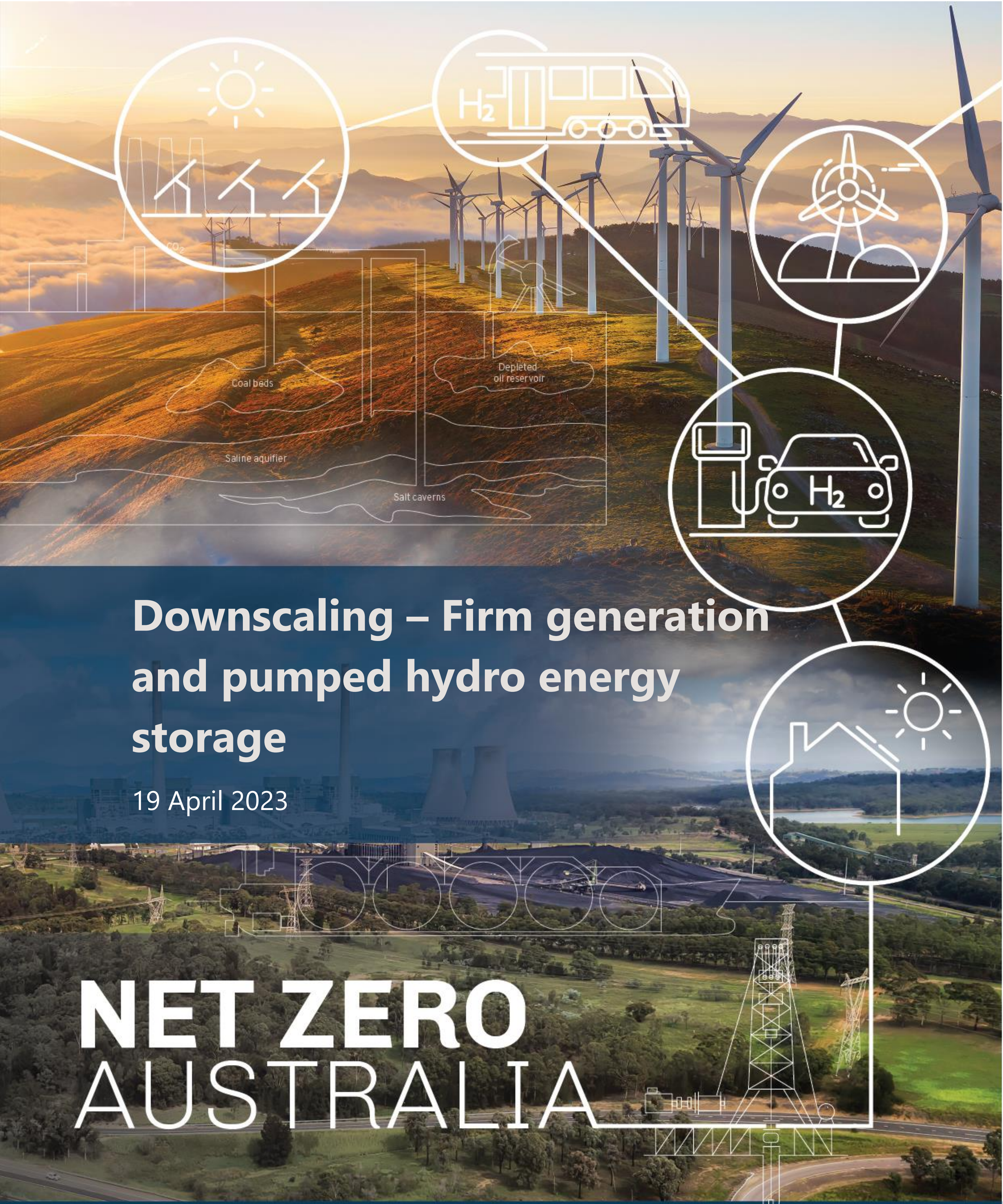


# Downscaling – Firm generation and pumped hydro energy storage

19 April 2023

NET ZERO AUSTRALIA


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ISBN 978 0 7340 5704 4

Vecchi, A, Davis, D, Brear, M 2023, 'Downscaling – Firm Generation and Pumped Hydro Energy Storage', *Net Zero Australia*, ISBN 978 0 7340 5704 4, <https://www.netzeroaustralia.net.au/>

*The Net Zero Australia (NZAu) project is a collaborative partnership between the University of Melbourne, The University of Queensland, Princeton University and management consultancy Nous Group. The study examines pathways and detailed infrastructure requirements by which Australia can transition to net zero emissions, and be a major exporter of low emission energy and products.*

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# Net Zero Australia

# Downscaling – Firm Generation and Pumped Hydro Energy Storage

## 19 April 2023

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[1] The University of Melbourne

# Contents

# 1 Context and scope

## 1.1 Introduction

Firm generation still supplies a significant share of Australian domestic electricity demand. In 2019-2020, 77.4% (205.2 TWh) of domestic power generation was supplied by fossil fuelled generators; renewable energy sources (RES), including hydropower, produced the remaining 22.6% (59.9 TWh). This yielded 190 Mt $CO_2$-e of greenhouse gas (GHG) emissions from the electricity sector [1].

The net-zero transition is now accelerating the shift in electricity production away from fossil fuels and towards renewables. An associated trend is the uptake of distributed energy resources, which were estimated to contribute about 16% of Australia's electricity in 2020, with peaks of 43% in WA and 55% in the NT [2]. In addition, as buildings, transport and industry sectors transition, many appliances and technologies will electrify or switch to alternative, low-emission energy sources. All the above leads to the increasing need for low-emissions electricity generation to be deployed, such as on- and off-shore wind and solar, along with some combination of storage and low-emission firm electricity generation.

This document therefore presents and discusses the changes to power system operation due to shifting supply technologies and demand-side behaviours. It focuses on the role that Pumped Hydro Energy Storage (PHES) and firm generation may play. Other forms of energy storage are discussed in the downscaling reports *Downscaling - Buildings, rooftop photovoltaics and batteries* and *Downscaling - CO2 capture, transmission, use & storage*.

## 1.2 Scope of this document

This document describes the background, methodology and outcomes of downscaling the *Net Zero Australia* (NZAu) Project's modelling results on firm generation and PHES. More specifically, the following are characterised and discussed:

- the retirement of the existing firm generation;
- the scheduling and siting of new firm generation;
- the representation of Australian power system operation before and after net-zero emissions are satisfied domestically; and
- the projected power and energy capacity requirements of electricity storage and the potential for PHES siting in Australia.

In so doing, this document complements the discussion of fossil fuel extraction in the companion downscaling report *Downscaling - Fossil fuel industries* by focusing on the *downstream* use of fossil fuel energy commodities and their evolution over time. Here, *firm generation* denotes power plants running on coal, gas and other liquid fuels as well as hydropower (but not PHES). Whilst the very substantial role of renewable generation is discussed, the siting of renewable projects and associated infrastructure is addressed in the companion downscaling report *Downscaling - Solar, wind & electricity transmission siting*. Concerning electricity storage, siting is crucial for PHES and is addressed in this downscaling report, to yield a plausible quantification of the PHES potential in Australia based on review of publicly available information and discussions with specialist PHES developers. Batteries do not exhibit geographical constraints and therefore are not considered as part of this siting discussion. Rather, behind-the-meter battery installation is also discussed in the companion downscaling report *Downscaling - Buildings, rooftop photovoltaics and batteries*.

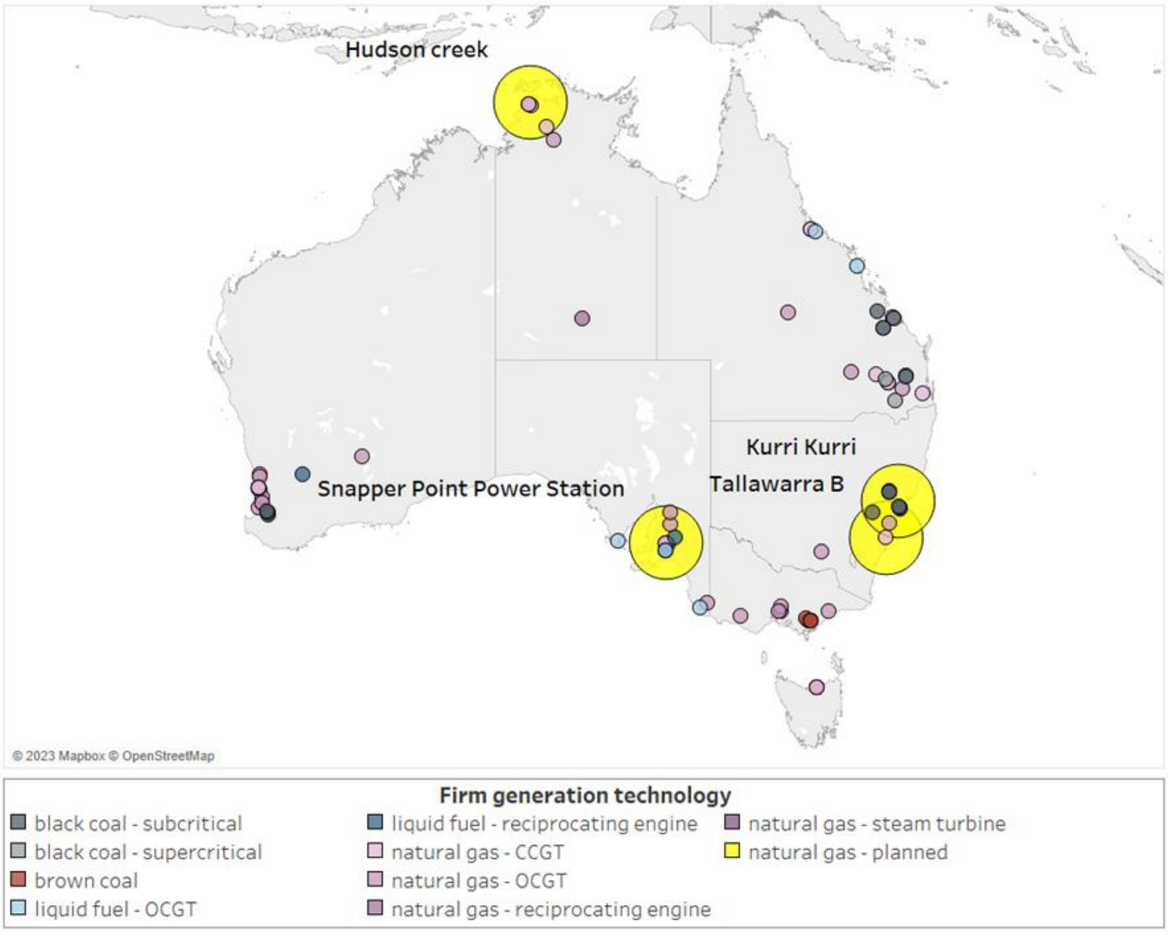
# 2 Background

## 2.1 Firm generation in Australia

Figure 1 shows the locations of operating firm generation plants in Australia in 2020, along with three planned new plants and one plant augmentation. This firm generation fleet is fully incorporated in the Regional Investment and Operations (RIO) platform used to study the optimal Australian decarbonisation pathways in the NZAu Project. All operational generators in 2020 are modelled, together with a number of new plants and plant capacity augmentations that are planned, as detailed below:

1. **Hudson Creek**: planned 15 MW, 6-units gas-fired power plant 15 km out of Darwin, NT [3] (included in the NZAu firm generation fleet from year 2022)
2. **Kurri Kurri**: planned 660 MW, 2-units open cycle gas turbine outside Newcastle, NSW [4] (included in the NZAu firm generation fleet from year 2024)
3. **Snapper Point**: planned 150 MW, 5-units GE TM-2500 aero-derivative open cycle gas turbine 22 km north-west of Adelaide, SA [5] (included in the NZAu firm generation fleet from year 2023)
4. **Tallawarra B**: 316 MW gas plant augmentation, with 5% green $H_2$ blend from 2025 in Yallah, NSW [6] (included in the NZAu firm generation fleet from year 2023).

**Figure 1 | Locations of operating firm generation plants in Australia and planned new plants/plant augmentations as of 2020.**



Australia's overall firm generation capacity is 47.8 GW, with 60%, 37% and 3% share for coal, natural gas and liquid fuel plants respectively, and 6.2 GW of hydropower. Further information on the existing firm fossil generation capacity across Australia is provided in Table 1, including their capacity and scheduled end-of-life (EOL).

**Table 1 | Existing and planned firm fossil generation in Australia as of 2020.**

| Technology | Existing units | Planned units | Capacity [GW] | Median Capacity [MW] | Median scheduled EOL |
|---|---|---|---|---|---|
| Black coal - subcritical | 12 | 0 | 17.1 | 1395 | 2036 |
| Black coal - supercritical | 4 | 0 | 2.9 | 792 | 2047 |
| Brown coal | 3 | 0 | 4.8 | 1450 | 2047 |
| Liquid fuel - OCGT | 7 | 1 | 0.9 | 63 | 2033 |
| Liquid fuel - reciprocating engine | 4 | 0 | 0.2 | 54 | 2070 |
| Natural gas - CCGT | 14 | 0 | 3.7 | 194 | 2046 |
| Natural gas - OCGT | 35 | 3 | 8.9 | 185 | 2047 |
| Natural gas - reciprocating engine | 2 | 0 | 0.3 | 143 | 2047 |
| Natural gas - steam turbine | 5 | 0 | 1.6 | 240 | 2039 |

The distributions of existing gas and coal fired plants by capacity and construction year are presented in Figure 2. The gas-fired fleet is largely made up of plants with a capacity below 400 MW. These are mostly open cycle gas turbine (OCGT) peakers. These assets, with their fast-ramping capability, are important in matching supply and demand and to ensure energy system operability [7]. They are also generally more recent builds than coal assets. Coal-fired power plants have a greater spread in capacity up to 3 GW. Most coal plants are now 30 to 40 years old, as demonstrated by the median EOL year for these assets in Table 1.

**Figure 2 | Capacity and construction year distributions of existing firm fossil generation.**

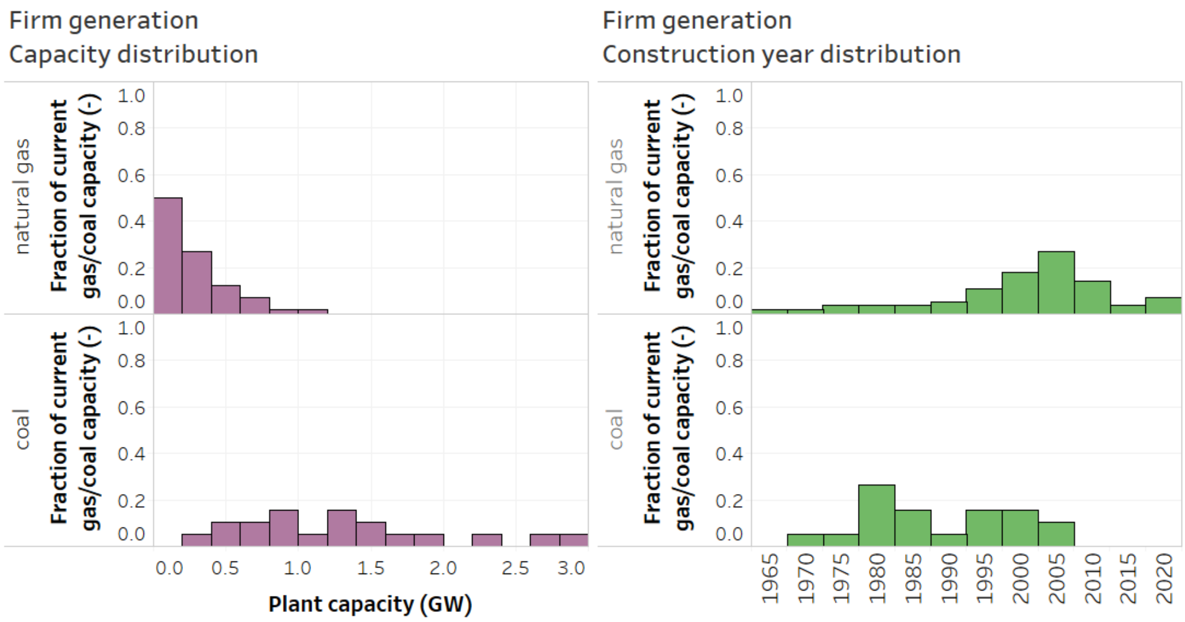



Figure 3 further ranks existing firm generation assets by age and rated capacity, while Figure 4 shows the capacity and year of firm generation assets whose retirements have been announced, firm generation by state and technology. Currently, 32 GW are scheduled to retire by 2050 nationwide; 7.5 GW by 2030. Of these retirements, black coal power plants account for 6.3 GW by 2030 (84% of the total), with a total of 22.3 GW by 2050 (69% of the overall capacity retired). The largest capacity of coal retirements is in New South Wales, including the 2 GW Liddell power plant by 2025 and the 1.3 GW Vales Point B by 2030. Past 2030, black coal generation is scheduled to retire also in Queensland. Notable examples are the 1.7 GW Gladstone plant in 2035, the 1.4 GW Tarong plant in 2040 and Stanwell (1.5 GW) in 2045. In Victoria, the 1.5 GW Yallourn brown coal power plant is currently set to retire in 2028.

These scheduled retirements are part of the 8.4 GW overall retirements by 2030 in the national electricity market (NEM), as mentioned in the AEMO ISP 2022 [8]. In the NZAu Project, input data considered is 5.5 GW planned retirements by 2030, but noting the Eraring plant closure is allowed on or after 2025, and not past 2031, which eventually brings the cumulative retired capacity up to 8.8 GW and consistent with AEMO ISP.

**Figure 3 | Existing firm fossil generation assets in 2020 in Australia by age and rated generation capacity (MW).**

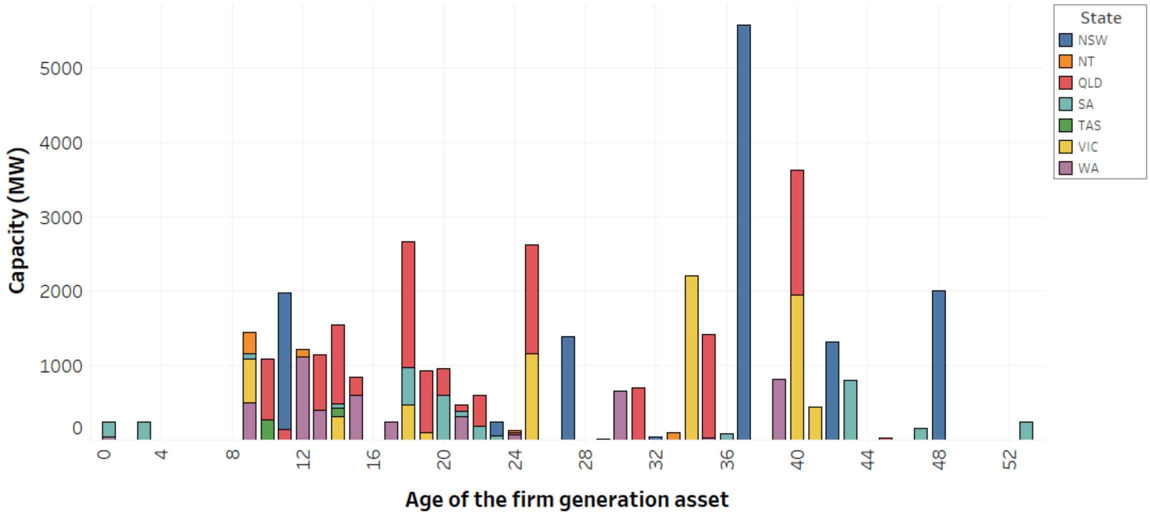
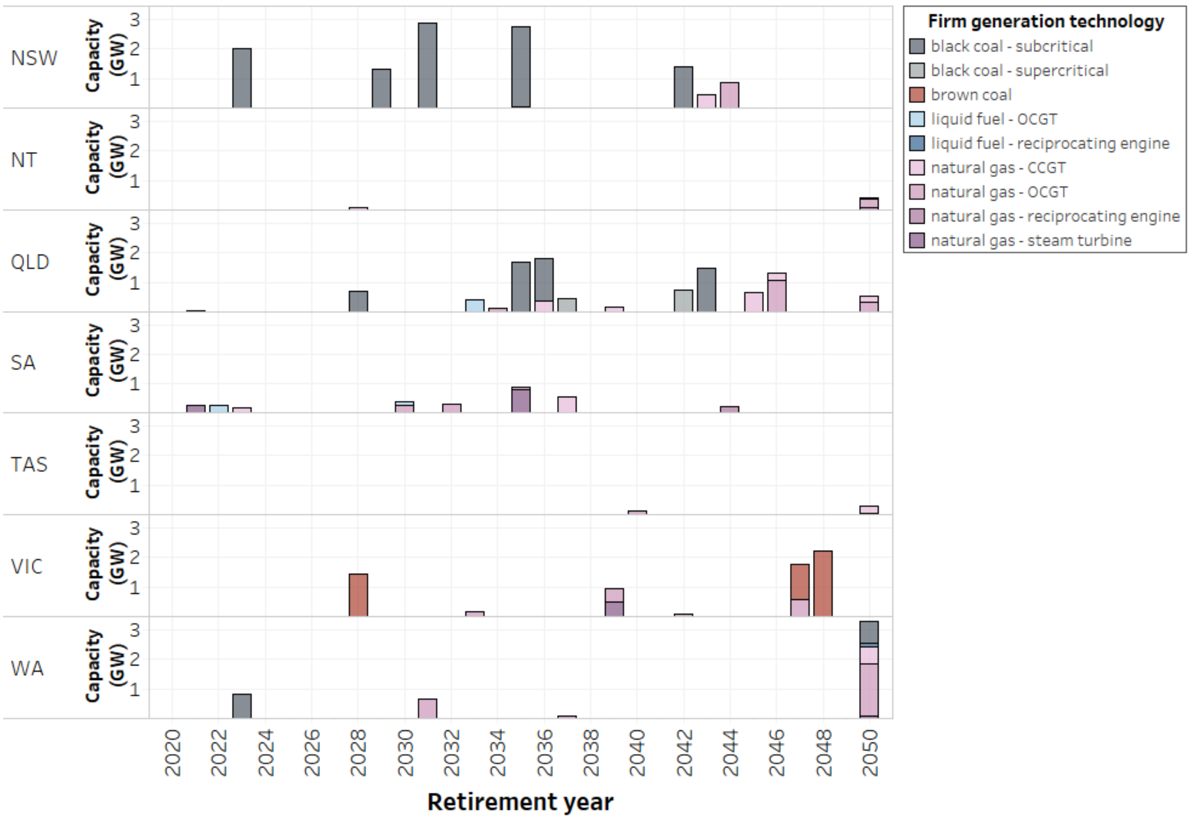



**Figure 4 | Capacity (GW) of scheduled firm fossil generation retirements in Australia by state and technology.**



## 2.2 PHES in Australia

With about 165 GW and 9000 GWh installed worldwide [9], PHES currently represents about 97% of the power and 99% of electricity storage capacity around the globe [10]. PHES can be thought as 'water battery' systems, where two water basins are connected via pipe and machinery (either independent hydraulic pumps and turbines or reversible equipment). Despite being a well-established and reliable storage technology, PHES requires suitable geographical conditions to be technically viable. Currently 3 PHES projects are in operation in Australia: Tumut 3 and Shoalhaven in New South Wales and Wivenhoe in Queensland, with a total of about 1.5 GW of power capacity and 19 GWh of energy storage capacity.

# 3 Outputs of RIO to be downscaled

Figure 5 shows the state-level generation capacity by fuel that is projected each year, as well as both plant retirements (negative capacity change) and new builds (positive capacity change). The firm generation installed capacity is plotted in Figure 6 for the whole of Australia, by either existing or planned assets and new-build assets.

**Figure 5 | Firm generation installed capacity evolution and annual capacity additions/retirements over time, as modelled with the RIO optimisation for selected scenarios.**

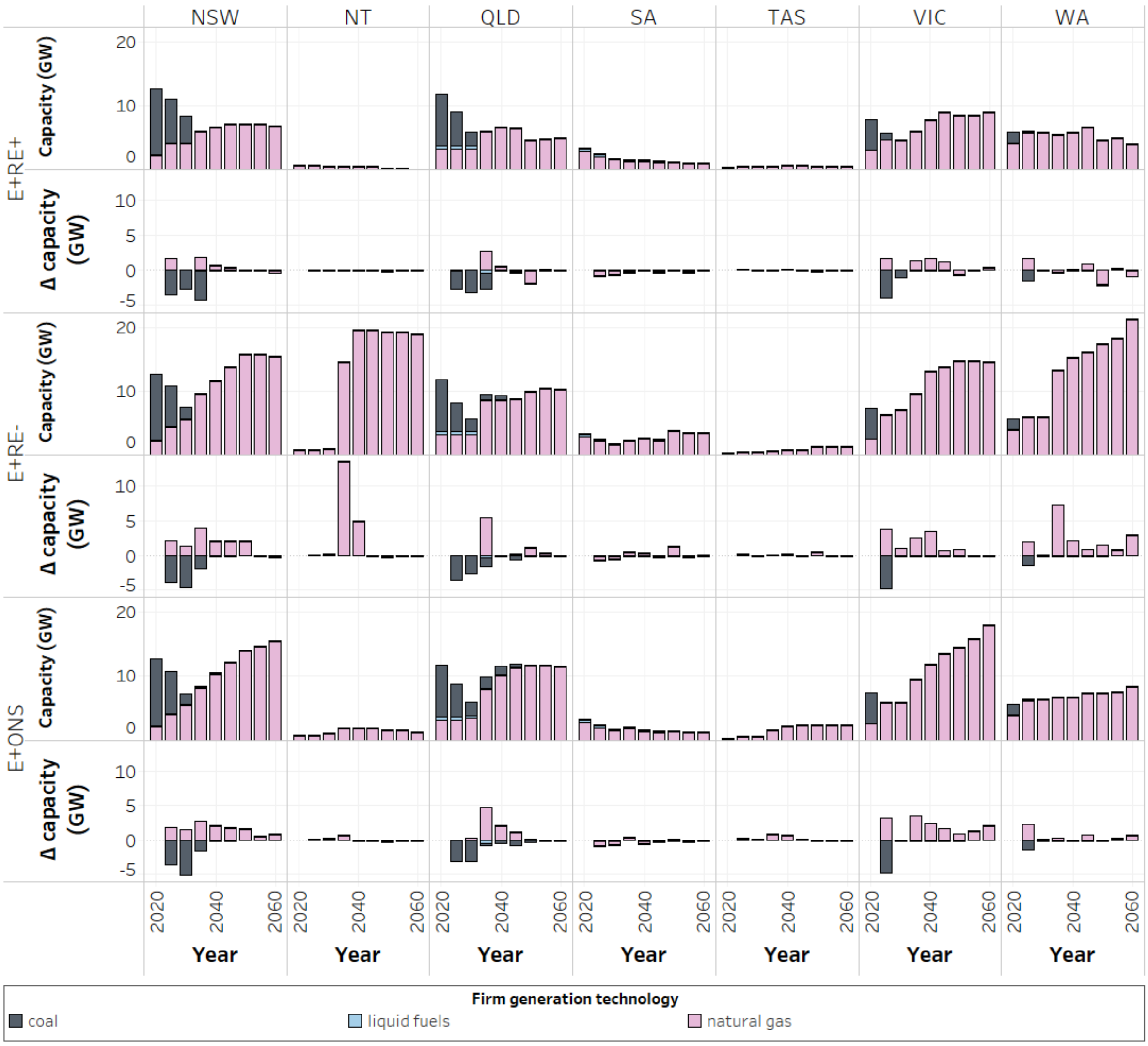


**Figure 6 | Existing/planned and new-build firm fossil generation installed capacity for natural gas and coal assets in Australia over time.**

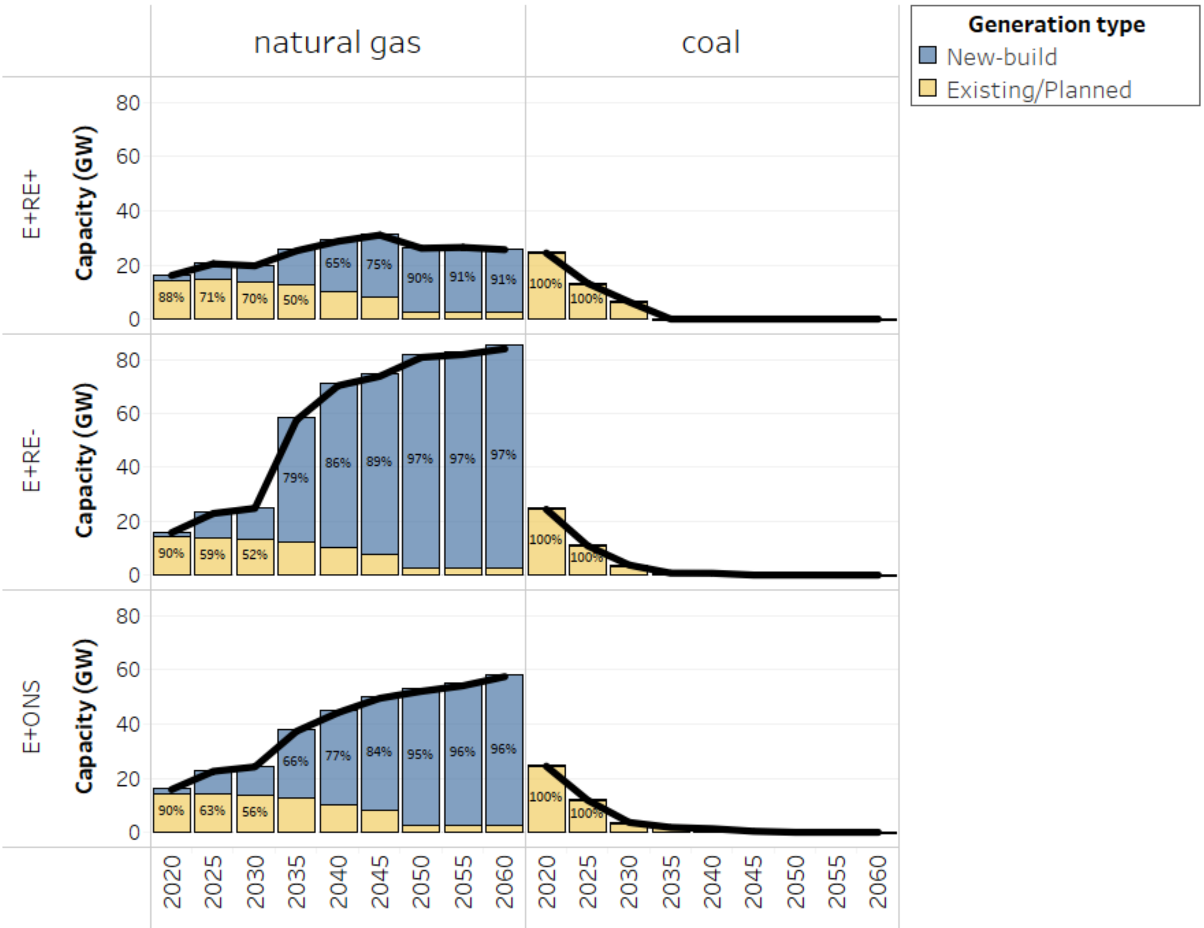
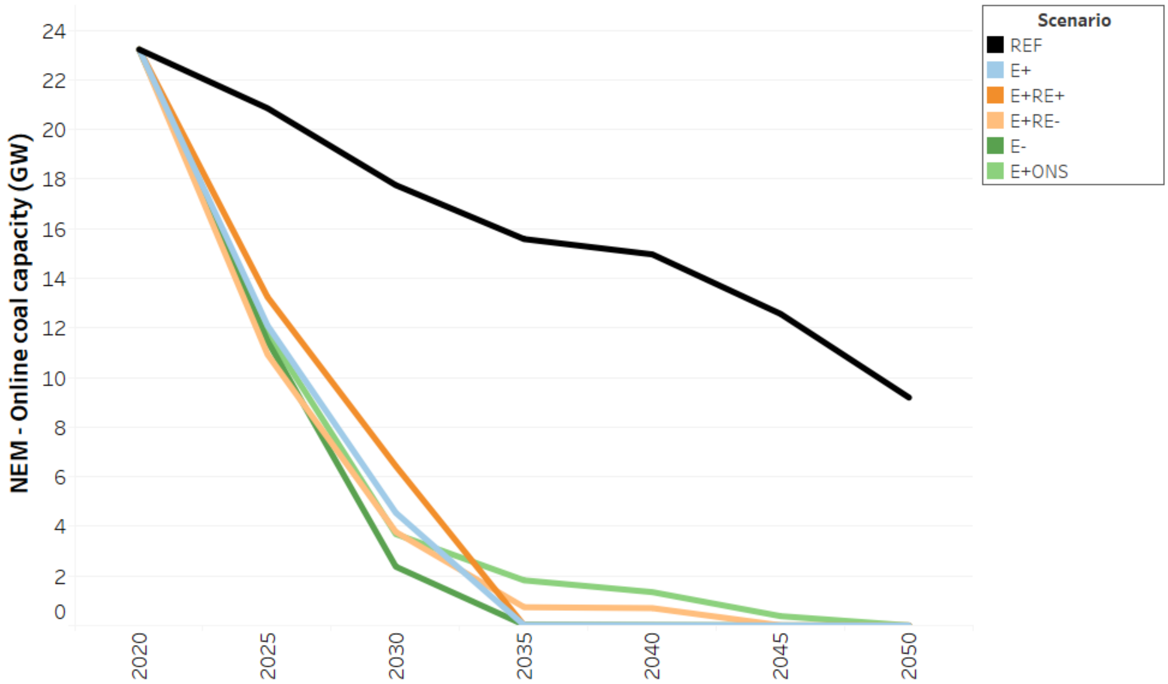



Figure 5 shows that, new firm generation involves only gas-fired generation, whilst coal is phased out across all scenarios. Firm generation retirements, particularly in the decade up to 2030 for coal-fired plants and later on for other assets, would likely free sites that are suitable for new builds. Nationwide, 52.4 GW of natural gas capacity is available by 2050 in the E+RE− Scenario and 17.7 GW in the E+RE+ Scenario. The E+ONS Scenario sits somewhere in the middle, with newly built gas generation providing firm supply for on-shored industrial processes like aluminium smelting.

Across all scenarios, gas assets can be served by synthetic methane and, from 2035 onwards, can be used with any blend of natural gas, synthetic methane and $H_2$. However, the NZAu Project's modelling results depict natural gas as the fuel of choice for most peaking assets which are run with flexibility and low capacity factors. $H_2$ blending in the gas pipelines serving firm generation never exceeds 4% values across scenarios as it appears cheaper to offset residual gas generation emissions with DAC, or gas combined cycles with embedded CCS in Victoria (1.9 GW by 2040), the Northern Territory (4 GW) and New South Wales (2.1 GW), in the E+RE− Scenario as discussed later in this report and in the companion downscaling report *Downscaling - CO2 capture, transmission, use & storage*. Thus, we find the continued but increasingly selective use of fossil natural gas in power generation is a part of optimal generation fleets that play a role in a net zero energy system, alongside much larger renewable and storage capacities.

Figure 7 shows the evolution of the online coal capacity in the National Electricity Market (NEM). We find that between 16.8 and 20.9 GW of coal capacity is to be retired by 2030, with almost no online capacity by 2040. After 2040 the only remaining coal capacity is 0.7 GW at the Kogan Creek power station in the E+RE– Scenario, which is then scheduled to be shutdown in 2042. In the E+ONS Scenario, an overall 1.3 GW is supplied in 2040 from Kogan Creek and Millmerran power plants, in Queensland and Mt Piper, in New South Wales. Of these power plants, only Millmerran remains operational past 2045 and supplies 0.34 GW before its retirement in 2050. We note that the RIO optimisation is formulated as a linear program, which therefore models power plant capacity as a linear variable. In reality, capacity changes can be expected to be lumpy, as such facilities have integer unit sizes and decisions to shut retire facilities may result in all units of a power plant being retired at once. Overall, our results align with those from the AEMO ISP study, which has found for the Step-change Scenario a total of 14 GW coal plant retirements by 2030 (which includes 8.4 GW already announced retirements) and all coal capacity to terminate by 2040. In the ISP's Hydrogen Superpower Scenario, 20 GW should be retired by 2030 [8].

**Figure 7 | Evolution of online coal generation capacity in the NEM, for different NZAu scenarios.**



# 4 Downscaling task

The following assumptions have been made in the downscaling task:

- the analysis is carried out for all scenarios considered in the NZAu Project, since RIO results on firm generation are affected by future choices on both demand- and supply-side measures; however, focus is given to the discussion of the E+RE+ and E+RE− scenarios;
- thermal generator capacities under 14.5 MW (below the smallest planned unit – Hudson Creek OCGT) are treated as rounding error from the optimiser, and set to 0;
- part-load operation of thermal generators is considered until a cut-off value of 10% plant capacity factor. If the generator is found to operate below this level, the asset is shut down or retired; and
- A 5-year conversion time of brownfield sites to host new builds (consistent with the temporal granularity of the present modelling) is considered.

The existing firm generation capacity was included in the RIO modelling by allocating it to the 15 regions considered. RIO then used these existing plants' operating cost and age for sequencing the retirement of generators. Some of the firm generation assets already have a planned date for their retirement, as shown in Table A.1. This retirement schedule is included in RIO; however, where the operation of a given plant to its end of life according to Table A.1 results in a higher total system cost than otherwise, the existing plant is allowed to retire early, just like any other firm generation asset with no planned retirement as of 2020.

The method for downscaling of firm generation then considers the following:

1. existing firm generation retirements;
2. siting and scheduling of gas generation new builds; and
3. power system operation with different generation mixes over the years.

## 4.1 Firm generation retirement

The plant retirement year from RIO modelling outcomes was compared with the currently scheduled retirement date for each asset [12] to identify early retirements and distinguish them from EOL retirements. Such analysis was carried out for black and brown coal generation, natural gas and liquid fossil fuels facilities.

## 4.2 Siting and scheduling of gas generation firm generation new builds

Brownfield siting of new builds is often preferable as it ensures land availability and on-site infrastructure already deployed – although brownfield sites of generation relying on different fuels may not have all the delivery infrastructure nearby (e.g. coal fired plants may not be sited near gas transmission pipelines). In light of this, brownfield sites were prioritized in the NZAu Project downscaling, for the siting of new firm generation, up to the capacity of the existing site since levelised costs at brownfield sites are typically 9-28% lower than greenfield installations [13]. So, as the initial step to this analysis, retired sites in the individual NZAu regions were tracked by date of availability and scenario, and further distinguished between EOL and early retirement sites. Each site also has a given capacity, which was assumed to coincide with the rated power output of its retired firm generation asset.

Then, the new-build capacity by each NZAu region was retrieved from RIO outputs. This includes the capacity associated with designated export zones and ports, which was further assigned to regions, in proportion to the number of export ports present.

With the above elements, for each 5-year period, the new capacity that was modelled with RIO to be built was assigned, first, to the available brownfield sites, based on a ranking system developed for this downscaling task to prioritise individual brownfield sites over others. That is, a score was assigned to each site as the summation of the below criteria:

- Criterion 1: Brownfield site was previously hosting a natural gas plant (binary score: 1 if yes, 0 if no)
- Criterion 2: Brownfield site is an EOL retirement (binary score: 1 if yes; 0 if no)
- Criterion 3: Population density in the SA2 region where the brownfield site is located (continuous score: normalized between 0 and 1, with 1 identifying the lowest populated area)
- Criterion 4: Proximity of existing gas transmission pipeline (continuous score: normalized between 0 and 1, with 1 identifying the site with the lowest linear distance from a gas pipeline)

Equal weight was attributed to each of the chosen indicators to rank the alternatives; however, this arbitrary choice could be changed to attribute different importance to the ranking criteria considered.

With the exception of new builds serving export demand, which were all sited at ports, all the remaining new gas generation capacity then sited by rank, progressively filling the available capacity at brownfield sites and updating the remaining brownfield site capacity for the next iteration. Should brownfield sites not have sufficient nominal capacity for siting new builds in any year, the remaining new firm generation capacity was assigned to greenfield sites in the respective NZAu region. When ports are available in the NZAu region, greenfield sites were located there, in the proximity of the main industrial loads and export facilities; if this is not the case, the cumulative greenfield capacity is assigned to the NZAu region without specifying a location. This represents an opportunity for electricity system planners to develop new sites for new firm generation assets and could be preferentially located in areas of poor system strength. For these greenfield sites, the number of units to be sited and built is then specified to reflect the capacity distribution of existing gas generation assets shown in Figure 2.

The siting of gas generation new builds was carried out for the E+RE+ and E+RE− scenarios. However, as shown in Figure 5 and previously discussed, the E+RE− Scenario represents the most challenging case in terms of gas generation deployment.

## 4.3 Power system operation with different generation mixes

We also provide analysis of hourly load and generation profiles, as modelled with the RIO optimization. This illustrates not only the role of firm generation in potential future electricity systems, but also highlights differences in aggregate power system operation resulting from: significant electrification of end uses; coupling of energy systems; and significant penetration of variable renewable generation. This analysis compares modelled power system operation in 2020 with that in 2050, for the E+RE+ and E+RE− Scenarios. For clarity of visualisation, generation technologies and load sources were aggregated, as reported in Table A.3.

## 4.4 Assessment of PHES site availability in Australia

In this work, PHES site availability in Australia was assessed by consulting publicly available information on ongoing commercial PHES site evaluations and development in Australia. The use of this type of information was considered to provide a reasonable demonstration of the sites that could support the energy transition, particularly given our discussions with developers of PHES projects. Such an approach results in much smaller estimates of total PHES resources than assessments based on geography, such as the *Global pumped hydro energy storage atlas* [14].

We consider publicly available studies ranging from pre-feasibility to sites under construction and those that are fully commissioned systems, the projects scoped were further categorised into:

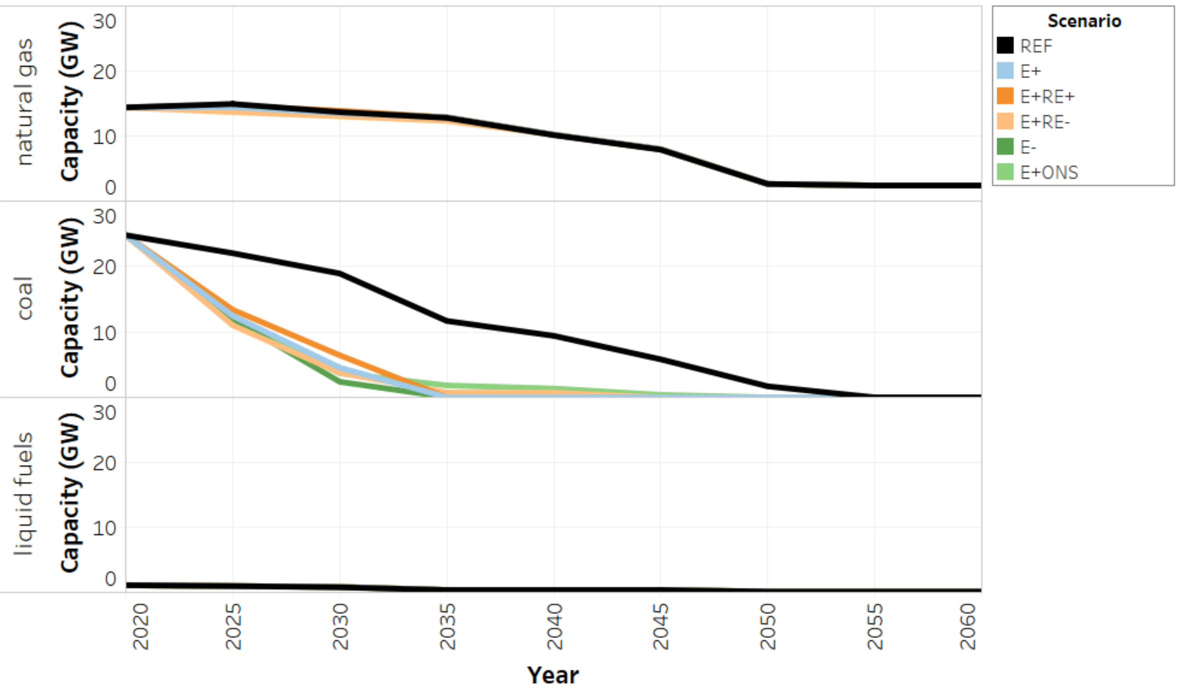
1. *Speculative*: Pre-feasibility study proposed, in progress, or under assessment – Pre-FEED stage;
2. *Prospective*: Pre-feasibility study successful. Feasibility study proposed, in progress, or under assessment – FEED stage;
3. *Committed*: Feasibility study successful. Financial close reached – detailed FEED or construction stage;
4. *Operational*: Site commissioned and currently under operation; and
5. *Discontinued*: project discontinued at any point of its assessment or implementation.

# 5 Results

## 5.1 Retirement of existing firm generation

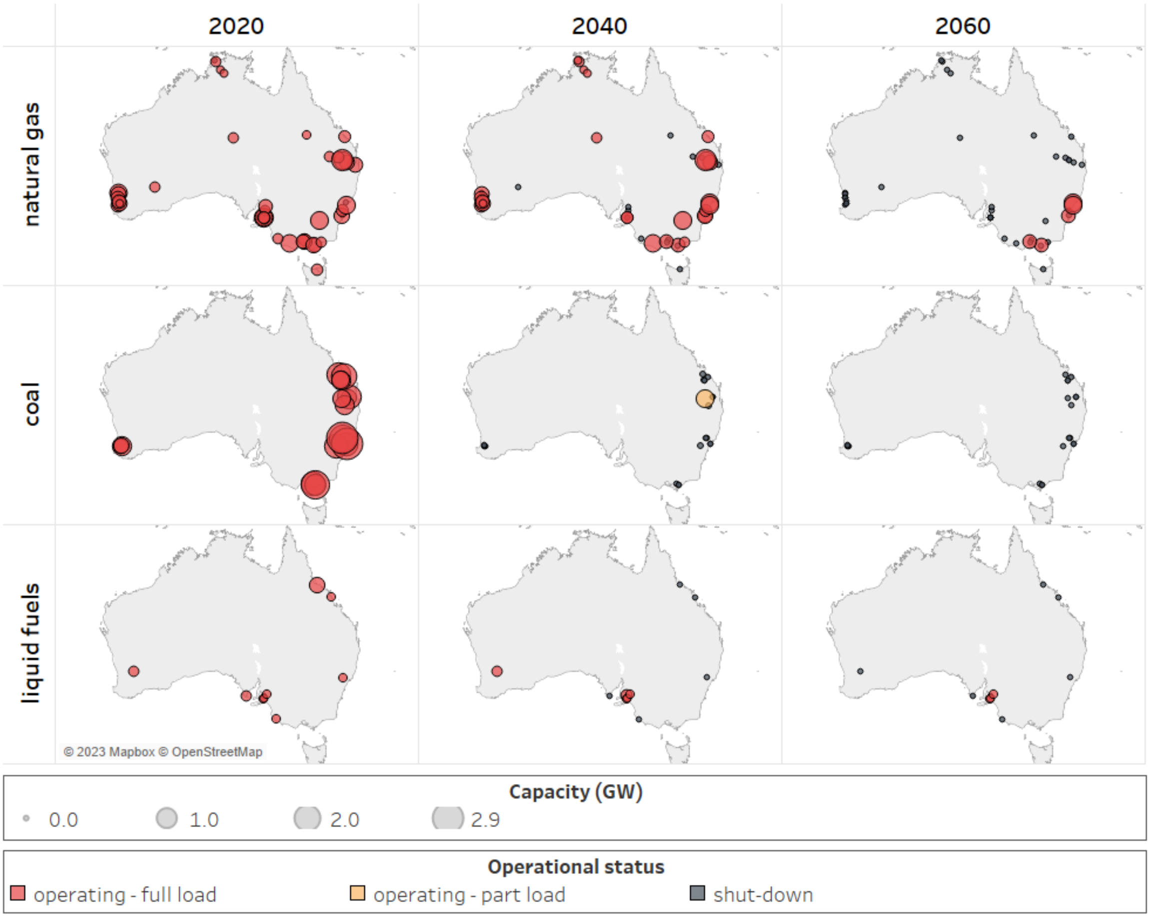
Figure 8 presents the installed capacity of *existing* firm fossil generation assets by fuel type and scenario. Existing plant locations and their retirement schedule are further shown for Scenario E+RE− in Figure 9. The only significant difference in installed capacity between the net-zero scenarios and the Reference Scenario can be seen for coal-fired generation, which undergoes rapid capacity reduction between 2020 and 2035. This is because the domestic emissions constraint has the effect of initially reducing coal generation output, due to its greater emission factor per unit energy produced than that of a gas asset (90 vs 50 kg-$CO_2$-e/GJ). Interestingly the domestic emissions constraint effects the early retirement of existing coal generation assets in all net-zero scenarios, with minimal variation across scenarios.

**Figure 8 | Installed capacity of existing firm fossil generation by source and scenario.**




Almost all existing thermal plants are shut down by 2060. No coal capacity remains by 2045, with the majority (~20 GW) of coal assets retired by 2030. The early retirements are reported in Table 2. Notably, there are no early retirements planned for existing gas plants or liquid fuel generation facilities: the capacity of existing generation in Figure 8 follows the same trajectory across scenarios and hence lines are overlaid. The average retirement figure of 2 GW p.a. is in line with historical trends [15].

**Figure 9 | Modelled retirement schedule for existing firm fossil generation; E+RE− Scenario.**




As also noted in Figure 9, the small capacity of liquid fuel generation is progressively retired, with only a handful of plants operating past 2050: Angaston, Lonsdale and Port Stanvac 1 in SA, which are more recently deployed reciprocating engine plants of 20 to 57 MW aggregated capacity each, for a total 128 MW. Gas, on the other hand, remains in the mix as a firm generation option. From 2050 onwards, 2.4 GW of the existing gas generation fleet are still in operation, mostly Kurri Kurri and Colongra, both 700 MW and Tallawarra 316 MW OCGT in NSW, Valley power and Laverton North (both 300 MW OCGT) in Victoria.

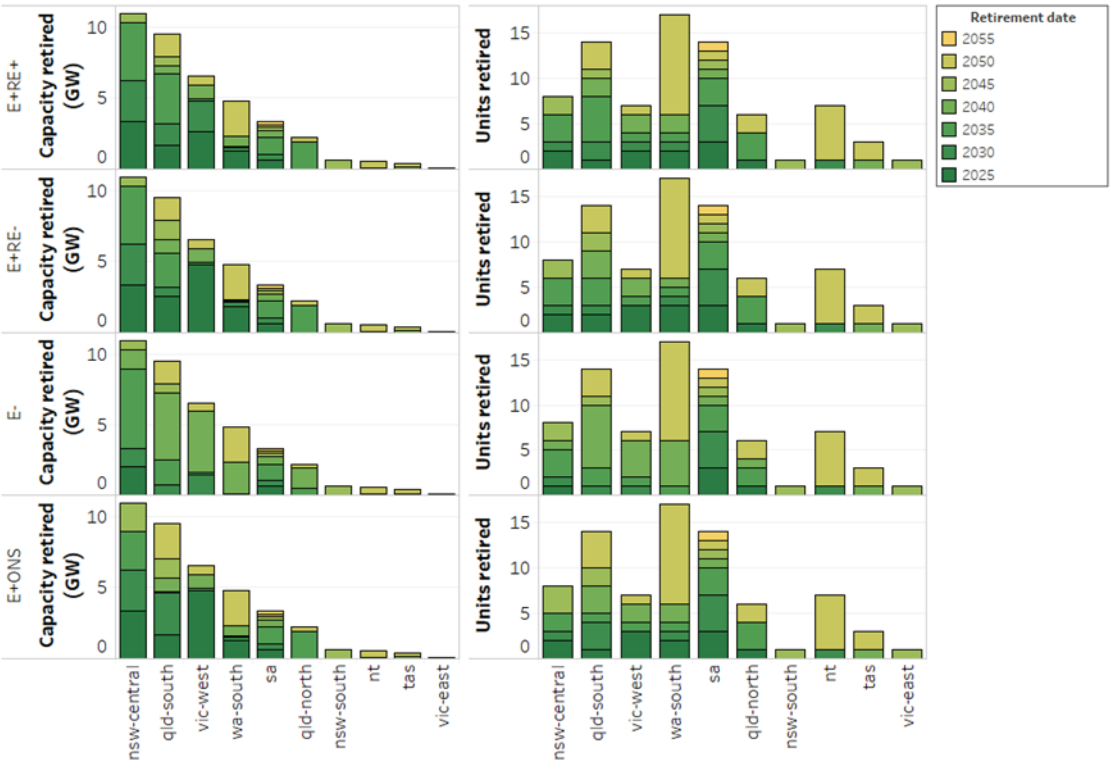
**Table 2 | Early coal plant retirement projected by RIO for the E+RE− Scenario.**

| Site name | Zone | Type | Capacity [MW] | Planned | Modelled |
|---|---|---|---|---|---|
| **Bluewaters** | WA-south | Black coal sub critical (existing) | 434 | 2050 | 2040 |
| **Callide C** | WA-south | Black coal super critical (existing) | 840 | 2051 | 2040 |
| **Collie G1** | WA-south | Black coal sub critical (existing) | 319 | 2050 | 2040 |
| **Eraring** | NSW-centre | Black coal sub critical (existing) | 2,880 | 2031 | 2030 |
| **Gladstone** | QLD-south | Black coal sub critical (existing) | 1,680 | 2035 | 2025 |

| | | | | | |
|---|---|---|---|---|---|
| **Kogan Creek** | QLD-south | Black coal super critical (existing) | 744 | 2042 | 2040 |
| **Loy Yang A** | VIC-west | Brown coal (existing) | 2,210 | 2048 | 2030 |
| **Loy Yang B** | VIC-west | Brown coal (existing) | 1,160 | 2048 | 2030 |
| **Millmerran** | QLD-south | lack coal super critical (existing) | 852 | 2051 | 2040 |
| **Mt Piper** | NSW-centre | Black coal sub critical (existing) | 1,390 | 2042 | 2035 |
| **Stanwell** | QLD-north | Black coal sub critical (existing) | 1,460 | 2043 | 2040 |
| **Tarong** | QLD-south | Black coal sub critical (existing) | 1,400 | 2036 | 2035 |
| **Vales Point B** | NSW-central | Black coal sub critical (existing) | 1,320 | 2029 | 2025 |
| **Yallourn W** | VIC-west | Brown coal (existing) | 1,450 | 2028 | 2025 |

The capacity and number of existing plant retirements by region and scheduled year are reported in Figure 10. New South Wales, Queensland and Victoria are the states where the most capacity is retired; WA and SA, on the other hand, is where the highest *number of units* is retired, being mainly black coal generation in WA and small OCGT units and reciprocating engines and some liquid fuels in SA. These small units retired in SA are generally below 300 MW – except for Pelican point and Torrens Island B – and mostly co-located with other generation assets so that a gradual asset phase-out can take place.

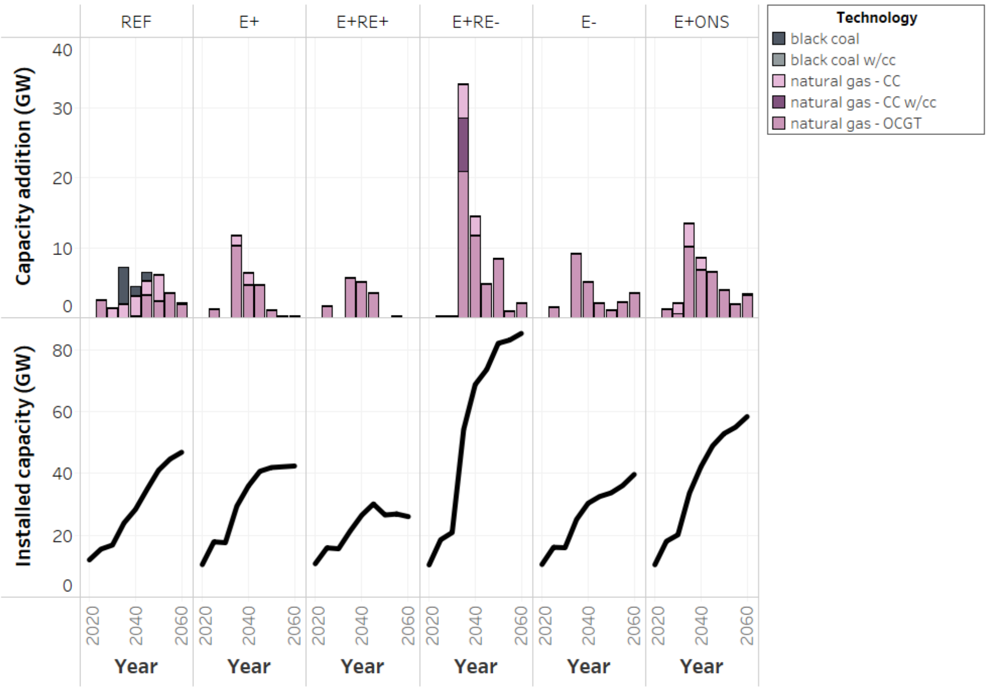
**Figure 10 | Downscaled capacity and number of existing firm fossil generation retirements by year and scenario, for each NZAu region.**




## 5.2 Siting new projects

Figure 11 shows the new firm generation capacity deployed by scenario, as modelled with RIO. These new builds all comprise natural gas plants – from a total over the years 2025 to 2060 of 20 GW in the E+RE+ Scenario to 71 GW in the E+RE− Scenario. Peak build rates are 34 GW in 5 years between 2045 and 2050 in the E+RE− Scenario. Overall, an average build rate of approximately 2 GW/year along the net-zero transition for the most challenging E+RE− Scenario is in line with the magnitude of historical generation addition (fossil and renewable) over the last 20 years in the NEM [16]. Of the capacity to be deployed, about 1 GW is already contracted and approaching construction, e.g. 660 MW of Kurri Kurri, to be commenced in July 2021 and Tallawarra B commenced in Feb 2022.

**Figure 11 | New firm fossil generation builds over time, by scenario and fuel type (top row) and cumulative firm generation installed capacity (bottom row).**




These builds compare with a total of about 38-40 GW of existing firm generation retiring between 2025 and 2050. Depending on the specific net-zero scenario considered, either Mt Piper or Milmerran are the last black coal plant to be shut down. By 2050, the residual gas capacity is 34 GW for the E+RE+ Scenario and 82 GW for the E+RE− Scenario with the E+ONS Scenario exhibiting an intermediate gas capacity result. It is also interesting to observe that, under constraints on the speed of renewable capacity deployment in Scenario E+RE−, 8 GW of CCGT with CCS are needed online by year 2035. A further 4 GW is intended to be sited in the Northern Territory, with the aim of ensuring a constant energy flow through the HVDC export cable to Singapore, while the remaining capacity is deployed in Victoria and New South Wales to meet emission targets before sufficient renewable generation can be sited.

Figure 12 shows the available brownfield locations where this new build capacity may be located. Most of these brownfield sites become available between 2030 and 2045. By 2045 brownfield sites are made available by the retirement of 5 GW of gas plant, 25 GW of coal plant and small amounts of liquid fuels. As such, the assessment of natural gas pipeline proximity becomes relevant for identifying suitable brownfield sites; this information is shown in Figure 13 and is used to allocate the siting of modelled new builds, as presented in Figure 14.

**Figure 12 | Brownfield sites for new firm fossil generation by year of availability for the E+RE+ and E+RE− Scenarios.**

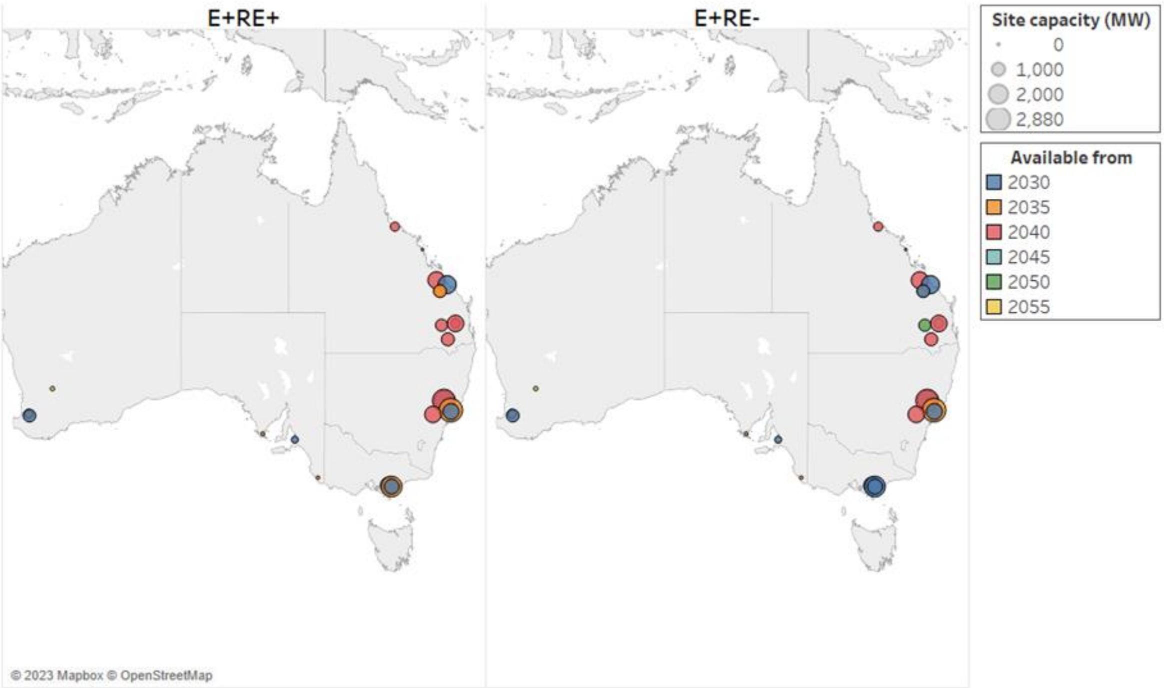
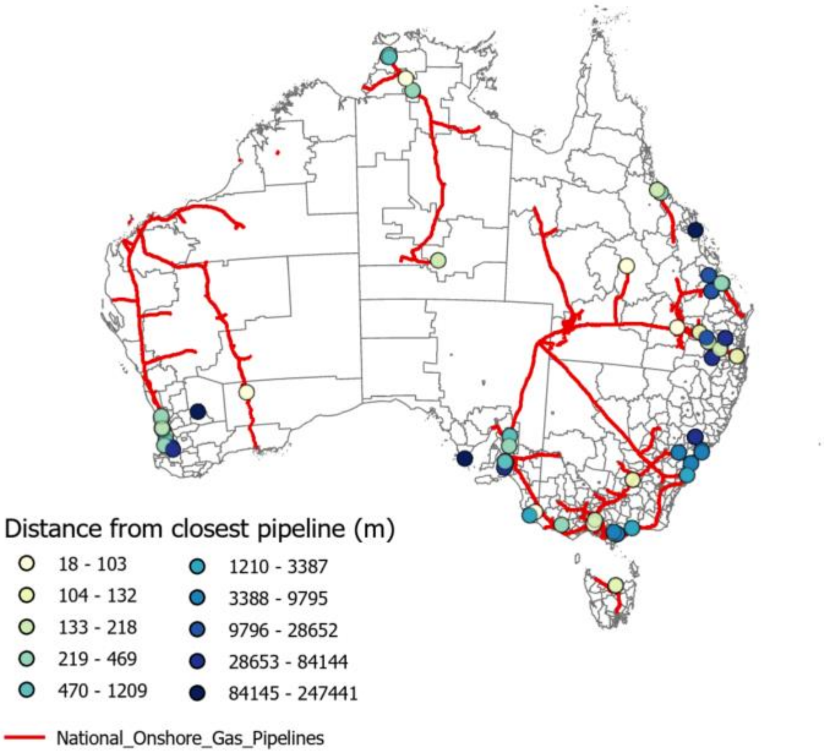


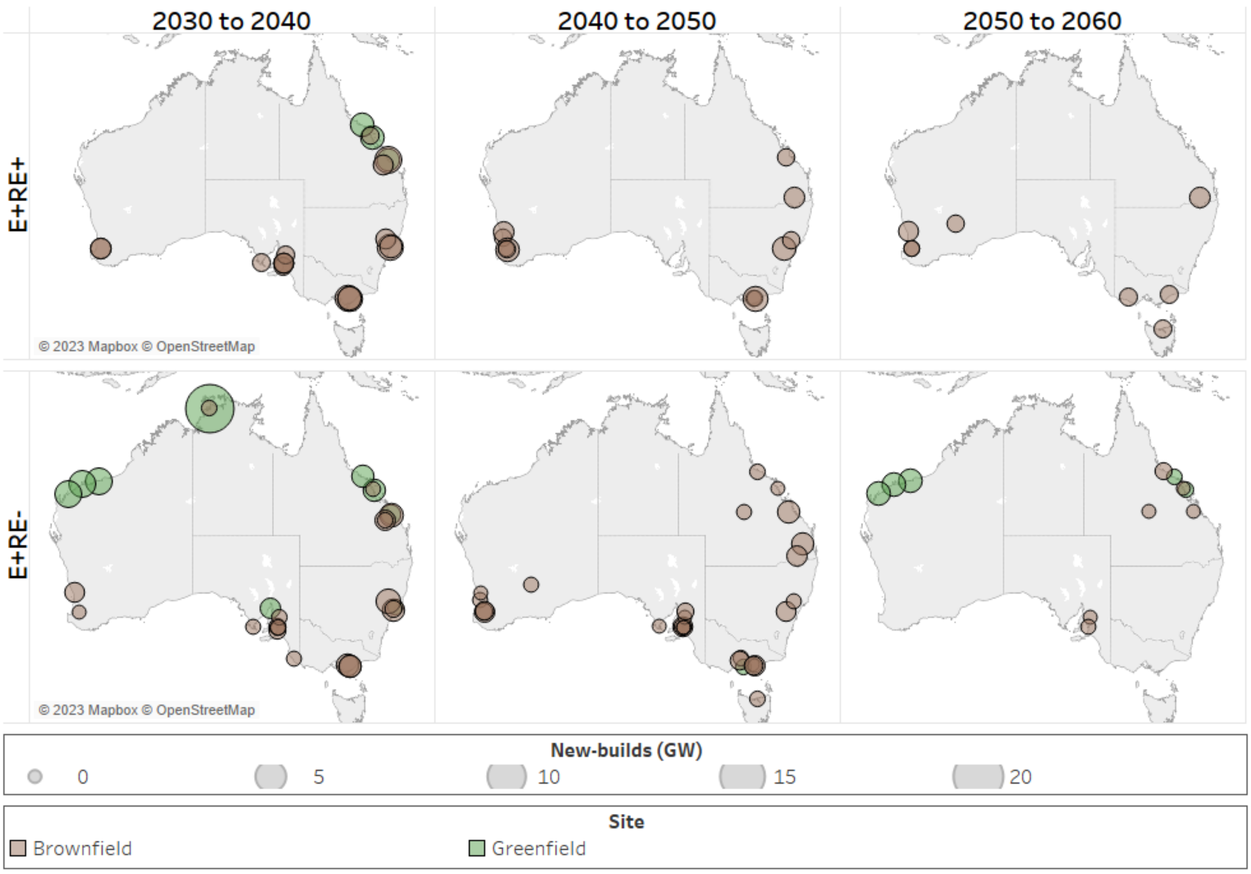

**Figure 13 | Locations of existing firm fossil generation, coloured by their proximity to existing natural gas transmission pipeline infrastructure.**



As Figure 14 shows, brownfield sites host new gas generation up to their existing capacity. As existing coal and gas generation is progressively retired in the two decades between 2030 and 2050, more brownfield sites become available and are used for new gas projects in the domestic system. This notably allows the installation of all the new gas generation facilities on brownfield sites between 2040 and 2050. By comparing scenarios, it is apparent how a slower uptake of renewables in the E+RE− Scenario requires more gas generation to be deployed and consequently the identification of more suitable locations for the installation of new plants.

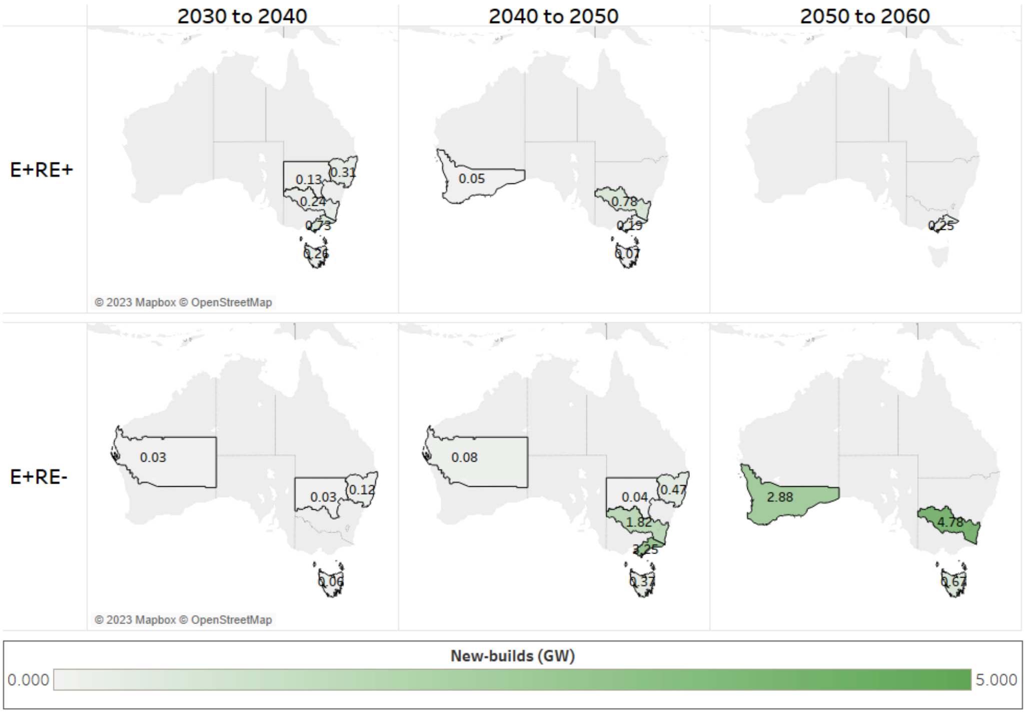
However, the large energy exports in this study result in the biggest capacity increase at the ports around the Australia. Co-located thermal generation nearby ports is needed to ensure a level of firming to the energy exports so they remain constant throughout the day, which is one of the constraints included in the NZAu modelling [16]. Brownfield sites conversion remains an economically attractive option to be pursued whenever possible, but the brownfield site availability seems to be insufficient to host the full projected new gas generation capacity at ports. This particularly applies to the E+RE– Scenario, in Western Australia (where 8.64 GW of new greenfield gas generation is to be sited in WA-north, between 2030 and 2040), in the Northern Territory (18 GW) and Queensland (2.6 GW).

**Figure 14 | Siting and scheduling of new build gas-fired generation, according to whether the sites are brownfield or greenfield, for the E+RE− and E+RE− scenarios. Each circle represents a new build gas generator that has been sited on a given brownfield/greenfield site around the country in that decade; circle size is proportional to the gas generator capacity.**



Finally, Figure 15 shows the remaining gas generation capacity that was found to be surplus to available brownfield sites, and therefore would require greenfield sites in various NZAu regions. Overall, this shows that, for the E+RE+ Scenario, minimal greenfield sites of less than 1 GW hosting capacity would be required in a few NZAu regions across the modelled transition. For the E+RE− Scenario however, a number of new-build plants must be located at greenfield sites. Most of this capacity is located in New South Wales South or Victoria East. Nevertheless, across all scenarios the need for greenfield sites to accommodate those new builds is relatively small, as emerges by comparing Figure 14 and Figure 15. In E+RE− Scenario, 14.6 GW of the overall 74 GW require additional greenfield sites, and only 3.8 GW of 20 GW, for the E+RE+ Scenario.

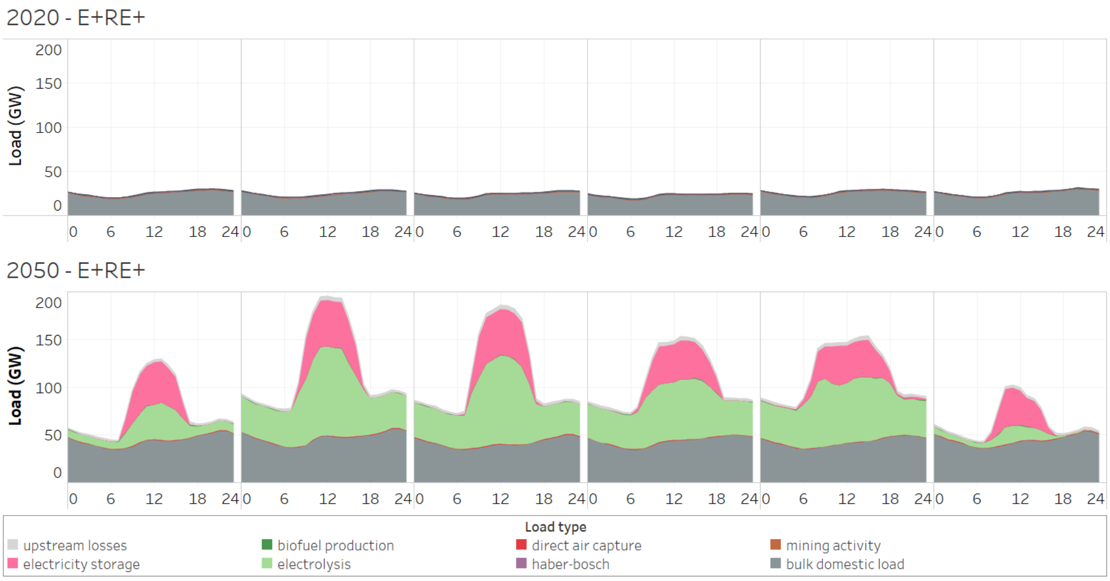
**Figure 15 | The capacity of the required greenfield sites for new gas-fired generation in different modelled regions, for the E+RE− and E+RE− scenarios.**




## 5.3 Australian power system operation in the net-zero transition

Figure 16 and Figure 17 illustrate how load and generation may transform between 2020 and 2050, using the NEM as the considered case study. These figures plot hourly load (Figure 16) and generation (Figure 17) profiles for the modelled NZAu regions that encompass the NEM, as modelled with the RIO hourly operations optimization. These dispatch plots are shown only for 6 representative sample days, however, we model 60 total representative days, which are sampled from a complete weather year and then individually assigned to one of the 365 days in the year, through suitable clustering techniques, to fully represent the annual system operation. In so doing, 4 extreme days including sun and wind droughts were also selected, to faithfully account for extreme conditions which, in a real setting, drive investments for system reliability [17]. This process is repeated for every modelled year, so that the most representative 60 days are updated every time. Detailed short-term dispatch with hourly resolution is computed for each sample day.

**Figure 16 | Hourly electrical load profiles projected for the modelled NZAu regions that encompass the NEM in the E+RE+ Scenario in 2020 and 2050, and for 6 representative days modelled.**




The growth in the bulk load between 2020 and 2050 – i.e. the aggregate load from residential, commercial, industrial and transport sectors (see Table A.3) – is due to the compounding effect of the modelled electrification measures and to population growth. This bulk load profile does not change between different E+ demand-side scenarios. However, extra load sources are added on top of the bulk load by 2050, which is characteristic of the sector-coupled and decarbonised energy systems. These extra load sources represent additional processes (e.g. up to 93 GW from electrolysis), whose addition results in peak loads for 2050 which are more than 4 times the peak load in 2020. Other additional contributions on top of the bulk load are contributed by DAC facilities, and the loads from storage charging (mainly batteries, up to ~40 GW) which is used to balance renewable variability.

Concerning generation, Figure 17 shows the role of black coal and gas generation in 2020 is largely displaced by variable renewable sources in 2050. This is further highlighted by the evolution of capacity factors of firm generation assets overtime in Figure 18. Regardless of the modelled scenario, a remarkable inflection in the utilisation of firm generation is observed, particularly for closed-cycle gas turbines whose capacity factors drop from 0.8-0.9 in 2020 to 0.1 or even lower values by 2040. Open-cycle gas turbines also display low capacity factors around or below 0.1. Starting from the early years of the net-zero transition, it is renewable generation with the support of energy storage supplying most of the baseload; thermal generation assets are confined to the provision and firm and dispatchable power in periods of low supply availability.

A number of different variable renewable sources play a role in supplying generation, with both onshore and offshore wind providing power throughout the modelled days. Solar PV is responsible for a pronounced generation peak in the middle part of the day, with coincides with energy storage charging (mainly batteries, supported by PHES), so that energy is then discharged overnight. Rooftop PV supplies the majority of solar (and renewable) generation in 2020, but a much smaller proportion in 2050. We note that these plots show the aggregated load and generation across a wide geographical area and do not show the modelled transmission flows between the constituent regions of the NEM. This therefore does not show the role that inter-regional transmission plays in supply-demand balancing over time and space. In 2050, the power volumes transferred through NEM regions are up to 35 GW.

**Figure 17 | Hourly electricity generation profiles projected for the modelled NZAu regions that encompass the NEM in the E+RE+ Scenario in 2020 and 2050, and for 6 representative days modelled.**

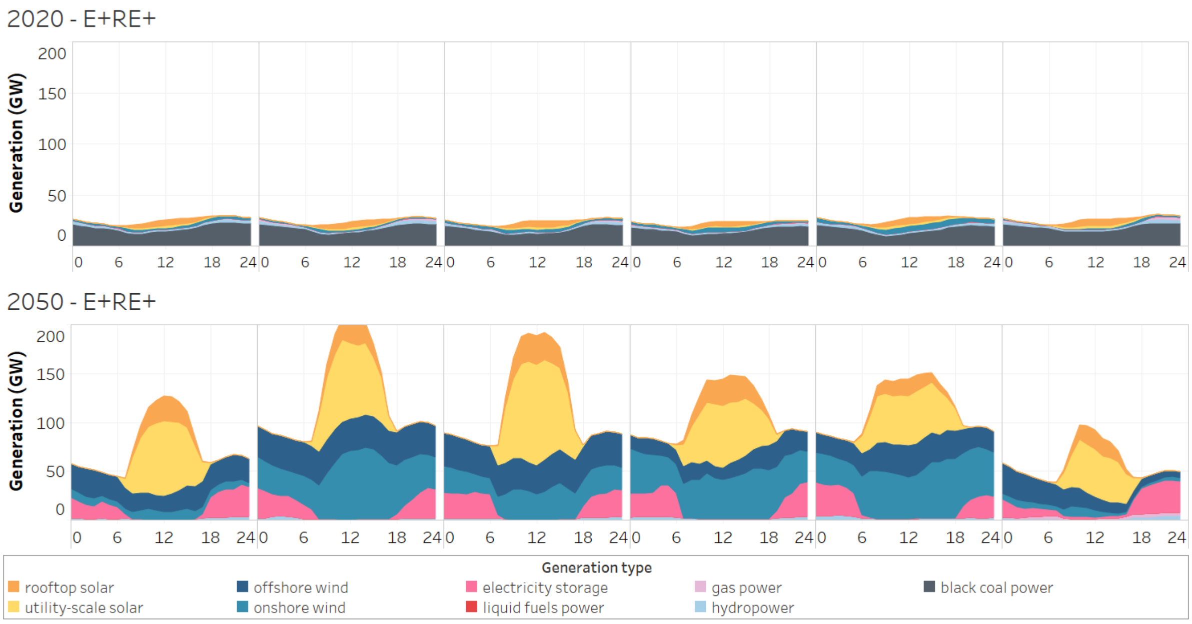
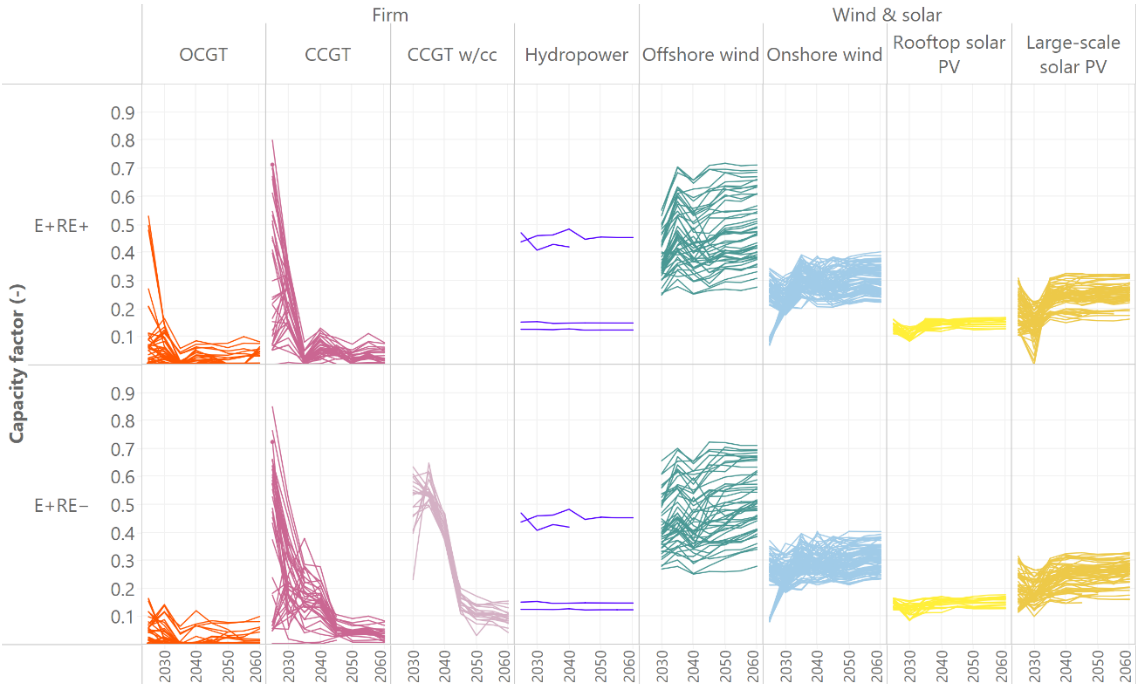



**Figure 18 | Time evolution of the capacity factor of firm and renewable generation for E+RE+ Scenario and E+RE− Scenario.**




Analysis in year 2050 is extended to the aggregated Australian (all modelled regions) power system in Figure 19 for the E+RE+ Scenario and Figure 20 for the E+RE− Scenario. In the E+RE+ Scenario, the contribution of solar PV is large and the aggregated 605 GWh of battery energy storage is deployed by 2050 with an associated duration of about 7h. Figure 19 highlights the complementary role of batteries in load-shifting abundant solar PV generation to peak periods in the evenings and overnight. Green hydrogen production via electrolysis also represents a significant portion of the total electrical load, which is largely supplied by renewable generation, and can be concentrated in the central part of the day to leverage sun availability. Underground $H_2$ storage then helps enable a flexible shift of this load.

In the E+RE− Scenario in Figure 20, less solar PV is installed and consequently, the generation is more evenly spread between different forms of variable renewable generation, with offshore wind playing the most significant role. In this Scenario, renewable deployment constraints reduce the amount of solar and onshore wind that can be deployed, while also finding the need for DAC as a significant load, and with less electrolysis. Here, 415 GWh batteries are deployed, which is a decrease relative to the above E+RE+ Scenario, since there is less need to shift solar PV generation to evening peaks. Once again, the value of shifting green $H_2$ production via electrolysis in times of the day that match the renewable resource availability is apparent.

**Figure 19 | Aggregate Australian domestic hourly generation and load profiles in 2050; E+RE+ Scenario, for 6 representative days modelled.**

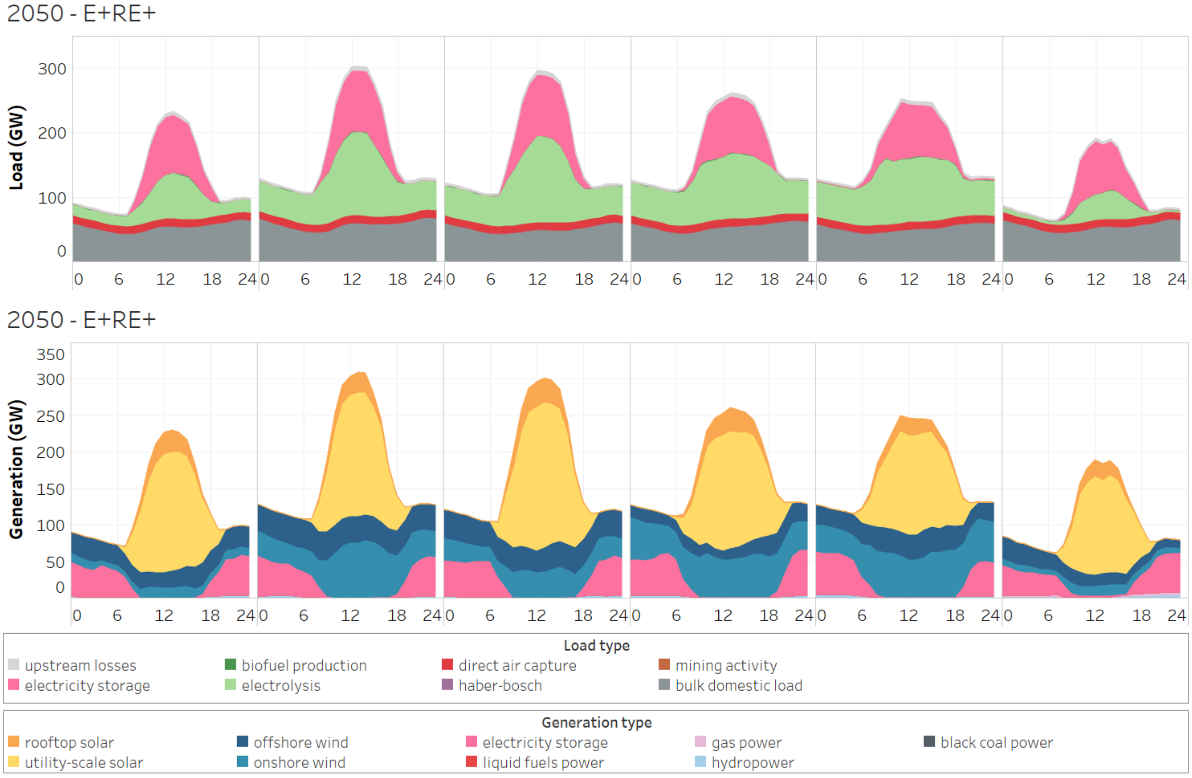
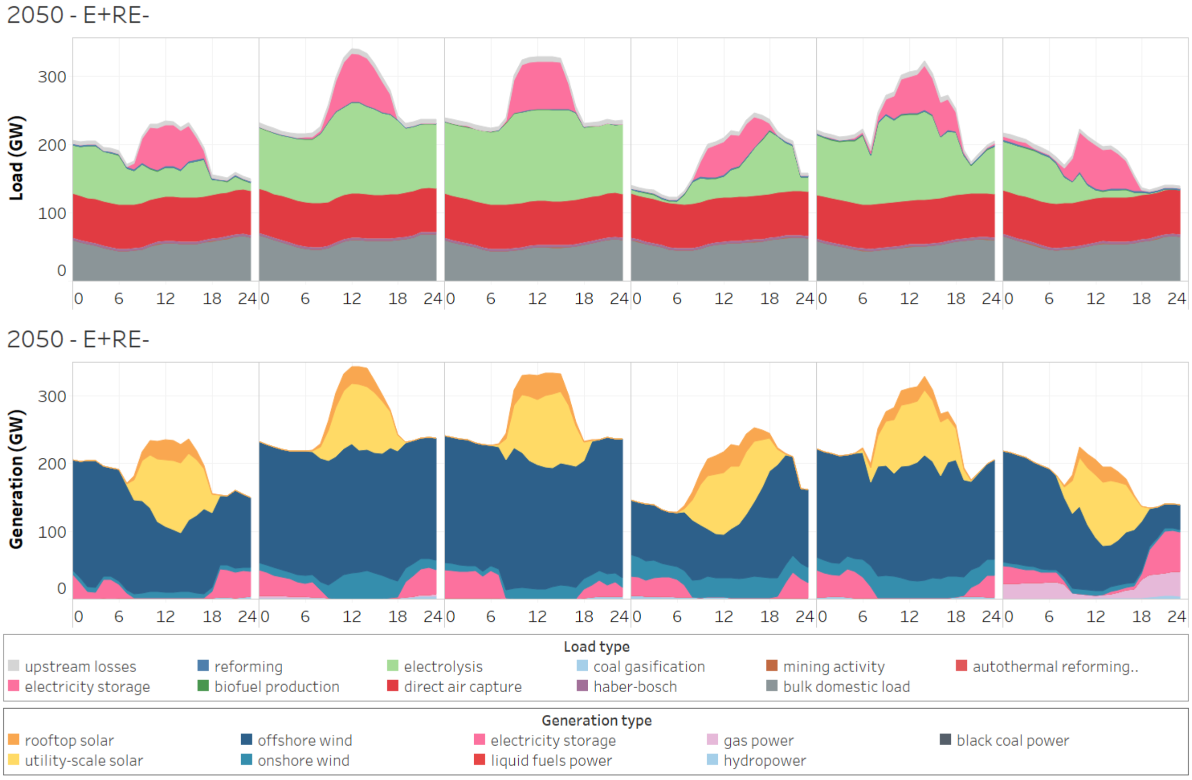


Figure 20 | Aggregate Australian domestic hourly load and generation profiles in 2050; E+RE− Scenario, for 6 representative days modelled.




## 5.4 Modelled PHES requirements in NZAu

The domestic PHES energy and power projections obtained from modelling the NZAu Scenarios with RIO optimisation platform are reported in Figure 21. The modelled PHES installations in 2050 by state and scenario is shown in Figure 22. We find that 10.5 GW and 11.5 GW of PHES are deployed in the E+RE+ and E+ONS Scenarios respectively, while 7 GW is deployed in the E+RE− Scenario. These PHES plants are rapidly deployed by 2030 in each of the modelled net-zero transitions. These capacities also include the contribution of two large PHES projects currently under construction, namely the 2 GW Snowy 2.0 in New South Wales and Kidston K2-Hydro in Queensland.

**Figure 21 | Optimal domestic PHES power and energy capacity modelled by the NZAu project, for the E+RE+, E+RE- and E+ONS Scenarios. We note that the 'existing & planned' electricity storage category includes Snowy 2.0 and Kidston K2-Hydro PHES projects, as well as a number of existing smaller battery storage projects.**

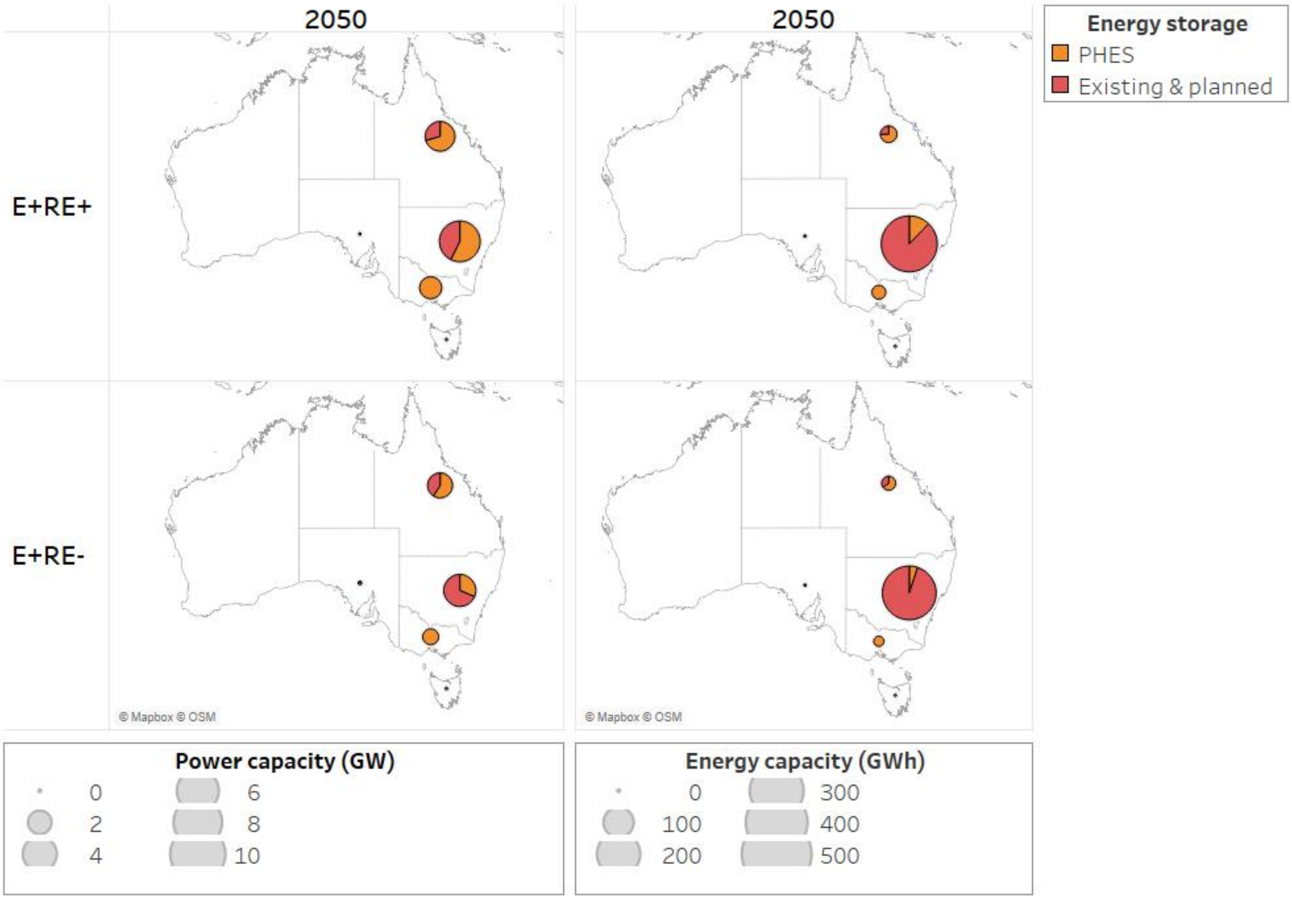

On the contrary, it is interesting to observe the continuous growth in PHES energy capacity over time, across scenarios. Even when disaggregating the large contribution of the 170 GWh of storage in Snowy 2.0 to the overall PHES energy capacity, new installed projects are set to grow from 70 to 80 GWh in the E+RE+ Scenario, from 30 to 40 GWh in the E+RE− Scenario and from 80 to 155 GWh in the E+ONS Scenario. At constant power capacity, this implies a growth in storage duration which is likely to follow the growing share of renewables in the power generation mix, where the associated intermittency is counterbalanced by longer storage durations requirements.

The storage durations modelled with RIO across all scenarios and NZAu domestic regions in 2050 are reported in Table 3. These storage duration vary between 11 and 37 h depending on the Scenario and year, with an average value of 15 h. Interestingly, the maximum limit of 48 h allowed in the NZAu Project was never selected in the optimisation, which suggests longer durations may be pursued for reliability and energy security purposes under stochasticity and with consideration of many possible weather-years: currently outside the scope the NZAu Project [16]. In addition to PHES, the NZAu modelling finds need for 60-100 GW of 7 h battery energy storage to balance the power system over daily timescales, and 50-90 GW $H_2$ storage with about 70 h duration to bridge the demand-supply gaps mostly for energy exports and other use as a fuel or a fuel precursor.

**Table 3 | Storage technology durations found in NZAu modelling across all years, scenarios and regions.**

| Energy storage technology | Min duration [h] | Mean duration [h] | Max duration [h] |
|---|---|---|---|
| **Battery energy storage** | 6 | 7 | 8 |
| **PHES** | 11 | 15 | 37 |
| **$H_2$ storage** | 22 | 67 | 98 |

Figure 22 | Predicted domestic PHES power and energy capacity in 2050 by state.




## 5.5 PHES site availability in Australia

A summary of the aggregated PHES energy and power potential estimated for the whole Australia based on project review is reported in Table 4. We find 7.9 GW and 165 GWh of speculative projects currently under pre-feasibility assessment across New South Wales and Queensland. On top of these, PHES potential accounts for an aggregate 10.5 GW power and 502 GWh between prospective and committed projects across Australia. This latter category includes Snowy 2.0 and Kidston, plus Central West and Dungowan (New South Wales), Baroota (South Australia) and Walpole (Western Australia). GHD, leading specialists in PHES, consider that these power and energy capacities and the distribution of projects are a reasonable representation of the potential for PHES in Australia [19]. Notably, sites that have either successfully overcome a pre-feasibility assessment or have already been committed for construction offer enough PHES capacity for the scales projected by the NZAu Project.

Table 4 | Aggregated summary of the pumped hydro energy storage sites across Australia.

| Category | States | Cumulative Capacity [GWh] | Cumulative Rated power [GW] | Notes |
|---|---|---|---|---|
| **Speculative** | NSW, QLD | 165 | 7.9 | P-FEED in progress or under assessment |
| **Prospective** | NSW, QLD, TAS | 142 | 7.5 | P-FEED successful; FEED in progress or waiting for financial close |
| **Committed** | NSW, QLD, SA, WA | 360 | 3.3 | Project committed or in construction |
| **Operational** | NSW, QLD | 19 | 1.4 | Currently operating |
| **Discontinued** | NSW, SA, VIC | 8 | 1.0 | Development discontinued |

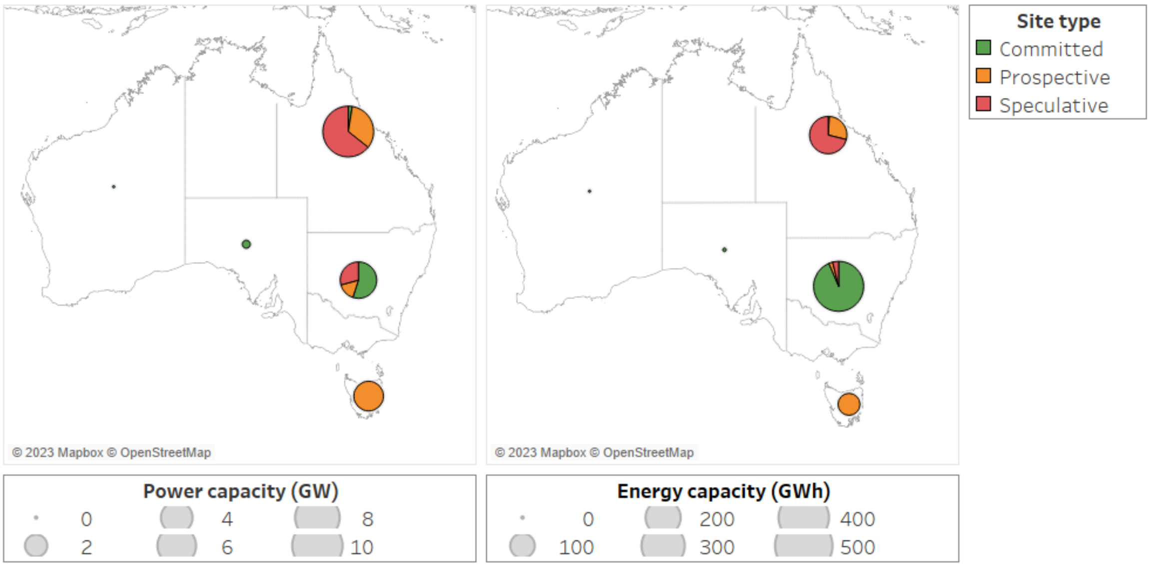
However, it is worth noting the comparison between the geographical distribution of PHES new builds in Figure 22 and the PHES site potential in Figure 23. About half the prospective projects (3.4 GW) are located in Tasmania and currently being assessed through the 'Battery of the Nation' initiative [20]. Six shortlisted sites have been further divided into 2 priority tiers on the basis of multi-criteria analysis using technical, environmental, social and commercial criteria by Hydro Tasmania. They are Lake Cethana, Lake Rowallan, Tribute (tier 1), Margaret-Burbury, Parangana and Poatina (tier 2).

We note that NZAu modelling predicts little capacity expansion in Tasmania (up to 1.2 GW in the E+ONS Scenario), likely due to the associated transmission costs required to connect Tasmanian PHES to the mainland. The NZAu project has found that these transmission costs would more than offset the lower cost and more favourable geography of PHES sites in Tasmania [16]. However, we also note that the federal government, through its Rewiring the Nation policy, has recently announced major support (complemented by contributions from the Tasmanian and Victorian governments) for the proposed Marinus Link interconnection between Tasmania and the mainland, which would of course enhance the prospects for PHES ocated in Tasmania.

We further find that 3.3 GW are located in Queensland, including state-financed Borumba, with 24 h duration, and the privately owned Capricornia Energy Hub and Big-T projects. Consistently, NZAu modelling finds between 1.2 and 2 GW of PHES in Queensland by 2050. On the other hand NZAu modelling has found between 1 and 3.2 GW (15 to 62 GWh) of PHES could be located in New South Wales, where only the 810 MW-9.7 GWh Phoenix project currently appears to be prospective – more exploration of speculative sites could bring about additional 1.5 GW and 14.6 GWh of extra capacity. Finally, the current absence of prospective PHES sites in Victoria, where NZAu modelling has found 0.8-1.6 GW of new PHES projects, could be mitigated by making better use of the Tasmanian PHES potential previously discussed and favoured by Marinus Link.

Alongside PHES, it is worth mentioning other long-duration energy storage technologies with 10+ hours of storage duration are currently in operation worldwide. Many of these are geographically unconstrained, which may overcome this significant challenge to PHES development [21]. Compressed Air Energy Storage (CAES) [22] and Liquid Air Energy Storage (LAES) [23] are currently in the early stages of commercial deployment and the Australian government has conditionally approved 45 $M funding for a 200 MW/1600 MWh CAES project under development by the company Hydrostor, which repurposes a mine in Broken Hill [24]. These solutions may reach competitive investment costs in the 20s $/kWh and complement PHES installation as long-duration energy storage.

**Figure 23 | Power and energy capacity potential of investigated sites for PHES projects in Australia.**




The above results align reasonably well with the extent of projects currently being scoped by various developers (both in energy and capacity terms). However, discrepancies have been observed between the location of prospective PHES sites and the project locations optimised in the NZAu Project, which may result in a higher energy system transition cost. Also, project lead times of 4-8 years and longer are emerging from common PHES practice, plus the current status of investigation in a number of sites may result in slower deployment than we have modelled.

# Appendices

## Appendix A

**Table A.1 | Beginning of operation and scheduled retirement for plants in the Australian firm generation fleet.**

| Firm generation asset | Operating since | Scheduled retirement | Firm generation asset | Operating since | Scheduled retirement |
|---|---|---|---|---|---|
| Alcoa Wagerup | 1985 | 2050 | Mortlake | 2011 | 2047 |
| Alinta Pinjarra | 2005 | 2050 | Mt Piper | 1993 | 2042 |
| Alinta Wagerup Gas Turbine | 2007 | 2050 | Mt Stuart | 1998 | 2033 |
| Bairnsdale | 2001 | 2042 | Muja | 1981 | 2023 |
| Barcaldine Power Station | 1996 | 2034 | Neerabup Gas Turbine 1 | 2008 | 2050 |
| Barker Inlet Power Station | 2019 | 2044 | Newport | 1980 | 2039 |
| Bayswater | 1983 | 2035 | Oakey Power Station | 2000 | 2050 |
| Bell Bay Three | 2006 | 2040 | Osborne | 1998 | 2023 |
| Bluewaters | 2008 | 2050 | Owen Springs Engine | 2011 | 2050 |
| Braemar | 2006 | 2046 | Parkeston | 1996 | 2037 |
| Callide B | 1989 | 2028 | Pelican Point | 2000 | 2037 |
| Callide C | 2001 | 2051 | Phoenix Kwinana | 2019 | 2050 |
| Channel Island CCGT | 1987 | 2028 | Pine Creek | 1996 | 2050 |
| Channel Island OCGT | 2011 | 2050 | Pinjar Gas Turbine | 1990 | 2031 |
| Cockburn CCGT | 2003 | 2050 | Port Lincoln GT | 1999 | 2030 |
| Collie G1 | 1999 | 2050 | Quarantine | 2002 | 2053 |
| Condamine A | 2009 | 2039 | Roma | 1999 | 2034 |
| Darling Downs | 2010 | 2045 | Smithfield Energy Facility | 1997 | 2044 |
| Dry Creek GT | 1973 | 2030 | Snuggery | 1997 | 2030 |

| | | | | | |
|---|---|---|---|---|---|
| **East Rockingham Resource Recovery Facility** | 2020 | 2050 | Somerton | 2002 | 2033 |
| **Eraring** | 1983 | 2031 | Stanwell | 1995 | 2043 |
| **Gladstone** | 1980 | 2035 | Swanbank E GT | 2002 | 2036 |
| **Hallett GT** | 2002 | 2032 | Tallawarra | 2009 | 2043 |
| **Hunter Valley GT** | 1988 | 2035 | Tamar Valley Combined Cycle | 2010 | 2050 |
| **Jeeralang** | 1979 | 2039 | Tamar Valley Peaking | 2010 | 2050 |
| **Katherine** | 1991 | 2027 | Tarong | 1985 | 2036 |
| **Kemerton** | 2005 | 2050 | Tarong North | 2002 | 2037 |
| **Kogan Creek** | 2007 | 2042 | Temporary Generation South | 2017 | 2022 |
| **Kwinana CCGT** | 2008 | 2050 | Tiwest | 1990 | 2031 |
| **Kwinana OCGT** | 2011 | 2050 | Torrens Island A | 1967 | 2021 |
| **Ladbroke Grove** | 2000 | 2035 | Torrens Island B | 1977 | 2035 |
| **Liddell** | 1972 | 2023 | Uranquinty | 2009 | 2044 |
| **Loy Yang A Power Station** | 1986 | 2048 | Vales Point B | 1978 | 2029 |
| **Loy Yang B** | 1995 | 2047 | Weddell | 2008 | 2050 |
| **Mackay GT** | 1975 | 2021 | Yabulu PS | 2005 | 2046 |
| **Merredin Gas Turbine** | 2011 | 2050 | Yabulu Steam Turbine | 2005 | 2046 |
| **Millmerran** | 2002 | 2051 | Yallourn W | 1980 | 2028 |
| **Mintaro GT** | 1984 | 2030 | Yarwun Cogen | 2010 | 2050 |

**Table A.2 | Generation technologies and load aggregation considered for producing hourly supply and demand charts.**

| Generation/load - aggregated | Generation/load included | Gen/load |
|---|---|---|
| **Reforming** | Autothermal reforming w/cc, reformation h2, reformation h2 w/cc | L |
| **Coal gasification** | Black coal gasification h2 w/cc, brown coal gasification h2 w/cc | L |
| **Biofuel production** | Biofuels, biofuels w/cc | L |
| **Mining activity** | Black coal mining, brown coal mining | L |
| **Bulk domestic load** | Commercial, industrial, residential, transportation | L |
| **Black coal power** | Black coal power, black coal supercritical (existing), black coal power w/cc, black coal (existing), black coal sub critical (existing) | G |
| **Gas power** | Gas combined cycle, gas combined cycle w/cc, gas combustion turbine, OCGT (existing), CCGT (existing), gas-powered steam turbine (existing), reciprocating engine (existing) | G |
| **Liquid fuels power** | OCGT liquid fuel (existing), reciprocating engine liquid fuels (existing) | G |
| **Electricity storage** | Battery storage, electricity storage, pumped hydro | G/L |

### Table A.3 | Pumped hydro energy storage projects at different stages of implementations currently being investigated in Australia.

| Site name | Capacity [MWh] | Rated power [MW] | Duration [h] | Location | State | Developers | Schedule | Category | Project cost & funding |
|---|---|---|---|---|---|---|---|---|---|
| **Central West** | 2600 | 325 | 8 | Yetholme | NSW | ATCO | Construction commenced: 2020<br>Completion expected: 2026 | Committed | 9 M$ funding from NSW Gov |
| **Stratford REH** | 2600 | 300 | 12 | Newcastle | NSW | Yancoal | Mine closing: 2024 | Speculative | |
| **Phoenix** | 9720 | 810 | 12 | Wellington | NSW | WaterNSW | Operation commences: 2030 | Prospective | 7 M$ funding from NSW Gov to progress feasibility studies |
| **Tumut 3** | 8400 | 600 | 14 | Tumut basin | NSW | Snowy Hydro ltd<br>Toshiba<br>Mitsubishi | Commissioned: 1973<br>Upgraded: 2012 | Operational | |
| **Shoalhaven** | 1645 | 235 | 7 | Kangaroo valley | NSW | Origin Energy<br>WaterNSW | Currently on hold | Discontinued | Cost: 7.2 M$<br>1.6 M$ from ARENA) |
| **Shoalhaven** | 5280 | 240 | 22 | Kangaroo valley | NSW | Origin Energy<br>WaterNSW | Commissioned: 1979 | Operational | |
| **Snowy 2.0** | 350000 | 2000 | 175 | Snowy Mountains | NSW | Snowy Hydro ltd | Construction commenced: 2020<br>Completion expected: 2026 | Committed | Cost: 3.8-4.5 B$<br>1.4 B$ equity injection from AU Gov |
| **Muswellbrook** | 2000 | 250 | 8 | Hunter Valley | NSW | AGL<br>Idemitsu Australia | | Speculative | 9.45 M$ funding from NSW Gov<br>950 k$ funding from ARENA |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Oven Mountain** | 7200 | 600 | 12 | Macleay River | NSW | Oven Mountain<br>Alinta Energy | Construction commenced: 2024<br>Completion expected: 2028 | Speculative | 9.64 M$ funding from NSW Gov |
| **Lyell** | 2800 | 350 | 8 | Central Tablelands | NSW | EnergyAustralia<br>Arup | Construction commencing: 2023<br>Commercial operation: 2027 | Speculative | Cost initial studies: 28 M$<br>11 M$ funding from NSW Gov |
| **Dungowan** | 3000 | 500 | 6 | Walcha plateau | NSW | Walcha Energy<br>GE Renewable Energy | Construction commencing: 2021<br>First generation: 2027 | Committed | Cost: 3-6 B$<br>53 M$ funding from NSW |
| **Glennies creek** | | | | Upper Hunter | NSW | Hunter Water Corporation<br>NSW Gov | Business case expected: 2024 | Speculative | Cost: 12.5 M$ for detailed business case 11.1 M$ from Fed Gov |
| **Mt Rawdon** | 20000 | 500 | 40 | Bundaberg | QLD | MRPH<br>Evolution mining | Operational: 2028 | Speculative | Cost: 3.34 B$ |
| **Flavian** | 10800 | 900 | 12 | Miriam Vale | QLD | Sunshine hydro<br>Energy Estate | Approval: 2024-2025<br>Operational: 2028 | Speculative | Cost: 2 B$ |
| **Pioneer-Burdekin** | 120000 | 5000 | 24 | Pioneer Valley | QLD | Queensland Hydro (publicly-owned) | Feasibility commencment: 2023<br>Feasibility duration: 18 months | Speculative | |
| **Kidston (K2-Hydro)** | 2000 | 250 | 8 | Kidston | QLD | Genex | Commenced in: 2021<br>Construction completed: 2024 | Committed | Cost: 777 M$<br>47 M$ funding from ARENA<br>3 M$ funding from Clean Energy |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | Funding Corporation |
| **Borumba** | 48000 | 2000 | 24 | Gympie | QLD | Queensland Hydro (publicly-owned) | Operational: 2028-2029 | Prospective | Cost initial studies: 22 M$<br>13 M$ funding from QLD Gov |
| **Capricornia Energy Hub** | 7200 | 900 | 8 | Eungella | QLD | Copenhagen Infrastructure Partners (CIP) | Operation commences: 2028<br>500 MW, 9 h stage 2 to follow in 2032 | Prospective | |
| **Wivenhoe** | 5700 | 570 | 10 | Fernvale | QLD | QLD state | Commissioned: 1985 | Operational | |
| **Big-T** | 4000 | 400 | 10 | Lake Cressbrook | QLD | Bechtel<br>BE Power<br>GE Renewable Energy | Final invevstment decision: 2023<br>Construction commencment: 2024<br>Operation commencment: 2026 | Prospective | Cost: up to 1.3 B$ |
| **Cultana** | 1800 | 225 | 8 | Port Augusta | SA | EnergyAustralia<br>Arup | | Discontinued | Cost initial studies: 9 M$ 500 k$ funding from ARENA |
| **Goat Hill** | 2000 | 250 | 8 | Lincoln Gap | SA | Altura Energy<br>Delta Electricity | Construction commenced: 2021<br>Construction completed: 2024 | Discontinued | Cost: 410 M$<br>4.7 M$ funding from SA Gov |
| **Baroota** | 2000 | 250 | 8 | Port Augusta | SA | Rise renewables<br>UPC AC Renewables Australia | Construction commencing: 2022<br>Construction completed: 2025 | Committed | |
| **Lake Cethana** | 6600 | 600 | 11 | Lake Cethana | TAS | Hydro Tasmania | Construction estimate: 4.5 years | Prospective | Cost: 900 M$ (1.5 M$/MW) |
| **Lake Rowallan** | 14400 | 600 | 24 | Lake Rowallan | TAS | Hydro Tasmania | Construction estimate: 4.5 years | Prospective | Cost: 990 M$ (1.65 M$/MW) |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Tribute** | 15500 | 500 | 31 | Lake Plimsoll | TAS | Hydro Tasmania | Construction estimate: 5 years | Prospective | Cost: 915 M$ (1.83 M$/MW) |
| **Margaret-Burbury** | 16000 | 800 | 20 | Queenstown | TAS | Hydro Tasmania | Construction estimate: 5 years | Prospective | Cost: 1.25 B$ (1.56 M$/MW) |
| **Parangana** | 2400 | 300 | 8 | Lake Parangana | TAS | Hydro Tasmania | Construction estimate: 4 years | Prospective | Cost: 510 M$ (1.7 M$/MW) |
| **Poatina** | 18600 | 600 | 31 | Poatina | TAS | Hydro Tasmania | Construction estimate: 4.5 years | Prospective | Cost: 1.1 B$ (1.7 M$/MW) |
| **Kanmantoo** | 2000 | 250 | 8 | Adelaide hills | SA | AGL | | Discontinued | |
| **Bendigo** | 180 | 30 | 6 | Bendigo | VIC | Arup | Further feasibility: 10 months | Discontinued | Cost initial studies: 1.5 M$ |
| **Walpole** | 22.5 | 1.5 | 15 | Walpole | WA | Western Power Power Research and Development | Commenced in: 2022 Construction completed: 2023 | Committed | 2 M$ funding from WA Gov |

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