelling assumptions to implement these policies in our market modelling.

4.4.1 Current energy policies

The LRET

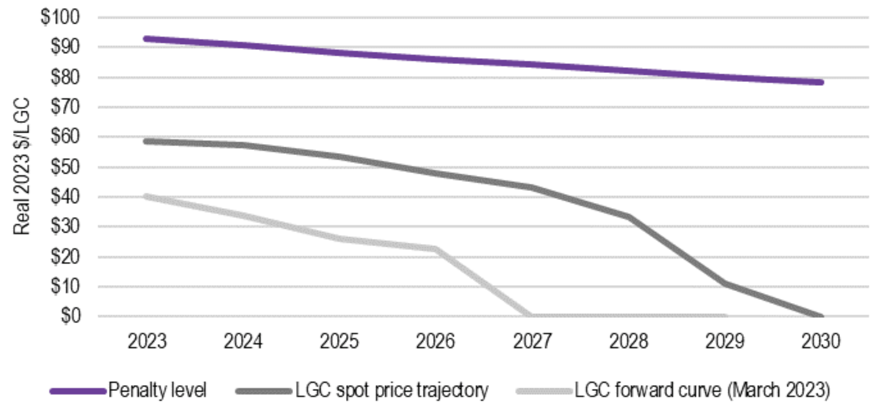
The Commonwealth Government's Large-scale Renewable Energy Target (LRET) has had a direct impact on the electricity sector through the incentives it provided for the development of centralised renewable generation. However, in more recent years, a combination of favourable electricity market conditions and rapidly declining cost of renewable technologies has encouraged large amounts of investment in new large-scale wind and solar capacity in the NEM.

The Reference case assumes an annual LRET target of 33,000 MWh from 2020 to 2030; the current policy. The target has been met and the scheme is now oversubscribed.

In the Reference case, the spot price trajectory of Large-scale Generation Certificates (LGCs)4 reduces the short-run marginal cost (SRMC) of all semi-scheduled wind and solar farms that are eligible to create LGCs.

Figure 4.6 shows the assumed price path for LGCs for the Reference case.

Figure 4.6 LGC price trajectory ($/LGC, real 2023)



Source: ACIL Allen; Voltage Market

Despite the oversupply of LGCs in the market, LGC prices are expected to keep their value up to 2029 due to increasing demand from voluntary surrender. However, LGC prices are projected to fall more rapidly after 2026 when demand of voluntary surrender tapers off.

Compared to our projected LGC prices, forward prices are lower than our projected LGC prices. This projects the expectation of the market on the impact of the Guarantee of Origin scheme on LGC demand. Since the scheme is still under consultation, the actual implications of the scheme on the LGC market are unknown.

4 1 LGC represents 1 MWh of eligible renewable generation

The NSW Roadmap

The New South Wales Electricity Infrastructure Roadmap (the Roadmap) seeks to support the development of 12,000 MW of transmission capacity by 2030.

The capacity allocation is expected to be the following:

- 7,380 MW in the New England Renewable Energy Zone (REZ)
- 3,300 MW in the Central-West Orana REZ (referred herein as Central West),
- another 1,320 MW in the remaining zones (South West, Southern, Central Tablelands and/or Central Coast).

The development of wind and solar generation in these REZs will be supported by competitive tender processes, awarding renewable projects access rights and Long Term Energy Service Agreements. The Roadmap also seeks to support an additional 2,000 MW of long-duration storage (excluding Snowy 2.0) to be built by 2030. The Roadmap, as set out in the New South Wales Electricity Infrastructure Investment Bill (the Bill), was legislated in December 2020.

In December 2021 AEMO Services published its 10-year tender plan, laying-out its schedule for running the competitive tender processes. Accounting for the duration of these tender processes and build times, the Reference case assumes the Roadmap capacity is added to the market in approximately a straight-line over the period from 2023 through 2032.

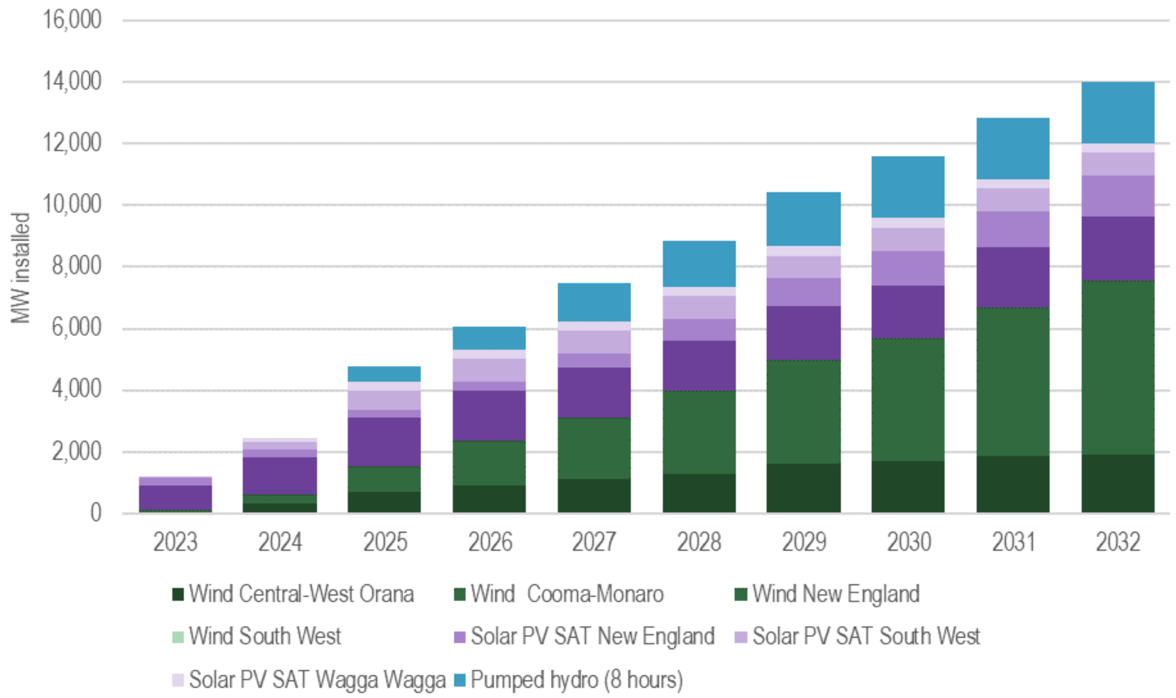
ACIL Allen has identified a total of 3,278 MW of generation and 1050MW/2030MWh of storage in committed and operational projects which are potentially eligible to form part of the Roadmap. These projects are for the most part located in either the New England or Central West zones and were identified as committed or existing in a generation information page published by AEMO under the National Electricity Rules after 14 November 2019 (per the eligibility requirement outlined in the Bill). They are assumed to enter the market between 2022 and 2024 and include:

Table 4.1 Committed New South Wales Roadmap projects

Projects	
Crudine Ridge Wind Farm (135 MW, Central West)	Nevertire Solar Farm (105 MW, Central West)
Goonumbla Solar Farm (69 MW, Central West)	Molong Solar Farm (36 MW, Central West)
Gunnedah Solar Farm (110 MW, Central West)	Metz Solar Farm (115 MW, New England)
West Wyalong Solar Farm (90 MW, South West)	Suntop Solar Farm (150 MW, Central West)
Wellington Solar Farm (174 MW, Central West)	Crookwell 3 Wind Farm (58 MW, Southern)
New England Solar Farm (400 MW, New England)	Rye Park Wind Farm (396 MW, Southern)
Hillston Sun Farm (85 MW, South West)	Avonlie Solar Farm (190 MW, South West)
Flyers Creek Wind Farm (145 MW, Central West)	Wellington North Solar Farm (300 MW, Central West)
Riverina Solar Farm (40 MW, South West)	Wollar Solar Farm (280 MW, Central West)
Riverina Energy Storage System 1 (60MW/120MWh)	Riverina Energy Storage System 2 (65MW/130MWh)
Broken Hill Battery (50MW/50MWh)	Darlington Point Energy Storage System (25MW/50MWh)
Waratah Super Battery (850 MW/ 1680MWh)	Stubbo Solar Farm (400 MW)
Walla Walla Solar Farm (300 MW)	

Source: ACIL Allen

Figure 4.7 Assumed New South Wales Roadmap capacity (MW) by technology



Source: ACIL Allen

The Queensland RETs

There are several initiatives by the Queensland Government. In September 2022, the Queensland Government has announced the Queensland Energy and Jobs Plan (QEJP). The plan includes the following key points:

— The QRET target of 50 per cent met by 2028 instead of 2030
— A renewable energy target of 70 per cent in Queensland by 2032
— A renewable energy target of 80 per cent in Queensland by 2032
— A minimum of 25 GW of wind and solar generation by 2035
— 7 GW of long duration storage by 2035
— Stated-owned coal fleet exists the market by 2035

So far, under the Powering Queensland plan the Queensland Government has committed to the following:

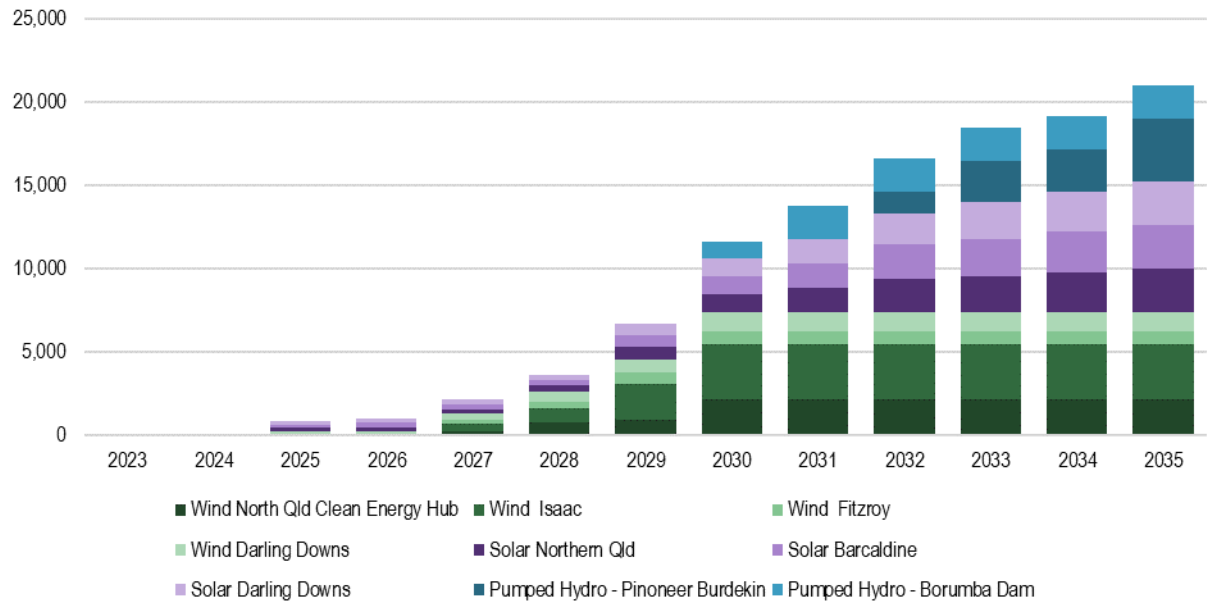
Establishment of CleanCo based around Wivenhoe and Swanbank E (and hydro plant in north Queensland) with the objective of 'firming up' contracted renewable energy and supporting up to 1,000 MW of majority Government owned renewable energy projects. In May 2020, CleanCo committed to:

a 400 MW power purchase agreement with the owners of MacIntyre wind farm resulting from the Government's Renewables 400 initiative. CleanCo also announced that it will build its own 100 MW wind farm on the same site.

a 320 MW power purchase agreement with the owners of Western Downs solar farm.

Our analysis shows that a further 15,256 MW of new wind and solar capacity will be required by 2035 to meet the QEJP targets. This capacity is assumed to be added to the market from 2025 such that the state's renewable energy penetration increases approximately linearly to 2035.

Figure 4.8 Assumed QEJP capacity (MW) by technology type and REZ



Source: ACIL Allen

The Victorian RETs

The Victorian Government has committed to renewable energy generation targets (VRET) of 40 per cent by 2025 and 50 per cent by 2030, which are enacted by the Victorian Renewable Energy Auction Scheme (VREAS). The scheme involves establishing power purchase agreements with entrant renewable projects which are allocated through reverse auctions.5

For the first round VRET auction, five projects totalling 807 MW of grid-based wind and solar PV projects were announced in September 2018.

For the second round VRET auction (VRET2), a further six projects totalling 623 MW of grid based solar PV projects, as well as an additional 365MW/600MWh of battery storage were announced in November 2022. This results in the 50 per cent target being met by 2025.

In 2022 Victoria updated its renewable energy target to 65 per cent renewable energy by 2030 and 95 per cent renewable energy by 2035.

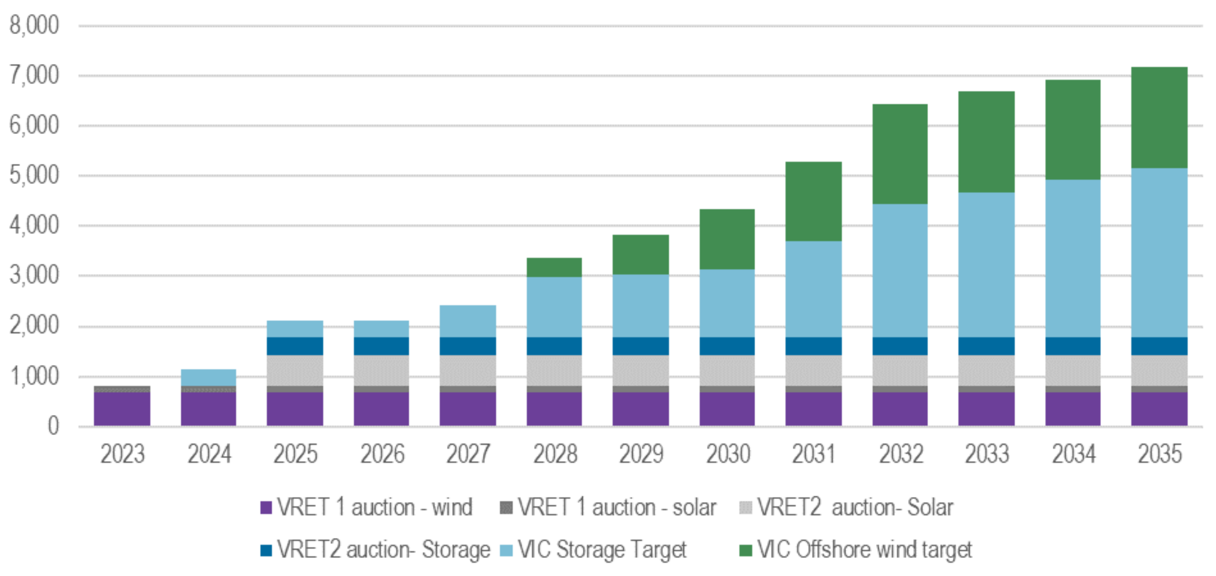
In addition to the two VRET auction rounds, Victoria also introduced the Victorian Solar Homes Program, which will increase the number of rooftop PV installations in Victoria.

In September 2022, Victoria has committed to at least 2.6 GW of energy storage capacity by 2030 and at least 6.3 GW by 2035.

Victoria also announced an offshore wind target of 2 GW offshore wind capacity by 2032, 4 GW by 2035 and 9 GW by 2040. These Victorian targets are not yet legislated; however, we have included the 2GW target to meet the legislated 95 per cent renewable energy target by 2035.

This reference case assumes that the Victorian goal of 95 per cent renewable energy by 2035 is met. Crucially this involves the closure of Loy Yang A and B power stations by 2035.

Figure 4.9 Assumed VRET capacity (MW) by technology type



Source: ACIL Allen

5 Section 7C in the Federal RET legislation effectively invalidates any state-based scheme which is substantially similar to the Federal scheme. This effectively prohibits the states from employing a certificate-based market scheme to encourage additional renewables. This is a key reason why state governments have preferred power purchase agreements allocated through reverse auctions.

The Tasmanian RET

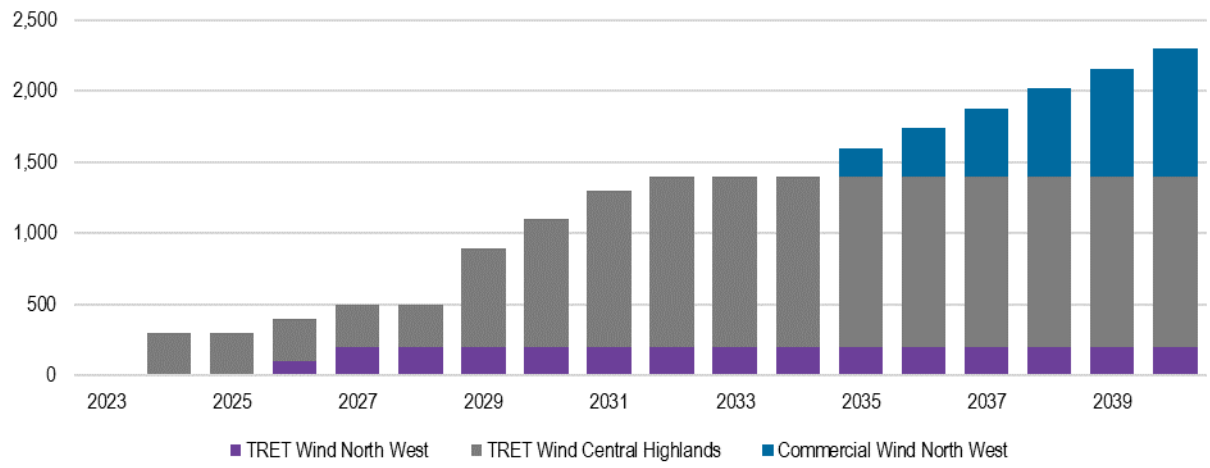
The Tasmanian Government announced the Tasmanian Renewable Energy Target (TRET) in mid-2020, which was legislated in late 2020. The TRET requires renewable generation equivalent to 150 per cent and 200 per cent of the region's energy requirements by 2030 and 2040, respectively. This equates to an additional 5,250 GWh and 10,500 GWh of annual generation by 2030 and 2040, respectively.

The Reference case assumes that the new renewable generation capacity is added to the market in approximately a straight-line over the period from 2027 through 2040. Most of the TRET is expected to be met by new large-scale wind generation, with a smaller contribution from new rooftop solar PV.

The Reference case assumes that the targets of 5,250 GWh by 2030 and 10,500 GWh by 2040 are met using expected generation outcomes (based on renewable resource) from new renewable capacity in Tasmania.

Our modelling shows that from 2033 onwards there is opportunity for additional commercial wind to enter the Tasmanian region on top of the projected TRET capacity. This is because of increased demand in Tasmania as a result of electrification, as well as increased interconnection between Tasmania and Victoria, following the assumed commissioning of MarinusLink between 2028 and 2031. By 2040 an additional 2,100 MW of commercial wind is projected to enter the Tasmanian region, in addition to the capacity entering with the support of the TRET (refer Figure 4.10).

Figure 4.10 Assumed TRET capacity (MW) by technology type and REZ



Source: ACIL Allen

South Australia's 100 per cent net renewable energy ambition

South Australia has indicated an ambition of 100 per cent net renewable energy generation by 2030 in their Climate Change Action Plan (2021-2025).

In June 2022 the South Australian government announced a Hydrogen Jobs plan. This plan includes the development of a 250 MW electrolyser, a 200MW hydrogen-fuelled power generator and a hydrogen storage facility by the end of 2025. The plan is said to unlock the development of a $20 billion pipeline of renewable energy projects.

The new interconnector EnergyConnect is also intended to support the expansion of renewable energy in South Australia as it connects the South Australian electricity network to New South Wales.

No further details have been released on how the renewable energy target in South Australia will be achieved. Therefore, ACIL Allen has not explicitly included the South Australian target in the Reference case.

4.5 Generation capacity

This section explains the rationale behind our assumptions relating to existing and new entrant supply.

ACIL Allen's approach to modelling the NEM's electricity supply is to:

1. incorporate changes to existing supply where companies have formally announced the changes – expansions and upgrades, mothballing, closure and change in operating approach
2. include plants that are considered to be committed projects (generally once a final investment decision has been reached) as named projects in the model database
3. include additional capacity requirements to satisfy government policies (including renewable energy targets assumed in the Reference case) as generic entrants.
4. include additional capacity determined to be commercially viable by the modelling as generic entrants.

Plant closures

With the exception of those plant that are assessed as being committed to close, ACIL Allen assesses the net revenue on a per kW/year basis for each generator (capital return per installed kW after accounting for variable and fixed O&M costs).

Where net revenues are projected to be negative on a sustained basis, the generator is closed. While this is an exercise in perfect foresight that is be available to plant owners, we consider it is a reasonable approach to model likely outcomes.

The O&M cost profiles for major coal-fired power station is not smooth as it is correlated with major maintenance cycles. However, the modelling assumes a smoothed fixed O&M profile for each station in the NEM as ACIL Allen does not have detailed maintenance schedule information. Therefore, the closure of a given generator, as suggested by the modelling, may in practice be brought forward or delayed slightly by the actual timing of major maintenance outages.

The Reference case assumes that the operating coal-fired generators do not extend beyond the end of their technical lives (Table 4.2). Life extension of coal-fired generators is considered unlikely given the continued trend in investment in renewable generation and less emission intensive firming generation, and the large capital outlays required to extend generator lives and short period of time available to recover the investment as Australia moves to net zero emissions. Coal generators will be unable to operate in a net zero emissions environment.

Owners of coal fired generators have submitted to AEMO an expected closure year as required by the National Electricity Rules (NER). In many cases the expected closure year is within one year of the end of technical life. Owners are required to provide this information and update it immediately where it changes. The Reference case assumes coal generators will not operate beyond their submitted closure years.

Table 4.2 Assumed end of technical life date and expected closure year

Generator	End of technical life date	AEMO expected closure year
Liddell	2022	2023
Vales Point B	2029	2029
Callide B	2028	2028
Gladstone	2029	2035
Yallourn	2032	2028
Eraring	2033	2027*
Bayswater	2035	2033
Tarong	2036	2034
Mt Piper	2043	2040
Stanwell	2045	2033
Loy Yang A	2048	2035
Callide C	2051	Unknown
Millmerran	2052	2051
Tarong North	2052	2034
Loy Yang B	2056	2035
Kogan Creek	2057	2035

Note: All ACIL Allen closure years are based on AEMO's expected closure years unless a coal plant is considered uneconomic before these dates. ACIL Allen also assumes all coal plant to be closed by before 2050.

**AEMO assumes Eraring to close by 2025, but we have assumed a delayed closure following the delayed start of Snowy 2.0.*

Source: ACIL Allen; AEMO

4.5.1 New committed supply

Table 4.3 shows the near-term entrants that ACIL Allen considers committed projects and are therefore included in the Reference case. These projects are not yet registered in the market but are expected to come online in the near-term future.

Table 4.3 Near-term addition to supply

ID	Region	Name	Generation Technology	Capacity (MW)	First energy exports
1	NSW1	Avonlie Solar Farm	Solar	190	Q3 2023
2	NSW1	Bango Wind Farm	Wind	85	Q3 2023
3	NSW1	Capital Battery	Battery	100	Q2 2023
4	NSW1	Crookwell 3 WF	Wind	58	Q1 2023
5	NSW1	Hunter Power Project	Natural gas	660	Q4 2023
6	NSW1	Rye Park WF	Wind	396	Q1 2024
7	NSW1	Flyers Creek WF	Wind	145	Q1 2024
8	QLD1	Bouldercombe Battery	Battery	50	Q2 2023
9	QLD1	Clarke Creek WF	Wind	450	Q3 2023
10	QLD1	Dulacca WF	Wind	180	Q3 2023
11	QLD1	Kaban WF	Wind	157	Q2 2023
12	QLD1	Kidston Storage Hydro	Pumped Hydro	250	Q3 2024
13	QLD1	Macintyre Wind Farm	Wind	923	Q4 2024
14	QLD1	Wambo WF	Wind	250	Q1 2024
15	QLD1	Karara WF	Wind	103	Q1 2024
16	SA1	Cultana Solar Farm	Solar	280	Q2 2023
17	SA1	Goyder South WF	Wind	100	Q3 2024
18	SA1	Torrens Island BESS	Battery	250	Q2 2023
19	NSW1	Riverina Solar Farm	Solar	40	Q4 2023

ID	Region	Name	Generation Technology	Capacity (MW)	First energy exports
20	NSW1	Wollar Solar Farm	Solar	280	Q2 2024
21	NSW1	Wellington North Solar Farm	Solar	300	Q3 2024
22	SA1	Tailem Bend Solar Farm 2	Solar	87	Q3 2023
23	SA1	Goyder South WF	Wind	412	Q3 2023
24	QLD1	Wandoan South Solar Stage 1	Solar	125	Q2 2023
25	VIC1	Wunghnu Solar Farm	Solar	80	Q3 2024
26	NSW1	Waratah Super Battery	Battery	850	Q1 2025
27	NSW1	Stubbo Solar Farm	Solar	400	Q1 2024
28	QLD1	Tarong West Wind Farm	Wind	500	Q1 2026
29	SA1	Tailem Bend Battery	Battery	51	Q3 2023
30	NSW1	Broken Hill Battery	Battery	50	Q3 2023
31	NSW1	Darlington Point Energy Storage	Battery	25	Q2 2023
32	NSW1	Riverina Energy Storage System 2	Battery	65	Q2 2023
33	VIC1	Kiamal Solar Farm Stage 2	Solar	150	Q1 2025
34	VIC1	Glenrowan Solar Farm	Solar	102	Q1 2024
35	VIC1	Derby Solar Farm	Solar	95	Q1 2024
36	VIC1	Fulham Solar Farm	Solar	80	Q1 2025
37	VIC1	Frasers Solar Farm	Solar	77	Q1 2024
38	VIC1	Horsham Solar Farm	Solar	118.8	Q1 2025
39	VIC1	Derby Battery	Battery	85	Q1 2025
40	VIC1	Fulham Battery	Battery	80	Q1 2025
41	VIC1	Kiamal Battery	Battery	150	Q1 2025

ID	Region	Name	Generation Technology	Capacity (MW)	First energy exports
42	VIC1	Horsham Battery	Battery	50	Q1 2025
43	QLD1	Herries Range Wind Farm	Wind	1000	Q1 2026
44	VIC1	Golden Plains Wind Farm	Wind	756	Q3 2025
45	QLD1	Western Downs Battery	Battery	200	Q3 2024
46	SA1	Blyth Battery	Battery	200	Q4 2024
47	NSW1	Liddell Battery	Battery	250	Q1 2025
48	VIC1	Gnarwarre Battery	Battery	250	Q1 2025
49	VIC1	Mortlake Battery	Battery	300	Q1 2025
50	SA1	Bungama Battery	Battery	200	Q3 2024
51	QLD1	Mt Fox Battery	Battery	300	Q1 2025
52	QLD1	Kingaroy Solar Farm	Solar	40	Q3 2023
53	NSW1	Walla Walla Solar Farm	Solar	300	Q2 2024
54	QLD1	Mica Creek Solar Farm	Solar	88	Q4 2023

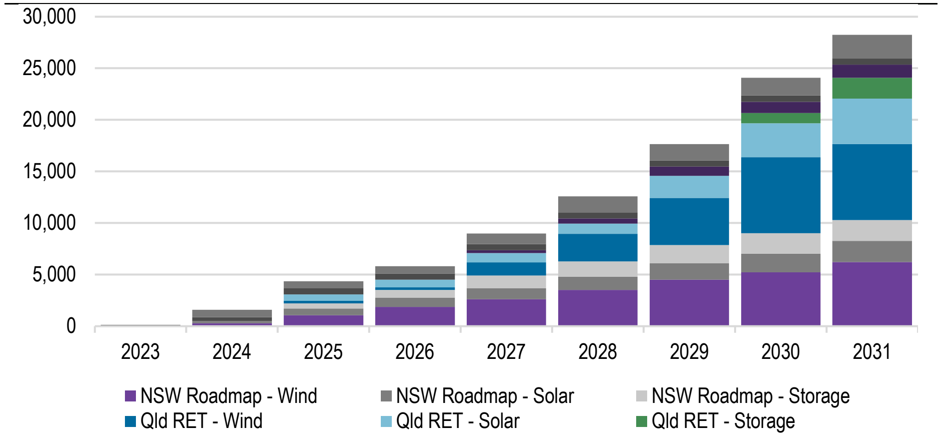
Source: ACIL Alen

4.5.2 New supply to meet state renewable energy targets

ACIL Allen analysis shows that the assumed state based renewable energy policies in the Reference case will require about 23,450 MW of new investment between 2023 and 2030, as shown in Figure 4.11. Although a significant task, it is considered feasible. For example, around 12,000 MW of renewable capacity has been commissioned in the NEM within the past decade.

Unless specified as part of the relevant policy, the Reference case introduces new investment to satisfy each policy on a least cost basis in terms of technology, location and timing.

Figure 4.11 Projected new investment (MW) resulting from assumed state-based renewable energy policies



Note: No state targets are assumed beyond 2040 (years between 2035 and 2040 are linearly interpolated)
Source: ACIL Allen

New commercial investment

In addition to near term committed investments and policy supported investment required to satisfy government policies, PowerMark introduces utility-scale new investment in generation capacity based on price signals rather than using some form of centralised planning criteria.

This approach simulates the investment decisions made by project proponents. The modelling assumes perfect foresight and introduces the most profitable new entrant in terms of scale, technology and location, provided that once it enters, it meets its required investment return over time.

A note on reserve levels

This approach to modelling new entry may result in reserve levels below what AEMO might consider required to ensure reliability criteria are met. If this is the case, it is implicitly assumed in the Reference case that AEMO utilises its Reserve Trader Role to contract for additional supply and that this supply is offered to the market at the market price cap. As this reserve plant offers its capacity at the market price cap and only operates when unserved energy is likely to occur, it does not affect projected market price outcomes.

Assumed capital costs of new candidate technologies

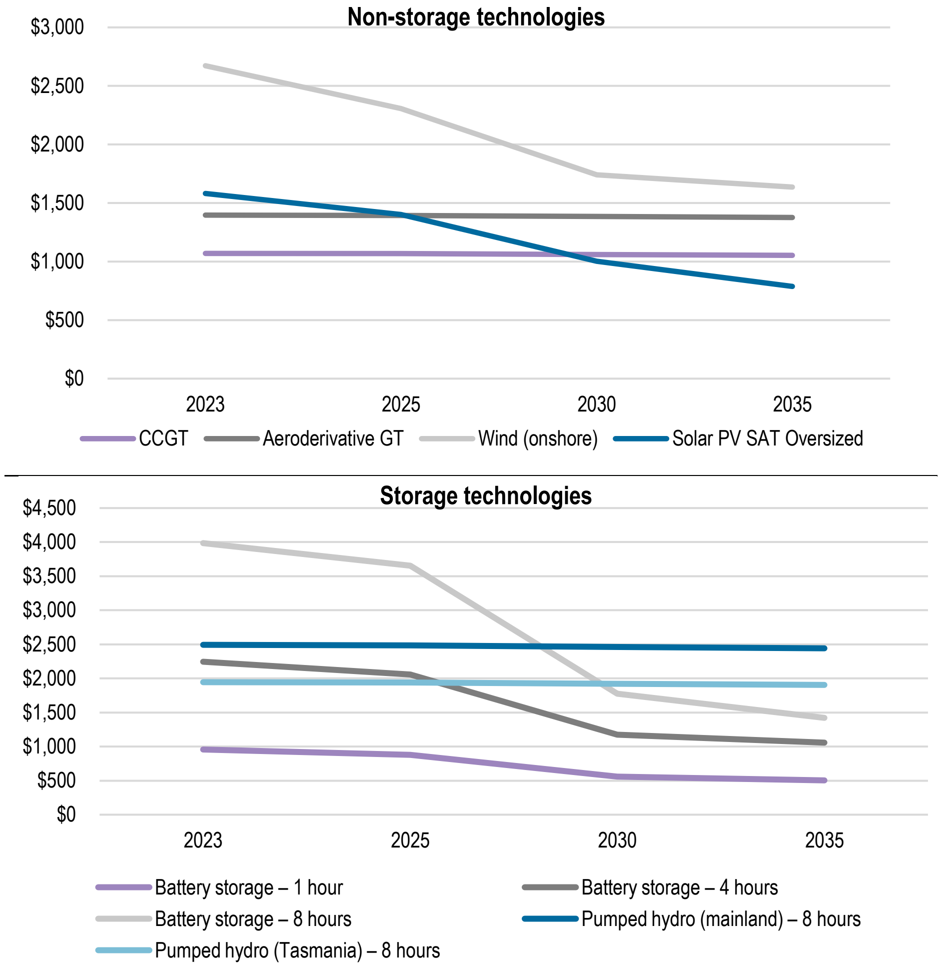
PowerMark includes several different technologies as candidates for commercial new investment in the Reference case.

The starting points for our capital cost estimates for wind, solar, CCGT and aero-derivative GT technologies are derived from our internal database of observed new entrant projects. Starting capital costs for storage technologies are based on a combination of published sources supplemented with de-sensitised information we have gathered when working for clients on development projects of similar type.

Figure 5.13 summarises the trend in assumed capital costs for non-storage and storage technologies in the Reference case. Mature technologies such gas fired generators and pump hydro are assumed to experience little if any further decline in capital costs. Wind and solar capital costs are assumed to experience a decline of about 40 and 50 per cent respectively between now and 2035, and battery storage costs are assumed to decline by about 50 and 60 per cent by 2035.

ACIL Allen maintains a database of cost and technical data for other technologies in addition to those shown above. However, we limit the list of candidate technologies adopted in the modelling to those which are viable under a range of different scenarios.

Figure 4.12 Assumed capital costs by new candidate technology and year of commissioning ($AUD/kW, real 2023)



Source: ACIL Allen

4.6 Fuel costs

Fuel costs are an essential input in a natural gas or coal generator's short-run marginal cost. Other technology types such as wind and solar have zero fuel costs, whilst pumped hydro and batteries face the cost of recharging and paying the pool price. The marginal cost of acquiring water for hydroelectric generators is usually zero or close to zero per MWh generated. However, most hydroelectric generators are energy constrained, and stored water has an opportunity cost, i.e., the value of its next best use).

For details on how ACIL Allen has formed its view of the future price of gas and coal used as a fuel for electricity generation, refer to appendix B.5.

4.6.1 Gas prices

Figure 5.17 shows the modelled wholesale prices for gas delivered to representative nodes in each region of Eastern Australia under the Reference case assumptions for a gas fired CCGT. The prices are inclusive of high-pressure gas transmission charges. Prices delivered into peaking plants have a $2/GJ premium added to account for the intermittency of their consumption.

In the short-term:

As a result of sustained high natural gas prices, the federal government has taken the extraordinary action of capping gas prices through the implementation of a temporary 12-month price cap on new domestic wholesale gas contracts by east coast producers, as well as a long-term mandatory code of conduct governing negotiations moving forward. The cap is set at $12/GJ and applies to gas contracted from existing fields, with prospective supply developments subject to a reasonable pricing provision under the mandatory code of conduct. The price cap will be reviewed in mid-2023 with the mandatory code of conduct and reasonable pricing provision reviewed after 12-months.

Wholesale contract gas prices are thus expected to average $12/GJ in 2023. The Reference case assumes that this price for gas is reflected in the fuel cost of all GPG from the start of 2023 onwards. It is assumed unlikely for gas to be contracted below the price cap. Spot markets including the STTM, GSH (except for Wallumbilla), and the DWGM are unaffected by the gas caps and are expected to continue to follow trends experienced in 2022, as the factors affecting prices during this period continue into 2023.

These factors include major disruptions in international gas and LNG markets from the Russia-Ukraine war which has resulted in LNG prices increasing dramatically (which has affected the domestic market through the LNG netback).

Coal generator capacity will also fall in 2023 with the full closure of Liddell power station anticipated in April 2023. This will place pressure on existing coal plant, and the return of the Callide C units to operation following long term outages at both units. These factors will contribute to demand for GPG in the NEM.

In the medium-term:

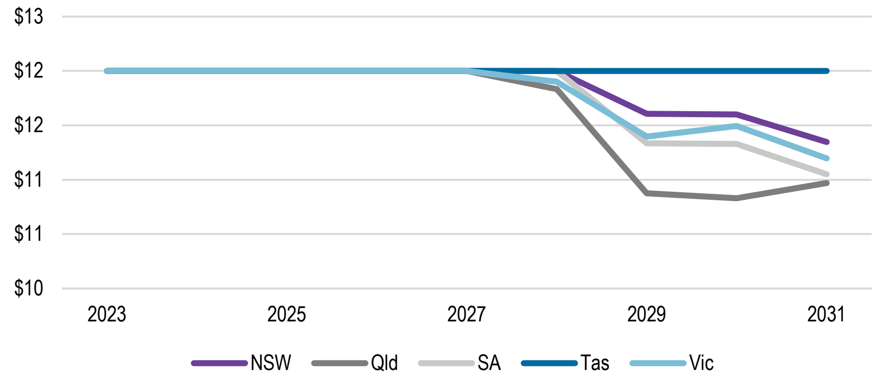
Gas prices are projected to remain at levels around the $12 per GJ out to the mid 2020s. While international LNG prices are expected to stabilise, additional domestic supply and access to LNG imports is expected to be delayed in the domestic market. Previous references cases had prices coming down to levels around the $10 per GJ for a sustained period, however this is now expected to be unlikely due to the effect of the price caps on supply investment decisions.

From the late-2020s through to the early-2030s, ACIL Allen projects domestic gas prices to fall, averaging between $10.20 and $11.60/GJ. The following supply is projected to come online and provide some downward pressure to prices during this period:

— Incremental supply from projects in the Gippsland Basin and the Otway Basin
— The development of an LNG import terminal. ACIL Allen anticipates the Port Kembla terminal to be the first LNG terminal likely to be built with first gas online by 2024.
— The Narrabri Gas Project by Santos from 2024

— Moderate volumes of commercial production during this period emerging from the Beetaloo Basin in the Northern Territory.

Figure 4.13 Assumed wholesale gas prices ($/GJ, real 2023)



Source: ACIL Allen

4.6.2 Coal & gas price caps

This reference case applies the gas and coal price caps starting from 2023. The caps are expected to end when market prices for export coal and gas fall below cap levels. Based on our assumptions, the coal price cap is in place until 2027, whereas the gas price cap is binding until the end of our modelling period.

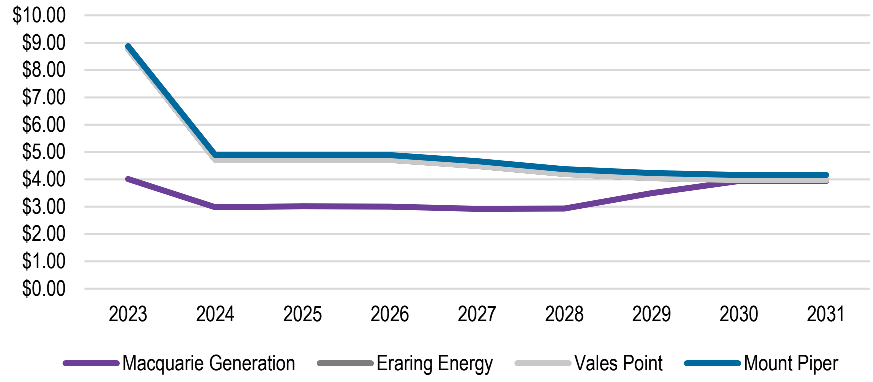
4.6.3 Coal prices

In this report, the price of coal for power generation refers to the marginal price of coal purchased by each power station. As with gas, the federal government has taken action to cap the price of thermal coal used in power generation to $125 per tonne. This measure is aimed at delivering power price relief to Australian consumers connected to the NEM. The price cap will apply to NSW coal generators, with state owned QLD generators instructed to bid in capacity as if running on coal purchased at a price not exceeding $125 per tonne. In this reference case, ACIL Allen assumes that the price cap will start to affect the bidding of generators in NSW and QLD from 2023.

NSW black coal generators

The delivered marginal coal prices into the NSW coal power stations are either linked to export parity coal prices or to the cost of production from supplying mines, whichever is the higher.

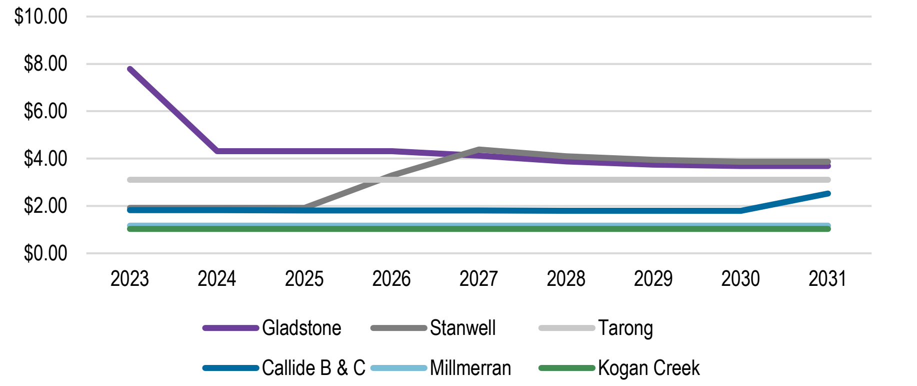
Figure 4.14 Assumed coal price into NSW stations ($/GJ, real 2023)



Source: ACIL Allen

Queensland black coal generators

Figure 4.15 Assumed coal price into Queensland stations ($/GJ, real 2023)



Source: ACIL Allen

Some Queensland power stations are exposed to the export coal price in Queensland. However, there is a significant volume of coal from captive mines in Queensland with much lower prices based on at cost- or cost-plus contracting arrangements.

In Queensland there are four types of coal supply arrangement.

Mine mouth – own mine

Power stations in Queensland relying on their own mine-mouth coal supply are least likely to be affected by export prices, and it has been assumed that they will offer marginal fuel costs into the market. They are Tarong, Tarong North, Kogan Creek and Millmerran.

Mine mouth – captive third-party mine

Callide B and Callide C are power stations with a mine-mouth operation with a third-party supplier. Therefore, they are likely to be under pressure to accept higher prices more in line with export parity, particularly with price reviews and contract renewal.

Transported from captive third-party mine

Stanwell power station has been in a long-term supply arrangement with the Curragh mine since 2004. In 2018-19, Stanwell signed a new supply agreement that will extend its coal supply to 2038. We have assumed that Stanwell will move to an export parity arrangement that imputes the coal netback price when the current agreement expires in the late 2020s.

Transported from third-party mine

Gladstone, which relies on transported coal from third party mines, is most exposed to pass-through of export prices. The Callide Boundary Hill mine is the lowest cost potential supplier of coal into Gladstone as this coal has poor yield for export. Gladstone is assumed to move to an arrangement where half its future coal supply will be at prices at export parity and the other half at prices from the lower cost Callide mine.

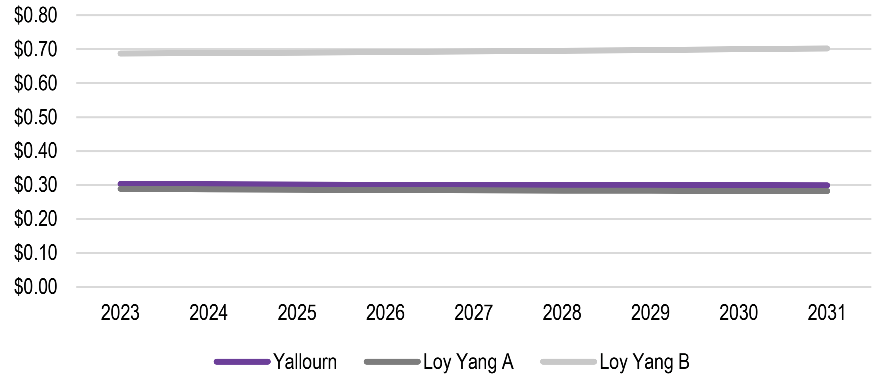
Victorian brown coal generators

Coal mined for power generation in Victoria is not suitable for export and hence not affected by fluctuations in export prices. Extensive deposits of brown coal occur in the tertiary sedimentary basins of the Latrobe Valley coalfield, which contains some of the thickest brown coal seams in the world.

Mine mouth dedicated coalmines supply all the power stations. Except for the Loy Yang B power station, the coal mines are owned by the same entities that own the power stations. Loy Yang B is supplied by the adjacent Loy Yang Power mine (owned by the nearby Loy Yang A power station) under a coal supply agreement that expires around 2050.

The marginal price of coal for the Victorian power stations is generally taken as the marginal cash costs of mining the coal.

Figure 4.16 Projected coal price into Victorian stations ($/GJ, real 2023)



Source: ACIL Allen

4.7 Interconnectors

Interconnectors can either be a source of lower-priced electricity entering a region or a means to export surplus capacity. Existing interconnectors and interconnector expansions assumed in the Reference case are shown in Table 5.3

4.7.1 Existing interconnectors

This section details the modelling assumptions of existing interconnectors in the NEM.

Assumed capacity

Interregional interconnection capacity assumed in the scenarios considers the limitations of the transmission system. Assumed interconnector capacities may be less than the physical capacity because of lower limits on parallel transmission paths and power system stability constraints.

For example, the physical capacity of the interconnecting transmission lines between NSW and Queensland is about 1,000 MW. However, the configuration of the transmission network in New South Wales limits the flow of generation from the Hunter Valley region in NSW to Queensland. Therefore, the capacity of the NSW to Queensland interconnection is limited to about 600 MW. This limit is reduced further during peak and shoulder periods.

The Basslink interconnector

The operation of the Basslink interconnector differs from that of other interconnectors in the NEM. Basslink is set in PowerMark as an entrepreneurial interconnector linking Tasmania to Victoria.

Basslink is owned and operated by Keppel Infrastructure Trust. Hydro Tasmania pays an annual facilitation fee for the exclusive right to offer Basslink capacity to the market and receives all spot market revenues (interregional settlements residues). In response to competition concerns, the Tasmanian Government has imposed restrictions on Hydro Tasmania, requiring all import capacity to be offered at zero dollars (but for exceptional circumstances) and a prohibition on offering capacity at negative prices in either direction.

Therefore, it is bid in a way that attempts to maximise the net revenue of the Hydro Tasmania assets while accounting for the energy-constrained capacity in Tasmania.

Basslink is currently in financial difficulty. Resolution of these difficulties may change the operation of Basslink (e.g., it might be approved as a regulated interconnector). The Reference case assumes that Basslink operation continues in its current form.

4.7.2 New interconnectors and upgrades

All interconnector upgrades assumed in the Reference case are included in AEMO's 2022 ISP list of "committed and anticipated projects". The commencement dates of the interconnectors are aligned with the ISP Hydrogen Superpower scenario since we are using the electrification demand from the Strong Electrification scenario which is a sensitivity of the Hydrogen Superpower scenario.

ACIL Allen's modelling shows that without an upgrade to the QNI following the deployment of the NSW Roadmap's 12,000 MW of renewable capacity, a significant volume of renewable generation would be commercially curtailed in New South Wales. Given AEMO's comments and ACIL Allen's own findings, it is reasonable to assume that the QNI Medium development would proceed to allow increased resource sharing between NSW and Queensland (noting that the current total transfer capability from NSW to Queensland is limited to 450 MW).

The Victorian Big Battery

From September 2021, the capacity of the interconnector between Victoria and New South Wales has been increased for specific periods of the day. The Victorian government requested AEMO to undertake a procurement process for a System Integrity Protection Scheme (SIPS) for the Victoria to New South Wales Interconnector. Neoen won the tender to build and operate the 300 MW/450 MWh battery (the "Big Battery").

The Victorian Big Battery has been installed at the Moorabool Terminal Station in the Geelong region and became operational from the 27th of September 2021.

The battery provides the SIPS service in the summer months (November to March). The interconnector capacity is expanded by 250 MW when the price differential between the two regions exceeds $100/MWh. For the remainder of the year, the battery operates commercially in the NEM. This SIPS service is assumed to be available for ten years.

Table 4.4 Assumed interconnector capacity

Interconnector	Forward direction	Year	Capacity (MW)
VNI	Vic to NSW	Sep 2022 (VNI Minor)	1,070 (590a)
Heywood	Vic to SA	2023	460 (500)
		Jul 2026	560 (600)
Murraylink	Vic to SA	2023	220 (180)
Basslink	Tas to Vic	2023	478 (478)
QNI	NSW to Qld	July 2023 (QNI Minor)	600 (1,290)
		Jul 2029 (QNI connect)	1,432 (2,050)
Terranora	NSW to Qld	2023	50 (150)
EnergyConnect	NSW to SA	Jul 2026	800 (800)
VNI West	Vic to NSW	Jul 2028	1,930 (1,800)
Marinus Link	Tas to Vic	Jan 2029 (first link)	750 (750)
		Jul 2031 (second link)	1,500 (1,500)

a This is expanded by 250 MW when the SIPS service is operational in summer months (assumed to occur when the price differential between the regions exceeds $100/MWh).

Note: Forward capability, with backward capability shown in brackets.

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