2023 Inputs, Assumptions and Scenarios Report

July 2023

Final report

For use in Forecasting and Planning studies and analysis

Important notice

Purpose

AEMO publishes this 2023 Inputs, Assumptions and Scenarios Report (IASR) pursuant to National Electricity Rules (NER) 5.22.8. This report includes key information and context for the inputs and assumptions used in AEMO's Forecasting and Planning publications for the National Electricity Market (NEM).

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Version control

Version	Release date	Changes
1.0	28/7/2023	Initial release

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Executive summary

The 2023 *Inputs, Assumptions and Scenarios Report* (IASR) details how AEMO will model the future in its forecasting and planning publications for the rest of 2023 and into 2024. It has been developed through collaboration with a broad range of industry participants, governments and consumer representatives. It reflects stakeholder feedback and significant refinement of inputs and assumptions from workshops, webinars, public forums, other engagements and more than 60 submissions to formal consultation.

Compared to the 2021 IASR scenarios (used in the 2022 *Integrated System Plan* (ISP)), the 2023 IASR scenarios have been refined with respect to the economic and technological change expected over the coming decades, consumer investment in consumer energy resources (CER), and electrification of other sectors to decarbonise.

Importantly, significant expansions in commitments to the energy transition to net zero by governments of jurisdictions across the National Electricity Market (NEM) have occurred over the past 12 months. The 2023 scenarios therefore encompass higher minimum rates of decarbonisation than were included in the previous 2021 scenarios, while retaining a wide breadth of energy futures to investigate power system needs and impacts of the energy transition.

Background and consultation

AEMO, through its forecasting and planning functions:

- Models the future of the NEM power system using a wide range of input data and based on a range of assumptions about which way the future may develop.
- Presents the forecasts based on a number of scenarios, with each scenario combining different assumptions and inputs to show a possible future.

AEMO delivers a range of forecasting and planning publications for the NEM, including the NEM *Electricity Statement of Opportunities* (ESOO), the *Gas Statement of Opportunities* (GSOO) for eastern and south-eastern Australia, and the ISP.

AEMO updates inputs, assumptions and scenarios every two years incorporating stakeholder engagement across industry, government and consumers. When relevant to AEMO's planning functions, inputs and assumptions may be updated as new data becomes available, government policy settings evolve, and stakeholders provide feedback[1].

AEMO published the Draft 2023 IASR for formal consultation in December 2022, and has used feedback received from over 60 formal submissions, as well as the wealth of stakeholder insight provided across a range of workshops, webinars, public forums and direct discussions, in preparing this final 2023 IASR.

This report is accompanied by a separate consultation summary report[2], which provides AEMO's considerations of the extensive stakeholder feedback received throughout the consultation process on the Draft 2023 IASR, including how the feedback has led to refinements of this 2023 IASR.

[1] Inputs and assumptions are updated at least annually, with scenarios re-examined biennially.

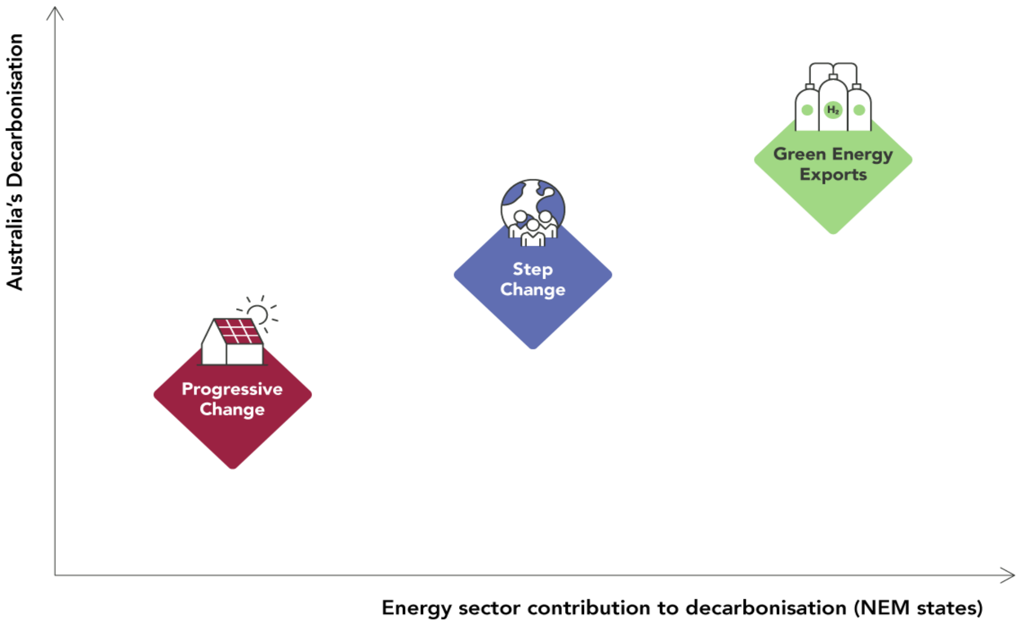
[2] At https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

The scenarios and sensitivities

The IASR scenario set is designed to traverse a range of plausible futures for energy demand, and in how that demand is satisfied. The pace of decarbonisation differs across scenarios, in concert with other scenario settings, to achieve a set of internally consistent possible future worlds. It is important to recognise that there are many potential futures, and that the final scenarios are used by AEMO to fulfil its role in developing forecasting and planning publications, and in doing so, inform government, industry and consumers of the risks and opportunities associated with the energy transformation.

The broad and deep push to decarbonise across jurisdictions reduces some of the uncertainty faced by AEMO's previous IASR publications. Due to the rapid pace of ongoing policy development, policies that meet the 'public policy clause' of the Rules, or where jurisdictions have demonstrated clear pathways to AEMO to meeting this clause prior to publication of the 2024 ISP, have been included in the policy collection influencing AEMO's planning functions.

Figure 1 2023-24 scenarios



AEMO has synthesised stakeholder feedback and refined the four draft scenarios into three (shown in Figure 1):

- ***Green Energy Exports*** – refines the 2021 *Hydrogen Superpower* scenario. This scenario reflects very strong decarbonisation activities domestically and globally to limit temperature increase to 1.5°C, resulting in rapid transformation of Australia's energy sectors, including a strong use of electrification, green hydrogen and biomethane.
- ***Step Change*** – refines the 2021 *Step Change* scenario. This scenario is centred around achieving a scale of energy transformation that supports Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels (and may be compatible with 1.5°C pathways for the NEM as well, depending on actions taken by other sectors of Australia's economy). Like the 2021 IASR *Step Change* scenario, this scenario relies on a very strong contribution from consumers in the transformation, with rapid and significant continued investments in CER which are highly orchestrated through aggregators or other providers with the benefits passed on to consumers. There is also strong transport electrification, as well as opportunities for

Australia's larger industries to electrify to reduce emissions, or use developing hydrogen production opportunities or other low emissions alternatives to support domestic industrial loads.

- ***Progressive Change*** – explores the challenges of meeting Australia's current Paris Agreement commitment of 43% emissions reduction by 2030 and net zero emissions by 2050. In this scenario, transformational energy sector investments continue, but economic and international factors place industrial loads at greater risk. Higher technology costs and supply chain challenges relative to other scenarios slow the pace of change compared to other scenarios.

Table 1 below provides a high-level comparison of key scenario settings at a given future year, in this case in 2040. For ease of understanding the relative scale of activities, investments or opportunities, a reference value typically reflecting the current level is also provided to compare with the settings at 2040.

Table 1 Scenario comparison at 2040

	Reference value for scenarios	*Green Energy Exports*	*Step Change*	*Progressive Change*
Electrification and energy efficiency savings				
% of road transport that is EV	2022-23: <1	72	60	32
% of residential EVs still relying on convenience charging	2022-23: ~75	38	46	56
Business electrification (TWh)	Max. potential: 41 [A]	36	25	20
% increase from current business consumption	n/a	26	18	15
Residential electrification (TWh)	Max. potential: 12 [A]	9	9	6
% increase from current residential consumption	n/a	16	15	11
Energy efficiency savings (TWh)	n/a	41	36	26
Underlying consumption				
NEM underlying consumption (TWh)	2022-23: 193	345	299	230
Hydrogen consumption (domestic) (TWh)	2022-23: 0	50	28	15
Hydrogen consumption (export, including green steel) (TWh)	2022-23: 0	183	7	0
Total underlying consumption (TWh)	2022-23: 193	578	335	246
Supply				
Distributed PV generation (TWh)	2022-23: 24	92	77	45
% of household daily consumption potential stored in batteries	2022-23: 1%	22%	21%	3%
% of underlying consumption met by CER	2022-23: 12%	16%	23%	18%
Share of electricity emissions in economy-wide emissions (NEM states only)	CY2021: 36%	1%	1%	9%
Estimate of NEM emissions production (MT CO_2-e)	CY2021: 132	2	1	22

Note: Totals tabulated above may not tally due to rounding.
A. For the purposes of this table, the 'maximum potential electrification' reflects the 2050 electrification forecast for the *Green Energy Exports* scenario. This scenario assumes that residential buildings are able to fully electrify by 2050 and that industries that are theoretically able to electrify have adopted those electrification technologies by 2050. In this way, the 2040 electrification values for each scenario can be put into context by comparing to this 'maximum potential electrification' value.

The *Slow Change* scenario described in the 2021 IASR and 2022 ISP is no longer consistent with the pace of transformation required by the collection of policies facing Australia's energy industry. In AEMO's stakeholder activities conducted prior to the release of the Draft 2023 IASR, a majority of stakeholders supported the *Slow Change* scenario's removal, consistent with its very low relative likelihood in the 2022 ISP.

While scenarios are fundamental to AEMO's forecasting and planning approach, a key role exists for sensitivity analysis to explore uncertainties pertaining to key assumptions. Stakeholders also identified many planning influences and assumptions that they considered deserved special consideration and analysis in the IASR and ISP, with many recognising that sensitivities are a targeted way to conduct such analysis.

AEMO considers the following sensitivities address key uncertainties:

- ***Rapid Decarbonisation*** examines the impact of bringing forward decarbonisation of the NEM, by applying the more aggressive emissions abatement pathway from the *Green Energy Exports* scenario.
- ***Electrification Alternatives*** examines the role of biomethane in a world where industrial electrification is delayed and reduced relative to the *Step Change* scenario.
- ***Low CER Orchestration*** examines the impacts of reduced effectiveness of consumer investment orchestration via virtual power plants (VPPs) than in the *Step Change* scenario.
- ***Reduced Energy Efficiency*** supports the evidence base for energy efficiency programs by providing an examination of the investments that may be avoided by delivering the forecast growth in energy efficiency.
- ***Higher Discount Rate*** and ***Lower Discount Rate*** will demonstrate the sensitivity of investment decisions for long-lived assets with different settings for valuing future benefit streams.
- ***Constrained Supply Chains***, exploring the costs and potential benefits of a less volatile annual rate of transition, from lesser supply chain capacity and more limited workforce availability.

AEMO also intends to include a sensitivity that explores risks relating to social licence, and has established an Advisory Council on Social Licence to assist in understanding social licence issues facing the energy transition for consideration in development of the ISP.

In examining three scenarios, increased consideration of these key uncertainties will be important, including dimensions of the scenarios that are uncertain but potentially impact planning requirements and investment needs. This is particularly important for the ISP, where sensitivity analysis enables evaluation of the robustness of the ISP's optimal development path (ODP).

Summary of key inputs and assumptions

This 2023 IASR and associated 2023 IASR Assumptions Workbook provide detail on the inputs and assumptions associated with each scenario. Below is a summary of some of the key inputs and assumptions.

Policy settings

AEMO is using the following federal and state public policies[3] in all scenarios.

[3] These policies meet, will meet, or are likely to meet the public policy clause criteria set out in the National Electricity Rules (NER) 5.22.3(b), which outlines which environmental or energy policies AEMO may consider in developing the ISP.

Table 2 Policies used in all scenarios

Policy type	Policies included
Emission reduction policies	• Federal – Emission reduction of 43% below 2005 levels by 2030 and net zero by 2050 under the *Climate Change Act (2022)* (C'th). • New South Wales – Emission reduction targets of 50% by 2030 and net zero by 2050 (legislation is pending). • South Australia – target of 60% (40% of 1990 levels) by 2050 under *the Climate Change and Greenhouse Emissions Reduction Act 2007*. • Victoria – target of 28-33% below 2005 levels by 2025, 50% by 2030, 75-80% by 2035 and net zero by 2050 under *Victoria's Climate Change Act 2017*; and the net-zero emission target by 2045 that is intended to be legislated.
Renewable energy targets	• Federal – Complementing the 2030 emissions target is the Federal Government's commitment to achieve an 82% share of renewable generation by 2030, announced in *the Powering Australia Plan*[4]. • New South Wales – new renewable generation that can produce the same electricity as 8 GW in New England REZ, 3 GW in Central-West Orana REZ, and 1 GW elsewhere by end of 2029 under the *New South Wales Electricity Infrastructure Investment Act 2020* (NSW EII Act). • Queensland – expansion of the Queensland Renewable Energy Target (QRET) to 50% by 2030, 70% by 2032, and 80% by 2035 under the Queensland Energy and Jobs Plan (QEJP); legislation is under consultation. • Tasmania – target of 150% of consumption by 2030 (on 2020 levels) and 200% by 2040 under the *Energy Co-ordination and Planning Amendment (Tasmanian Renewable Energy Target) Act 2020.* • Victoria – Victorian Renewable Energy Target (VRET) of 40% by 2025, 50% by 2030 under the *Renewable Energy (Jobs and Investment) Act 2017*, and intentions to update VRET with 65% of the state's generation to come from VRE by 2030 and 95% by 2035.
Storage targets	• New South Wales – target of 2 gigawatts (GW) of deep storage by 2030 under the NSW EII Act. • Queensland – Development of Borumba Pumped Hydro Energy Storage (now classified as an Anticipated project under AEMOs' generation commitment criteria[5]). • Tasmania – Battery of the Nation will be considered as a generation development option. • Victoria – Storage targets of 2.6 GW by 2030 and 6.3 GW by 2035 (legislation is pending).
Offshore wind targets	• Victoria – 2 GW by 2032, 4 GW by 2035, and 9 GW by 2040 as stated in the Offshore Wind Policy Directions Paper and Implementation Strategy Statements One and Two (legislation is pending).
Hydrogen policies	• New South Wales – Renewable Fuels Scheme (legislated in 2021 and is expected to start in 2024) of the NSW Hydrogen Strategy. • Queensland – The QEJP has allocated funding to support the Kogan Renewable Hydrogen Project[6]. • South Australia – Hydrogen Jobs Plan, which includes a 250 MW electrolyser and a 200 MW hydrogen-capable generator, that has significant budget commitments.
Transmission support policies	• New South Wales – Consideration of various transmission development options under the NSW Electricity Infrastructure Roadmap, including Renewable Energy Zone network infrastructure projects and priority transmission infrastructure projects (PTIPs) under the NSW EII Act. Waratah Super Battery System Integrity Protection Scheme will be treated as a committed project, and Central-West Orana Transmission Project will be treated as an anticipated project. • Queensland – Consideration of various transmission development options and Queensland Renewable Energy Zone (QREZ) infrastructure, as described in the SuperGrid Infrastructure Blueprint and Queensland Renewable Energy Zone (QREZ). CopperString 2032 will be treated as an Anticipated project with the Townsville to Hughenden connection being modelled quantitively as a REZ network expansion. • Victoria – Consideration of various transmission development options, including coordinating the planning and development of REZs through VicGrid, supported by the *National Electricity (Victoria) Act*

[4] Available at https://www.energy.gov.au/government-priorities/australias-energy-strategies-and-frameworks/powering-australia.

[5] Projects are modelled as committed or anticipated based on criteria covering five areas of development: land/site acquisition, contracts for major components, planning and other approvals, financing, and construction.

[6] See https://www.treasury.qld.gov.au/programs-and-policies/queensland-renewable-energy-and-hydrogen-jobs-fund/.

Policy type	Policies included
	2005 (NEVA). The Western Renewables Link and the Mortlake Turn-in will be treated as an Anticipated projects.
Transmission landholder payment schemes	• Payment schemes that compensate landholders for hosting transmission infrastructure in addition to the compensation provided through conventional land acquisition frameworks: – New South Wales – Strategic Benefit Payments Scheme. – Queensland – SuperGrid Landholder Payment Framework. – Victoria – Landholder Payments For A Fairer Renewables Transition.
Energy Efficiency policies	• Federal – Building Code of Australia (BCA) 2010, the National Construction Code (NCC) 2019, NCC 2022, National Australian Built Environment Rating Systems (NABERS), Energy for Offices and Commercial Building Disclosure (CBD) and Equipment Energy Efficiency (E3) program (or Greenhouse and Energy Minimum Standards [GEMS]). • New South Wales – Energy Efficiency Scheme (ESS) and Peak Demand Reduction Scheme (PDRS) under the New South Wales Energy Security Safeguard. • Victoria – Victorian Energy Upgrades (VEU) program • South Australia – South Australian Retailer Energy Efficiency Scheme (SA REES)
Other government policies	• Safeguard Mechanism, the Capacity Investment Scheme, and the re-development of publicly owned coal-fired generation in Queensland into clean energy hubs (as defined in the QEJP).

The scenarios also consider various other jurisdictional subsidies, programs and schemes that impact on consumer energy resources, and other influences that affect the scale and shape of consumers' ongoing use of energy, including the role for fuel-switching between energy sources.

Electrification and other decarbonisation levers

Electrification refers to the process of fuel-switching from fossil fuels such as oil, coal or natural gas to using electricity. A key driver for the energy transition is Australia's goal to develop a net zero economy, and electrification is forecast to provide a significant contribution to that outcome. This includes:

- Transport (electric vehicles (EVs)) is the main driver of electrification across scenarios.
- Industry (primarily manufacturing and mining) makes up the bulk of electrification other than EVs.
- Victoria has the largest share of residential electrification in the scenarios, due to its current high level of gas use for residential heating.

Other activities and investments are also required across Australia's economy, and the scenarios and sensitivities explore different levels of use of these other levers, including energy efficiency investments, direct emissions offsets (from improved land use and sequestration activities), and other activities that will affect consumers' use of fossil fuels.

Technology and fuel costs

The *GenCost 2022-23 Final report*[7], published by the CSIRO and AEMO, highlights the increase in build costs for most technologies that is expected to take place over the next few years as a result of supply chain constraints and inflationary pressures. These cost pressures are projected to continue over the medium term.

[7] At https://www.csiro.au/en/research/technology-space/energy/energy-data-modelling/gencost.

Renewable energy zones

Stakeholders including state governments have helped AEMO refine and expand modelling inputs related to REZs. Inputs have been updated to reflect new REZs, redefine existing REZs, update offshore REZ resource limits and include new transmission limits.

Transmission augmentation options and costs

Transmission network expansion is a key input , enabling increased transfer capacity for REZs and the backbone of the interconnected network, a key need to enable the energy transition. The 2023 *Transmission Expansion Options Report* forms part of the 2023 IASR. It describes the engagement of independent experts and provision of industry and stakeholder advice, culminating in a report summarising the conceptual design, lead time, location and project cost estimates (including network augmentation costs, connection costs and system strength remediation costs) for candidate transmission projects to inform the development of the 2024 ISP.

Next steps

AEMO will use these inputs, assumptions and scenarios in its planning work including in developing the 2023 ESOO in August 2023, the Draft 2024 ISP due in December 2023, the final 2024 ISP due by June 2024 and the 2024 GSOO due in March 2024.

AEMO publishes all relevant and material milestones for the ISP in its ISP Timetable[8]; stakeholders may review this information, which is updated as needed on the timing of the ongoing ISP activities. AEMO also publishes opportunities for engagement[9] that stakeholders may also wish to get involved in.

[8] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp.

[9] See https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/opportunities-for-engagement.

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1 Introduction

AEMO develops publications that provide stakeholders with key forecasting and planning advice, including:

- ***Electricity Statement of Opportunities* (ESOO)** – provides operational and economic information about the National Electricity Market (NEM) over a 10-year outlook period, with a focus on electricity supply reliability. The ESOO includes a reliability forecast identifying any potential reliability gaps in the coming five years, as defined according to the Retailer Reliability Obligation (RRO). The final five years of the 10-year ESOO forecast provide an indicative forecast of any future material reliability gaps. The ESOO also includes 20-year forecasts of annual consumption, maximum demand, and demand side participation (DSP). It is published annually, with updates if required.
- ***Gas Statement of Opportunities* (GSOO)** – provides AEMO's forecasts of annual gas consumption and maximum gas demand and uses information from gas producers about reserves and forecast production, to project the supply-demand balance and potential supply gaps over a 20-year outlook period in eastern and south-eastern Australia. It is published annually, with updates if required.
- ***Integrated System Plan* (ISP)** – is a whole-of-system plan that efficiently achieves the power system needs of a transforming energy system in the long-term interests of consumers. It serves the regulatory purpose of identifying actionable and future ISP projects, as well as the broader purposes of informing market participants, investors, policy decision-makers and consumers. It provides a transparent roadmap over a long-term horizon, optimising net market benefits while managing the risks associated with the change necessary to facilitate the NEM's energy transition. AEMO published the inaugural ISP for the NEM in 2018, and publishes it every two years, requiring action to be taken by the relevant transmission network service providers and Joint Planning Bodies under the ISP framework

AEMO typically forecasts and models the future in these publications through a scenario planning approach.

This report documents the scenarios, and their respective inputs and assumptions, that are used in this modelling. The scenario set traverses a range of outcomes based on key uncertainties facing the energy sector as it decarbonises:

- The **pace of decarbonisation** of the Australian economy, and the role that the energy sector plays in enabling the transition to a net zero economy.
- The **role of consumers** in supporting the decarbonisation through ongoing uptake of consumer energy resources (CER), and the potential of those resources to be coordinated through virtual power plants (VPPs).
- The **scale and speed of electrification** (switching from other fuels to electricity) in the consumer, business, industrial and transport sectors. These sectoral transformations may bring significant change to the traditional way industry, business and consumers use energy.
- The **community benefits and impacts of the energy transition**, including broad economic growth opportunities, as well as the appetite or reluctance for new energy infrastructure needed to decarbonise the NEM.

- The **uptake of hydrogen**, its derivations, and other renewable fuels such as biomethane to complement electrification activities to decarbonise the economy and provide potential green export commodity opportunities.

The scenarios are of critical importance in AEMO's planning and forecasting publications, but also in the regulatory investment test for transmission (RIT-T) assessments conducted by transmission network service providers (TNSPs).

The information in this report is supported by the 2023 IASR Assumptions Workbook, which provides more granular detail about the inputs and assumptions for use in 2023-24 forecasting, modelling, and planning processes and analysis.

The IASR Consultation Summary Report (Consultation Report) complements this report, highlighting the breadth of stakeholder feedback received throughout the development of this 2023 *Inputs, Assumptions and Scenarios Report* (IASR) and AEMO's considerations of, and response to, the feedback.

The use of scenarios is enhanced by sensitivity analysis. Sensitivities describe the outcomes where a scenario has a limited number of its parameters varied. AEMO, with stakeholder input, has developed a set of sensitivities that support the assessment of how forecasting and planning results might differ if a key assumption differed.

All dollar values provided in this report are in real 2023 Australian dollars unless stated otherwise.

1.1 Consultation process

AEMO strongly believes that engaging with stakeholders on planning inputs, assumptions and methodologies is essential to enable appropriate actions by stakeholders, policy-makers and broader consumers. Being transparent, collaborative and stakeholder-focused is, therefore, one of AEMO's four Corporate Priorities[10].

In developing this 2023 IASR, AEMO has consciously sought to meet and exceed the requirements to develop, consult on, and publish the IASR in accordance with the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines[11]. While these Guidelines require AEMO to follow a "single stage consultation process", AEMO has preferred more regular consultation and engagement than the minimum requirement, using both formal and informal channels to seek and to consider stakeholder feedback, improve transparency and clarity around the ISP decision-making process, and validate that changes made in response to stakeholder feedback are appropriate. To achieve this, AEMO has undertaken a variety of stakeholder engagement processes, including:

- Involving stakeholders in the development stages of select inputs, assumptions and scenarios, prior to publishing the Draft 2023 IASR, and following it, particularly in the Forecasting Reference Group[12] (FRG), an open forum that provides AEMO and stakeholders an opportunity to engage on key inputs as they are under development.
- A single stage consultation process to obtain stakeholder feedback on the Draft 2023 IASR, consistent with the AER's Forecasting Best Practice Guidelines.

[10] Priority 3: Engaging our stakeholders. See *AEMO Corporate Plan FY 2023*, 15, at https://aemo.com.au/-/media/files/about_aemo/corporate-plan/2022/fy23-aemo-corporate-plan.pdf.

[11] At https://www.aer.gov.au/system/files/AER%20-%20Forecasting%20best%20practice%20guidelines%20-%2025%20August%202020.pdf.

[12] See https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg.

- Webinars to explain how AEMO perceived stakeholder feedback and inform how the feedback resulted in updates to the scenarios and their inputs and assumptions.
- Numerous meetings with stakeholders including distribution network service providers (DNSPs), the Clean Energy Investment Group, and the AER.
- Regular engagement with the ISP Consumer Panel to consult on the scenarios, sensitivities, and assumptions, ensuring that the Panel's experience and consumer perspectives is a key influence on AEMO's consideration in developing this 2023 IASR.

The Consultation Report published alongside this IASR provides a detailed summary of the consultation process undertaken in the development of this report. The Consultation Report explains how engagement with stakeholders has shaped the scenarios, as well as the inputs and assumptions. The report provides detailed responses to all material issues raised in written submissions and in verbal feedback sessions with consumer representatives. This 2023 IASR should be read in conjunction with that Consultation Report.

The 2023 *Transmission Expansion Options Report* was consulted on separately and is released in parallel to the IASR. The reference for the stakeholder engagement is summarised in Table 6 in the *Transmission Expansion Options Report.*

Table 3 below summarises key engagement activities conducted to support the development of this 2023 IASR[13].

Table 3 Stakeholder engagement on the 2023 IASR

Activity	Date
Scenarios webinar 1	13 July 2022
Scenarios webinar 2	31 August 2022
FRG meetings on draft component forecasts	31 August, 21 and 28 September 2022
Release of Draft IASR	16 December 2022
What the ISP means for consumers	24 January 2023
Draft IASR webinar	2 February 2023
Consumer advocates verbal submission session	9 February 2023
Submissions close on Draft IASR	16 February 2023
Draft 2023 IASR submissions reflections webinar	22 March 2023
Scenarios and sensitivities update webinar	15 June 2023
2023 IASR publication	28 July 2023

The Draft 2023 IASR documented the draft of inputs, assumptions and scenarios, including information available at that time, with the report noting which information would change over time. This final 2023 IASR now reports the updated results.

[13] Presentations and recordings of webinars are available at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/opportunities-for-engagement.

2 Scenarios

The use of scenario planning is an effective practice when planning in highly uncertain environments, particularly through disruptive transitions. Scenarios therefore should purposefully cover the breadth of potential and plausible futures impacting the energy sector, and capture the key uncertainties and material drivers of these possible futures in an internally consistent way. AEMO uses scenario modelling to assess costs, risks, opportunities, and development needs through the energy transition, in the long-term interests of consumers.

The 2023 IASR scenarios enable this by intentionally varying combinations of inputs associated with major sectoral uncertainties, including:

- The health and evolution of the Australian economy, and its impact on energy consumption.
- The decarbonisation pathway for the Australian economy as it transitions to net zero emissions, with specific focus on the transformation on the energy sector.
- The scale and pace of electrification of Australia's residential, commercial, industrial and transportation sectors (and others) as a key driver of the energy sector's transformation.
- The scale of CER, which comprise small-scale embedded generation and storage technologies, such as residential and commercial photovoltaic (PV) systems, battery storage, and electric vehicles (EVs). CER also refers to other resources that enable greater demand flexibility.
- Progress and cost outlooks for enabling technologies across electricity generation, storage and CER.
- The role of emerging energy technologies affecting Australia's decarbonisation pathway and economy, including hydrogen and manufactured products that utilise it (such as green steel and ammonia products), and other technologies (such as biomethane) that may impact the emissions intensity of energy.

In developing the set of scenarios, and having regard to the AER's Cost Benefit Analysis Guidelines (CBA Guidelines)[14], AEMO has considered several core principles for scenario development. The scenarios should be:

- **Internally consistent** – the underpinning assumptions in a scenario must form a cohesive picture in relation to each other.
- **Plausible** – the potential future described by a scenario narrative could come to pass.
- **Distinctive** – individual scenarios must be distinctive enough to provide value to AEMO and stakeholders.
- **Broad** – the scenario set covers the breadth of possible futures.
- **Useful** – the scenarios explore the risks of over- and under-investment.

2.1 Stakeholders have provided input in developing the scenarios

The scenarios maintain similarity with AEMO's previous scenarios, developed and described in the 2021 IASR and applied in 2022 forecasting and planning publications, including the 2022 ISP, ESOO and GSOO. Stakeholders have provided feedback to AEMO that retaining and evolving existing scenarios in planning the energy transition is generally preferred, compared to developing entirely new scenarios. Scenario longevity,

[14] At https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

where appropriate, allows for increased comparison of modelling outcomes and insights to support stakeholder decision-making. For example, the 2024 ISP Consumer Panel noted that there "*may be value in seeking to retain the same scenarios for at least two ISPs*"[15].

Stakeholders provided significant feedback on the breadth and ambition of the scenarios during AEMO's Draft 2023 IASR consultation. Through this engagement, AEMO has adapted the scenario collection to consolidate the primary scenarios presented here and enable increased insight from sensitivity analysis that can complement the scenarios.

AEMO also recognises that some changes to the scenario collection have been necessary to ensure the collection keeps pace with the energy market transformation. For example, the ambition of governments to increase the pace and commitment to decarbonisation has allowed AEMO to remove the 2021 IASR's *Slow Change* scenario from the collection, as it is no longer consistent with Australia's commitment to transition to net zero. Other changes relative to the 2021 IASR scenarios are explained in each scenario description.

2.2 Scenario narratives and descriptions

AEMO's scenarios examine the future needs of the power system, and enable evaluation of the investments required to support the energy transition to net zero emissions. The scenarios are intentionally diverse, reflecting a range of current and future trends in energy consumption, consumer energy investments, and technology costs. All policies that meet the relevant requirements are included (see Section 3.1).

AEMO's revised set of scenarios maintains fundamental themes described in the 2021 scenario collection, but reflects reduced uncertainty regarding the pace of decarbonisation for the energy sector, particularly since Australia's commitment to net zero emissions by 2050 and updated commitments to the Paris Agreement:

- ***Green Energy Exports*** – reflects very strong decarbonisation activities domestically and globally aimed at limiting temperature increase to 1.5°C, resulting in rapid transformation of Australia's energy sectors, including a strong use of electrification, green hydrogen and biomethane. The NEM electricity sector plays a very significant role in decarbonisation.
- ***Step Change*** – achieves a scale of energy transformation that supports Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels. The NEM electricity sector plays a significant role in decarbonisation and the scenario assumes the broader economy takes advantage of this, aligning broader decarbonisation outcomes in other sectors to a pace aligned with beating the 2°C abatement target of the Paris Agreement. The NEM's contribution may be compatible with a 1.5°C abatement level, if stronger actions are taken by other sectors of Australia's economy simultaneous with the NEM's decarbonisation. Consumers provide a strong foundation for the transformation, with rapid and significant continued investments in highly orchestrated CER, including electrification of the transportation sector.
- ***Progressive Change*** – meets Australia's current Paris Agreement commitment of 43% emissions reduction by 2030 and net zero emissions by 2050. This scenario has more challenging economic conditions, higher relative technology costs and more supply chain challenges relative to other scenarios.

The scenario collection spans a range of futures, considering a broad set of inputs. The scenarios include consideration of the role and influence of policy, regulatory, commercial and consumer level decisions on the pace

[15] 2022 ISP Consumer Panel, *Report on AEMO's IASR for the 2022 ISP,* September 2021, p 38, at https://aemo.com.au/-/media/files/major-publications/isp/2021/isp-consumer-panel-report-on-2021-iasr.pdf.

and breadth of the energy transition, and scenario narratives respect both domestic and international influences, such as population growth, consumer investments, supply chains and international demand for green energy.

The scenario dimensions are internally consistent, but there could conceivably exist many different combinations that are also plausible futures. The scenario set is not intended to predict only those inputs that are likely and their combinations. For example, a slow domestic economy can still benefit from fast technological progress internationally, or targeted developments domestically, and therefore contrasting scenario dimensions are possible and plausible. Various dimension combinations can be constructed to produce similar high-level impacts depending on the balance of countervailing inputs. This 2023 IASR collection has preferred a more linear relationship with the dimensions, to increase the ease of understanding and comparing scenarios, rather than it reflecting that AEMO or stakeholders have considered that the inputs must align in that manner.

Scenario likelihoods

AEMO recognises the energy transition is well underway, yet numerous uncertainties remain influencing the scale and likelihood of various actions that will drive a faster or slower pace of continuing change in the NEM and Australia's broader energy markets.

For the 2022 ISP, AEMO conducted a Delphi Panel of experts to assist in the determination of scenario likelihoods. AEMO will again engage with stakeholders prior to the Draft 2024 ISP to refresh the scenario likelihoods for the 2023 IASR scenario collection. This collaborative approach will ascertain the appropriate new weightings for these scenarios, settings that are crucial to ensure that the investments needed to address the pace and scale of the energy transition are appropriately considered.

Event-driven scenarios

Event-driven scenarios may be deployed to explore clearly observable and reasonably probable independent events or investment decisions that may materially change the benefits of a candidate development path in the 2024 ISP. These events may occur in any future world, and may serve as a sign-post to pivot from one development path to another.

If relevant, AEMO may examine and explore the possibility for an event-driven scenario(s) to complement or substitute for any of the three core scenarios, in the event that the core scenario's assumptions are impacted by a given event. This approach may enable AEMO to recommend consideration of these in subsequent regulatory analyses conducted by TNSPs.

For the 2024 ISP, AEMO will examine potential events that may increase, or reduce, the need for transmission investments. For example, stakeholders have identified significant consumer load growth opportunities for new industrial, mining and manufacturing loads in regional South Australia. These may need transmission investment to support efficient and effective operations. AEMO will explore whether such an event – that is, the potential commitment of significant new loads beyond the core scenarios' growth and electrification forecasts – would support alternative development preferences.

Comparing to the 2021 IASR scenarios

In consultation with stakeholders, and in response to feedback received directly from submissions to AEMO's Draft 2023 IASR, AEMO has consolidated the four-scenario collection from the 2021 IASR, to three scenarios. The previous *Slow Change* has been withdrawn as it no longer is internally consistent with Australia's updated emissions reduction ambitions and commitments. Stakeholders generally supported this decision in the Draft 2023 IASR consultation submissions, reflective of the relatively low scenario weighting determined for the 2022 ISP for this scenario.

The adjusted scenario collection compares with the 2021 IASR scenarios as follows:

- The ***Green Energy Exports*** **scenario** refines the 2021 IASR *Hydrogen Superpower* scenario, again reflecting very strong decarbonisation activities, resulting in rapid transformation of Australia's energy sectors and a strong shift towards electrification. The scale of hydrogen production expected to connect to the NEM is lower than in the 2021 IASR *Hydrogen Superpower* scenario.
- The ***Step Change*** **scenario** remains very similar to the 2021 IASR *Step Change* scenario, with strong action on climate change at utility and consumer scale. It once again features highly engaged energy consumers, with CER investments that are predominantly orchestrated to maximise system efficiency. Like in the 2021 IASR *Step Change*, the scale of electrification across other sectors is high, with relatively fast commitments made by industry and consumers to reduce emissions levels where alternative energy sources exist.
- The ***Progressive Change*** **scenario** features slower economic growth and load risks (similar to the 2021 IASR *Slow Change* scenario), and only modest technology cost change (reflecting the 2021 IASR *Progressive Change* scenario). The scenario incorporates decarbonisation investments at a pace of uptake consistent to meet national and state-based policy, including Australia's 43% emissions reduction target by 2030. This level of investment will yield a faster pace of transition than the 2021 IASR *Slow Change* scenario.

2.2.1 *Green Energy Exports*

A scenario with very rapid and widespread transformation of the economy making a very significant contribution from the electricity sector aimed at achieving a temperature rise limited to 1.5°C. Consumer investments are very high, and global demand for green energy contributes to a new and very strong green energy export economy.

Scenario purpose

To test the implications and needs of the power system experiencing very rapid change to decarbonise and support a technical expansion of the economy to realise the benefits of Australia's renewable generation potential, supporting a hydrogen economy and the flow-on benefits to economic growth for domestic consumers having access to alternative green energy sources (for example, increasing local manufacturing opportunities).

This scenario represents a world with very rapid action towards decarbonisation, technology cost improvements, and robust domestic and international economic outcomes. Technology cost reductions improve Australia's capacity to expand "green commodity" exports, including hydrogen and other energy-intensive products such as green steel, supporting stronger domestic economic outcomes relative to other scenarios. The availability of low-cost and low emissions energy, support domestic energy consumers as well as international customers, supplementing declining exports of traditional emissions-intensive resources from global decarbonisation efforts.

While well beyond current levels, this scenario has rapid investment in decarbonisation investments. For consistency, there is a high degree of electrification and energy efficiency investments across many sectors, and consumers further increase their investment in consumer energy resources (including electrified vehicles), and energy efficient homes. The transport sector, in particular, rapidly embraces electric and hydrogen-fuelled options to decarbonise both light and heavy vehicle fleets.

The energy transition in Australia is in step with actions globally, which are assumed to be occurring at a commensurate level. A mixture of electrified and molecular energy options enables consumers of all types (residential, commercial and industrial) to decarbonise efficiently at a greater level than is currently occurring.

2.2.2 *Step Change*

A scenario with strong industry and consumer energy investments to decarbonise, and actions to lower emissions across Australia's economy above current levels. In this scenario the NEM provides a strong and economy-enabling contribution to that purpose through a fast-paced transformation.

Scenario purpose

To test the needs in the power system to support strong decarbonisation of the electricity sector, supporting other sectors decarbonising their current energy activities through electrification. Consumers increase their investment in CER, with high success in orchestrating these consumer investments for the benefits of power system security and reliability.

This scenario includes growing momentum to embrace a step change from the status quo, increasing the pace of the transition in the energy sector to support an economy-wide transition to net zero. Domestic and international action increases to achieve the minimum objectives of not only Australia's current commitments to the Paris Agreement, but the longer term goal of contributing to the limiting of global temperature rise to well below 2°C compared to pre-industrial levels. Economy-wide decarbonisation investments increase at pace above current levels, with faster and deeper cuts to emissions across the economy aligned to beating the objective to limit temperature rise to well below 2°C. With a relatively fast pace of transformation affecting the NEM, it may be compatible with even greater limitation of temperature rise to 1.5°C, if even more rapid and widespread complementary action was taken by other sectors of Australia's economy.

In this scenario, moderate growth in the global and domestic economy underlies the appetite to address climate change and provides a supporting environment for the development and uptake of relevant technologies.

Under the *Step Change* scenario, rapid transformation of the energy sector is enabled at utility scale by assumed continued cost reductions for renewable energy investments, and strong consumer appetite and willingness to invest to contribute directly through high uptake of CER, and electrified transport. Successful coordination of CER is assumed to be facilitated as consumers shift to this new innovative use of behind-the-meter assets, with an assumption of growing savings through energy efficiency measures.

It is also assumed that consumers and industry consolidate their energy supplies, with high growth in electrification and changing solutions for consumers in improved building design, smart appliances, and digitalisation that help consumers manage energy use.

Under this scenario the scale of hydrogen production in the NEM is limited, with significantly less availability than the *Green Energy Exports* scenario.

2.2.3 *Progressive Change*

A scenario that assumes ongoing challenges in global economic conditions that limits broader actions that could increase the current pace of change of Australia's transition to net zero. The scale of action therefore focuses on achieving current domestic and global policy objectives. Under this scenario the pace of decarbonisation across the economy may be inconsistent with limiting temperature rise to below 2°C by 2100 even if current energy sector objectives are met. Consistently, under this scenario, less ambitious actions are taken in other sectors of the economy, there are assumed to be significant supply chain constraints, and/or more measured global action.

Scenario purpose

To test the needs in the power system with a slower energy transition, and lesser growth across Australia's economy. As a consequence, this scenario also potentially allows:

- The risk of over-investment in the power system to be assessed, with lower operational demand.
- System security risks (and investments) associated with a decline in minimum demand to be explored.

This scenario captures a slower global recovery from the COVID-19 pandemic and ongoing disruptions affecting international energy markets and associated supply chains. Challenging economic conditions and business pressures increase the relative risk of industrial load closures, and slow the pace of investment to extend beyond current commitments regarding decarbonisation, further limiting the economic advantages that may exist with a near zero emissions intensive energy system.

In this scenario, lower disposable incomes and slower and lesser cost reductions are incorporated in the uptake of CER, including a lower pace of growth affecting transportation electrification. For example, ongoing consumer investment in improving building and appliance energy efficiency is more muted, and broader electrification (including by consumers in preferring and being willing to invest in alternative heating appliances to traditional fossil fuelled alternatives) is also slowed in the short to medium term.

Global progress towards net zero ambitions is in line with currently announced policies and ambitions, and while Australia likewise delivers on its commitment to a 43% reduction of emissions by 2030, and net zero by 2050, this is unlikely to be consistent with the pace and breadth of change expected to limit temperature rise to 2°C by 2100.

2.3 Key scenario parameters

Table 4 summarises decarbonisation targets, key demand drivers, technological improvements and other key parameters for each of the scenarios. Details are provided in the 2023 IASR Assumptions Workbook. All scenarios deliver at least 43% emissions reduction by 2030 and net zero by 2050 for the energy sector but vary by the pace of the transition to net zero, considering global, national and sectoral influences, leading to variations in the needs of the future energy system.

Table 4 Key parameters, by scenario

Parameter	*Green Energy Exports*	*Step Change*	*Progressive Change*
National decarbonisation target	At least 43% emissions reduction by 2030. Net zero by 2050	At least 43% emissions reduction by 2030. Net zero by 2050	At least 43% emissions reduction by 2030. Net zero by 2050
Global economic growth and policy coordination	High economic growth, stronger coordination	Moderate economic growth, stronger coordination	Slower economic growth, lesser coordination
Australian economic and demographic drivers	Higher (partly driven by green energy)	Moderate	Lower
CER uptake (batteries, PV and EVs)	Higher	High	Lower
Consumer engagement such as VPP and DSP uptake	Higher	High (VPP) and Moderate (DSP)	Lower
Energy efficiency	Higher	Moderate	Lower
Hydrogen use	Faster cost reduction. High production for domestic and export use	Medium-Low production for domestic use, with minimal export hydrogen.	Low production for domestic use, with no export hydrogen.
Hydrogen blending in gas distribution network[A]	Up to 10%	Up to 10%	Up to 10%
Biomethane/ synthetic methane	Allowed, but no specific targets to introduce it	Allowed, but no specific targets to introduce it	Allowed, but no specific targets to introduce it
Supply chain barriers	Less challenging	Moderate	More challenging
Global/domestic temperature settings and outcomes[B]	Applies Representative Concentration Pathway (RCP) 1.9 where relevant (~ 1.5°C)	Applies RCP 2.6 where relevant (~ 1.8°C)	Applies RCP 4.5 where relevant (~ 2.6°C)
IEA 2021 World Energy Outlook scenario	Net Zero Emissions (NZE)	Sustainable Development Scenario (SDS)	Stated Policies Scenario (STEPS)

A. Hydrogen blending into the gas distribution network will need to accommodate the technical requirements of distribution pipelines, as well as the capabilities of connected gas appliances. Higher blends than ~10% by volume are assumed possible for industrial use but may require equipment change and/or shifts to dedicated hydrogen transmission pipelines.
B. RCPs were adopted in the IPCC's first Assessment Report, see https://www.ipcc.ch/report/ar5/syr/.

2.3.1 A snapshot at 2040

Following the key parameter scenario dimensions described above, Table 5 compares the scenarios in a snapshot of 2040, providing a high-level comparison of key inputs affecting energy demand and supply. For ease of understanding the relative scale of activities, investments or opportunities, a reference value typically reflecting the current level is also provided.

The inputs are described in detail in Section 3, and estimates presented here will be confirmed in the 2024 ISP.

Table 5 Scenario comparison at 2040

	Reference value for scenarios	Green Energy Exports	Step Change	Progressive Change
Electrification and energy efficiency savings				
% of road transport that is EV	2022-23: <1	72	60	32
% of residential EVs still relying on convenience charging	2022-23: ~75	38	46	56
Business electrification (TWh)	Max. potential: 41 [A]	36	25	20
% increase from current business consumption	n/a	26	18	15
Residential electrification (TWh)	Max. potential: 12 [A]	9	9	6
% increase from current residential consumption	n/a	16	15	11
Energy efficiency savings (TWh)	n/a	41	36	26
Underlying consumption				
NEM underlying consumption (TWh)	2022-23: 193	345	299	230
Hydrogen consumption (domestic) (TWh)	2022-23: 0	50	28	15
Hydrogen consumption (export, including green steel) (TWh)	2022-23: 0	183	7	0
Total underlying consumption (TWh)	2022-23: 193	578	335	246
Supply				
Distributed PV generation (TWh)	2022-23: 24	92	77	45
% of household daily consumption potential stored in batteries	2022-23: 1%	22%	21%	3%
% of underlying consumption met by CER	2022-23: 12%	16%	23%	18%
Share of electricity emissions in economy-wide emissions (NEM states only)	CY2021: 36%	1%	1%	9%
Estimate of NEM emissions production (MT CO_2-e)	CY2021: 132	2	1	22

Note: Totals tabulated above may not tally due to rounding.
A. For the purposes of this table, the 'maximum potential electrification' reflects the 2050 electrification forecast for the *Green Energy Exports* scenario. This scenario assumes that residential buildings are able to fully electrify by 2050 and that industries that are theoretically able to electrify have adopted those electrification technologies by 2050. In this way, the 2040 electrification values for each scenario can be put into context by comparing to this 'maximum potential electrification' value.

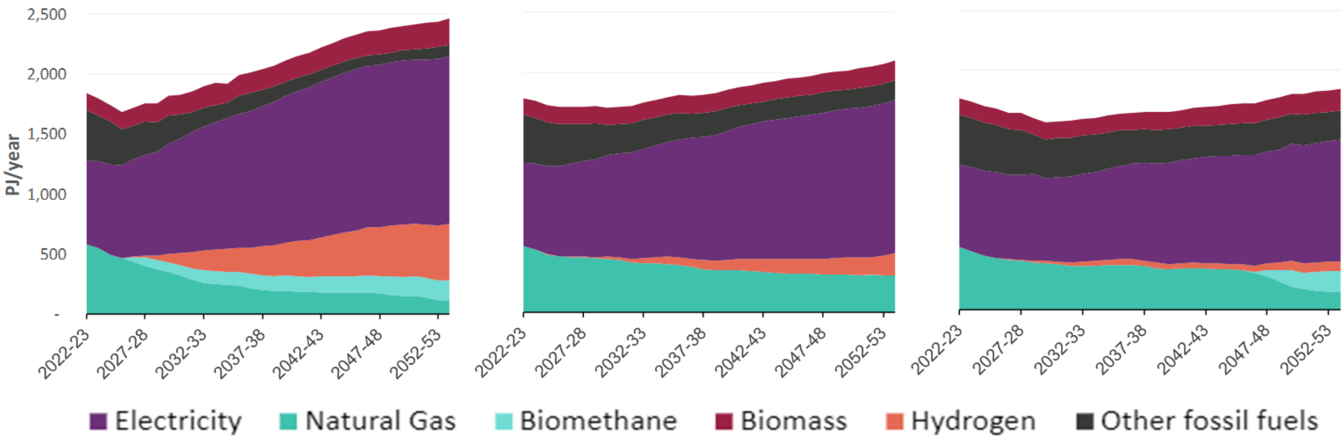
2.3.2 Comparing energy end-use across the scenarios

Figure 2 shows end-use domestic fuel consumption by scenario, as estimated across the economic activities within the NEM-connected jurisdictions, illustrating that:

- *Green Energy Exports* shows an increase in energy use reflecting stronger economic and population growth. Electricity is the largest provider of energy, and electrification of natural gas and other fossil fuels is a key decarbonisation pathway. Domestic hydrogen use provides energy for hard-to-abate industrials, and emerging opportunities to expand the domestic economy, with biomethane providing a minor (but material) share.
- *Step Change* shows a modest increase in total energy use. Electrification of natural gas and other fossil fuels is the most significant growth driver, while a wedge of domestic hydrogen use emerges amidst declines in gas and fossil fuel use. Note that the graph excludes export hydrogen.

- *Progressive Change* includes lesser change in overall energy use, reflecting lower economic and population growth. Electrification represents the greatest share of the energy transformation, with minor shares in biomethane and hydrogen use across the decades to 2050.

Figure 2 End-use domestic fuel consumption by scenario (L to R), *Green Energy Exports, Step Change, Progressive Change* 2022-23 to 2052-53 (PJ/year)



Includes hydrogen for green steel, excludes hydrogen for export.

2.4 Sensitivities

The three scenarios capture a range of plausible futures that vary inputs and assumptions to allow the risk of under-investment (or overdue investment) and over-investment (or premature investment) to be assessed in the ISP. The scenarios will also be used to examine reliability and security assessments of the electricity and east coast gas markets.

There is inherent uncertainty around the set of inputs that make up each scenario, which creates risks for decision-making in a scenario based planning approach. Sensitivity analysis is often used to complement scenario based planning approach. Sensitivities can be used to test how variation of significant input assumptions in the scenarios influence the outcomes of the resulting plan.

In developing the ISP, sensitivity modelling is used to test the resilience of the energy outcomes and investments against various uncertainty in inputs. This is adopted to increase confidence in the robustness of the investment conclusions. For the ISP for example, sensitivities are deployed to test whether the optimal development path – that is, the mix of generation, storage and transmission investments needed to meet consumer needs – is robust to key risks and uncertainties, to limit potential investment regret. Most commonly this would involve change to a single variable at a time. There may also be change to multiple variables, although this is less common, as it is then unclear in isolation which variable was the primary driver for any result variation.

This chapter outlines key sensitivities that AEMO has already identified to model in the 2024 ISP, informed by stakeholder feedback throughout AEMO's IASR and ISP Methodology engagement activities. The list of sensitivities is not constrained to these key assumptions, and AEMO will deploy additional sensitivity analysis as appropriate to ensure plans are as robust and resilient to future conditions as is practical in modelling timeframes for each modelling purpose.

Key sensitivities include:

- ***Rapid Decarbonisation*** examines the impact of bringing forward decarbonisation of the NEM, by applying the more aggressive emissions abatement pathway from the *Green Energy Exports* scenario. It will be examined by applying a tighter carbon budget for the NEM, consistent with the pace of transition in *Green Energy Exports* aimed at limiting temperature rise to 1.5°C by the end of the century through the energy sector.
- ***Electrification Alternatives*** examines the role of biomethane in a world where industrial electrification is delayed and reduced relative to the *Step Change* scenario. It will be examined by reducing the pace and breadth of electrification across industrial energy use, retaining a more diverse mix of fossil and renewable molecular energy forms in the primary energy mix, including a growing and material role for biomethane in decarbonising industry.
- ***Low CER Orchestration*** examines the impacts of reduced effectiveness of consumer investment orchestration via virtual power plants (VPPs) than in the *Step Change* scenario. It will be examined by reducing the degree of orchestration assumed for consumer devices, demonstrating the utility-scale response that would be needed to complement a more passive CER fleet.
- ***Reduced Energy Efficiency*** examines the key role that investments to reduce energy waste can have on infrastructure investments. It will be examined by limiting energy efficiency savings to only those targeted by existing and committed relevant policy developments.
- ***Higher Discount Rate*** and ***Lower Discount Rate*** will demonstrate the sensitivity of investment decisions for long-lived assets with different settings for valuing future benefit streams, considering expert guidance outlined in Section 3.7.1.
- ***Constrained Supply Chains***, exploring the costs and potential benefits of a less volatile annual rate of transition, from lesser supply chain capacity and more limited workforce availability requiring proactive management of finite resources. It will be examined by applying greater constraints on the development capabilities to deliver generation, storage and transmission investments associated with technical supply chain and workforce considerations.

Social licence is another key consideration for the energy transition. 'Social licence' is a term commonly used to refer to local community acceptance of new infrastructure development. The efficient and effective transition of the energy sector will rely on both government and the energy industry understanding and delivering the community's ambition and needs for the future power system, both broadly in the community, and in the places that host new development. AEMO has established an Advisory Council on Social Licence to assist in understanding social licence issues facing the energy transition for consideration in development of the ISP. AEMO intends to include a sensitivity that explores risks relating to social licence. For instance, alternative assumptions that reflect greater limitations and higher cost to address social licence issues could also be considered.

AEMO will be guided by modelling outcomes in both the draft and final ISP to understand what other sensitivity analysis could be insightful to ensure robust investment recommendations, including actionable ISP projects. This could include testing the impact of alternative timings of generator closures, alternative fuel prices, removal of investments intended to be delivered through policy mechanisms and other potential influences.

For other forecasting and planning activities, sensitivity analysis may examine different assumptions that affect the assessments of reliability, security, and energy adequacy, as opposed to the future development needs of the power system that affect investments. In this sense, sensitivity analysis is developed and implemented as appropriate within the scope of modelling being conducted.

3 Inputs and assumptions

3.1 Policy settings

Input vintage	July 2023
Source	Australian governments
Updates since Draft IASR	Significant number of policies or aspect of policies have been incorporated since the Draft 2023 IASR.

Policy settings constantly evolve as governments progress policy initiatives. Since the 2022 ISP was released, many new and refined policy positions have been developed by multiple jurisdictions, often to support the electricity sector transition.

For the 2023 IASR, AEMO considered environmental and energy policies with reference to the 'public policy clause'[16]. The public policy clause allows AEMO to consider a current environmental or energy policy of a participating jurisdiction where that policy has been sufficiently developed to enable AEMO to identify the impacts of it on the power system and at least one of several other criteria is also satisfied. The criteria most relevant for the purposes of the 2023 IASR are enactment of the policy in legislation and a material funding allocation to the policy in a budget of a participating jurisdiction.

On 19 May 2023, Energy Ministers agreed to amendments to the national electricity laws to incorporate an emissions reduction objective into the National Electricity Objective (NEO)[17]. Currently, it is expected that the amendments will pass through South Australian parliament in September 2023, and AEMO will apply the new emissions objective to the ISP two months from commencement.

The emissions objective is presently proposed, subject to stakeholder consultation, to be complemented by a requirement that the AEMC prepare and maintain a list of participating jurisdictions' targets, that contribute, or are likely to contribute to reducing Australia's greenhouse gas emissions – with the list of those targets being stated in a 'targets statement' to provide transparency to the regulated community. These targets must, at a minimum, be considered by AEMO in applying the objective to the ISP[18]. The public policy clause is included in the Commonwealth's rule change proposal currently under consultation by the AEMC[19], identifying rules for harmonisation with the new objective. The rule change will consider whether policies considered by AEMO in determining power system needs should include targets in the AEMC's 'targets statement'[20].

In identifying policies that may be included in the 2024 ISP, AEMO has, in consultation with each jurisdiction, included those policies that currently meet the public policy clause or are expected to satisfy the clause, or be included in the AEMC's targets statement, before the delivery of the 2024 ISP. These policies are relevant to the

[16] NER 5.22.3(b).

[17] See https://www.energy.gov.au/government-priorities/energy-and-climate-change-ministerial-council/working-groups/national-energy-transformation-partnership/incorporating-emissions-reduction-objective-national-energy-objectives.

[18] Information Paper, *Incorporating an emissions reduction objective into the national energy objectives*, May 2023, p8, at https://www.energy.gov.au/sites/default/files/2023-06/Incorporating%20an%20emissions%20reduction%20objective%20into%20the%20national%20energy%20objectives%20-%20Information%20Paper.pdf.

[19] Rule change proposal and consultation paper available on the AEMC's website at https://www.aemc.gov.au/rule-changes/harmonising-electricity-network-planning-and-investment-rules-and-aer-guidelines-updated-energy.

[20] NER clause 5.22.3(a) defines the power system needs relevant to the ISP, while clause 5.22.3(b), the public policy clause, defines the policies AEMO may consider in determining power system needs.

energy transition, and will impact Australia's emissions reduction objectives, particularly for the energy sector. Should a policy not meet the public policy clause, or not be included in the AEMC's targets statement, prior to delivery of the 2024 ISP, that policy will be removed as a modelling input/assumption. Instead, sensitivity testing may be used in the 2024 ISP to show the impact of including that policy at a later date.

Table 6 summarises the policies included in this 2023 IASR.

The sub-sections following Table 6 describe the various policy settings to be applied in the 2023 IASR scenario collection.

Table 6 Summary of policies included in the 2023 IASR

Policy type	Federal	Australian Capital Territory	New South Wales	Queensland	South Australia	Tasmania	Victoria
Emission reduction	43% below 2005 levels by 2030 and net zero by 2050 under the *Climate Change Act (2022)* (C'th)		Economy-wide emission reduction targets of 50% by 2030 and net zero by 2050		Emission reduction target of 60% by 2050		Emission reduction target of 28-33% by 2025, 50% by 2030, 75-80% by 2035 and net zero by 2050 Unlegislated but announced net zero emission target by 2045
Renewable energy targets	82% renewable energy target by 2030		Construct new renewable generation by end of 2029 that can produce the same electricity as 8 GW in New England REZ, 3 GW in Central-West Orana REZ, and 1 GW elsewhere (NSW EII Act)	Expansion of QRET to 50% by 2030, 70% by 2032, and 80% by 2035		150% TRET target by 2030 and 200% by 2040	VRET of 40% by 2025, 50% by 2030 and the intentions for further VRET of 65% by 2030 and 95% by 2035; Victorian Renewable Energy Target (VRET) auctions 1 and 2
Storage targets			Target of 2 GW of deep storage by 2030 under the NSW EII Act	Support to Borumba pumped hydro energy storage (PHES) (based on normal commitment criteria);		Battery of the Nation (as development candidate)	Intentions to legislate storage targets of 2.6 GW by 2030 and 6.3 GW by 2035
Offshore wind targets							Intentions to legislate offshore wind targets of 2 GW by 2032, 4 GW by 2035, and 9 GW by 2040
Hydrogen policies			Renewable Fuels Scheme of the NSW Hydrogen Strategy	Support to Kogan Renewable Hydrogen Project[21]	Hydrogen Jobs Plan including 250 MW electrolyser project, 200 MW hydrogen turbine.		

[21] See https://www.treasury.qld.gov.au/programs-and-policies/queensland-renewable-energy-and-hydrogen-jobs-fund/.

Policy type	Federal	Australian Capital Territory	New South Wales	Queensland	South Australia	Tasmania	Victoria
Transmission support policies			REZ network infrastructure projects and priority transmission infrastructure projects under the NSW EII Act, including Waratah Super Battery System Integrity Protection Scheme as Committed and Central-West Orana Transmission Project as Anticipated.	SuperGrid Infrastructure Blueprint and Queensland Renewable Energy Zone (QREZ) infrastructure will be treated as options. CopperString 2032 development is considered to be Anticipated with the Townsville to Hughenden connection being modelled quantitively as a REZ network expansion.			NEVA-supported transmission projects and VicGrid planning of REZs, including some projects treated as development options and others as Anticipated projects (for example, Western Renewables Link and the Mortlake Turn-in as Anticipated).
Transmission land payment programs			Strategic Benefit Payments Scheme	SuperGrid Landholder Payment Framework			Landholder Payments For A Fairer Renewables Transition
CER-related policies	SRES	PV subsidies for pensioners/ veterans, and Sustainable Households Scheme (batteries and PV)	Energy efficiency and peak demand reduction target under the NSW Energy Security Safeguard, and the Renewable Fuels Scheme		Voluntary retailer contributions feed in tariff		Victorian solar panel rebate, solar battery rebate
Electric vehicles	EV fringe benefits tax (FBT) exemption, infrastructure funding and fleet purchases	ACT EV stamp duty, registration and financing savings			EV subsidy and free registration	Stamp duty waiver	Zero emissions vehicle subsidy
Energy efficiency	National Construction Code 2022; National Australian Built Environment Rating System; Greenhouse and Energy Minimum Standards; National Energy Performance Strategy;		New South Wales Energy Savings Scheme		South Australian Retailer Energy Efficiency Scheme		Victorian Energy Upgrades program
Other government policies	Safeguard Mechanism Capacity Investment Scheme	ACT's ban on new gas connections		Conversion of publicly owned coal-fired generation in Queensland into clean energy hubs.			Gas Substitution Roadmap

3.1.1 Australia's emissions reduction targets

Climate Change Act (2022) (C'th)

In September 2022, the Federal Government legislated Australia's economy-wide emissions reduction target, committing to reducing greenhouse gas emissions by 43% below 2005 levels by 2030 and achieving net zero emissions by 2050. These targets are complemented by an emissions budget for the period 2021-2030 amounting to 4,381 million tonnes of CO_2-e. The updated target has also been submitted to the United Nations Framework Convention on Climate Change (UNFCCC), in Australia's updated Nationally Determined Contribution (NDC) under the Paris Agreement.

Complementing the 2030 emissions target is the Federal Government's commitment to achieve an 82% share of renewable generation by 2030, announced in *the Powering Australia Plan*[22]. This target is not contained within the legislative targets of the *Climate Change Act*, but AEMO considers it sufficiently developed as a policy to be considered within all scenarios.

AEMO will model the legislated carbon budget to 2030 consistent with the 43% emissions reduction target, as well as a net zero emissions economy (by 2050) as committed policy, across all scenarios. AEMO will also model the 82% share of renewable generation by 2030 across all the scenarios.

More detail on the forecast carbon budgets for the NEM can be found in Section 3.2.

Safeguard Mechanism

The Safeguard Mechanism is a federal policy aimed at reducing emissions at Australia's largest industrial facilities in line with Australia's 2030 and 2050 emission reduction targets. It sets out a number of targets for participating industrial facilities, including the requirement that net emissions from all Safeguard facilities should not exceed 100 million tons of carbon dioxide equivalent ($MtCO_2$-e) in 2030 (and net zero in 2050)[23].

The bolstered Safeguard Mechanism was not included explicitly in the multi-sector modelling exercise commissioned from CSIRO and ClimateWorks Centre (CWC) (see Section 3.3.4 for further details on the multi-sector modelling), as the reformed policy was legislated after the modelling was finalised. However, the multi-sector modelling does achieve substantial levels of decarbonisation for large industrial facilities, predominantly through business electrification. The levels of emissions reductions modelled are broadly consistent with the emissions targets of the Safeguard Mechanism. Additionally, AEMO directly surveys many of the large industrial loads that are included in the Safeguard Mechanism and in that process, gains insights into how these facilities intend to meet the policy requirements, whether through energy efficiency upgrades, process improvements or electrification. AEMO considers that the scope of decarbonisation in the industrial sector across the scenario collection sufficient to reflect the intent and potential impact of the policy.

State-based emissions targets

All states and territories in the NEM have net zero emissions ambitions, although most are still developing the legislative and other frameworks to meet these ambitions. State-based positions regarding emissions reduction either legislated or with expected legislation are shown in Table 7.

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[22] Available at https://www.energy.gov.au/government-priorities/australias-energy-strategies-and-frameworks/powering-australia.

[23] Enacted via the *National Greenhouse and Energy Reporting Act 2007.*

Table 7 State-level emission reduction ambitions (relative to 2005 levels, economy-wide targets unless otherwise stated)

	New South Wales (Financial year)	**Australian Capital Territory** [AC] (Financial year)	**Queensland**	**South Australia** [A] (Calendar year)	**Tasmania** [C] (Financial year)	**Victoria** (Calendar year)
Instrument	Currently unlegislated, but legislation expected for the 2030 and 2050 targets; Targets were announced via the NSW Climate Change Policy Framework 2016 and underpinned by the Net Zero Plan Stage 1	*Climate Change and Greenhouse Gas Reduction Act 2010*		60% reduction by 2050 legislated via *Climate Change and Greenhouse Emissions Reduction Act 2007*	*Climate Change (State Action) Amendment Act 2022*	2025,2030 and 2050 legislated via *Victorian Climate Change Act 2017*; Legislation expected for 2035 and 2045 targets.
2025		50-60% reduction				28-33% reduction
2030	50% reduction [B]	65-75% reduction			**Net zero or lower**	45-50% reduction
2035						75-80% reduction
2040		90-95% reduction				
2045		**Net zero**				**Net zero** [B]
2050	**Net zero**			**60% reduction**		**Net zero**

Notes: Timing of emissions reduction ambition may be rounded to the nearest 5 yearly increment, for presentation purposes
A. Relative to 1990 levels.
B. Unlegislated at the time of publication.
C. While Tasmania's and Australian Capital Territory's legislated climate change targets aim to achieve net zero emissions, AEMO recognises the low emissions intensity of the electricity sector for the jurisdictions, and considers that an electricity-sector equivalent carbon budget would be inappropriate to reflect the economy-wide application of the legislations.

Some jurisdictions have legislated these ambitions (Victoria[24], Australian Capital Territory[25], and Tasmania[26]), while there have been public announcements by several other jurisdictions to legislate (New South Wales[27], South Australia[28]), and update already legislated targets (Victoria's 2035 and 2045 target)[29].

For the 2023-24 forecasting and planning activities, AEMO will incorporate the jurisdictional targets except for Tasmania and Australian Capital Territory in all scenarios as electricity-sector carbon budgets, providing a complementary constraint to the NEM carbon budget that meets the Federal Government commitments.

[24] See the *Victorian Climate Change Act 2017*, which results in five-yearly emissions reduction targets with the aim of reaching net zero by 2050. The Victorian Government has announced interim targets for 2025 (28-33% below 2005 levels) and 2030 (50% below 2005 levels).

[25] Under the *Climate Change and Greenhouse Gas Reduction Act 2010*, the Australian Capital Territory set a target to achieve net zero emissions by 2045, as well as an interim 40% reduction target over 1990 emissions by 2020. The Climate Change and Greenhouse Gas Reduction (Interim Targets) Determination 2018 also sets a range of interim reduction targets over 1990 emissions: 50-60% less by 2025, 65-75% less by 2030, and 90-95% less by 2040.

[26] Under the Tasmania *Climate Change (State Action) Amendment Act 2022*, however given the State has a low emissions intensity already, application of this emissions target to the electricity sector in isolation of the broader regional economy would be inappropriate.

[27] See https://www.chrisminns.com.au/nsw_labor_announces_net_zero_legislation.

[28] See https://www.environment.sa.gov.au/topics/climate-change/climate-change-legislation.

[29] See https://www.premier.vic.gov.au/setting-ambitious-emissions-reduction-target.

The emissions reduction target for the Australian Capital Territory cannot be converted to an electricity-sector equivalent budget, as there is no existing fossil-fuel generation, and no fossil fuel new-entry candidate generators are considered in the Australian Capital Territory. Given the low emissions intensity of the electricity sector in Tasmania, an equivalent carbon budget of zero emissions for the sector would be inappropriate given the economy-wide nature of the target. More information on the NEM and state carbon budgets is in Section 3.2.3.

3.1.2 Relevant federal and state energy policies

New South Wales Electricity Infrastructure Roadmap

In 2020, the New South Wales Government released its Electricity Infrastructure Roadmap[30] and enabling legislation, the *Electricity Infrastructure Investment Act 2020* (NSW EII Act), providing a plan to transform New South Wales's electricity system reliably and affordably. The NSW EII Act sets out minimum objectives to construct, by the end of 2029, sufficient renewable generation infrastructure to produce at least the same amount of electricity in a year as:

- 8 GW of generation capacity in the New England Renewable Energy Zone (REZ).
- 3 GW of generation capacity from the Central-West Orana REZ.
- 1 GW of additional generation capacity.

Although the capacities are specified in these REZs, the generation constructed and operated under Long-Term Energy Service Agreements (LTESAs) are not required to be located in those REZs, or any REZ if the project demonstrates "outstanding merit", nor to match the capacities specified.

The NSW EII Act also sets a minimum objective for the construction of 2 GW of long-duration storage infrastructure (classified as storage with capacity that can be dispatched for at least eight hours) by the end of 2029. This is in addition to Snowy 2.0.

The New South Wales objectives exclude any generation capacity that was either existing or committed at or before AEMO's November 2019 Generation Information page. Therefore, any generation that has progressed to committed or existing since that time is included as contributing to the objectives of the NSW EII Act.

In May 2023, AEMO Services Limited (as New South Wales Consumer Trustee) released the Draft 2023 Infrastructure Investment Opportunities (IIO) Report, which includes an updated development trajectory for generation and storage infrastructure[31]. Details of this trajectory and recipients of LTESAs[32] can be found in the accompanying IASR Assumptions Book.

AEMO Services Limited has also commenced competitive tenders for firming infrastructure[33].

AEMO will reflect these renewable energy, generation and storage tenders in all scenarios of the 2023-24 forecasting and planning activities. AEMO will also apply the longer-term generation and storage development requirements from the Draft 2023 IIO Report.

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[30] See https://www.energy.nsw.gov.au/nsw-plans-and-progress/major-state-projects/electricity-infrastructure-roadmap.

[31] At https://aemoservices.com.au/publications-and-resources/infrastructure-investment-objectives-report/2023-iio-report.

[32] See https://aemoservices.com.au/-/media/services/files/media-releases/010523-asl-mr-aemo-services-nation-leading-tender-and-contract-design-delivers-for-nsw.pdf?la=en.

[33] More information can be found at https://aemoservices.com.au/-/media/services/files/publications/market-briefing-4/224213-aemo-briefing-notes-firming-infrastructure-v2_con5.pdf.

Transmission projects that meet AEMO's committed and anticipated project commitment statuses are committed in AEMO's modelling in all scenarios, with all other options considered as development candidates in the ISP. More information on the committed and anticipated projects is published in the 2023 *Transmission Expansion Options Report*.

Queensland Energy and Jobs Plan (QEJP)

In September 2022 the Queensland Government released the QEJP, which identifies initiatives for the development of renewable and firming generation in Queensland, including:

- Expansion of the Queensland Renewable Energy Target (QRET) to achieve 50% renewable energy by 2030, 70% by 2032 and 80% by 2035.
- Development of the Borumba Dam (2 GW/24 hr) and Pioneer-Burdekin (up to 5 GW/24 hr) pumped hydro energy storage (PHES) projects, between 2030 and 2035.
- Hydrogen-ready gas developments, including a 200 megawatts (MW) peaking project at Kogan Creek.
- Conversion of publicly owned coal generators into clean energy hubs by 2035, potentially in a phased manner to ensure reliability and security is maintained.
- Establishment of Queensland Renewable Energy Zones.
- Transmission investments, at up to 500 kilovolts (kV), to build new backbone transmission connecting energy storage and renewables to load centres.

In June 2023, the Queensland Government released the draft *Energy (Renewable Transformation and Jobs) Bill 2023*[34] to legislate the QEJP. The draft legislation sets up planning and governance frameworks to ensure an orderly transition – including Renewable Energy Zones, Queensland Energy System Advisory Board, Energy Industry Council, and the Queensland Renewable Energy Jobs Advocate.

The legislative settings for the expansion of QRET within the draft legislative package are now under consultation.

Queensland's 2023-24 Budget identified significant funding for the QEJP initiatives, although the funding cannot lock firming projects to a specific timetable. AEMO recognises these significant financial commitments and will apply normal project commitment assessments to these projects, as evaluated in AEMO's Generation Information releases.

The QEJP has also identified several transmission options that will be required to develop and connect the PHES and Queensland REZ initiatives (up to 500 kV). AEMO includes these options as part of the 2023 *Transmission Expansion Options Report*.

Tasmanian Renewable Energy Target (TRET)

The TRET is a legislated renewable energy target, requiring development of sufficient renewable energy capacity to double current electricity consumption (or 21,000 gigawatt hours [GWh] of production) by 2040, with an interim target of 150% (or 15,750 GWh) by 2030.

This policy meets the appropriate criteria for commitment in all scenarios of the 2023-24 forecasting and planning activities.

[34] At https://statements.qld.gov.au/statements/97857 - :~:text=The%20draft%20Energy%20(Renewable%20Transformation,%2C%20and%2080%25%20by%202035.

Victoria's emissions reduction, renewable energy, storage, and offshore wind development targets

Victoria's *Climate Change Act (2017)* provides a legislated framework to reduce greenhouse gas emissions by 2050 to meet a net-zero economy, with short-term targets at five-yearly steps.

Underpinning Victoria's electricity sector contributions to this objective is the Victorian Renewable Energy Target (VRET) and the Victorian Energy Upgrades (VEU) program, and a target for 50% zero-emission vehicles new sales by 2030.

The currently legislated VRET mandates 40% of the region's generation (including CER) be sourced from renewable sources by 2025, and 50% by 2030. In October 2022, the Victorian Government announced it would update its renewable energy target to 65% by 2030, and 95% by 2035.

These updates to the VRET are intended to be legislated and will be included in all scenarios of the 2023-24 forecasting and planning activities (including specific projects that are funded via auctions conducted to date[35]).

The Victorian Government has also pledged a target[36] of 2.6 GW of renewable energy storage capacity by 2030, with an increased target of 6.3 GW of storage by 2035. Victoria's new storage targets[37] is expected to be legislated and will include both short and long-duration energy storage systems, which can hold more than eight hours of energy.

Given the intended legislative framework is expected to meet the public policy clause, AEMO will include the energy storage targets in all scenarios of the 2023-24 forecasting and planning activities.

The Victorian Government has released its Offshore Wind Policy Directions Paper[38] and two Offshore Wind Implementation Statements[39] which aim to develop 2 GW of offshore wind capacity by 2032, 4 GW by 2035, and 9 GW by 2040, with first power aimed by 2028.

AEMO considers that the Victorian Offshore Wind policy is intended to be legislated and is sufficiently developed to enable assessment of impacts on the power system, therefore AEMO will include the updated policy in all scenarios of the 2023-24 forecasting and planning activities.

Large-scale Renewable Energy Target (LRET)

Australia's Renewable Energy Target (RET) established targets for large-scale and small-scale renewable investments. The LRET in particular aimed to deliver 33,000 GWh of Australia's electricity from renewable sources by 2020. While the LRET was met in September 2019, high-energy users are required to continue meeting their obligations under the scheme until 2030[40].

AEMO's modelling assumptions do not explicitly capture the LRET, as the target has been met and continued operation of these facilities is expected within the modelling without requiring additional constraints.

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[35] See https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets/victorian-renewable-energy-target-auction-vret1.

[36] At https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets.

[37] At https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets.

[38] At https://engage.vic.gov.au/download/document/26672.

[39] At https://www.energy.vic.gov.au/renewable-energy/offshore-wind-energy/for-industry-and-developers.

[40] See https://www.cleanenergycouncil.org.au/advocacy-initiatives/renewable-energy-target.

Jurisdictional policies regarding hydrogen development

Various jurisdictions have announced funding to support the establishment of hydrogen technologies, particularly renewable hydrogen production, including:

- The South Australian Government has allocated $593 million over the period 2022-23 to 2025-26 to the Hydrogen Jobs Plan[41] which seeks to establish hydrogen production and power generation in South Australia. The output from a **250 MW electrolyser** project is included in the hydrogen production forecasts for each scenario. The electrolyser is expected to be complemented with **a 200 MW hydrogen-capable generator.** These initiatives are on track to meeting the public policy clauses and therefore AEMO is including it for the purposes of ISP assessments.
- The QEJP has allocated funding to support the Central Queensland Hydrogen Project, and the 200 MW peaking Kogan Renewable Hydrogen Project[42]. This initiative is on track to meeting the public policy clauses and therefore AEMO is including it for the purposes of ISP assessments.
- The New South Wales Government has allocated $150 million in grant funding to support hydrogen hubs in the state[43]. Additionally, the New South Wales Hydrogen Strategy[44] laid out a number of stretch targets, such as producing 110,000 tonnes per annum of hydrogen in 2030, and 700 MW of electrolyser capacity. Up to $3 billion of incentives were allocated to support industry development, including network charge exemptions for electrolysers, and hydrogen hubs in the Illawarra and Hunter. A key outcome of the NSW Hydrogen Strategy, the Renewable Fuels Scheme,[45] is legislated to produce 8 petajoules (PJ) per annum of renewable hydrogen by 2030. **The effect of the legislated Renewable Fuels Scheme is included in hydrogen production needs for each scenario**.
- The Tasmanian Government is funding the establishment of a green hydrogen hub at Bell Bay[46]. **This will not be explicitly modelled.**
- The Federal Government recently announced a $2 billion Hydrogen Headstart policy, which will provide production credits to approximately 1 GW of electrolyser capacity, across a small number of projects. Funding is to be available from 2026-27, and would be paid at the time of production. The government expenditure is contingent on projects being assessed and meeting criteria demonstrating sufficient merit. Consultation on the program is currently underway, and therefore whether or not projects are connected to the NEM, and their production volumes and schedules will not be known until the funding agreements have been established. **This will not be explicitly modelled.**

Capacity Investment Scheme

In December 2022, the Federal Government announced the Capacity Investment Scheme, which will provide a national framework to drive new renewable dispatchable capacity and ensure reliability and affordability in

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[41] See https://www.ohpsa.sa.gov.au/about-the-project and https://www.statebudget.sa.gov.au/our-budget/jobs-and-economy/hydrogen.

[42] See https://www.treasury.qld.gov.au/programs-and-policies/queensland-renewable-energy-and-hydrogen-jobs-fund/.

[43] See https://www.energy.nsw.gov.au/business-and-industry/programs-grants-and-schemes/hydrogen-hubs-nsw.

[44] See https://www.energy.nsw.gov.au/sites/default/files/2022-08/2021_10_NSW_HydrogenStrategy.pdf

[45] See https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard/renewable-fuel-scheme#:~:text=The%20Renewable%20Fuel%20Scheme%20was%20established%20under%20the,will%20commence%20in%202024%20and%20run%20until%202044.

[46] See https://www.premier.tas.gov.au/site_resources_2015/additional_releases/tasmanias-green-hydrogen-feasibility-study-findings.

Australia's rapidly changing energy market. It will be a revenue underwriting mechanism aimed at unlocking around $10 billion of investment in clean dispatchable power to support energy reliability and security.

In the 2024 ISP, AEMO recognises that the Capacity Investment Scheme is a key measure by which the Federal Government will support the energy transition, although the specific mechanisms for its implementation in the medium and long term are yet to be determined. As the first phase of the scheme, New South Wales will receive Federal Government support to deliver almost 1 GW of additional dispatchable capacity, complementing actions to tender for firmed capacity by the Consumer Trustee, by underwriting up to an additional 550 MW of firmed capacity, complementing the initial firm capacity tender by the NSW Consumer Trustee of 380 MW, resulting in firm capacity of 930 MW in 2028-29.

Open tenders will determine the projects to gain Capacity Investment Scheme support, with first auctions under the scheme anticipated in 2023. AEMO will incorporate this first phase of the CIS within the Draft 2024 ISP, and will monitor the development of the longer term mechanism; if developed sufficiently to apply more broadly, AEMO may incorporate into the final 2024 ISP.

3.1.3 Transmission project support

National Electricity (Victoria) Act 2005 (NEVA) – 2020 amendment for expedited transmission approval

The NEVA facilitates expedited approval of transmission system upgrades, enabling the Minister to approve or accelerate approvals for augmentations of the Victorian transmission system. Several projects are currently supported under the NEVA and have advanced to the point where they are considered committed or anticipated developments. These include the specified augmentations for Western Renewables Link, the Mortlake turn-in, the Murray River REZ and Western Victoria REZ minor augmentations, the Victorian Big Battery, and other projects providing system strength services. For more information on these developments, see Section 3.9.3.

The Victoria – New South Wales Interconnector West (VNI West) project is also subject to NEVA Orders which act to accelerate the project and specify requirements for its configuration. These orders relates only to the Victorian side of VNI West. VNI West is currently an Actionable ISP project.

AEMO has considered the development of projects supported under the NEVA as transmission options in the 2023 *Transmission Expansion Options Report*, or as committed or anticipated projects in some cases as outlined in AEMO's transmission augmentation information page[47].

Rewiring the Nation

In October 2022, the Federal Government announced the Rewiring the Nation framework, which aims to modernise the grid and ensure the country's transmission networks are ready for the renewables and storage investment needed for the decarbonisation task ahead. The framework will prioritise transmission projects of national significance and support a transition to renewable energy. The Rewiring the Nation framework is looking at a range of measures to support development of ISP projects and REZ developments, including $20 billion of concessional loans and equity to invest in transmission infrastructure projects that will help strengthen, grow and

[47] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

transition Australia's electricity grids. The Federal Government has so far made two announcements under Rewiring the Nation:

- Agreement between the Federal, Victorian and Tasmanian Governments for access to concessional finance (around 80% of costs) and equity investment (around 20% of costs) for MarinusLink, as well low-cost debt for Battery of the Nation projects ($1 billion), transmission network in REZs in northern Tasmania, VNI West KerangLink ($750 million), and Victorian REZ projects including offshore wind[48].
- Agreement between the Federal and New South Wales Governments for access to $4.7 billion in concessional finance for critical transmission and REZ projects in New South Wales, including connecting Snowy 2.0 (supported by access to $3.1 billion from the New South Wales Transmission Acceleration Facility)[49].

The Federal Government has also entered into a $385 million underwriting agreement under the Rewiring the Nation program to support Transgrid's procurement of long lead items for the HumeLink and VNI West projects to accelerate their delivery and lower costs.

AEMO will not incorporate the impact of concessional finance in the draft or final 2024 ISP.

Electricity Infrastructure Investment Act (New South Wales) 2020 (NSW) – REZ network infrastructure projects and priority transmission infrastructure projects (PTIPs)

The Minister may direct that REZ network infrastructure projects and PTIPs be carried out. While a range of projects are under development, two have now reached delivery stages.

Waratah Super Battery is being delivered with a System Integrity Protection Scheme to improve transfer capabilities between: Central New South Wales (CNSW) to Sydney, Newcastle and Wollongong (SNW); Southern New South Wales to Central New South Wales; and Central New South Wales to Northern New South Wales in a reverse direction while the scheme is in place.

Waratah Super Battery is a PTIP under the NSW EII Act[50], and is listed as a committed project in AEMO's transmission augmentation information page[51]. Transgrid has been appointed as the network operator for the project, and Akaysha Energy has been appointed as the service provider.

Central-West Orana Transmission project will provide the new network infrastructure for the Central-West Orana REZ, including high-capacity transmission lines and energy hubs to transport power from solar and wind generators.

Central-West Orana Transmission project is a REZ network infrastructure project under the NSW EII Act[52], and is listed as an anticipated project in AEMO's transmission augmentation information page[53]. EnergyCo is overseeing the planning and approval processes for the project, and has selected ACE Energy as the first ranked network operator for the project.

[48] See https://www.pm.gov.au/media/rewiring-nation-plugs-marinus-link-and-tasmanian-jobs.

[49] See https://www.pm.gov.au/media/landmark-rewiring-nation-deal-fast-track-clean-energy-jobs-and-security-nsw.

[50] More information available at https://www.energyco.nsw.gov.au/projects/waratah-super-battery.

[51] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

[52] See https://www.energyco.nsw.gov.au/cwo.

[53] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

Queensland SuperGrid Infrastructure Blueprint, Queensland Renewable Energy Zone, and CopperString 2032

The Queensland Government has announced its Queensland SuperGrid Infrastructure Blueprint and its draft Queensland Renewable Energy Zone roadmap under the Queensland Energy and Jobs Plan.

The SuperGrid is intended as the optimal infrastructure pathway for the Queensland Energy and Jobs Plan and includes references to four new high-voltage transmission network backbone projects to connect new pumped hydro energy storage and renewable energy generation. AEMO has considered the development of the blueprint projects as transmission options in the 2023 *Transmission Expansion Options Report*.

The draft Queensland REZ roadmap was released for consultation in July 2023, developed in line with the Queensland Energy and Jobs Plan to meet the government's renewable energy targets. AEMO is undertaking extensive joint planning with Powerlink as the roadmap is developed.

The Queensland Government has announced that it is actively working to deliver the CopperString 2032 transmission project – approximately 1,100 km of transmission lines from Mount Isa to south of Townsville – to connect the North West Minerals Province to the NEM. CopperString 2032 is listed as an anticipated project in AEMO's transmission augmentation information page[54]. The Townsville to Hughenden connection will be modelled quantitively as a REZ network expansion.

Jurisdictional landholder payment schemes

In some jurisdictions, landholder payment schemes have been recently established to provide payments to landholders for hosting transmission infrastructure. These payments are in addition to any compensation that is paid under conventional land acquisition frameworks. AEMO will model landholder payment schemes in New South Wales, Queensland and Victoria. If new landholder payment schemes are announced, AEMO will use reasonable endeavours to model them.

New South Wales

In October 2022, the New South Wales Government established a Strategic Benefit Payments Scheme[55] for new major transmission projects. Under this scheme, private landowners hosting new high voltage transmission projects critical to the energy transformation and future of the electricity grid will be paid a set rate of $200,000 (in real 2022 dollars) per kilometre of transmission hosted, paid out in annual instalments over 20 years.

Queensland

Taking effect from May 2023, Powerlink's SuperGrid Landholder Payment Framework[56] will offer payments to landowners that host new transmission infrastructure. Powerlink will also become the first transmission company in Australia to offer payments to landholders with properties adjacent to new transmission infrastructure. To represent this framework, AEMO will apply a cost of $230,000 per km of new transmission, paid out in a lump sum – noting that landholders can decide between a lump sum or annualised payments.

[54] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

[55] See https://www.energyco.nsw.gov.au/sites/default/files/2023-01/overview-strategic-benefit-payments-scheme.pdf.

[56] See https://www.powerlink.com.au/sites/default/files/2023-05/SuperGrid-Landholder-Payment-Framework.pdf.

Victoria

In February 2023, the Victorian Government announced it will pay landholders whose properties host new power transmission lines $8,000 per kilometre per year for 25 years ($200,000 over the 25-year period), to help smooth the state's transition to a 95% renewable grid by 2035.

3.1.4 Environmental protection and nuclear technology

Currently, Section 140A of the *Environment Protection and Biodiversity Conservation Act (1999)* (C'th) prohibits the development of nuclear installations. This is a legislated policy and as such AEMO is including the policy across all scenarios. Nuclear technology therefore is an excluded technology option.

3.1.5 Other policies affecting consumer demand

Numerous state and federal policies support the development of CER, including small-scale technology certificates (STCs) and Australian carbon credit units (ACCUs). Additional policies included are listed in Table 8.

Energy efficiency policies

Australian governments have implemented a range of energy efficiency policies that encourage investments in activities to lower energy consumption, including:

- Building energy performance requirements contained in the Building Code of Australia (BCA) 2010, the National Construction Code (NCC) 2019 and NCC 2022.
- Building rating and disclosure schemes of existing buildings such as the National Australian Built Environment Rating System (NABERS) Energy for Offices and Commercial Building Disclosure (CBD).
- The Equipment Energy Efficiency (E3) program (or Greenhouse and Energy Minimum Standards [GEMS]) of mandatory energy performance standards and/or labelling for different classes of appliances and equipment.
- State-based schemes, including the New South Wales Energy Savings Scheme (ESS), the Victorian Energy Upgrades (VEU) program, and the South Australian Retailer Energy Efficiency Scheme (SA REES).
- In November 2022, the Federal Government commenced consultation on the National Energy Performance Strategy (NEPS)[57] which aims to develop a framework for improving energy performance across the economy through energy efficiency and demand management.

New South Wales Energy Security Safeguard

New South Wales has a target for energy efficiency savings through its established Energy Security Safeguard[58], both in general through the ESS, and at time of peak demand through the Peak Demand Reduction Scheme (PDRS). Both are modelled, with details listed in Section 3.3.11 for energy efficiency and Section 3.3.14 for the PDRS.

[57] See https://consult.dcceew.gov.au/neps-consultation-paper.

[58] See https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard.

Victoria Gas Substitution Roadmap

The Victorian Government released its Gas Substitution Roadmap[59] in October 2022 outlining options for replacing gas usage (such as energy efficiency, electrification, hydrogen and biogas) to reduce emissions and consumer costs.

Australian Capital Territory ban on new gas connections

The Australian Capital Territory Parliament in June 2023 passed the *Climate Change and Greenhouse Gas Reduction (Natural Gas Transition) Amendment Act 2023*[60] allowing the ACT Government to develop regulation banning new gas connections in the territory. The regulation is expected to commence in late 2023.

Table 8 Other policies affecting consumer demand

State	Policy	Description
Federal	*Treasury Laws Amendment (Electric Car Discount) Bill 2022* will encourage uptake of electric vehicles through fringe benefit tax exemption for EVs.	A range of fleet/sales outcomes are forecast across scenarios; adjusting the EV forecasts to explicitly accommodate may introduce potential for double counting of uptake drivers. More detail is available in the CSIRO EV report[A].
Australian Capital Territory	The ACT government is making available an $3,500 residential subsidy ($35,000 for business) targeting deployment of 36 MW of battery storage under its Next Generation Energy Storage scheme[B].	Minimum addition of 5,000 batteries by 2023.
Australian Capital Territory	Pensioners who own their home are eligible for up to 50% (with a cap of $2,500) of a home solar system under its Home Energy Support scheme[C].	Minimum addition of 5,000 systems over five years.
Victoria	The Solar Homes Program[D] policy 700,000 home solar systems over 10 years. Policies include a subsidy of half the cost of solar (up to a value of $1,400) including means-tested interest free loans. Another feature is a landlord-tenant agreement whereby renters can also access an additional 50,000 systems. In addition, the policy includes battery subsidies for up to 17,500 homes. Rebates of up to $2,950 are available.	Minimum addition of 70,000 residential solar systems per year to 2028-29 with some allowance for variation between scenarios in first two years to reflect uncertainty and updated scheme subsidy availability (the exact subsidies available is announced annually and can vary year to year). Minimum addition of 5,000 residential battery systems over the next three years, not falling below that rate thereafter.
Victoria	Victorian Energy Efficiency Certificates under the Victorian Energy Upgrades program[E] support both energy efficiency investments and CER investments.	The value of certificates is assumed to increase 2% per annum in *Progressive Change* and 5% in *Step Change* and *Green Energy Exports*.

A. CSIRO, Electric vehicle projections 2022, at https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.
B. See https://www.climatechoices.act.gov.au/policy-programs/next-gen-energy-storage.
C. See https://www.climatechoices.act.gov.au/policy-programs/home-energy-support-rebates-for-homeowners.
D. See https://www.solar.vic.gov.au/solar-homes-program.
E. See https://www.energy.vic.gov.au/for-households/victorian-energy-upgrades-for-households.

3.2 Emissions and climate assumptions

Decarbonisation is a significant driver affecting the pace of the energy transition.

[59] See https://www.energy.vic.gov.au/renewable-energy/victorias-gas-substitution-roadmap.

[60] See https://www.legislation.act.gov.au/b/db_66446/.

Traditional drivers of energy infrastructure development such as load growth or asset replacement now need to be considered alongside actions needed to reduce emissions, and the pace of change will be affected by both domestic and global influences.

AEMO scenarios in this 2023 IASR are underpinned by national carbon budgets that are compatible with global temperature targets (relating to Relative Concentration Pathways, see Section 3.2.2 for more details) by aligning to International Energy Agency (IEA) scenarios.

The CSIRO and CWC supported AEMO's development of national carbon budgets by deploying multi-sector modelling to identify the decarbonisation efforts across the economy needed to meet these temperature constraints. The model uses a number of decarbonisation pillars (such as electrification, fuel-switching, efficiency improvements, and emission sequestering) to reduce emissions in a growing economy.

To achieve each temperature target, the model avoids use of temperature 'overshoots', where short- and medium-term action on emission reductions is delayed, aligning to a slower transition and a higher temperature increase by the end of the century, only to see significant emission sequestering scaled up in the future, resulting in net negative emissions in future years, and re-aligning to the target temperature outcomes.

To achieve the emissions pathways therefore relies on actions not just within the energy sector, but also in other parts of Australia's economy, particularly ongoing deployment of carbon sequestration, in particular via land use, land use change and forestry (LULUFC). Least cost solutions for Australia's economy will consist of a mixture of each of the four decarbonisation pillars, and all options will benefit from earlier action to reduce the need for later, more aggressive actions.

The multi-sector modelling translates the national carbon budgets to NEM carbon budgets that ultimately underpin the ISP, as discussed in the ISP Methodology[61]. These NEM carbon budgets (and their underlying trajectories) recognise that the electricity sector has a key role to play as an early mover, enabling the decarbonisation of other sectors via electrification and increased energy efficiency.

The scenarios also include a number of complementary carbon budgets, to reflect Federal Government's policy to 2030, and state government policy as described in the previous sections. The derivation of NEM-wide and state-level targets is further discussed in Section 3.2.3.

3.2.1 Alignment to IEA's World Energy Outlook scenarios

AEMO's 2023 IASR scenarios have been aligned to the IEA's World Energy Outlook (WEO) scenarios to anchor them to global narratives on developments and commitments to the Paris Agreement. By doing so, AEMO's scenarios are consistent with global economic settings and temperature goals. IEA's scenarios provide a global backdrop to economic and multi-sector modelling. They describe economic growth and international fuel price projections which are partly driven by global conditions and climate outcomes.

The scenarios also help provide context for "Australia's share" of meeting various temperature outcomes, as well as guidance to the multi-sector modelling regarding the uptake rate and limits on energy efficiency and electrification across scenarios.

The 2022 WEO, released in October 2022, assessed three scenarios, which were also modelled in the 2021 WEO. The Net Zero by 2050 (NZE) is a normative scenario, in that it is designed to achieve a specific outcome

[61] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/isp-methodology.

and show a pathway to reach it. The Announced Pledges Scenario (APS) and the Stated Policies Scenario (STEPS) are exploratory, in that they define a set of starting conditions and then see where they lead.

The 2022 WEO did not include the previously modelled Sustainable Development Scenario (SDS), another normative scenario to model a "well below two degrees". APS outcomes are close to SDS's in some respects, particularly in terms of their temperature increase by the end of the century.

The 2021 WEO scenarios are summarised in Table 9.

Table 9 The 2021 IEA WEO scenario summaries

IEA scenario	Summary narrative
Stated Policies Scenario (STEPS)	This scenario provides a conservative benchmark for the future because it does not take for granted that governments will reach all announced goals. Instead, it takes a more granular, sector-by-sector look at what has actually been put in place to reach these and other energy-related objectives, taking account not just of existing policies and measures but also of those that are under development. The STEPS explores where the energy system might go without a major additional steer from policy makers. As with the APS, it is not designed to achieve a particular outcome.
Announced Pledges Scenario (APS)	This was a new scenario in the 2021 WEO. It takes account of all the climate commitments made by governments around the world, including NDCs as well as longer-term net zero targets, and assumes they will be met in full and on time. The global trends in this scenario represent the cumulative extent of the world's ambition to tackle climate change as of mid-2021. The remaining difference in global emissions between the outcome in the APS and the normative goals in the NZE scenario (last in this list) or the SDS scenario shows the "ambition gap" that needs to be closed to achieve the goals agreed in Paris in 2015.
Sustainable Development Scenario (SDS)	This is a normative scenario that maps out a pathway consistent with the "well below 2°C" goal of the Paris Agreement while achieving universal access and improving air quality. Like the NZE, the SDS is based on a surge in clean energy policies and investment that puts the energy system on track for key Sustainable Development Goals (SDGs)[A]. In this scenario, all current net zero pledges are achieved in full and there are extensive efforts to realise near-term emissions reductions, advanced economies reach net zero emissions by 2050, China around 2060, and all other countries by 2070 at the latest. Without assuming any net negative emissions, this scenario is consistent with limiting the global temperature rise to 1.65°C (with a 50% probability).
Net Zero by 2050 (NZE)	This is a normative IEA scenario that shows a narrow but achievable pathway for the global energy sector to achieve net zero CO_2 emissions by 2050, with advanced economies reaching net zero emissions in advance of others. This scenario also meets key energy-related United Nations Sustainable Development Goals by achieving universal energy access by 2030 and major improvements in air quality. The NZE does not rely on emissions reductions from outside the energy sector to achieve its goals but assumes that non-energy emissions will be reduced in the same proportion as energy emissions. It is consistent with limiting the global temperature rise to 1.5°C without a temperature overshoot (with a 50% probability).

A. The SDGs are a collection of 17 interlinked objectives formulated by the United Nations General Assembly in 2015 as a "shared blueprint for peace and prosperity for people and the planet", and include goals such as no poverty, affordable and clean energy, and climate action for example. See https://sdgs.un.org/goals.

In mapping the IEA's 2021 scenarios to the scenarios in this 2023 IASR, AEMO provides the following observations:

- With a more stringent emission target aiming to achieve the aspirational 1.5ºC target of the Paris Agreement, and with significant structural changes in global energy consumption underpinning its narrative, the ***Green Energy Exports*** scenario is most closely aligned to NZE.
- The IEA's SDS scenario from the 2021 WEO is consistent with the Paris Agreement target of limiting temperature increase to well below 2ºC, which aligns to AEMO's ***Step Change*** scenario.
- The ***Progressive Change*** scenario aligns best to STEPS, as it reflects currently legislated and/or funded policy positions only. The scenario reflects a challenging global economic outlook and additional policies are not the focus in this scenario.

3.2.2 Alignment with the Relative Concentration Pathways

The IASR scenarios also map to the RCPs framework used by the Intergovernmental Panel on Climate Change (IPCC)[62]. There are multiple RCPs defined, representing trajectories of emissions and land-use and their resulting impact on temperate increases. AEMO scenarios map to these temperature pathways as follows:

- AEMO's ***Green Energy Exports*** scenario sees a global drive to limit temperature rise to 1.5ºC by the end of the century, and is best aligned to RCP1.9 which targets that 1.5ºC outcome.
- The ***Step Change*** scenario is aligned to RCP2.6, which is consistent with a temperature rise less than 2ºC by the end of the century and in line with the Paris Agreement.
- The ***Progressive Change*** scenario is aligned to RCP4.5, which is consistent with a temperature rise of approximately 2.6ºC by the end of the century.

The mapping of scenarios to IEA scenarios and RCP temperature targets is summarised in Table 10.

By mapping the 2023 IASR scenarios to global outlooks in this manner, forecast components that are influenced by global conditions and broader economic narratives may be more internally consistently forecast.

Table 10 Mapping of scenarios between studies

2023 IASR scenario	2021 WEO scenario	RCP Framework
Green Energy Exports	NZE	RCP1.9
Step Change	SDS	RCP2.6
Progressive Change	STEPS	RCP4.5

Overshooting the emissions pathways

It is technically possible that a scenario could follow one RCP within the forecast period, and then transition to a more stringent decarbonisation trajectory between the end of the forecast period and 2100. Some contemporary scenarios used by others in the energy industry apply a temporary 'overshoot' of emissions levels, before recovering through negative emissions that would reduce cumulative carbon emissions and eliminate the emissions deficit, on the assumption that climate impacts of exceeding the target threshold are reversible if sufficiently temporary. As such, an 'overshoot' approach could appear to offer a reasonable balance between economic costs associated with rapid transitions, while achieving the climate goals in the longer term.

In AEMO's modelling, an overshoot approach would allow a higher carbon budget to apply to 2050 than would otherwise apply. AEMO has not adopted an overshoot approach in development of the 2023 IASR scenarios and as such do not overshoot the emissions budgets associated with their RCP-aligned 2100 temperature outcome at any time.

3.2.3 Translating international climate scenarios to NEM carbon budgets

To ensure the scenarios adopt emissions abatement outcomes consistent with the scenario narratives and mapping to the WEO scenarios and RCPs described above, multi-sector modelling has been used to produce carbon budgets for the Australian economy[63] as well as for the electricity sector (including a distinct budget for the NEM), among other forecasting influences described in Section 3.3.4.

[62] See, for example, https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_Chapter04.pdf.

[63] The economy wide carbon budget is broadly consistent with the 2021 to 2030 carbon budget defined in the *Climate Change Act (2022).*

CSIRO and CWC's detailed methodology and insights can be found in the supplementary materials to this 2023 IASR[64].

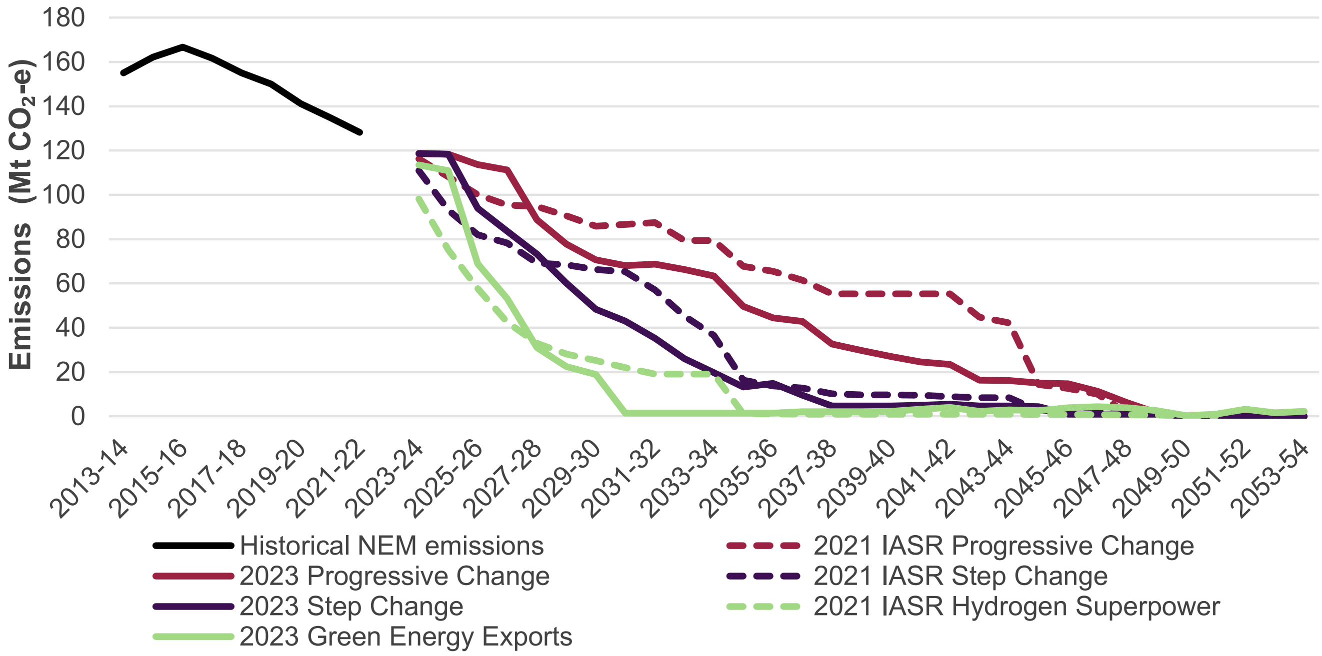
As described in greater detail in the CSIRO/CWC report, the carbon budgets and other multi-sector modelling considered decarbonisation investments to meet the scenario's required emissions pathways while minimising economic costs associated with each defined transition, subject to physical, technological, and policy constraints, and assuming appropriate reductions in carbon intensity from technological improvement and deployment. End-use demand sectors including agriculture, mining, manufacturing, other industry, commercial and services, residential, transport (road and non-road), and land use, including forestry are captured in the methodology.

NEM-wide carbon budgets

AEMO's modelling for electricity-sector planning purposes capture increased electrical load via electrification, hydrogen production requirements, energy efficiency, and the NEM emissions budgets to maintain a consistent level of abatement as forecast by the multi-sector model. For gas-sector assessments, these influences are considered from a gas perspective, particularly the fuel-switching from natural gas to electricity, or other molecular energy forms such as biomethane or hydrogen.

Figure 3 presents the NEM emission trajectories produced by the multi-sector modelling from 2023-24 to 2051-52 by scenario, compared to historical NEM emissions. The emission trajectories presented in the 2021 IASR (also produced by multi-sector modelling in 2021) are included for comparison. These emissions trajectories are driven by long-term assumptions regarding the temperature outcomes that are scenario-specific, as discussed in previous sections.

Figure 3 Actual and forecast NEM emission trajectories from multi-sector modelling, all scenarios



64 https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-climateworks-centre-2022-multisector-modelling-report.pdf.

In line with the ISP Methodology[65], and as applied in the 2022 ISP, AEMO will apply the aggregate NEM emissions from the multi-sector modelling as cumulative carbon budgets in AEMO's models. Table 11 presents the cumulative carbon budgets that will be applied for each scenario.

Table 11 NEM cumulative carbon budgets in 2024 ISP modelling (Mt CO_2-e)

	Federal Government's 2030 carbon budget from 2024-25 to 2029-30	Long-term temperature-linked carbon budget from 2024-25 to 2051-52
Green Energy Exports	630	357
Step Change	630	681
Progressive Change	630	1,203

The NEM carbon budgets have generally reduced in comparison to the 2021 IASR, mainly due to the shift in the modelling horizon. Comparing the cumulative emissions budgets between the 2021 and 2023 IASR modelling over the same horizon as seen in Table 12 below, there is a reduction of approximately 9% in *Step Change* due to lower levels of sequestration over the 2030s and 2040s onwards and energy efficiency forecasts.

Table 12 Comparison of long-term temperature-linked NEM carbon budgets over the period from 2023-24 to 2050-51 between 2022 IASR and 2023 IASR, (Mt CO_2-e) (not modelled)

	2021 IASR	2023 IASR
Green Energy Exports	453	467
Step Change	891	813
Progressive Change	932[A]	560[A]

A. The *Progressive Change* cumulative budget in the 2022 ISP was only applied from 2030-31 to 2050-51. The 2023 IASR's multi-sector modelling for *Progressive Change* over the same period 2030-31 to 2050-51 demonstrates a much smaller carbon budget as there is now a 43% emissions reduction target by 2030).

AEMO's carbon budgeting presented in Table 11 includes consideration of both the 2050 trajectory to net zero, as well as an additional carbon budget to 2030 to ensure the emissions reduction stipulated in the *Climate Change Act (2022)* is achieved in all scenarios (as a minimum requirement). The Act sets out an Australia-wide carbon budget over the period from 2020-21 to 2029-30 amounting to an indicative 4,381 Mt CO_2-e. After applying insights from the multi-sector modelling observed across the scenarios, and in the absence of a sectoral-equivalent budget for the electricity sector, AEMO has calculated the resulting carbon budget for the NEM equal to 630 Mt CO_2-e.

AEMO will model the budgets presented in Table 11 in the 2024 ISP, applied to the noted modelling horizons.

Across all the scenarios, Australia is required to achieve net zero emissions by 2050 at the latest. This is a net zero target, rather than a gross zero target, and the use of carbon sequestration provides an important contribution to this goal, including from sequestration opportunities from the land use, land use change and forestry (LULUCF) sector[66] or DAC (see Section 3.3.4).

[65] At https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-isp-methodology.pdf.

[66] LULUCF can sequester carbon via the conservation of high-carbon ecosystems, combined with increased afforestation, reforestation, and agroforestry rates, or through investment in technology-based solutions such as CCS.

State-level carbon budgets

A number of jurisdictions have committed, or announced intentions to commit to, state based emissions reduction targets. As discussed in Section 3.1, AEMO incorporates these state-wide targets as carbon budgets for NEM activities within each jurisdiction.

Table 13 Legislative instruments enabling the state-level emission reduction ambitions

Year	Legislative instrument
Australian Capital Territory	*Climate Change and Greenhouse Gas Reduction Act 2010*[A]
New South Wales	Currently unlegislated, but legislation expected for the 2030 and 2050 targets Targets were announced via the New South Wales Climate Change Policy Framework 2016 and underpinned by the Net Zero Plan Stage 1
Queensland	-
South Australia	60% reduction by 2050 legislated via *Climate Change and Greenhouse Emissions Reduction Act 2007*
Tasmania	Target of net zero emissions or lower from 2030[1]
Victoria	2025, 2030, 2035, and 2050 legislated via *Victorian Climate Change Act 2017* Legislation expected for 2045 targets.

A. While Tasmania's and Australian Capital Territory's legislated climate change targets aim to achieve net zero emissions, AEMO recognises the low emissions intensity of the electricity sector for these jurisdictions, and considers that an electricity-sector equivalent carbon budget would be inappropriate to reflect the economy-wide application of the legislations for these regions.

AEMO has derived carbon budgets for the state targets using a similar approach to the NEM-wide carbon budget. The states' economy-wide targets are scaled to electricity sector targets using factors based on the NEM emissions figures from the Clean Energy Regulator and economy-wide emission figures from Australia's National Greenhouse Accounts.

The state carbon budgets are developed by applying a linear trend between key milestone years that are stated in any state objective (for example, if needing to meet a specific objective by 2030, and by 2050, then the trajectory for achieving these is linear between the start of the modelling and 2030, and again from 2030 and 2050). Carbon budgets are then created to be equal to the cumulative carbon targets across all years.

Unlike the NEM-wide carbon budgets, AEMO proposes to model these as soft constraints, such that the model may choose to breach them at a cost if it was part of the most optimal solution. This is considered appropriate because these targets are net zero targets (not zero emissions) and some level of NEM emissions may be appropriate and cost-efficient if offset by emissions savings or carbon sequestration in other sectors, especially in light of the zero or very close to zero targets in some states.

Table 14 below presents the resulting carbon budgets that will be modelled for each of the states. More information is available in the 2023 IASR Assumptions Workbook.

Table 14 State carbon budgets in the 2024 ISP (Mt CO_2-e)

State	2024-25 to 2029-30	2030-31 to 2051-52	2024-25 to 2051-52
New South Wales	212	286	Not applicable
Queensland	Not applicable	Not applicable	Not applicable
South Australia	Not applicable	Not applicable	65
Tasmania	Not applicable	Not applicable	Not applicable
Victoria	218	166	Not applicable

3.3 Consumption and demand: historical and forecasting components

AEMO updates its projections of energy consumption and demand at least annually[67]. AEMO's Forecasting Approach applies methodologies that examine electricity and gas customer segments, and enables forecasting of key forecast components affecting those customer segments. This approach enables appropriately granular models to be deployed in a way that provides transparency of method and influence on energy consumption, and enables scenario diversity where key uncertainties exist. Updates to these forecast components are informed by stakeholder consultation through the FRG and other engagement opportunities where appropriate, and consider a range of forecasting components, including:

- Economic and population growth drivers.
- Climate and weather.
- CER.
- Large industrial loads (LILs), informed by stakeholder surveys.
- Electrification and other fuel-switching opportunities in the context of possible decarbonisation pathways.
- Energy efficiency.

AEMO uses a range of historical data to train models for developing electricity consumption component forecasts. Historical data are updated at varying frequencies, from live meter data to monthly, quarterly, or annual batch data, and include:

- Operational demand meter reads.
- Estimated network loss factors.
- Other non-scheduled generators.
- Distributed PV uptake.
- Battery storage uptake.
- Gridded solar irradiance and resulting estimated distributed PV normalised generation.
- Weather data (such as temperature and humidity levels).

[67] Updated forecasts (within a year) can be issued in case of material change to input assumptions.

The *Electricity Demand Forecasting Methodology*[68] and *Gas Demand Forecasting Methodology Information Paper*[69] detail how model inputs are applied to develop electricity and gas forecasts for energy consumption, and maximum and minimum demand. The resulting aggregate forecasts that consider these components, and apply AEMO's forecasting approach described in these methodologies, are available on AEMO's Forecasting Portal[70].

The following sections describe the individual model inputs and component forecasts. Where appropriate, comparisons are made with this 2023 IASR's scenarios against relevant 2021 IASR scenarios.

3.3.1 Historical demand data

Input vintage	• March 2023 for demand data • May 2023 for loss data • May 2023 for auxiliary load data
Source	• SCADA/EMMS/NMI Data • Generation Information page • AER and network operators
Updates since Draft IASR	• Updated loss data

Operational demand

Operational demand as generated is collected through the electricity market management system (EMMS) by AEMO in its role as the market operator. Operational demand as generated includes generation from scheduled generating units, semi-scheduled generating units, and some non-scheduled generating units[71].

Generator auxiliary load

Estimates of historical auxiliary load are determined by using the auxiliary rates provided by participants through AEMO's Generation Information survey process. This is used to convert between operational demand as-generated (which includes generator auxiliary load) and operational demand sent-out (which excludes this component).

Network losses

The AER and network operators provide AEMO with annual historical transmission loss factors. The AER also provides AEMO with annual historical distribution losses which are reported to the AER by distribution companies. AEMO uses the transmission and distribution loss factors to estimate half-hourly historical losses across the transmission network for each region in MW or megawatt hours (MWh).

Large industrial loads

AEMO's *Electricity Demand Forecasting Methodology* defines a methodology for identifying large loads for inclusion in the LIL sector. AEMO collects the historical consumption of these LILs from National Metering Identifier (NMI) meter data.

[68] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/forecasting-approach-electricity-demand-forecasting-methodology.pdf.

[69] At https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2023/2023-gas-statement-of-opportunities-methodology---demand-forecasting.pdf.

[70] At https://forecasting.aemo.com.au/.

[71] A small number of exceptions are listed in Section 1.2 of https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf.

Residential and business demand

AEMO splits historical consumption data (excluding industrial loads identified above) into business and residential segments using a hybrid bottom-up and top-down approach, as detailed in Appendix A6 (Residential-business segmentation) of the *Electricity Demand Forecasting Methodology*. The bottom-up approach is based on sampling of AEMO residential meter data. The top-down approach considers annual ratios between the two segments provided by electricity distribution businesses to the AER as part of their processes in submitting a Regulatory Information Notice.

Distributed PV uptake and generation

AEMO sources historical PV installation data from the Clean Energy Regulator and applies a solar generation model to estimate the amount of power generation at any given time. Refer to Section 3.3.8 for details. AEMO's Distributed Energy Resource (DER) Register[72] is used for validating the historical PV installation data.

3.3.2 Historical weather data

Input vintage	March 2023
Source	Bureau of Meteorology (BoM)
Updates since Draft IASR	Added most recent BoM data to train forecasting models

AEMO uses historical weather data for training the annual consumption and minimum and maximum demand models as well as forecast reference year traces. The historical weather data comes from the Bureau of Meteorology (BoM), using a subset of the weather stations available in each region, as shown in Table 15.

AEMO selected these weather stations based on data availability and correlation with regional consumption or demand. AEMO uses one weather station per region, except where weather stations have been discontinued.

Table 15 Weather stations used in consumption, minimum and maximum demand forecasts

Region	Station name	Date range	BoM site number
New South Wales	Bankstown Airport AWS	January 1989 ~ Now	066137
Queensland	Archerfield Airport	July 1994 ~ Now	040211
South Australia	Adelaide (Kent Town)	October 1993 ~ July 2020	023090
	Adelaide (West Terrace)	July 2020 ~ Now	023000
Tasmania	Hobart (Ellerslie Road)	January 1882 ~ Now	094029
Victoria	Melbourne Regional Office	January 1955 ~ January 2015	086071
	Melbourne (Olympic Park)	May 2013 ~ Now	086338

[72] For more information, see https://aemo.com.au/energy-systems/electricity/der-register/about-the-der-register.

3.3.3 Historical and forecast other non-scheduled generators (ONSG)

Input vintage	February 2023 for installed capacity (Generation Information page) March 2023 for historical and forecast ONSG generation
Source	• Generation Information page • Settlements data • NMI data • DER Register
Updates since Draft IASR	Updated installed capacity and added generation forecast

AEMO reviews its list of other non-scheduled generators (ONSG, which is non-scheduled generation that excludes distributed PV) using information from AEMO's Generation Information[73] dataset obtained through surveys, and supplements where applicable with submissions from network operators, the DER Register and publicly available information.

For ONSG generation, AEMO uses the generators' Dispatchable Unit Identifier (DUID) or NMI to collect historical generation output at half-hourly frequency.

AEMO's current view of ONSG is contained in the Generation Information page. As at the February 2023 release, used for the development of the energy and demand forecasts, aggregate capacity by region is shown in Figure 4 below. Note that this excludes any ONSG that is used solely as peaking capacity, as these generators are modelled as part of AEMO's DSP forecast instead (see Section 3.3.14).

Figure 4 Aggregate ONSG capacity, by NEM region (MW)

AEMO forecasts commissioning or withdrawal of ONSG generators based on firm commitment statuses of these generators in the short term and applying historical trends of ONSG by technology type (for example, gas or

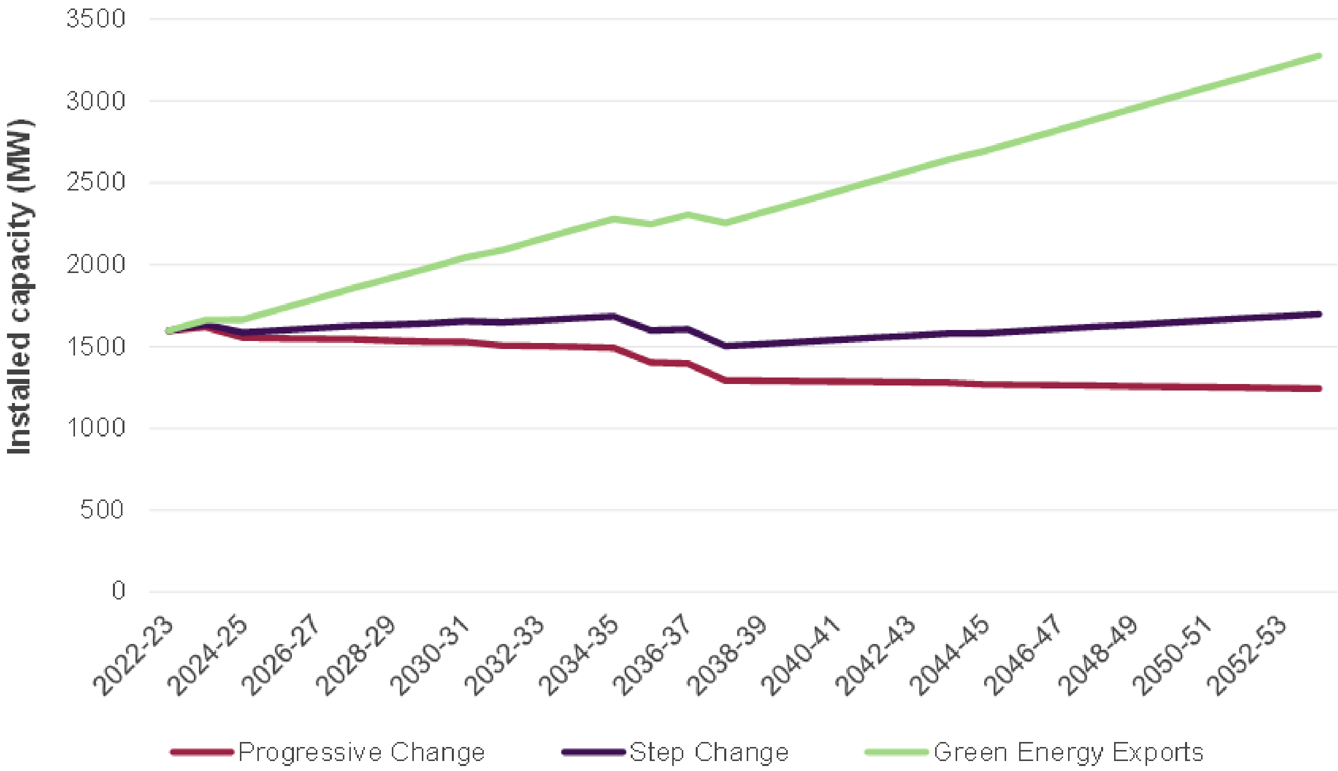
[73] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

biomass-based cogeneration, or generation from landfill gas or wastewater treatment plants) for the *Step Change* scenario in the long term.

For the *Progressive Change* scenario, the same withdrawal of capacity is modelled, but forecast growth is slightly slower. The *Green Energy Exports* scenario on the other hand has significant more growth assumed for renewable technologies (small-scale wind and biomass). Figure 5 shows the NEM-wide installed capacity for the three scenarios.

Historical capacity factors by technology type are used to forecast generation using the projected installed capacities, offsetting the electricity consumption in the forecast.

Figure 5 Forecast NEM-wide other non-scheduled generation capacity



3.3.4 Multi-sector modelling influences to demand forecasts

Input vintage	July 2023
Source	CSIRO and CWC
Update since Draft IASR	• Adjusted residential electrification in line with analysis of AEMO meter data that suggested limited electrification to date (similar analysis was done for the 2023 GSOO) • Smoothed industrial electrification • Updates of fuel-switching to hydrogen and biomethane including reduced hydrogen blending into distribution networks in *Green Energy Exports*, and development of the *Electrification Alternatives* sensitivity.

AEMO engaged consultants CSIRO and CWC to model least-cost pathways for the Australian economy to achieve emissions targets within the parameters of scenario-based demand drivers, including economic growth, CER and road transport EV forecasts affecting the domestic and export economy where relevant. This included consideration of the mix of energy forms appropriate to achieve these targets, including the potential development of alternative gaseous fuels (such as hydrogen and biomethane).

Using the CSIRO and CWC AUS-Times model, this multi-sectoral approach provides whole-of-economy interactions, by simultaneously considering a range of options available to meet scenario-specific emissions targets at the least cost. The emissions targets align to specific global temperature outcomes, informed by the RCP and IEA WEO scenario definitions (See Table 4 in Section 2.3 for key scenario parameters).

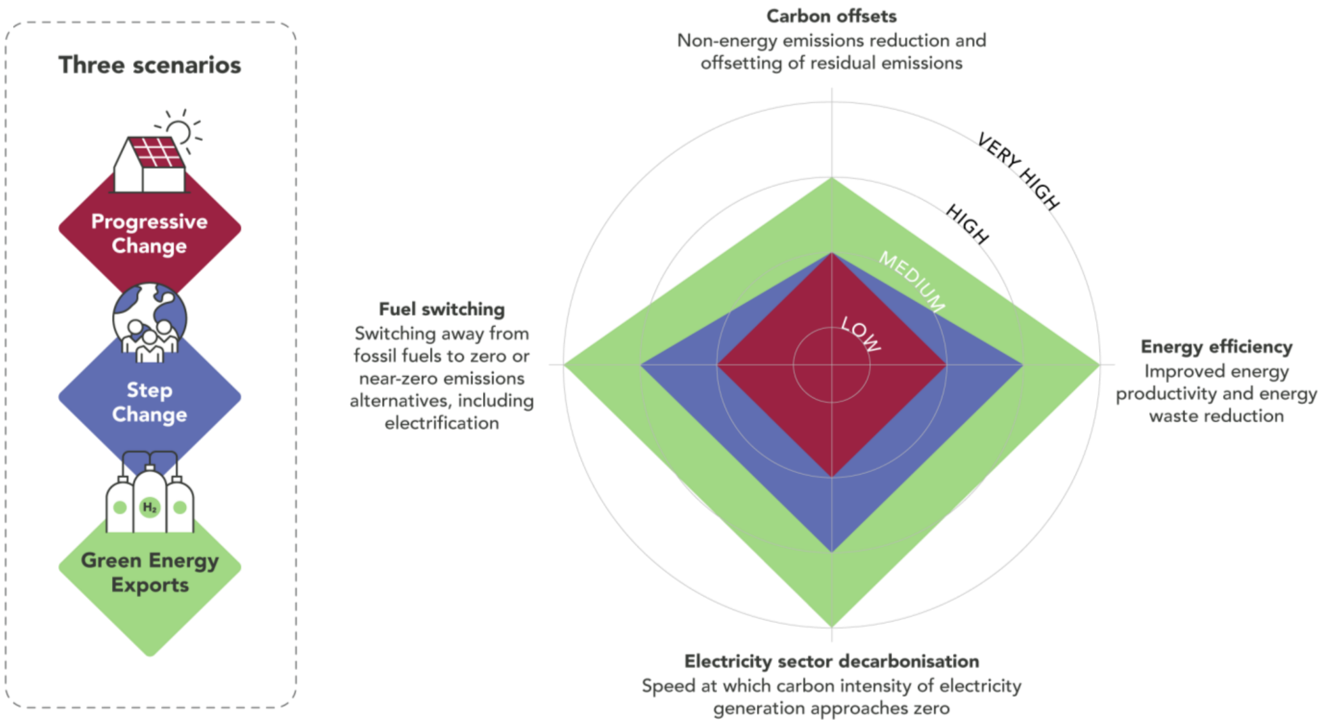
The options to transition Australia's economy broadly align with four pillars of decarbonisation, and the scenarios apply varying levels of each pillar to meet the intent of the scenario narratives and factoring the uncertainty around future technology improvements, costs, and barriers to deployment. These pillars complement traditional component forecasts outlined in subsequent sections, considering scenario drivers that may not be readily captured by trend-based or historical regression modelling.

The four pillars are:

- **Energy efficiency** to improve energy productivity and reduce energy waste.
- Decreasing carbon intensity of electricity generation to near zero.
- **Switching away from fossil fuels** to zero or near-zero emissions alternatives, including electrification and alternative gases.
- **Non-energy emissions reduction and offsetting** of residual emissions through sequestration (mainly in the land-use sector).

The scenarios consider all four pillars of decarbonisation to varying degrees, to align with the scenario narratives and to reflect the uncertainty around future technology improvements, costs, and barriers to deployment. Figure 6 illustrates the scale of utilisation of the four pillars across the scenarios.

Figure 6 Forecast utilisation of the four pillars of decarbonisation, by scenario



The model outputs that have been explicitly used to inform this 2023 IASR include:

- Future energy consumption trends and fuel-switching opportunities, particularly the electrification of other sectors of Australia's economy. Outputs were also adopted as long term primary energy consumption drivers for BMM and LIL growth.
- National and NEM emissions pathways (see Section 3.2.3 for further details), including forecast needs for emission sequestration via land use sequestration, direct air capture, and carbon capture and storage.
- Domestic hydrogen demand, as a substitute for other energy sources, complementing assumed hydrogen export demand in the scenarios (see Section 3.3.6 for further details).

Table 16 describes, at a high level, the key assumptions and outcomes from the multi-sector modelling. Further details may be found in subsequent subsections and the CSIRO and CWC supporting report[74].

Table 16 Key assumptions and outcomes from the multi-sector modelling

	Green Energy Exports	*Step Change*	*Progressive Change*
Electrification (Section 3.3.6)	There is a high degree of electrification investment across many sectors. Even with homes and businesses having the option of relying on alternative gases (such as hydrogen and biomethane) for their heating requirements, this scenario has the strongest amount of electrification overall, including high contributions from transport and industry – 35 TWh in 2030 and 142 TWh in 2050, owing to high rates of electrification in the industrial sectors. This scenario has the strongest amount of electrification overall, including high contributions from transport and industry	The degree of electrification is high, particularly from the transport sector, where EVs soon become the dominant form of road passenger transportation as state targets are assumed to be met. Consumers switch from gas to electricity to heat their homes, and electrification investments reduce the emissions intensity of manufacturing and other industrial activities with appropriate decarbonisation of the electricity sector. This scenario has the second largest amount of electrification overall –25 TWh in 2030 and 121 TWh in 2050.	Investment in residential and commercial electrification is more muted due to challenging economic conditions. This scenario has a moderate amount of electrification – 16 TWh in 2030 and 82 TWh in 2050. Transportation electrification provides a relatively large contribution to electrification as growth in EVs increase progressively through the 2030s and beyond. The rate of transport electrification though is the lowest of all scenarios.
Carbon sequestration across NEM states (see below)	This scenario includes significant use of emissions sequestration to maintain alignment to the 1.5°C aligned decarbonisation pathway for the Australian economy. These activities commence at the earliest relative timing of all scenarios. Sequestration increases then stabilises at approximately 142 Mt CO_2-e/year (million tonnes of carbon dioxide equivalent per year) in 2034. Direct air capture (DAC) plays a role in capturing emissions from 2030 but early activities in other sequestration and land use activities reduce the reliance on this emerging technology.	This scenario gradually increases the use of sequestration, with 26 Mt CO_2-e/year in 2030 and 65 Mt CO_2-e/year in 2040 sequestered. By 2050, sequestration provides 159 Mt CO_2-e/year of emissions offsets. DAC starts in the late 2030s, and is a more reliant form of sequestration to meet emissions reduction objectives given the slower pace of activities than in the *Green Energy Exports* scenario.	Sequestration progressively increases to 38 Mt CO_2-e/year by 2030. After nearly a decade at that level, it then increases over the period to 2050, reaching 162 Mt CO_2-e/year in 2050. DAC is deployed latest across all scenarios but provides a material contribution to the means by which Australia meets net zero 2050 targets in the last decade of the forecast horizon.

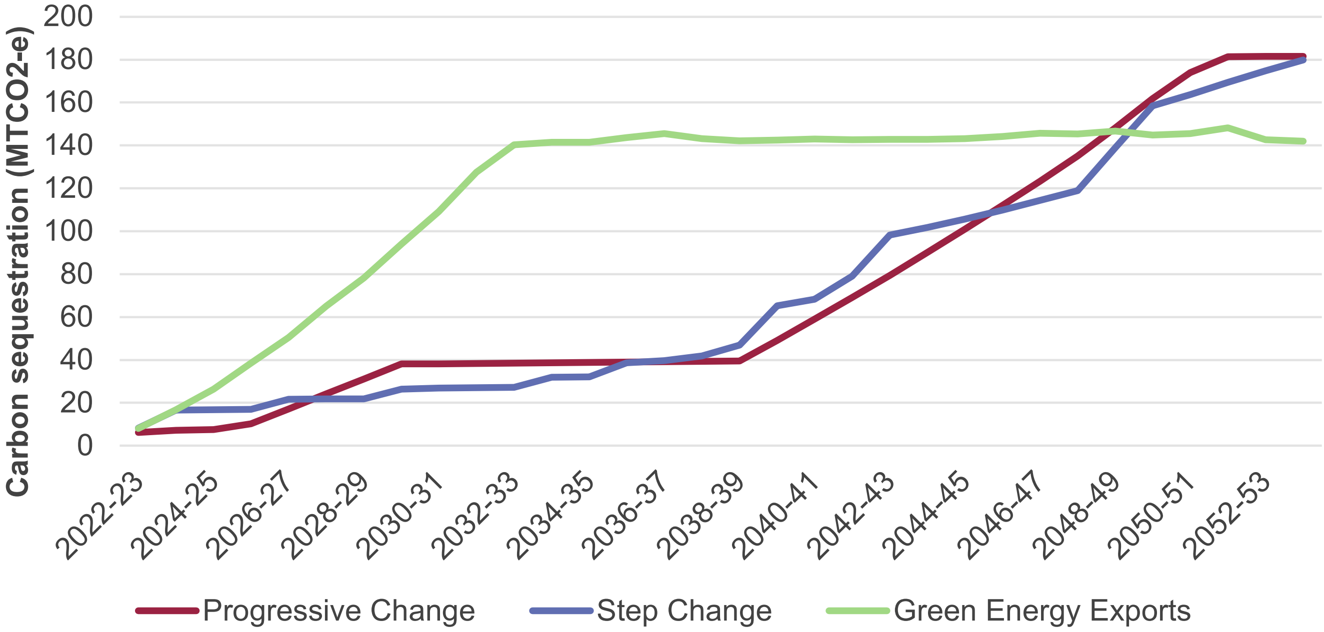
[74] CSIRO and CWC 2022 Multi-sector modelling report, at https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

	Green Energy Exports	*Step Change*	*Progressive Change*
Fuel-switching and alternative gas production (Section 3.3.7)	Natural gas use declines quickly, replaced by a combination of electrification and alternative molecular fuels including hydrogen and biomethane. The scenario assumes technology and cost breakthroughs, enabling significant scaling of hydrogen and hydrogen-related facilities for export (and domestic use to a lesser scale). Biomethane production is strongest overall in this scenario.	Natural gas use declines quickly over the period to 2050. It is replaced by a combination of high electrification and moderate hydrogen production. Biomethane is not competitive without subsidies in this scenario. NEM-connected hydrogen exports (and hydrogen-based technologies such as green steel or ammonia) are present but very limited compared to *Green Energy Exports* scenario.	Natural gas use declines gradually over the period to 2050, although lower economic conditions also provide a disruptive influence to industrials. Gas use is replaced by a combination of electrification and small amounts of hydrogen in the early years. In the late 2040s biomethane replaces more of the natural gas.

Carbon sequestration

AEMO incorporates varying levels of carbon sequestration in the scenarios in order to achieve the carbon budgets that apply in net zero emission futures. Emissions can be sequestered via land-use sector sequestration (capturing carbon via natural biological processes), via the use of direct air capture (DAC) technologies, or via the use of carbon capture and storage (CCS) technologies from emitting processes. Figure 7 below presents the estimated emissions captured from sequestration activities in the NEM.

Figure 7 Carbon sequestration due to land-use sequestration and process-based carbon capture and storage in NEM states



The emergence of DAC is subject to technological deployment and cost uncertainty but provides an anticipated level of emissions abatement that may enable negative emissions outcomes in future years. As discussed above in Table 16, DAC is assumed to become technically and commercially feasible at some scale around 2040 in all scenarios, and in some scenarios provides a material portion of the longer term growth in total sequestration outcomes by 2050. Assumed to be a relatively expensive option, DAC deployment will be naturally lessened if actions are taken earlier to reduce the carbon intensity of the economy.

3.3.5 Electrification

Input vintage	• July 2023 rebase for non-transport electrification data • March 2023 for transport electrification data
Source	• CSIRO and CWC (multi-sector modelling) • CSIRO (road transport modelling, incorporating data from Federal Chamber of Automotive Industries, Electrical Vehicle Council, Origin Energy, Energex and Ergon Networks)
Updates since Draft IASR	• Rebased to 2022-23 • Rebased residential electrification in line with analysis of AEMO meter data that suggested limited electrification to date (similar analysis was done for the 2023 GSOO) • Smoothed industrial electrification • Road transport model forecasts rebased based on March 2023 actuals

Decarbonisation of the Australian economy requires emissions-intensive energy sources for residential, commercial and industrial processes to shift towards low and no emissions alternatives. In considering electrification, AEMO includes the potential electrification of future NEM loads (including the transport sector), and expansion of existing grid-connected loads.

The cost-efficiency of electrification depends on many factors including appliance replacement costs, electricity infrastructure capabilities and costs, and the availability of alternative low emissions fuels, such as hydrogen and biomethane. AEMO has therefore considered a range of electrification outcomes, with the *Green Energy Exports* scenario adopting both a high degree of electrification and fuel-switching to hydrogen.

In the residential and commercial building sectors, space heating, cooking, and water heating appliances can all be electrified from gas or liquefied petroleum gas (LPG). It is also noted that a proportion of existing LPG use may transition to bio-LPG where electrification is not practical. Electrification of the transport sector is expected in all scenarios, although the pace and magnitude of electrified transportation also varies across scenarios.

The industrial sector comprises a range of subsectors, each with their own fuel use characteristics. While most oil and gas demand can be electrified (or switched to alternative gases), high-heat processes are challenging to electrify without further technological advances. Examples of such processes are the direct reduction process for iron and steel, and high temperature blast furnaces. Scenarios requiring faster emissions reduction assume greater technological advances to achieve the emissions reduction goals (potentially driven by domestic or international research initiatives, or early-adopter or policy support).

Figure 8 below shows electrification forecasts, including transport. By 2050 at least 82 terawatt hours (TWh) of new electricity supply is required – almost half of the NEM's current operational consumption. The *Step Change* and *Green Energy Exports* scenarios show accelerated electrification for the residential, commercial and industrial sectors compared to the *Progressive Change* scenario. The residential sector alone contributes between 11 TWh and 14 TWh in 2050.

Slower investment in electrification is forecast compared to the 2021 IASR scenarios primarily due to lower electrification forecasts for industry, and less evidence to date of the scale of widespread electrification that was anticipated in the near term previously. The multi-sector modelling for this 2023 IASR includes more granular representation of industrial processes and increased consideration of technical and commercial limits informed by work on the Australian Industry Energy Transitions Initiative (ETI)[75]. On the other hand, the increased commitments towards electrification included within each scenario's policy settings (for example, Australia's

[75] Australian Industry Energy Transitions Initiative, at https://energytransitionsinitiative.org.

increased commitments to the Paris Agreement and the Safeguard Mechanism affecting industrial facilities) has resulted in increased forecast electrification for the *Progressive Change* scenario compared to the lowest of the 2021 IASR scenarios (2021's *Slow Change* scenario).

Figure 8 Total electrification forecast per scenario, including transport

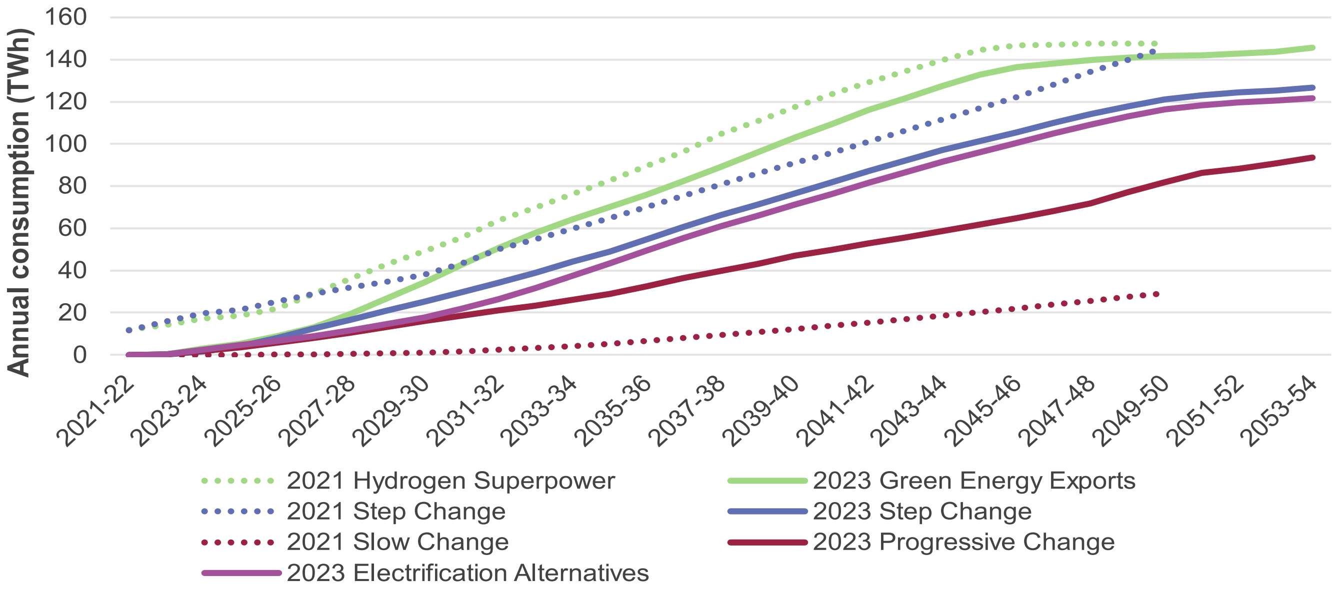
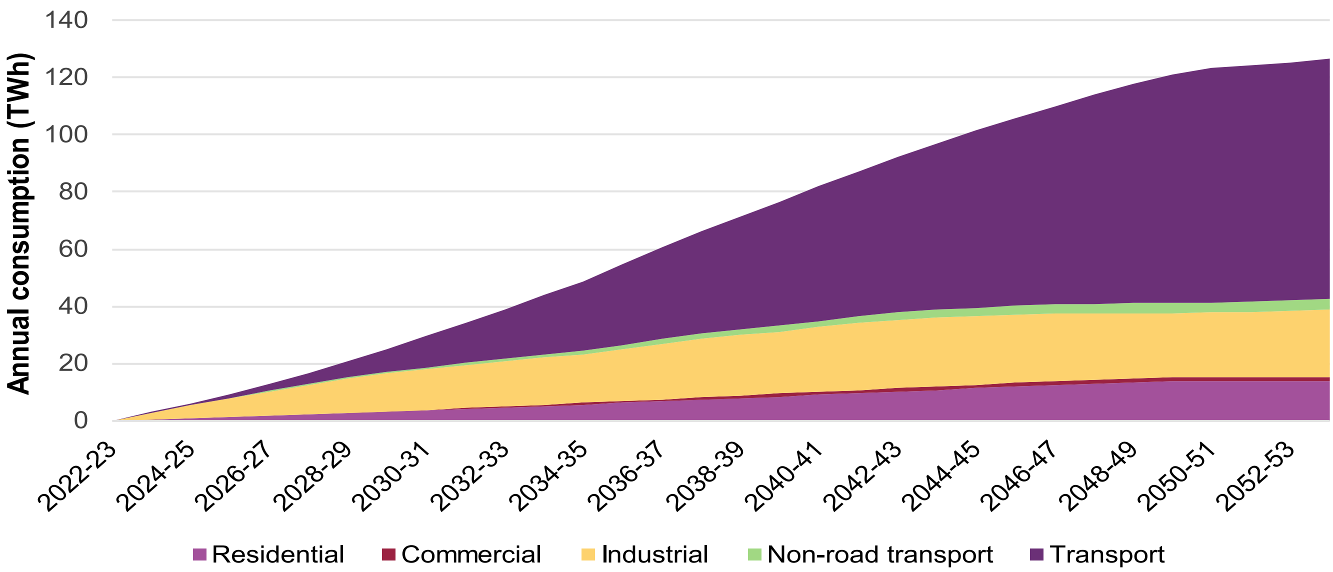


Figure 9 breaks down electrification by sector in the *Step Change* scenario. Transport electrification is forecast to contribute an increasing share of electrification, 36-50% of total in 2035 and 55-66% in 2050 across the range of scenarios. Industrial electrification is forecast to take up the largest share in the remaining sectors, driven by technologies like mechanical vapour recompression (MVR), electric boilers, and electric calcination in alumina refining. Technologies to electrify mining processes and a shift towards the uptake of electric haulage trucks would also contribute to industrial electrification. In contrast, electrification in Victoria is forecast to be driven primarily by residential consumers, owing to the large amount of gas currently used to heat homes.

Figure 9 Breakdown of electrification by sector, *Step Change*, 2022-23 to 2053-54



Impact of electrification on daily and seasonal load shape

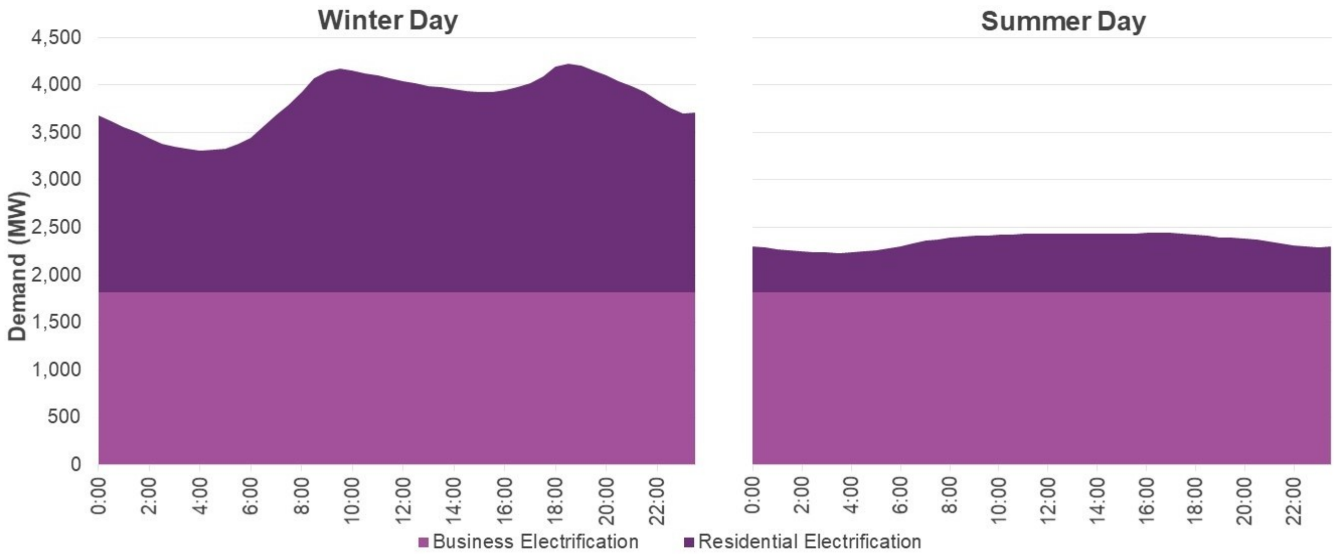
In converting non-transport electrification into half-hourly data, AEMO assumes:

- Business consumption shows relatively low seasonality, on aggregate, and therefore electrification of the business sector (including industrials) approximates a baseload.
- Residential electrification is primarily driven by gas to electricity fuel-switching. To maintain heating load seasonality, AEMO assumes that electrified loads maintain the shape of current residential and small commercial volumetrically tariffed ("Tariff V") gas loads.

Newly electrified loads are assumed to mirror existing electricity temporal consumption patterns, generally with more load in the day than overnight. Figure 10 contrasts two example daily load profiles of residential and business electrification (excluding the transport sector). The business electrification load is assumed to be flat across the year and across the day as large industrial loads electrify their processes. The residential load profile varies across the day and is much higher in winter compared to summer due to heating load.

The electrification component only captures the energy needed to perform the activities previously performed by alternative fuels, with inherent fuel-conversion efficiency gains as appropriate. Changes in the efficiency of the individual appliances over time are captured separately within the Energy Efficiency component (see Section 3.3.11).

Figure 10 Example electrification daily load shape contrasting winter and summer (Victoria 2050-51, *Step Change* scenario)



Electrification of the transport sector

The replacement of internal combustion engines with battery electric vehicles (BEVs), and plug-in hybrid electric vehicles (PHEVs) is a considerable disruptor to current energy use and carbon emissions that will affect the infrastructure needs of the power system. Consumers' transport re-charging needs (and options) will contribute significantly to future daily demand profiles for the NEM.

Electric vehicles (EVs) represent a significant opportunity for consumers to contribute to optimising power system outcomes, and it will be valuable for consumers to re-imagine their vehicle 'fuelling' behaviours as regular vehicle charging replaces the less regular trips to the petrol bowser. Consumer participation in schemes that allow orchestration of charging will be valuable, and such behaviour is assumed to differing extents across the scenarios.

Detailed modelling of EVs in the Australian transport sector was carried out by CSIRO, with key results regarding vehicle uptake and driving distances an input to the CSIRO multi-sector modelling. The EV forecast considers a range of new government strategies and policies that have been introduced since the 2021 IASR, in addition to the pre-existing state policies. State EV strategies include uptake targets (for example, 50% sales share for EVs by 2030), subsidies, public charging infrastructure funding and changes to road user charges. As noted in Section 3.1, the EV modelling interprets the impact of the policies as a range of possible fleet/sales outcomes across the scenarios. More detail is available in the CSIRO EV report[76].

The EV forecast is influenced by EV sales data from peak bodies and government departments, trial data on charging behaviour and public charging electricity use data. The latter public charging data has increased AEMO's understanding of fast charger demand profiles.

This section describes the scale of transport electrification relative to other economic sectors, the uptake of EVs in the transport fleet, and their impact on electricity consumption in the NEM (annual and half-hourly). More data is available in the 2023 IASR EV Workbook[77].

Relative scale of transport electrification versus other sectors

Transport electrification contributes a significant overall emissions reduction and is forecast to provide approximately half the newly electrified NEM load. The passenger and small commercial vehicle fleet is forecast to be dominated by EVs in future, encouraged by strengthening government policies, while heavier transport may be slower to electrify and/or require alternative fuel sources such as hydrogen fuel cells (affecting the domestic demand for hydrogen). Biofuels could be extremely important in industries such as aviation, which currently lacks an electric alternative for commercial-scale transport.

The current EV fleet size (as at end March 2023) across the NEM is approximately 0.5% of the total road transport fleet[78]. EV uptake over the last year has exceeded previous forecasts, as pandemic-related disruption has been minimised to some extent by EV manufacturers developing their own supply chains and new contracting arrangements. The high level of pre-orders has provided more certainty to drive ongoing EV production. Even so, demand has exceeded supply, and overall vehicle and model availability is impacting uptake, and there remains reasonable potential for supply chain disruptions, which is considered within the scenario forecasts.

Figure 11 shows the projections for BEV and PHEV fleet size in the NEM by scenario, compared to the 2021 IASR.

The *Step Change* scenario assumes cost parity with ICE vehicles by 2027, aided by a range of EV strategies by Australian governments and continued expansion of global EV production capacity. BEV fleet numbers are forecast to reach between 12 to 23 million (63% to 97% of whole fleet) by 2050 across the scenarios, with the *Green Energy Exports* scenario reaching maximum penetration by 2045; sales after this point are due to replacement of retiring vehicles and the impact of population growth only. This inflection point occurs later in the other scenarios.

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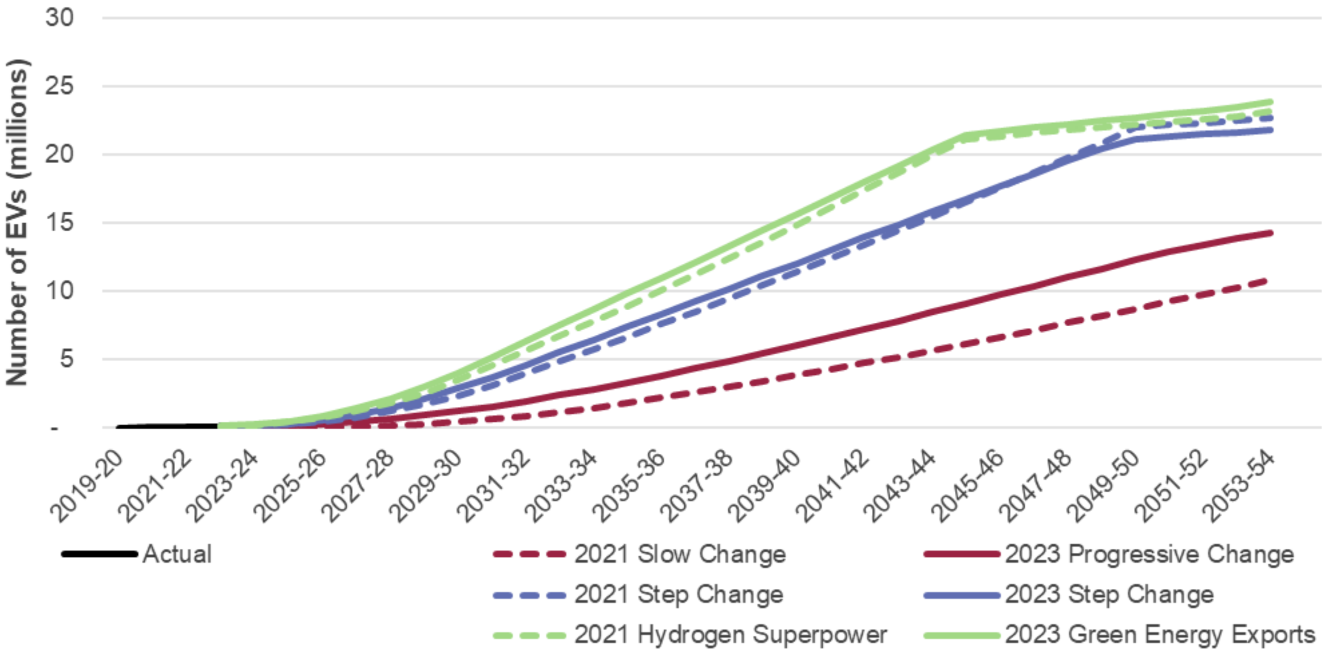
[76] CSIRO, Electric vehicle projections 2022, at https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

[77] 2023 IASR EV workbook, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios

[78] See https://www.fcai.com.au/sales/get-vfacts.

Figure 11 Projected BEV and PHEV fleet size by scenario, 2020 to 2054



Electricity consumption from EVs

AEMO recognises that EV users will adopt a wide range of charging behaviors and technologies, and that these will change day to day, and over the longer term as electrified transport becomes commonplace, and infrastructure, charging technologies and tariffs adapt to this emerging sector. An individual user will switch between different charging methods frequently, depending on the influences that affect each driver's vehicular habits. AEMO's electricity consumption forecasting for EVs includes allowance for:

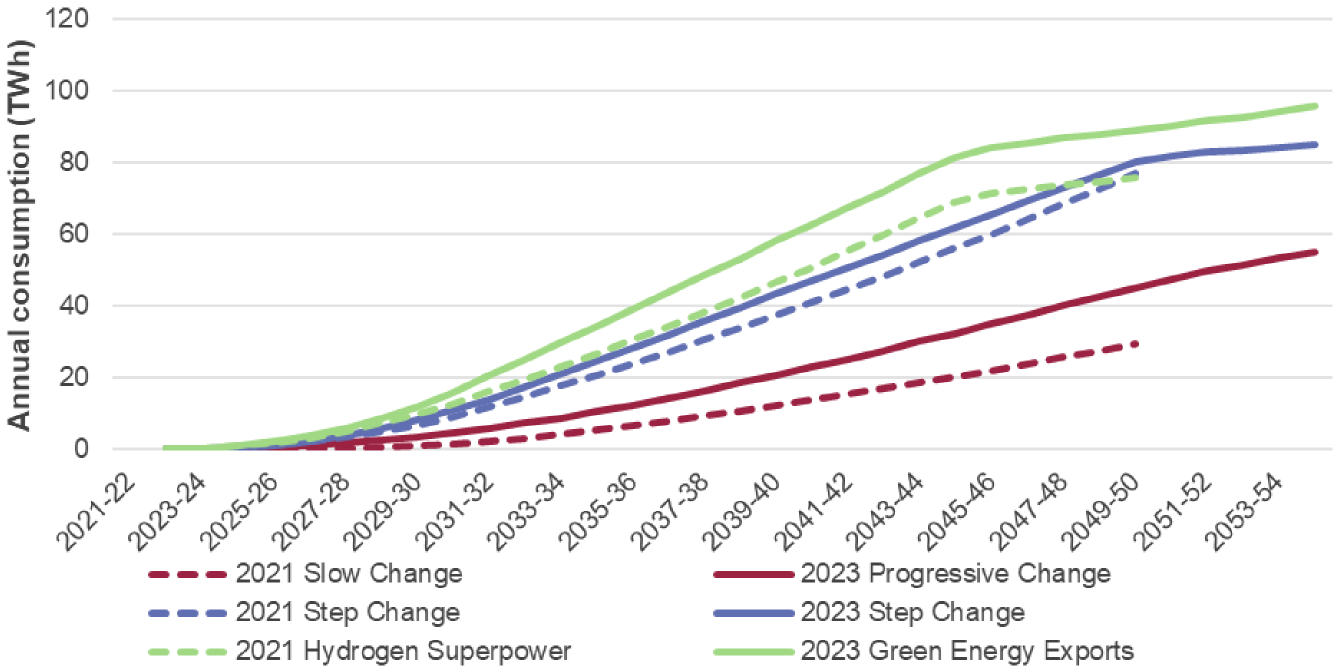
- the availability, popularity, and technical characteristics of home, business and public charging facilities;
- evolving vehicle mix (including motorcycles, passenger and commercial vehicles of different sizes, trucks and buses);
- varying travelling distances; and
- market share of short range and long-range vehicles.

Annual consumption is predominantly informed by vehicle mix and travelling distance assumptions, while the instantaneous demand across the day is influenced by all these factors, In this section, AEMO presents a normalised consumption and vehicle charging profile; this represents the average vehicle considering all of these factors, rather than reflecting the behaviour of any individual consumer.

Annual consumption

Electricity consumption from BEVs is shown in Figure 12, informed by vehicle type mix and travelling distance assumptions. Compared to AEMO's 2021 IASR, this forecast includes a greater share of larger and more energy intensive passenger vehicles (based on the latest uptake data) so consumption has increased by a greater percentage than by vehicle count[79] alone. The projected consumption of almost 90 TWh by EVs by 2050 in the *Green Energy Exports* scenario equates to almost half of today's total operational consumption in the NEM.

Figure 12 BEV and PHEV electricity consumption by scenario



Daily charging types and profiles

A range of half-hourly charging profiles were developed for each vehicle type and charging type, and vary across the months and years, to account for travel variation and assumed yearly improvements in vehicle efficiency affecting new vehicles. There are also variations across state, and between weekdays/weekends.

The profiles are 'after diversity' - reflecting the expected average load per vehicle on a given day, rather than representing a typical individual vehicle. This diversity-reflective profile is much lower than individual charger capacities, as each vehicle typically may only charge once or twice a week. The profiles are also normalised to 7kWh for easy comparison of shapes between profiles, being a nominal charging volume needed to recharge a typical sized vehicle for an average daily travel distance (30km). The profiles are later scaled to reflect the aggregate cohorts of vehicle types and sizes from the uptake forecast.

The vehicle charging types used by AEMO include a mix of static and dynamic profiles, described as follows:

- Static profiles supported by wall socket and dedicated high power chargers (AC level 1 and 2 respectively, with the latter including three phase versions), available at homes, car parks, shopping centres or workplaces:
  - Convenience – driven by user's lifestyle choices other than cost reduction, and occurs at a residence
    - *An EV owner adopting this charge profile typically would charge their vehicle when returning to the home each evening, with some workplace or carpark charging as well. Charging preference has little regard to electricity costs.*

[79] CSIRO, Electric vehicle projections 2022, at https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

  - 'Smart' daytime – driven by consumer adoption of time of use (TOU) tariffs with charging targeted to reduce peaks, with a focus on daytime charging
    - *An EV owner adopting this charge profile typically would take advantage of charging opportunities at home, or away from home, that are focused during the daytime hours, absorbing solar production at potentially lower costs to the driver.*
  - 'Smart' night-time – driven by consumer adoption of TOU tariffs with charging targeted to reduce peaks, with a focus on night-time charging.
    - *An EV owner adopting this charge profile typically would have higher overnight charging than the 'smart daytime' owner, typically at home, but after the household's peak evening loads. Some daytime charging would be used as well, if convenient.*
  - Fast charging – unlike the above static charging profiles, this is enabled by DC fast public charging (Level 3) and ultra-fast public charging (Level 4), and available only at public locations with dedicated infrastructure.
    - *An EV owner adopting this charge profile would typically charge rapidly while stopped at highway facilities, or at carparks, or workplaces with dedicated facilities. Given these activities typically occur during daytime hours, this profile has a daytime bias.*
- Dynamic profiles support the user in managing their household or the broader grid's load, with lower costs compensating the user for use of the vehicle's battery and any potential loss of flexibility. The profiles include a pure load profile, and those that have two-way energy flows:
  - Coordinated charging – vehicle charging is assumed to be optimised by retailer or aggregator to occur when demand otherwise is low (typically associated with high PV generation). This profile does not include energy flows from the EV battery to the home or grid.
  - Vehicle to Grid (V2G) – allows use of the vehicle as a battery, storing energy which can be called on by a retailer or aggregator to supply back into the grid.
  - Vehicle to Home (V2H) – allows use of the vehicle as a battery, storing energy which can be called on by the resident's energy management system to supply back into the home.

The charging profiles are detailed in the 2023 IASR EV Workbook published with this 2023 IASR[80]. Note that charging to support subsequent discharging for home/grid is not included in the workbook as it is determined dynamically in the modelling.

Figure 13 represents the 2023 IASR half-hourly charging profiles of all the different static charging types. The profiles below are shown for a typical January weekday in New South Wales, under the *Step Change* scenario.

[80] 2023 IASR EV Workbook, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

Figure 13 Static charging profiles of different EV charging types for residential vehicles in New South Wales normalised to 7kWh/day

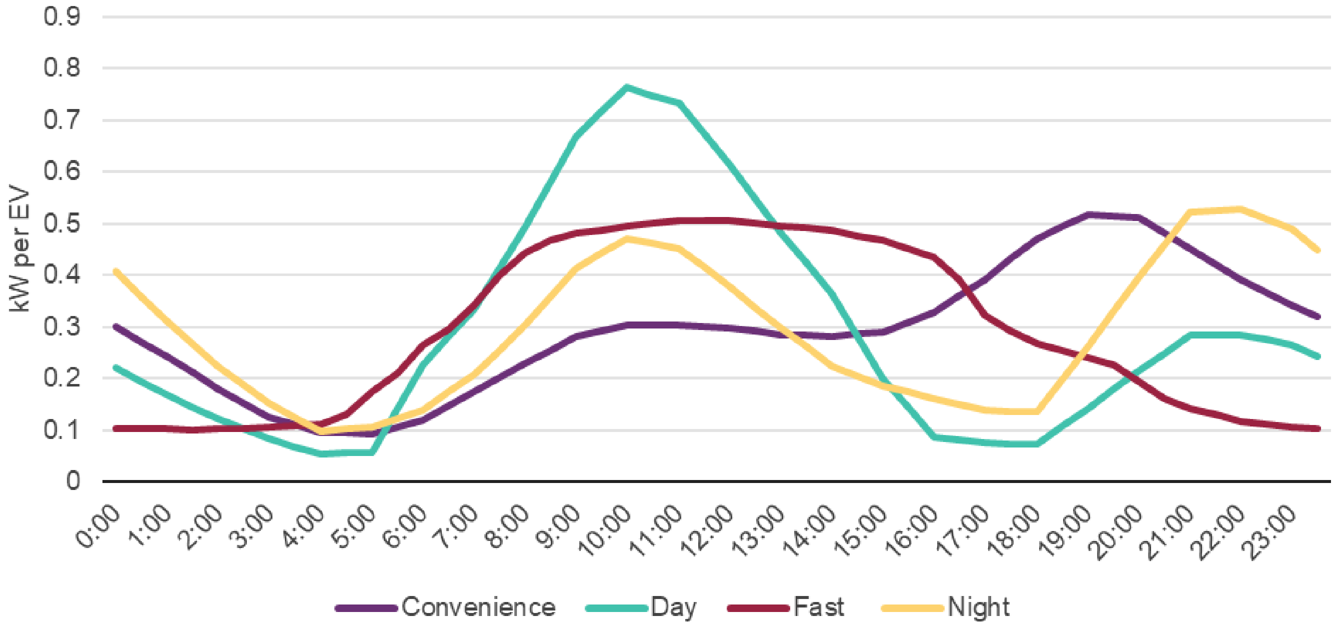
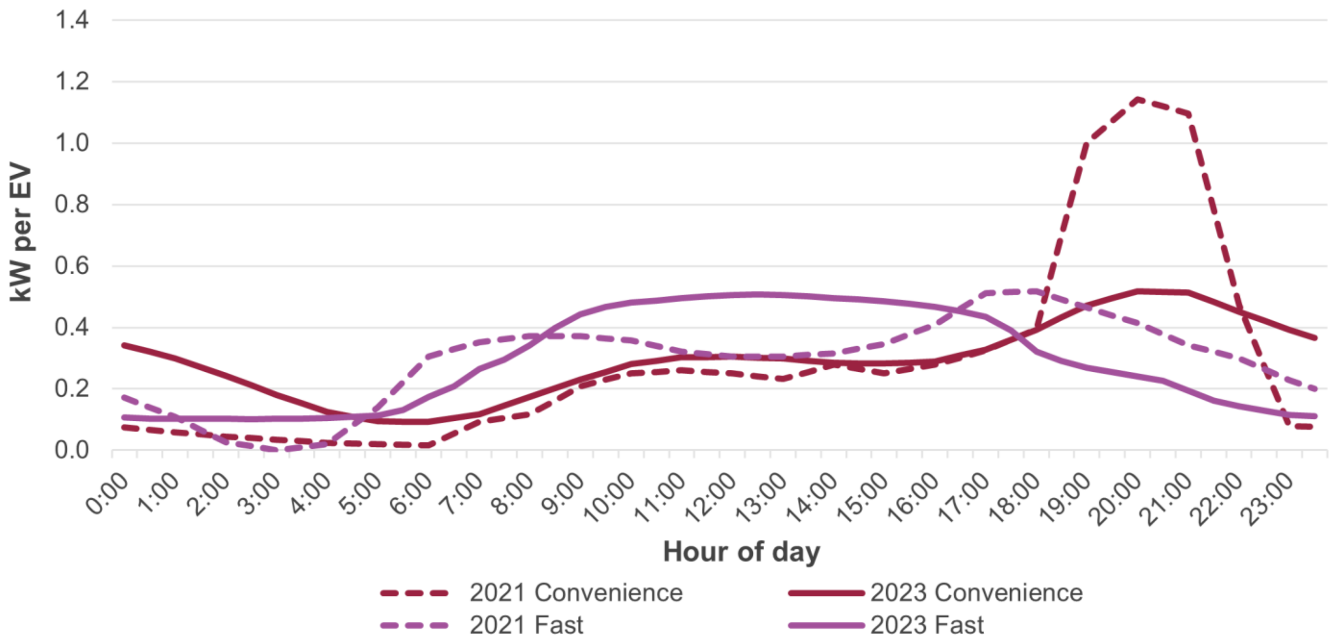


Figure 14 below shows typical convenience and fast charge profiles used in this 2023 IASR, compared to profiles applied in the 2021 IASR.

Figure 14 Normalised after diversity EV charging profiles (medium-sized residential EVs in Victoria based on a typical January weekday, 2030, *Step Change* scenario)



The convenience profile for this 2023 IASR was informed by new data made available from a range of Australian trials, including Energex and Ergon Energy Network and Origin Energy[81]. The 2021 IASR convenience profile peaked at an average of almost 1.2 kilowatts (kW) per EV, based on the assumed diversity of vehicle charging, and assumptions regarding the relative popularity of dedicated (AC level 1 and 2) chargers. New trial data indicates that dedicated high power chargers (AC level 2) are less popular than previously assumed, so the lower charging peak of 0.6kW is considered appropriate.

The fast charge profile used in 2021 was based on traffic movements as the best available proxy while public charging data was scarce. It showed mostly daytime demand with two peaks. For the 2023 IASR, AEMO developed a new fast charge profile based on analysis of public fast charger meter data. The new data shows a single flatter peak during the day, reflecting less correlation with traffic movement.

Note these normalised, 'after diversity' profiles are not intended to represent the overall EV charging peak. Many factors, such as the overall popularity of each charging type, and their popularity trends over time, are needed to model overall EV charging demand trends.

The popularity of the charging types will change over time due to technology improvements, infrastructure availability and relative cost effectiveness. TOU tariffs and increasing uptake of dynamically controlled charging is forecast to drive a shift in consumer behaviour to more middle-of-the-day charging to reflect the assumed pass-through of broader grid cost savings from these behaviours.

Figure 15 illustrates the popularity of EV charging types in the *Step Change* scenario for residential medium vehicles in New South Wales, and Table 17 provides further snapshots for 2030 and 2050 across different scenarios for the same state.

AEMO forecasts that smart charging will be preferred to convenience charging over time and will be most prevalent in scenarios that embrace a more rapid and broad transition, such as in *Green Energy Exports* and *Step Change*.

[81] See:

- Energex and Ergon Energy Network 2022, EV smart charge (Queensland) insights: Issue 2 Weekend and weekday consumption profiles, Ergon Energy.
- Ergon Energy Network 2022, EV smart charge (Queensland) insights: Issue 5 Diversified charging profiles, Ergon Energy.
- Origin Energy 2022, Origin Energex EV smart charging trial: Lessons learnt report, ARENA.
- Origin Energy 2021, Origin EV smart charging trial: Interim report, ARENA.
- Philip, T., Lim, K. and Whitehead, J. 2022, Driving and charging an EV in Australia: A real world analysis, Australasian Transport Research Forum, 28-30 September, Adelaide, Australia.

Figure 15 Split of charging types for medium residential vehicles (New South Wales, *Step Change*)

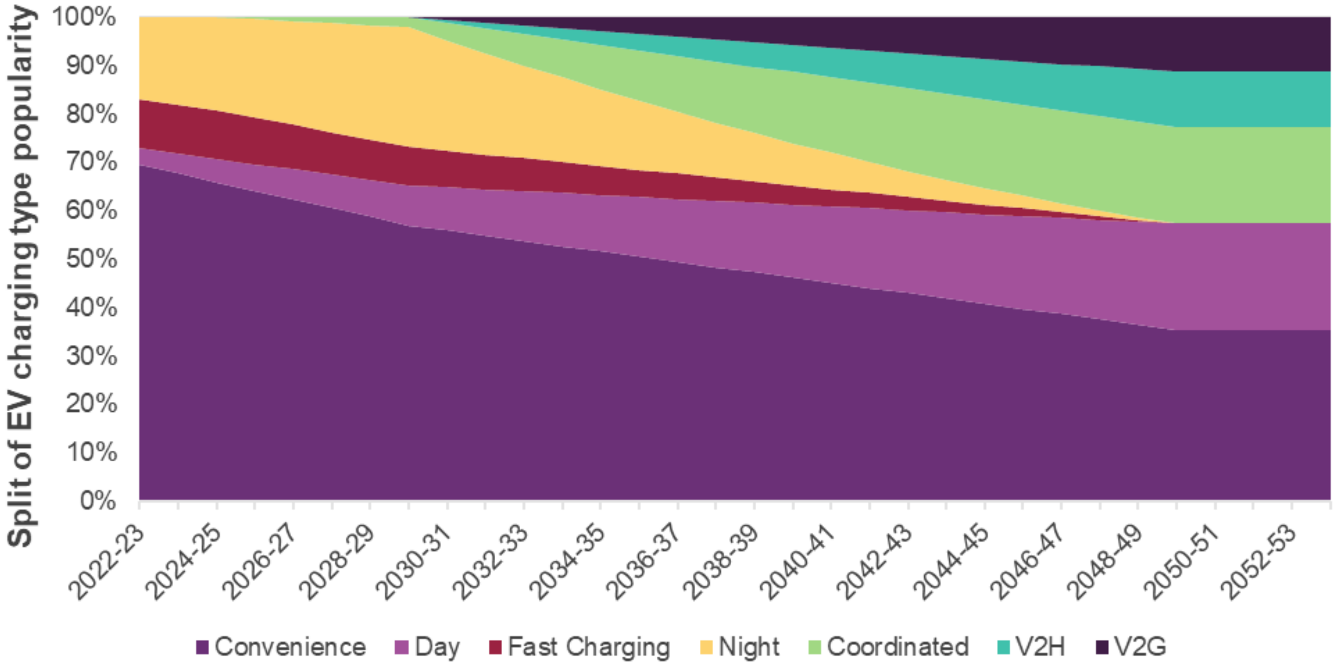


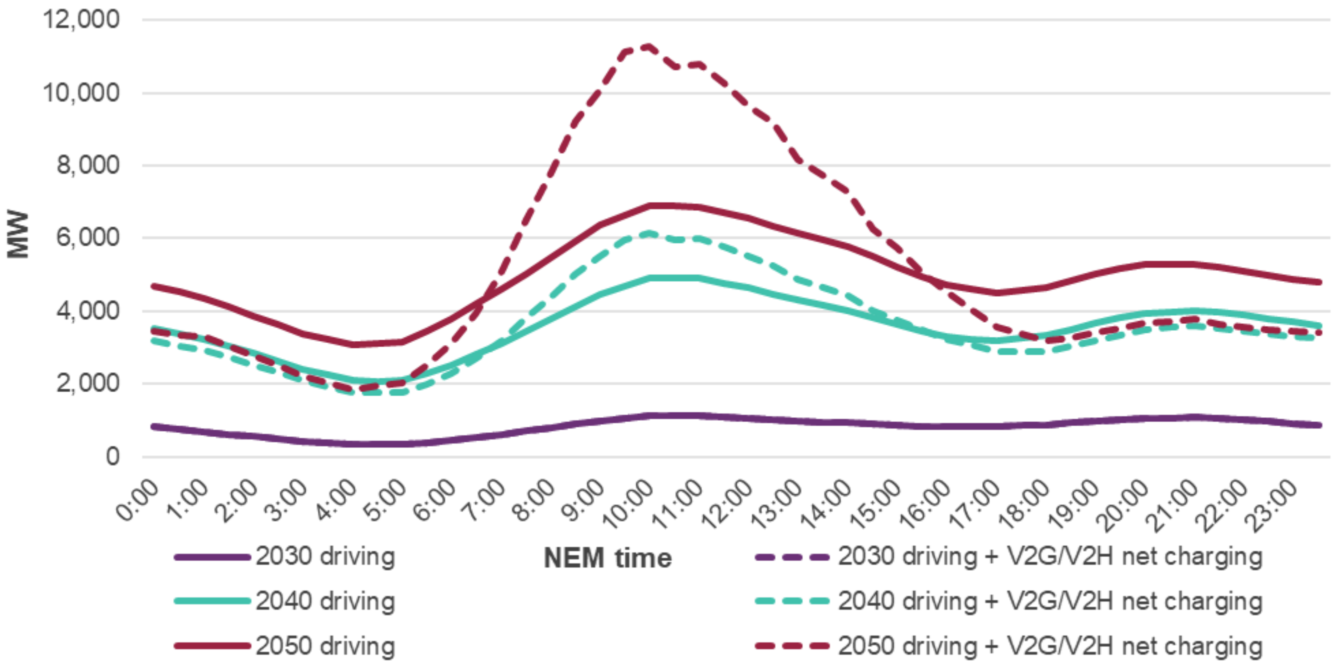
Table 17 Popularity of EV charging types for residential vehicles in New South Wales, by scenario for 2030/2050

	Convenience (%)	Day (%)	Fast charge (%)	Night (%)	Coordinated (%)	V2G (%)	V2H (%)
	2030						
Green Energy Exports	52	8	8	26	2	2	2
Step Change	57	8	8	25	2	0	0
Progressive Change	54	6	10	30	0	0	0
	2050						
Green Energy Exports	23	21	0	0	22	17	17
Step Change	35	22	0	0	20	11	11
Progressive Change	58	16	10	6	0	5	5

Figure 16 illustrates the modelled typical daily energy consumption for all vehicles in the NEM for *Step Change* on a typical January weekday in 2030, 2040 and 2050. The solid lines show consumption patterns to charge the EV fleet. The dashed lines isolate vehicles that include two-way operations, providing dynamic use of spare battery capacity and therefore consumption patterns exceed the driving needs of the owner (but discharge spare stored energy at other times of the day when available also, to reduce household or grid needs). The coordinated charging type's profile is not shown as it will reflect dynamic orchestration decisions.

Where the dashed line is greater than the solid line, EV batteries are charging for later discharge to the home or grid, and where the dashed line is below the solid line, they are discharging. Note that the two respective areas between lines are approximately equal and opposite, but discharging area is slightly lower due to round trip inefficiencies.

Figure 16 Illustrative *Step Change* energy flows for all NEM EVs for 2030, 2040, 2050 (typical January weekday)



Further information regarding the drivers for vehicle uptake, and charging behaviours and consumption, is provided in the CSIRO report[82].

3.3.6 Fuel-switching and alternative gas production

Input vintage	June 2023
Source	CSIRO and CWC/AEMO
Updates since Draft IASR	Updates of fuel-switching to hydrogen and biomethane including reduced hydrogen blending into distribution networks in *Green Energy Exports*, and development of the *Electrification Alternatives* sensitivity.

To achieve the emissions reductions targets outlined in the scenario narratives, fuel-switching away from fossil fuels is required over time in all sectors. Natural gas can be substituted by electricity (discussed in Section 3.3.5), as well as low or zero emissions molecular fuels such as hydrogen, biomethane or renewable LPG. This section reports the forecast activities to fuel-switch from solid, liquid and gaseous fossil fuels to alternative fuels, particularly those that are low or zero emissions alternatives to electrification.

Hydrogen production

Domestic hydrogen use

Significant hydrogen production announcements have been made across the eastern states of Australia, as evidenced by CSIRO's HyResource[83] listing of projects. Although every state has outlined hydrogen strategies the cost, timing and magnitude of an eventual hydrogen economy within Australia is highly uncertain. Hydrogen

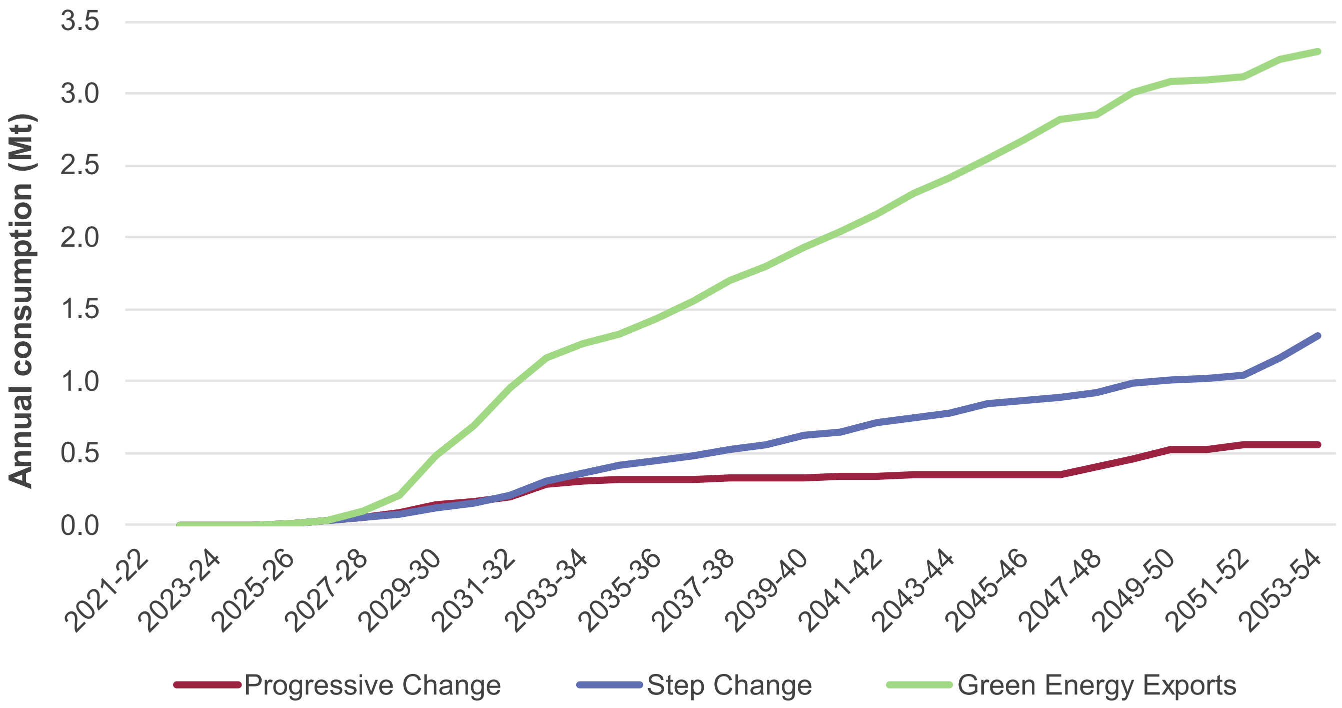
[82] CSIRO. Electric vehicle projections 2022, at https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

[83] CSIRO, HyResource, at https://research.csiro.au/hyresource/.

developments though may be significant in affecting the needs of the power system, and AEMO considers various hydrogen futures within the 2023 IASR scenarios.

The assumed hydrogen production for domestic use (including the transport sector) in the NEM regions is forecast within the multi-sector modelling, where it was an endogenous variable, and is shown in Figure 17.

Figure 17 Domestic hydrogen consumption across NEM (all sectors, including transport)



Hydrogen uptake is lowest in *Progressive Change*, due to lower economic activity assumed in that scenario and less technological improvements that may lower the cost of emerging technologies such as hydrogen electrolysis. *Step Change* sees moderate consumption of domestic hydrogen, mostly in the industrial and transport sectors, complementing electrification and biomethane trends. The *Green Energy Exports* scenario has the strongest uptake, due to a high learning rate driving down costs; in this scenario, hydrogen volumes are boosted by significant exports.

The hydrogen forecast in the residential and commercial sectors reaches 8-10% (by volume) in distribution pipelines by 2030 in all scenarios. All scenarios assume that a 10% hydrogen blending share (by volume, equivalent to approximately 3% by energy content) by 2030 is technically possible without physical modifications to the gas distribution system or material impacts to gas appliance operating conditions. This level of distribution blending is consistent with near-term government aspirations and current developments (for example, Hydrogen Park South Australia, Hydrogen Park Gladstone, HyP Murray Valley).

Industrial gas supply is forecast to reach between 40-80% hydrogen (by volume, equivalent to approximately 16-54 % by energy content) by 2050 across the scenarios, assuming that hydrogen-compatible pipelines supply industry hubs directly from local electrolyser facilities.

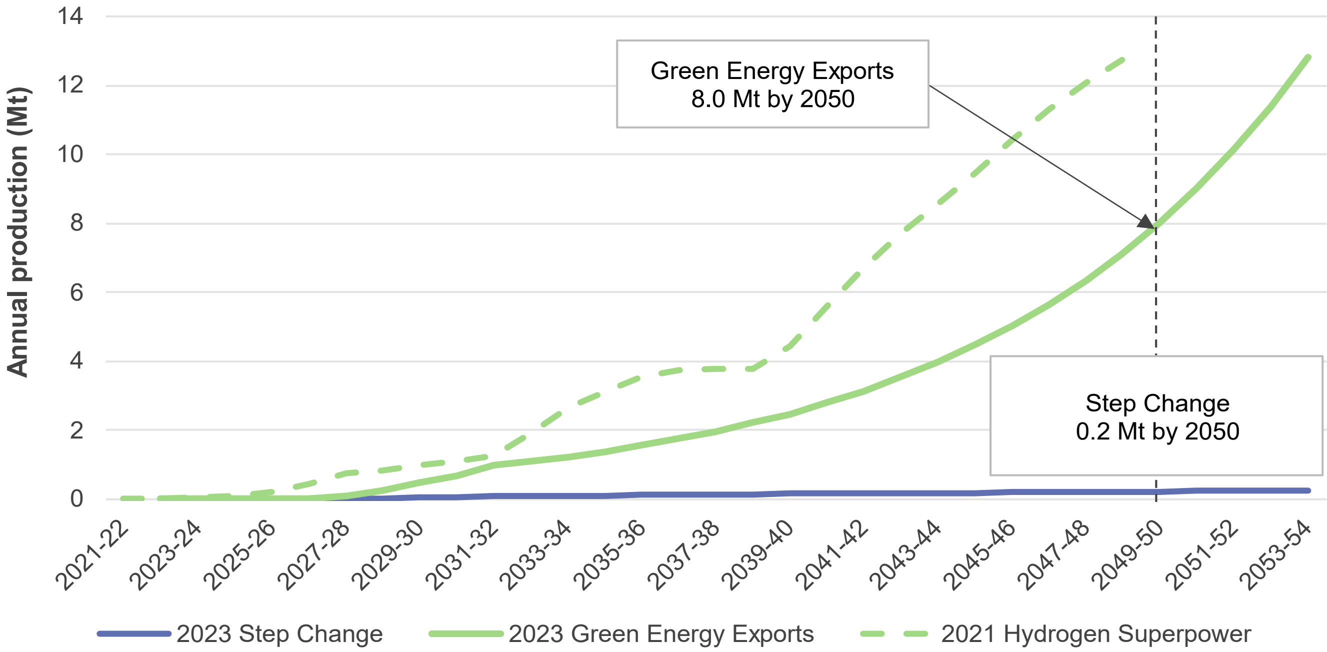
Export hydrogen

Australia is considered well placed to export green hydrogen to its international neighbours, due to high quality renewable energy potential and a history as a reliable international energy and resource supplier. Several Australian states have developed plans for construction of hydrogen export facilities, making use of existing and expanded port infrastructure[84].

The assumed quantities of NEM-connected export hydrogen are shown in Figure 18. Note that no export hydrogen is assumed in the *Progressive Change* scenario.

Export hydrogen in the NEM assumed in this 2023 IASR is lower than the 2021 IASR's *Hydrogen Superpower* scenario. Based on stakeholder feedback from the 2021 IASR and 2022 ISP, AEMO now considers that the 2021 IASR scale of hydrogen development is beyond the reasonable bounds of scenario planning for AEMO's purposes. The *Green Energy Exports* scenario continues to provide insight on the impact of a material hydrogen industry in planning the future needs of the NEM. In this scenario, export hydrogen facilities are assumed to develop within the NEM, with half of these facilities grid-connected, to achieve a scale of production commensurate with Australia's current share of global LNG demand. The assumed global hydrogen demand in *Green Energy Exports* reflects the forecast corresponding to the IEA-WEO 2021 NZE scenario.

Figure 18 Export hydrogen production across NEM



The *Progressive Change* scenario assumes that the NEM connects no hydrogen export facilities.

Biomethane

Biomethane blended into transmission or distribution gas pipelines has the potential to offset natural gas use. Natural gas consumption forecasts will therefore be influenced by the availability of biomethane. Biomethane production is currently very low, and it therefore represents a potential alternative fuel source, with high forecast uncertainty.

[84] See https://www.epw.qld.gov.au/about/initiatives/hydrogen/enabling-queenslands-hydrogen-production-and-export-opportunities-report and https://www.planning.nsw.gov.au/sites/default/files/2023-03/hydrogen-guideline.pdf.

Due to this uncertainty, each scenario's biomethane forecast, particularly in the short to medium term, is largely assumption driven tied to the scenario's narrative to emissions reductions. Small volumes of biomethane are assumed in *Step Change* while larger volumes are assumed in *Green Energy Exports.* A significant replacement of natural gas with biomethane is assumed in the *Electrification Alternatives* sensitivity.

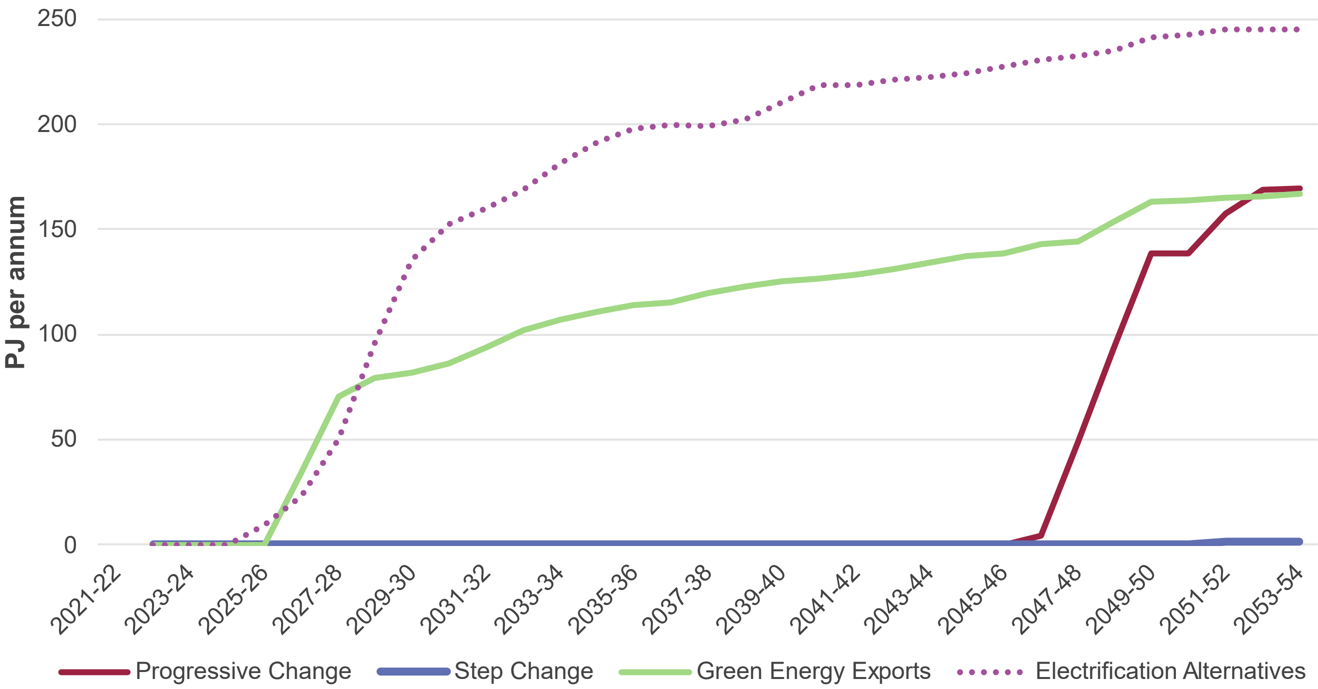
AEMO has reviewed a range of Australian reports on biomethane potential. The Bioenergy Roadmap[85] report's 'Targeted Deployment' scenario estimates that by 2030 up to 105 PJ per annum of supply could exist in the existing gas pipeline network, with an additional 240 PJ of biomethane available for industrial heat.

In the same report, the 'Business As Usual' scenario, over one-third (355 PJ) of the long-term sources in NEM regions identified are organic wastes and residues, which may provide consistent year-round energy with minimal seasonality constraints and would represent a near-zero emission fuel supply of renewable gases[86] and solid fuels.

In terms of current biomethane volume close to pipelines in the NEM jurisdictions, the Future Fuels[87] study finds 45 PJ per annum within modest distance. The same report indicated a volume weighted price of approximately $23/GJ (excluding network costs) which may present, for certain industries, an attractive alternative relative to the capital and operational costs of electrification.

Biomethane features in the *Green Energy Exports* scenario, and is explored further in the *Electrification Alternatives* sensitivity.

Figure 19 Biomethane use by scenario (including the *Electrification Alternatives* sensitivity)



85 See https://arena.gov.au/assets/2021/11/australia-bioenergy-roadmap-report.pdf.

86 Organic wastes and residues include biogas from landfill, sludge, and other biogas captured for combustion, with a near zero scope 1 emission factor.

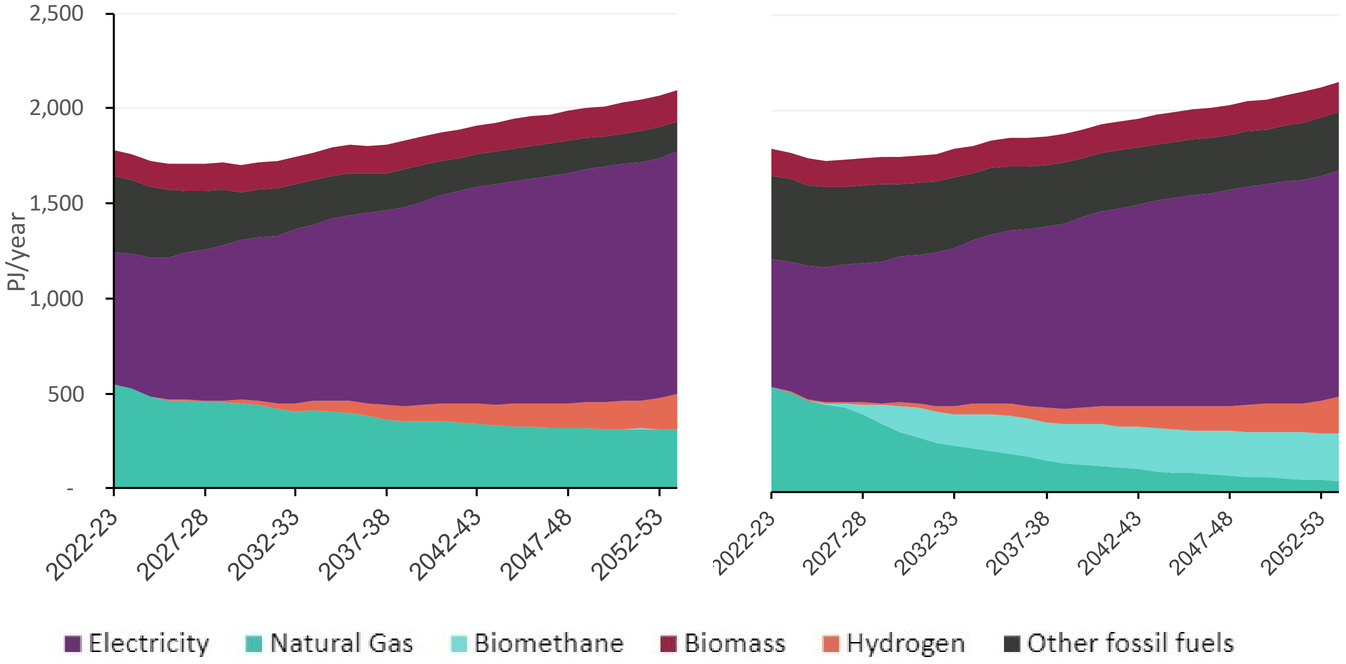
87 See https://www.futurefuelscrc.com/wp-content/uploads/RP1.2-04-BiomethaneViability_summary.pdf.

Electrification Alternatives sensitivity

As discussed in Section 3.3.5, existing parts of Australia's economy use energy intensive processes that may not be technically or commercially capable of electrification in the near term. A clear electrification alternative for these industrial processes will be to replace the molecular or fossil fuel (oil, diesel, coal etc) feedstocks with low or zero emissions molecular alternatives, including biomethane and hydrogen.

As outlined in Section 2.3.1, AEMO has developed an *Electrification Alternatives* sensitivity to explore the impact of delayed and deferred industrial electrification; Figure 20 compares the resulting fuels used in NEM regions (across all economic sectors) in the *Step Change* scenario to this sensitivity.

Figure 20 Fuel-switching in the *Step Change* scenario (left) versus *Electrification Alternatives* sensitivity (right)



The figures show the impact on energy shares with the assumed change affecting industrial electrification. In this sensitivity, increased biomethane adoption provides an offset to delayed actions to switch away from fossil fuels.

3.3.7 Consumer energy resources

Input vintage	May 2023
Source	• CSIRO • Green Energy Markets • Clean Energy Regulator
Updates since Draft IASR	Consultant forecasts from 2022 have been rebased using actuals from the Clean Energy Regulator.

CER predominantly describes consumer-owned devices that can generate or store electricity as individual units and which may be passive but also may have the 'smarts' to actively manage energy import and export. It can also refer to consumer shared devices, such as community batteries and other resources that enable greater demand flexibility.

These CER forecasts include small-scale embedded generation such as residential and commercial rooftop PV systems (less than 100 kW), battery storage, and EVs (described already in Section 3.3.5). Larger PV systems between 100 kW and 30 MW (referred to as PV non-scheduled generation, or PVNSG) may also be installed by larger energy consumers, or may be driven by opportunities to generate energy, much like a utility-scale generator installed in the transmission system. For the purposes of the 2023 IASR, the PVNSG forecasts are included in this section.

In AEMO's forecast, CER (including PVNSG) captures household energy technologies, larger systems representing either small-scale commercial systems, community schemes, or any other embedded system within the distribution system that is not a scheduled resource in the NEM dispatch system.

Given the importance of CER (including PVNSG) and the opportunity it presents to the energy sector, AEMO obtained forecasts from CSIRO and Green Energy Markets (GEM) to provide greater confidence than a single forecast. The two consultant forecasts utilise the same underlying assumptions and scenario narratives, and encompass usage patterns and uptake rates.

The two consultants' forecasts were selected according to Table 18 below, with 'average' indicating a simple average of GEM and CSIRO.

Table 18 Consultant scenario mapping for CER

Scenario	*Green Energy Exports*	*Step Change*	*Progressive Change*
PV forecast mapping	GEM	Average	CSIRO
PVNSG forecast mapping	GEM	GEM	CSIRO
Battery and VPP forecasts mapping	Average	Average	CSIRO

The consultant forecasts were selected based on best match with the scenario narratives, retention of appropriate forecast relativities between scenarios, and suitability in reflecting the uncertainty inherent in long-term forecasts.

CSIRO's outlook was more closely aligned with the lower starting assumptions of *Progressive Change*, while the elevated outlook seen in GEM's forecasts best represented the ambitious assumptions of the *Green Energy Exports* scenario. AEMO considers that averaging PV, battery and VPP forecasts for *Step Change* provides a balanced view of outlooks, and maintains an appropriate relationship with the 2021 IASR forecasts.

Details of assumptions underpinning each consultant's forecasts are provided in their reports that supplement this IASR (see Appendix A2).

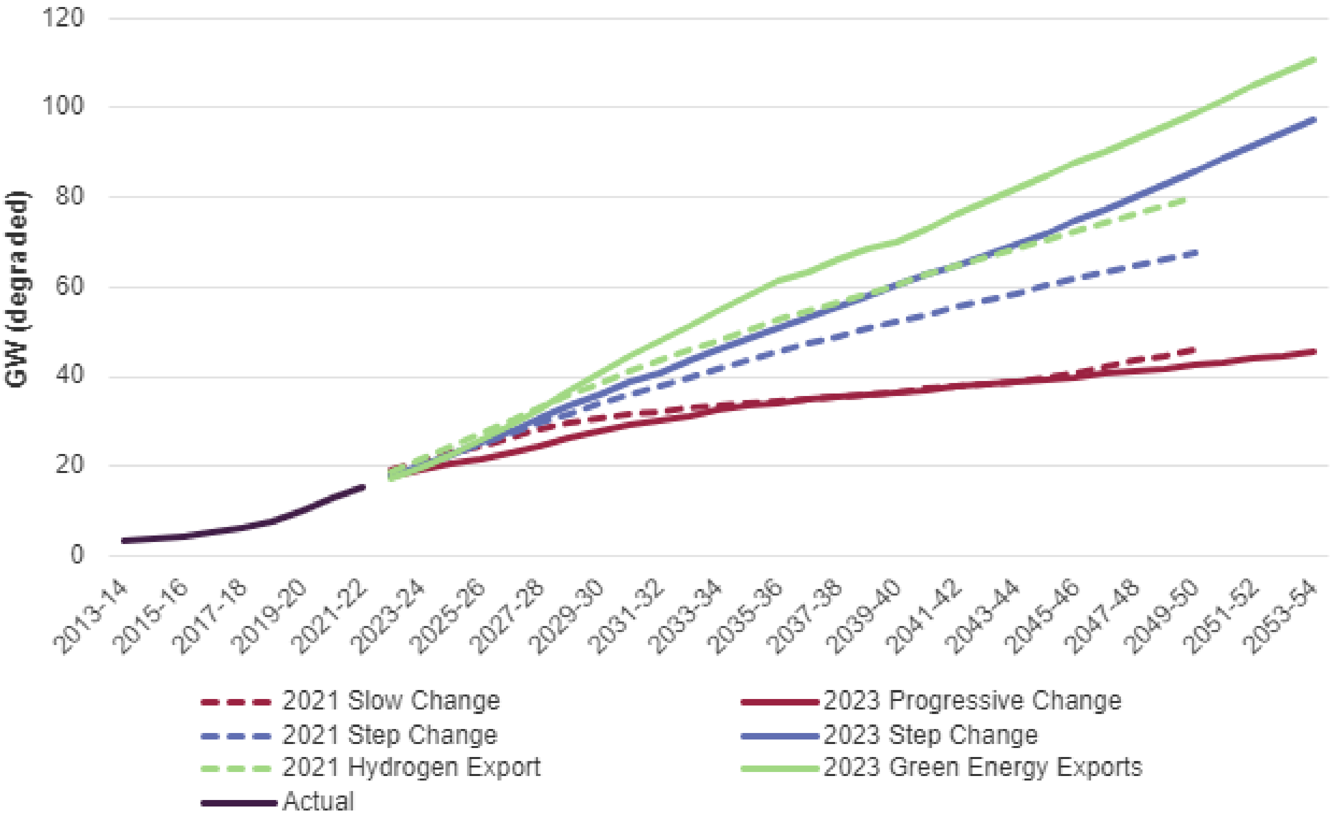
Distributed PV

Distributed PV systems, including residential and commercial rooftop PV, and larger embedded PVNSG systems, have in aggregate grown by approximately 2.3 GW over the 2022 financial year across the NEM, leading to a total existing NEM capacity of about 15.3 GW. All scenarios include ongoing growth in PV. Owner occupied houses (a prime candidate for PV installation) currently have around 35% PV uptake, and in 2050 that increases to between 70 and 90% across scenarios. Some detached dwellings will be impeded by shading or ownership considerations (rental premises may be less likely to invest in PV systems without alternative financial models), and the forecasts recognise the increasing opportunity for PV installations to occur on other dwelling types, such as townhouses, terraces, and to a lesser extent apartments, as well as increasing potential uptake for detached rented dwellings.

The methods for forecasting PV uptake assume consumer benefit decision-making, whereby an appropriate payback hurdle must be overcome considering a broad range of consumer and dwelling types. However, even with a strong financial pay-off of solar installation, the above does not assume that all home owners choose to install solar panels, as the life of a PV system is relatively long[88] relative to median housing ownership holding periods (10 years for New South Wales[89]), and so the owners that choose to install solar panels have a broader impact than the duration of their current home ownership.

Figure 21 shows the projected cumulative PV capacity installed across the NEM for each scenario according to the scenario mapping in Table 18. Compared to the 2021 IASR, the 2023 IASR distributed PV forecasts reflect a slowdown in the short term, influenced by post-pandemic spending habits and supply chain constraints, and a greater long-term uptake trajectory, influenced by a forecast reduction in the cost of PV systems. The forecasts shown reflected the degraded capacity, reflecting that panels will reduce in their efficiency and effectiveness over time, and they also recognise the increase in average system size on replacement.

Figure 21 Actual and forecast NEM distributed PV installed capacity (degraded) by scenario, 2014 to 2054



Battery storage uptake

Distributed residential and commercial battery systems have the potential to materially change the future demand profile in the NEM, particularly the maximum and minimum demand of the power system. The extent of this impact depends on a number of factors, including:

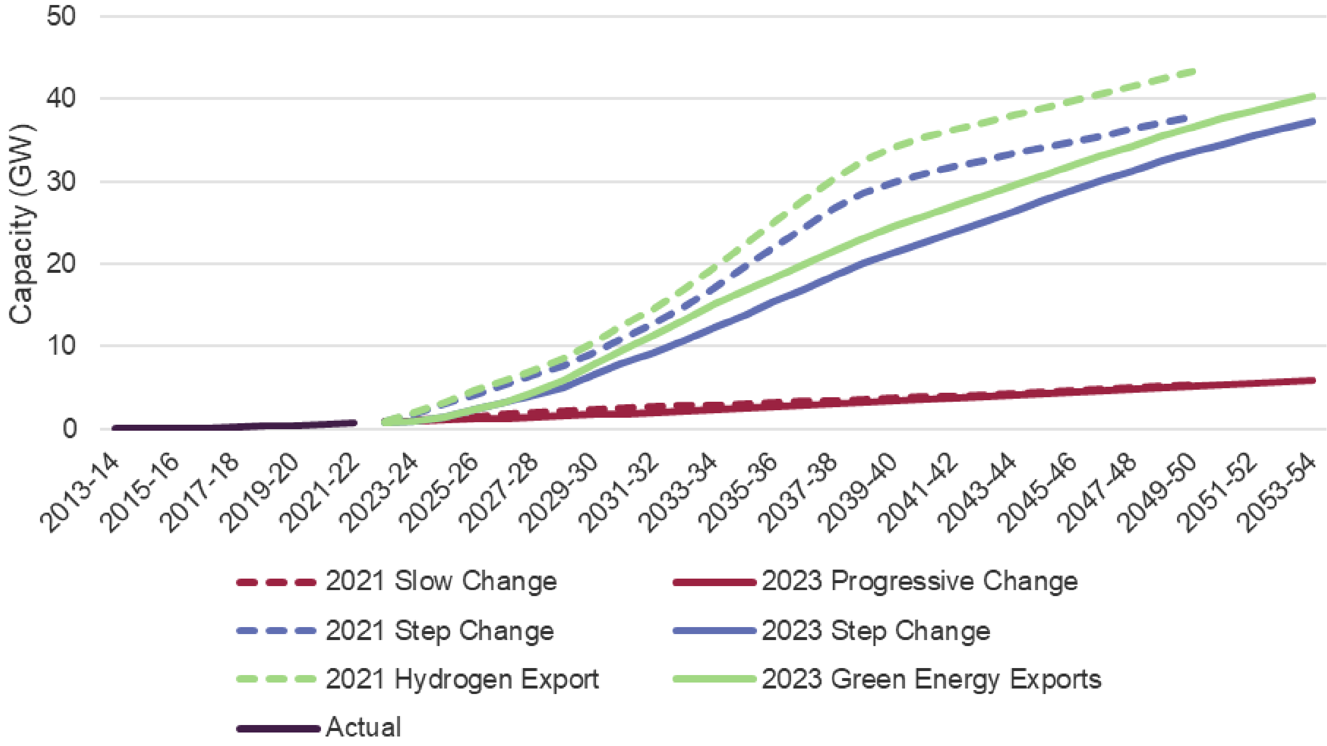
[88] PV panels may have an effective lifespan as long as 25-30 years, sufficiently long that a PV system's life may include inverter equipment replacement at its end of life (approximately 10-15 years) to extract maximum value from the panels' lifespan.

[89] See https://www.treasury.nsw.gov.au/sites/default/files/2022-04/trp22-13-holding-periods-of-residential-property-buyers-in-nsw.pdf.

- The energy storage capacity (kWh), and charge/discharge power (kW) of the battery system installed.
- The capacity of any PV system installed at the same premises, and the volume and timing of energy consumption of the household or business.
- The uptake of VPP programmes, whereby aggregator organisations remotely influence battery operation, to achieve energy system goals either directly or via suitable pricing

Figure 22 shows the total forecast installed capacity of distributed batteries across the NEM for all scenarios. The 2023 IASR forecasts are moderated by lower than anticipated year-on-year growth of small-scale batteries to date, and a lower reduction of battery capital costs in the short term as forecast by the *GenCost 2022-23 Final report*[90] technology cost forecasts, resulting in slower growth relative to the 2021 IASR forecasts.

Figure 22 Distributed battery forecasts for the NEM



Aggregated energy storage – virtual power plants

A VPP broadly refers to the involvement of an aggregator to orchestrate CER via software and communications technology, to deliver energy services similar to large-scale inverter-based generation and storage developments. This is in contrast to typical household battery installations which are configured to offset household energy costs by reducing the volume of grid supplied energy and increase self-consumption of complementary PV generation.

AEMO continues to collaborate across the industry to establish VPP demonstrations and identify the role VPPs could have in providing reliability, security, and grid services. While VPPs in the NEM are currently operating at a small scale, VPP trials are demonstrating the potential value to the grid if deployed at scale, and the value to participating consumers.

[90] At https://www.csiro.au/en/research/technology-space/energy/energy-data-modelling/gencost.

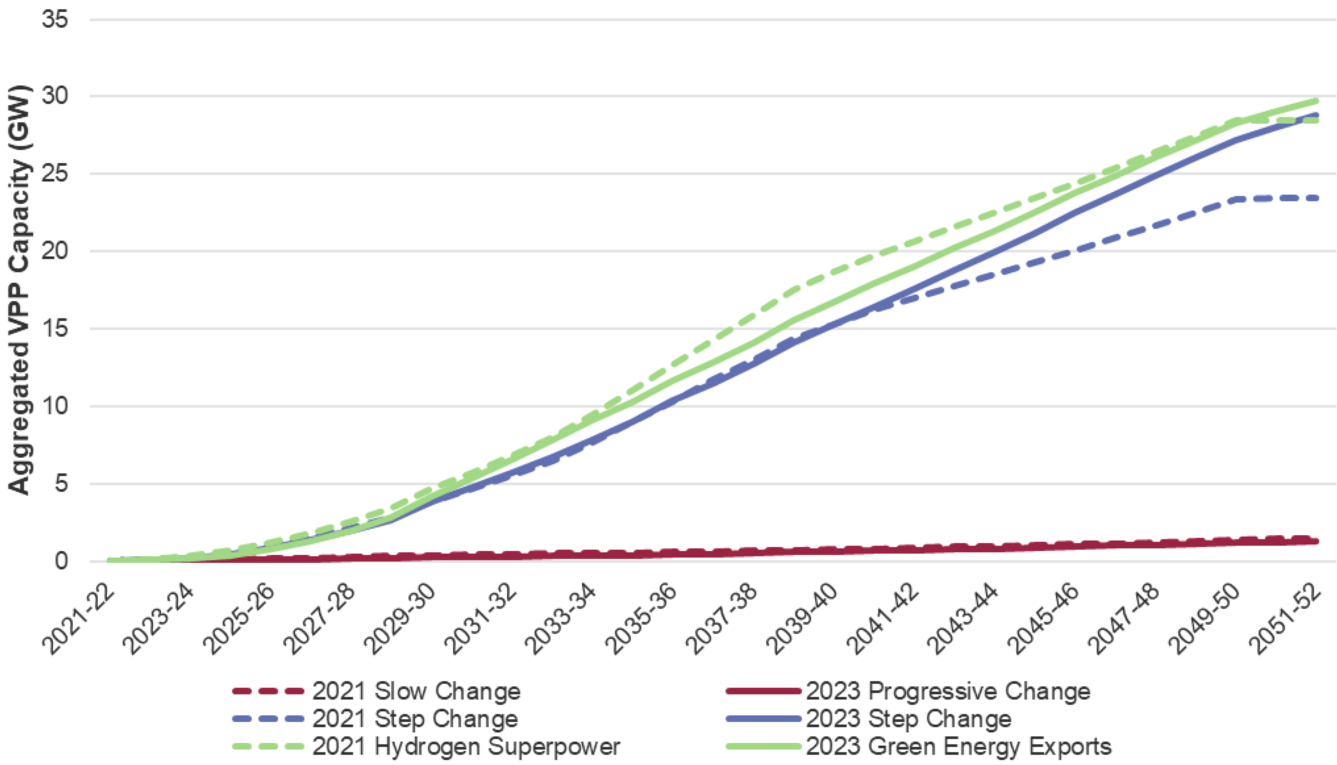
The role of orchestrating CER to provide energy for the power system at large will be a significant influence on the scale of network and utility scale investments needed to maintain reliability, security and affordability through the energy transition. Consumer resources that increase load flexibility and provide reliable capacity to meet system peaks will offset other investments.

The *Step Change* scenario assumes that financial incentives will be provided by aggregators to provide for orchestration of battery charging and discharging profiles. In this way, VPP schemes offer to positively increase the uptake of distributed batteries, particularly if financial incentives sufficiently reduce consumer investment costs.

AEMO has developed a *Low CER Orchestration* sensitivity to investigate the impacts on power system needs of a lower uptake of CER relative to the *Step Change* scenario. This sensitivity considers a future with less operational effectiveness of VPP programs and therefore, correspondingly lowering levels of CER orchestration.

The VPP capacity forecast in the NEM is shown in Figure 23. Assumed rates of customer adoption of VPPs have been revised downward slightly relative to the 2021 IASR forecasts, following stakeholder consultation.

Figure 23 Aggregation trajectories for VPP forecasts



Note: the *Low CER Orchestration* sensitivity tests the same distributed battery capacity as *Step Change*, but with no growth of VPP.

Hosting capacity for distribution-connected CER

AEMO and DNSPs recognise that strong PV penetration has changed the historical role of the distribution networks, and at times their direction of flow. This presents various operational challenges, and DNSPs are continuously analysing potential long-term solutions that will improve outcomes for consumers. Enabling CER uptake and operation is a strategic imperative of DNSPs to support consumers' contributions to the energy transition. Various solutions are emerging, such as dynamic export limits, and the customer export curtailment value which will provide a mechanism for appropriate network investment funding to enable further CER penetration. AEMO, in consultation with DNSPs, recognises and assumes that distribution networks will be appropriately augmented to facilitate the level of CER penetration and operation in any given planning scenario.

Continued collaboration between NSPs and AEMO remains important to enable the transition to net zero. Emerging and maturing technologies such as EVs and distributed batteries will increase network complexity and opportunity, leading to beneficial changes to the dynamics of PV generation on the distribution network. Further, orchestration of loads and small generation on DNSP networks may create opportunities to manage apparent loads at the transmission grid connection point.

3.3.8 Economic and population forecasts

Input vintage	July 2023
Source	• Oxford Economics Australia (OEA)[91] • ABS Population Series
Updates since Draft IASR	Economic forecasts from October 2022 have been rebased using ABS National Accounts data

In 2022, AEMO engaged OEA to develop long-term economic forecasts for each Australian state and territory as a key input to AEMO's demand forecasts.

Compared to other countries, the Australian economy performed reasonably well following the COVID-19 pandemic, with strong monetary and fiscal policy having propped up household incomes and supported domestic consumption in the short term. Strong global commodity prices for key mining inputs also contributed to the strength of the Australian economy through the pandemic. Despite this, Australia has not been immune to the supply shortages and high inflationary pressures seen globally as we continue to navigate the aftermath of the pandemic-driven slowdown. Global energy markets have also been affected by the ongoing Russia-Ukraine conflict. In response, the Reserve Bank of Australia started lifting the official cash rate in May 2022[92], earlier than previously expected, and has continued to do so well into 2023[93].

To capture some of these recent trends, the OEA forecasts were rebased using the financial year 2021-22 Australian Bureau of Statistics (ABS) National Accounts release[94].

[91] *BIS Oxford Economics* was renamed *Oxford Economics Australia* in May 2023, and is referred to throughout this 2023 IASR as OEA. This change of trading name does not impact the relevance or appropriateness of any inputs or assumptions provided to AEMO.

[92] The first increase to the cash rate was 3 May 2022. See statement by Philip Lowe, Reserve Bank Governor, at https://www.rba.gov.au/media-releases/2022/mr-22-12.html.

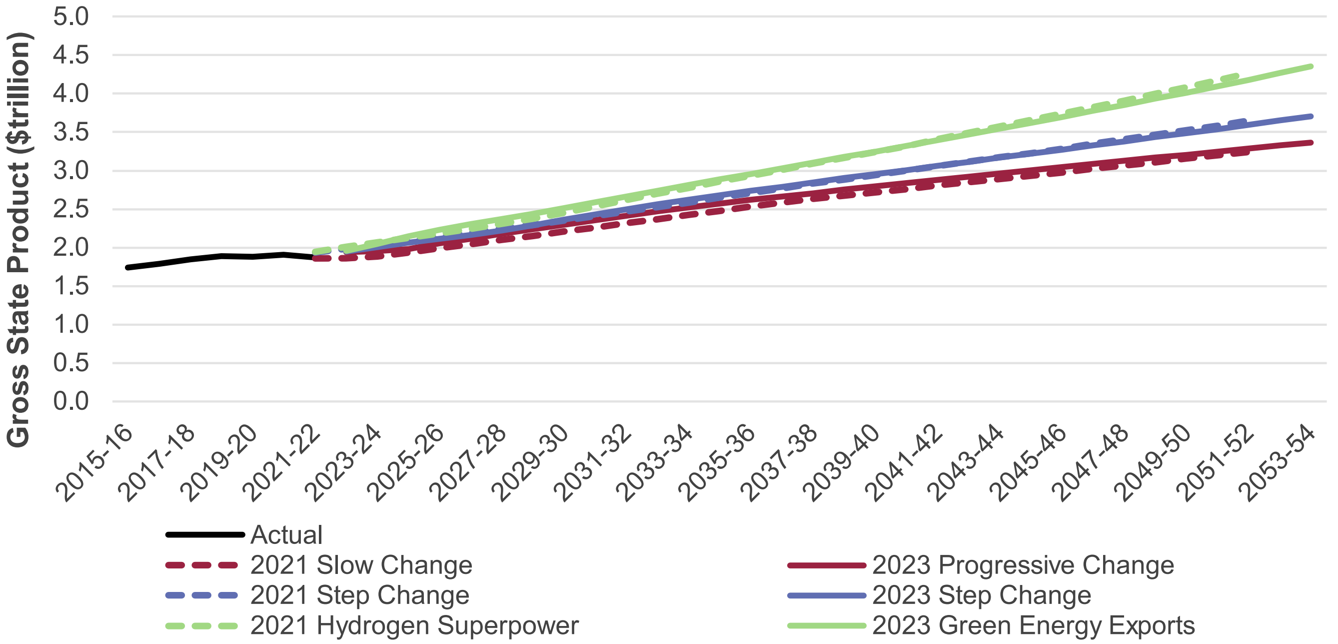
[93] See statement by Philip Lowe, Reserve Bank Governor, released 6 June 2023, at https://www.rba.gov.au/media-releases/2023/mr-23-13.html.

[94] Oxford Economics Australia forecasts were rebased using the Australian Bureau of *Statistics Australian System of National Accounts, 2021-22 financial year* release, at https://www.abs.gov.au/statistics/economy/national-accounts/australian-system-national-accounts/2021-22.

Australia's net zero emissions commitment is intended to accelerate the structural change set to impact the Australian economy. In the OEA forecasts, the mining sector is expected to continue to see strong growth during the transition, before projected growth in emissions-intensive sectors decline and growth in the services sectors dominates the outlook. In most scenarios, Australia is expected to outperform many other developed economies in the long term, driven by strong net overseas migration. Further detail for the OEA forecasts is contained in the accompanying report[95].

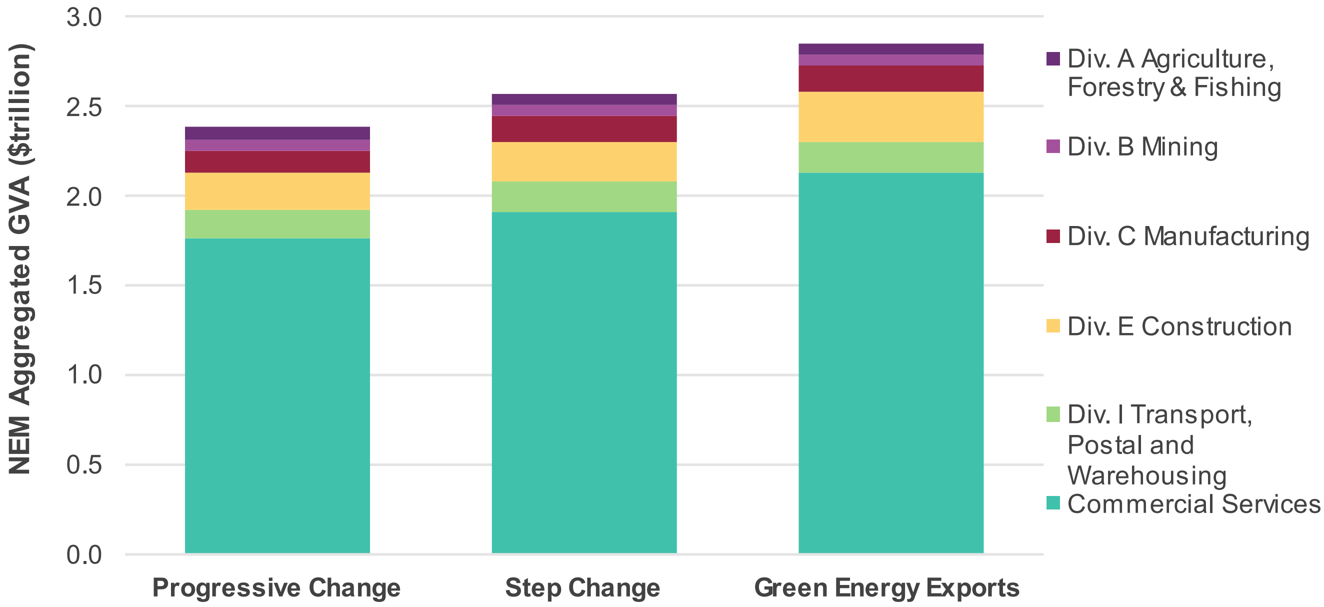
Figure 24 shows the rebased forecast economic outcomes for gross state product (GSP) of the aggregated NEM regions, demonstrating the uncertainty across the scenarios. Figure 25 further provides a breakdown of the relative economic activity of each sub-sector, demonstrating the forecast economic significance of the commercial services sector and the relative sectoral breakdowns across scenarios in 2042-43.

Figure 24 NEM aggregated gross state product forecast for NEM regions



95 Oxford Economics 2022 Macroeconomic Projections Report: Final, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/bis-oxford-economics-2022-macroeconomic-outlook-report.pdf.

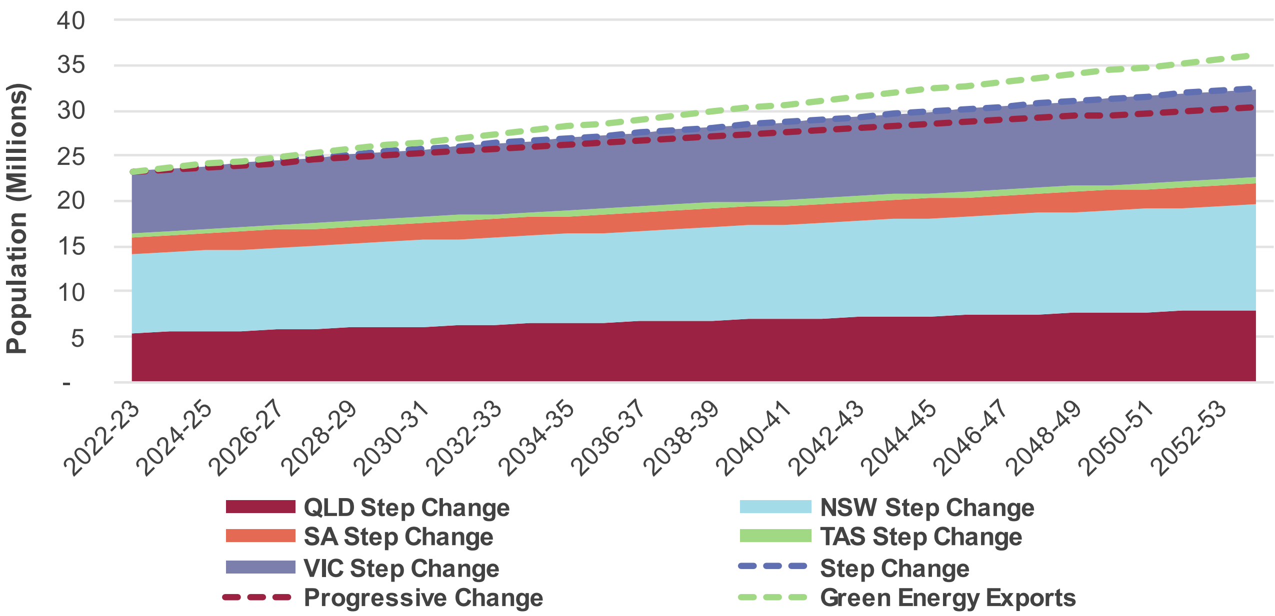
Figure 25 2042-43 NEM aggregated gross value added (by ANZSIC division)



Population growth is also a key driver of Australia's economic growth. OEA produces its own forecasts for AEMO, using ABS death rates and its own assessments for fertility rates, net overseas migration (NOM), and net interstate migration (NIM)[96].

Figure 26 demonstrates the population forecast across the NEM regions in *Step Change*, and the relativity of the other scenarios in aggregate.

Figure 26 NEM aggregated population forecast



[96] A comparison of OEA's population forecast and assumptions against the Centre for Population's 'Population Statement' can be found in the 2022 Macroeconomic Projections Report, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/bis-oxford-economics-2022-macroeconomic-outlook-report.pdf.

The population forecast is largely unchanged from the 2021 IASR forecasts, with the international border re-opening broadly lining up with expectations and fertility rate assumptions remaining roughly the same. However, state compositions were revised, with outwards NIM for New South Wales and Victoria increasing in the short term compared to the 2021 forecasts. Additionally, the 2022 OEA forecasts include historical revisions back to 2016-17 following the release of the 2021 Census data. NOM lost during the pandemic is not expected to be recovered in the future, although from 2022-23 international migration has returned to the long-run average. In the long term, Queensland is expected to be the relative winner out of the NEM regions, with strong forecast population growth driven by greater interstate migration and a positive labour market outlook. Under the *Step Change* scenario, NEM aggregated population is expected to increase by ~8.9 million people from 2023-24 to 2053-54.

3.3.9 Households and connections forecasts

Input vintage	July 2023
Source	• ABS • OEA • AEMO meter database
Updates since Draft IASR	Updated with AEMO's latest actual connections data

AEMO's forecast of residential electricity consumption is mainly driven by forecast growth in electricity connections. As Australia's population increases, so does the expected number of new households which require electricity connections.

Economic activity and migration (described in the previous section) has a positive influence on the domestic population. The Australian population forecast is relatively unchanged compared to the 2021 projections, as past forecasts of the timing of the relaxation of border restrictions has been reasonable. This updated forecast also recognises updated historical information released as part of the 2021 Census.

AEMO's 2023 connections model incorporates this updated population forecast and uses connections data from AEMO's metering database to project the number of residential connections. In the short term, AEMO's updated forecast indicates a decrease compared to the 2021 projection, with a decline of approximately 112,000 connections expected by 2026-27 under the *Step Change* scenario. This decline is primarily attributed to a projected downturn in construction activity driven by unfavourable short-term economic conditions and supply chain limitations impacting the construction sector. Stronger growth is forecast post 2027, due to increased construction activity, supported by more favourable economic conditions domestically and assumed relief of current supply chain bottlenecks.

Figure 27 shows the residential connections actual and forecast for all scenarios across the NEM, and Figure 28 shows the aggregated forecast dwellings growth for the NEM regions.

Figure 27 Actual and forecast NEM residential connections, all scenarios, 2015-16 to 2053-54

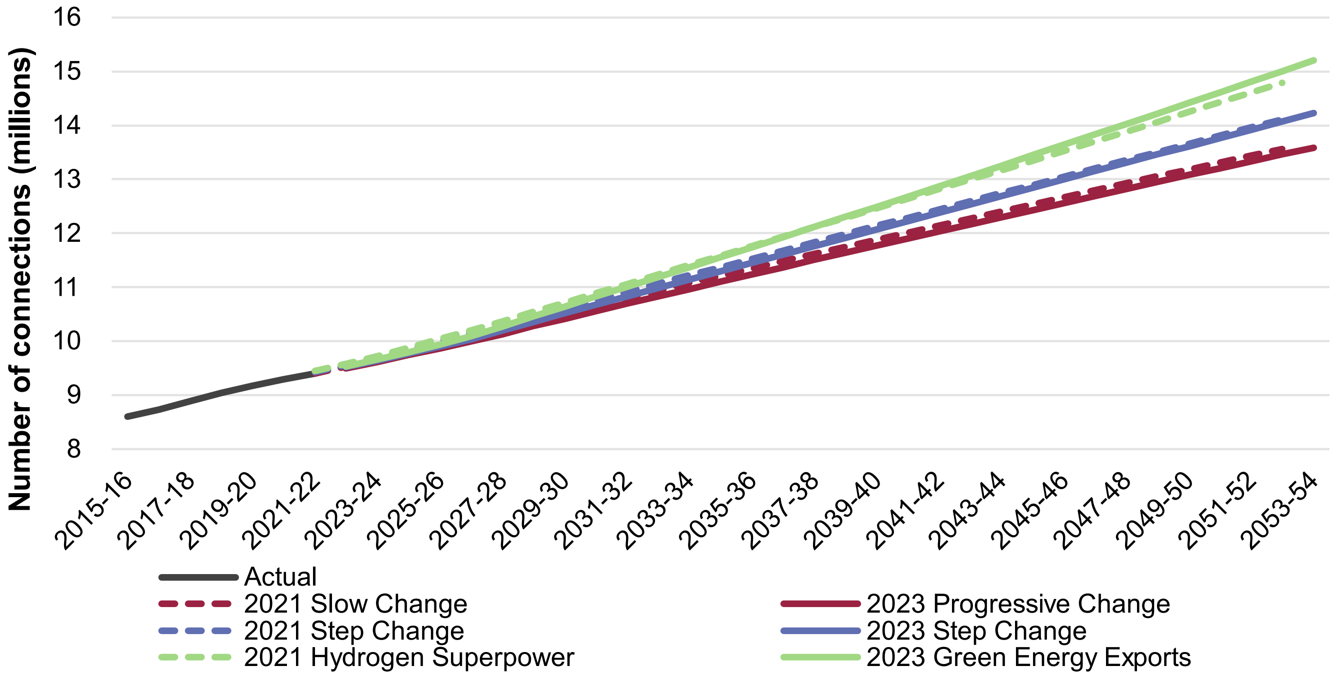
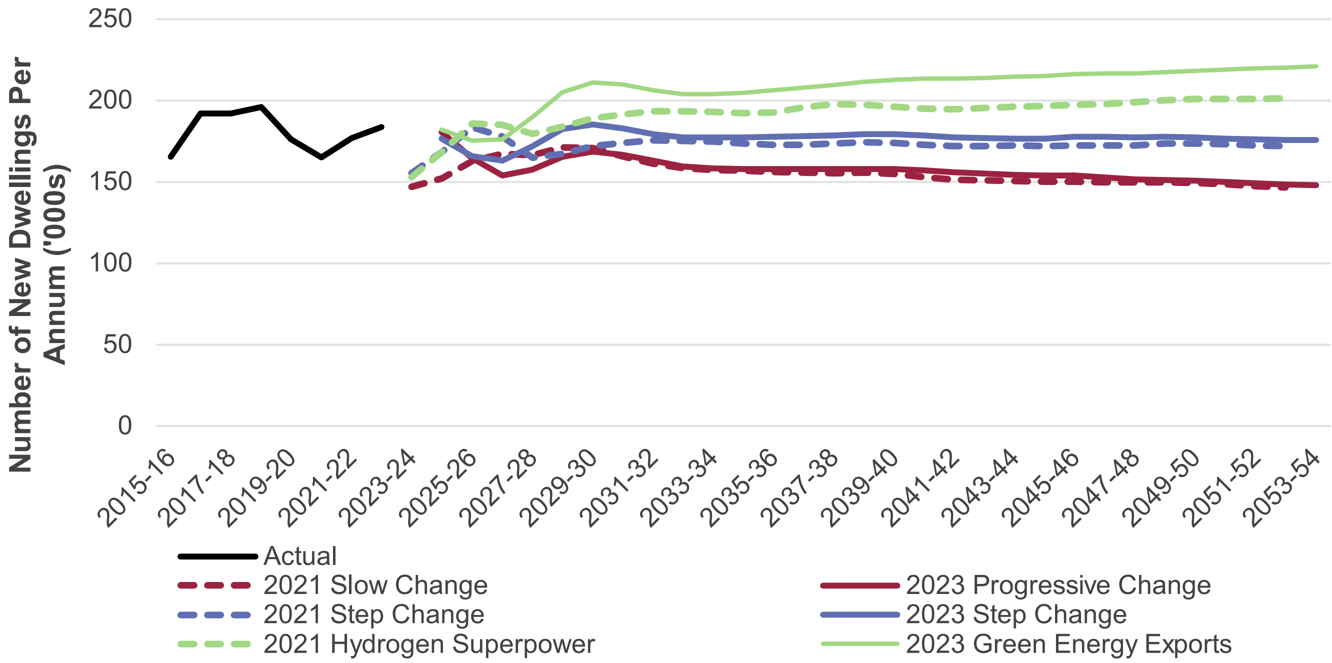


Figure 28 Actual and forecast NEM aggregated dwellings growth per annum, all scenarios, 2015-16 to 2053-54



3.3.10 Large industrial loads

Input vintage	June 2023
Source	• Surveys/Interviews • AEMO meter database • Network service providers • LIL forecasts of multi-sector modelling • Economic outlook • Media search/announcements
Updates since Draft IASR	Further refinement of survey responses from individual LILs

AEMO forecasts LILs separately from small and medium commercial enterprises, due to their significant contribution to overall energy consumption, and the fact that individual business circumstances may not be appropriately captured in broader econometric models. LILs are defined as loads over 10 MW at least 10% of the time.

AEMO currently sources information regarding LILs from:

- Historical data at the NMI level.
- Surveys and interviews, with surveyed loads provided with forecast conditions consistent with the economic outlook provided by OEA to increase survey consistency.
- AEMO's standing data requests from network service providers (NSPs) regarding prospective and newly connecting loads.
- Media searches and company announcements.

The LIL forecasts therefore capture the expected consumption of the largest existing, new and prospective industrial customers.

Prospective large industrial loads which are committed projects[97] have been included in the forecasts from the expected start-up dates, and provide a minimum growth rate of LILs for all scenarios. When information on the expected energy consumption on these prospective projects has not been provided, assumptions have been made around the load factors for those projects consistent with existing similar industrial loads.

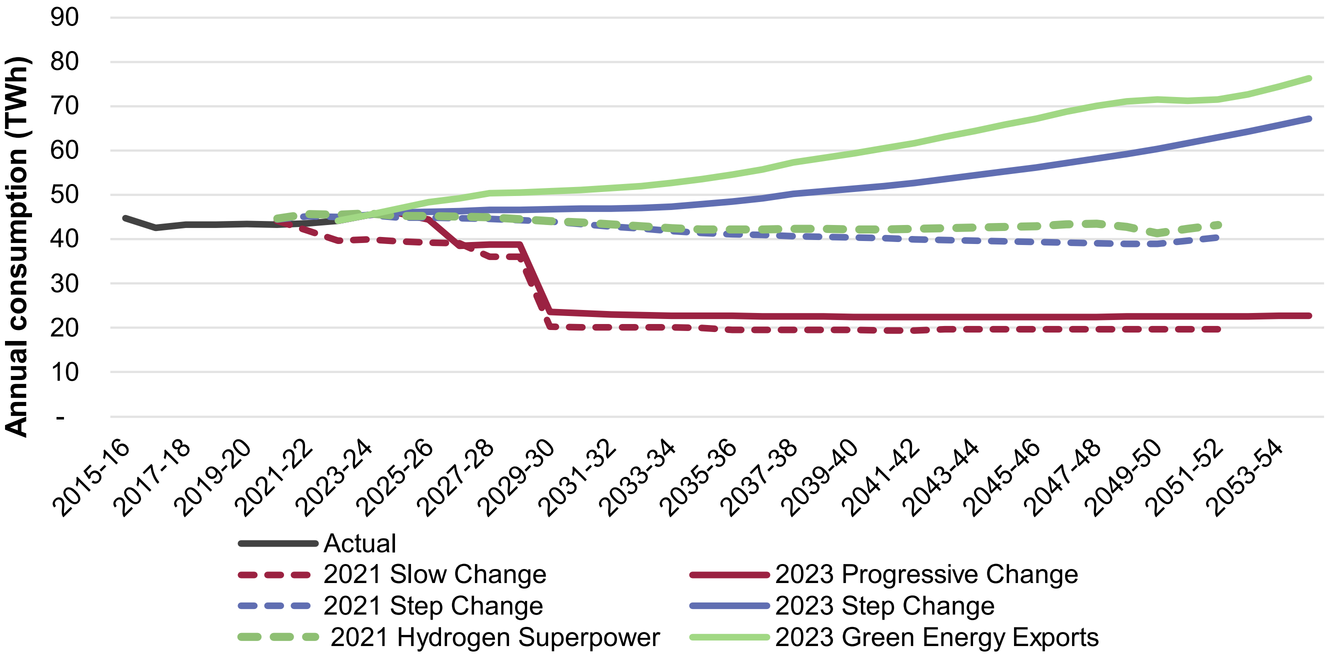
Figure 29 compares the LIL electricity consumption forecast to the 2021 forecasts. In the short to medium term, the 2023 IASR forecasts an increase in electricity consumption from planned expansions across the NEM.

In the medium to long term, the forecasts are informed by projected growth from mining and manufacturing sectors, driven by decarbonisation objectives and declining electricity costs, particularly from renewables.

To reflect the scenario's description of challenging economic conditions and to explore overinvestment risks associated with electricity system investments, the *Progressive Change* scenario considers closure risks for major electricity consumers in the short to medium term, although incorporates electrification forecasts in the longer term leading to rebounding consumption growth across the load category.

[97] See Section 2.1 of the 2022 Electricity Demand Forecasting Methodology for criteria on committed projects, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/forecasting-approach-electricity-demand-forecasting-methodology.pdf.

Figure 29 2023 NEM LIL electricity consumption forecast



Liquified natural gas

Queensland's LNG industry is a material contributor of existing industrial electricity loads, consuming approximately 5% of AEMO's total business consumption category in the NEM.

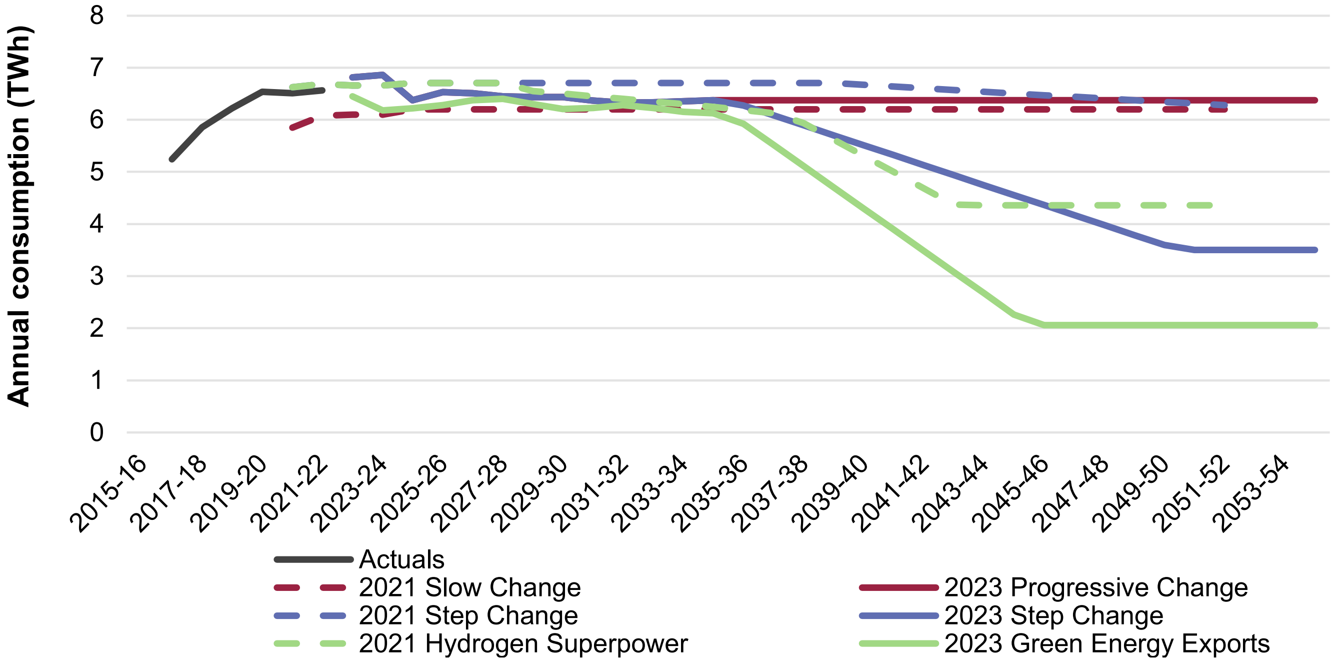
The LNG forecasts estimate the expected electricity consumption of the operations of coal seam gas (CSG) fields operating in the NEM by considering surveyed data provided by the LNG consortia, as per other LILs. This data considers the anticipated operating range of CSG facilities over the short to medium term. The longer-term forecast is developed by extending the surveyed trend across the scenario collection, applying assumed global trends for each scenario.

The international LNG market faces an uncertain future. Global demand for liquid fuels will shift as each country determines how it will achieve its own decarbonisation commitments, with some commentators predicting ongoing strong growth through until 2050 and others predicting a notable decrease[98]. For the NEM's LNG exports facilities in Queensland, AEMO considers that market conditions are unlikely to be conducive to any major new infrastructure to increase export capacity – and the existing LNG export facilities already operate at high utilisation factors. AEMO therefore considers that the upper range of reasonable forecasts for LNG operations is for operations to continue at current high utilisation levels.

Figure 30 below shows the LNG forecast for electricity consumption that was applied in the 2021 IASR, compared to the latest forecast estimates based on survey data provided by the Queensland LNG consortia, calibrated to the LNG export forecasts used in the 2023 GSOO. The range of scenario forecasts reflects the varying global economic and decarbonisation pathways across the scenarios, and the resulting impact on international gas consumption.

[98] The International Energy Agency outlined an uncertain future for LNG; see International Energy Agency (2021), *Net Zero by 2050: A roadmap for the Energy Sector*, at https://www.iea.org/reports/net-zero-by-2050.

Figure 30 LNG electricity consumption forecast



3.3.11 Energy efficiency forecast

Input vintage	July 2023
Source	• Strategy Policy Research (SPR) • CSIRO and CWC Multi-sector modelling
Updates since Draft IASR	Policy-driven energy efficiency forecasts have been updated through consultancy. The methodology, input assumptions and draft forecast by SPR were presented to FRG in March 2023.

For the 2023 IASR, AEMO undertook two separate approaches to modelling energy efficiency. Outcomes from the multi-sector modelling conducted by CSIRO-CWC illustrated the role of energy efficiency under varying decarbonisation pathways, using a combination of annual uptake rates by sector and technology[99], and scenario-specific variations based on relativities observed in the IEA WEO 2021 scenarios.

AEMO also engaged SPR to model policy-led energy efficiency savings expected to be delivered by federal and state government measures and market-led energy efficiency likely to occur without policy intervention. Where available, forecast savings and advice from relevant government departments were considered in SPR's forecasts. The forecasts also considered the effects of non-realisation of reported potential savings as well as non-additionality[100] across overlapping policy measures. Where a policy will also encourage fuel-switching from gas to electricity, the associated electrification impacts were generally accounted for as effective negative estimated energy efficiency savings for electricity.

[99] Based on ClimateWorks Australia's (2014) Deep Decarbonisation Pathways Project, at https://www.climateworkscentre.org/wp-content/uploads/2014/09/climateworks_pdd2050_initialreport_20140923-1.pdf and ClimateWorks Australia's (2016) Low Carbon. High Performance: Modelling Assumptions, prepared for ASBEC (Australian Sustainable Built Environment Council), at https://www.asbec.asn.au/wordpress/wp-content/uploads/2016/05/160509-ClimateWorks-Low-Carbon-High-Performance-Modelling-Assumptions.pdf.

[100] Energy savings are only attributed to a measure to the extent that it can be established that they are additional to those that would have occurred in the absence of the measure. The portion of claimed savings that cannot be established as additional are known as non-additional'.

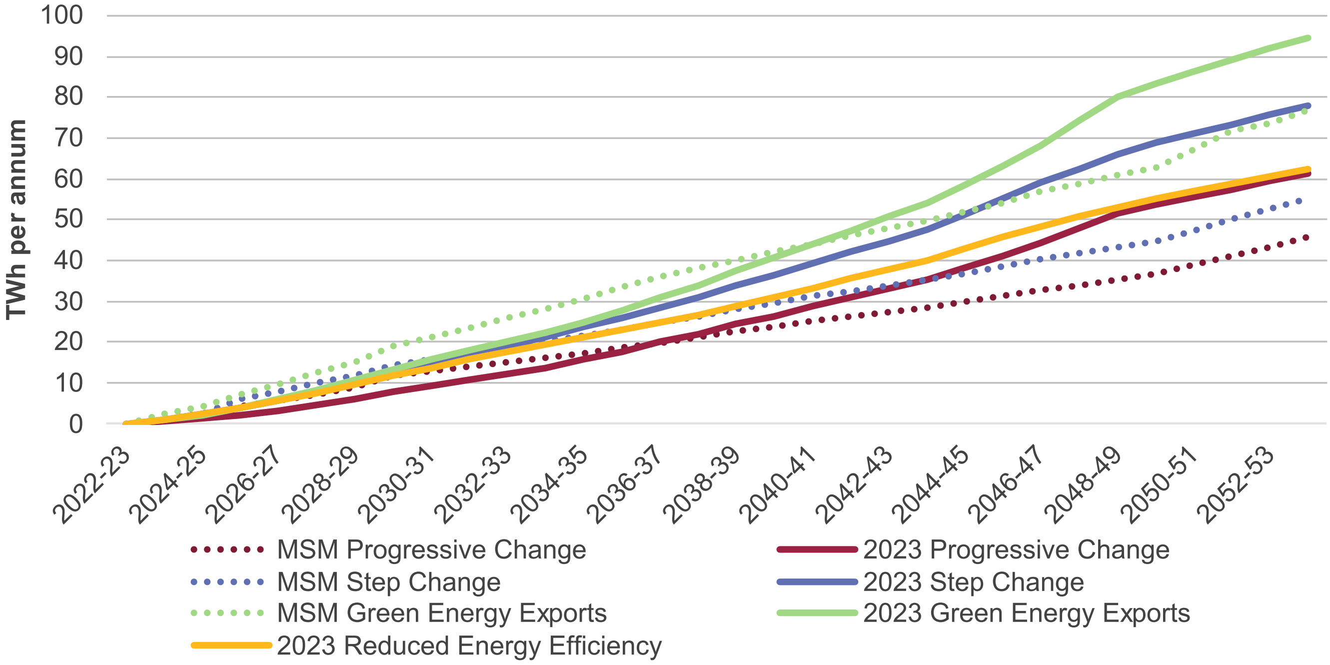
SPR's forecasts adopted scenario-specific demand drivers such as economic, population, dwellings and connections growth, combined with varying fuel shares (as informed by outcomes of multi-sector modelling) and levels of policy expansion beyond existing settings.

Generally, the scenarios deploy a relatively high level of energy efficiency across the scenarios, with varying levels of ambition affecting the scale of policy expansions and development of possible future/hypothetical policies. The savings by 2050 for example lead to between 30% and 50% of avoided electricity consumption relative to current levels of operational consumption. This excludes the increased efficiency relative to incumbent fuel supply requirements through electrification (that is, the increased energy efficiency of electrical devices relative to the fuel requirements from existing technologies and processes).

Considering the scenarios reflect expansions beyond existing policy, given the scale of potential and cost-effective expansion that would be expected to meet the scenario narratives, AEMO has developed a sensitivity to examine the impact to power system investment needs if only existing energy efficiency policies are considered in the *Step Change* future. This sensitivity provides information on the difference in energy consumption if the energy efficiency assumed in the *Step Change* scenario does not occur providing a baseline to demonstrate the value that arises from the impacts of changes to the existing policy environment.

Figure 31 shows the total electricity consumption savings due to energy efficiency, as forecast by SPR compared to CSIRO-CWC's multi-sector modelling.

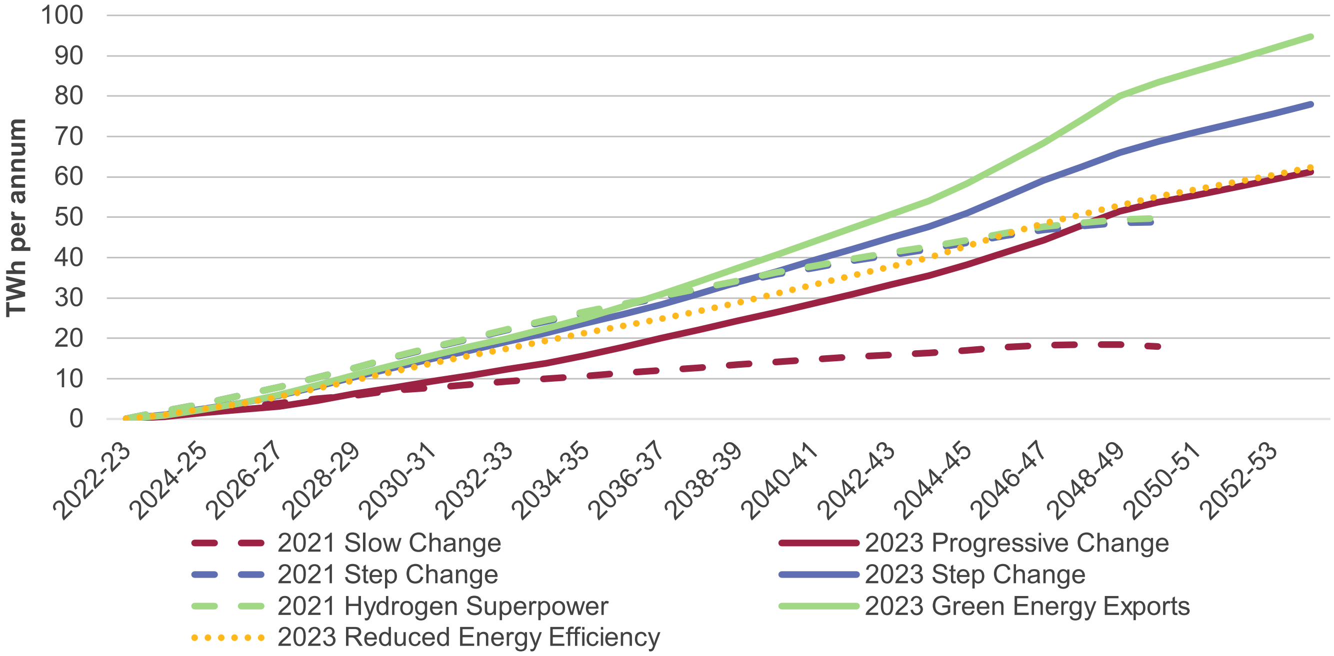
Figure 31 Forecast energy efficiency savings, compared to multi-sector modelling outcomes, 2022-23 to 2053-54 (TWh)



SPR's outcomes of energy efficiency savings are higher than corresponding projections from multi-sector modelling from the mid-2030s to early 2040s depending on scenario, demonstrating the strong role for continued development and expansion of government measures to maintain savings growth. Conversely, stronger and timely policy measures are needed to realise the energy efficiency savings projected by multi-sector modelling in the late 2020s. Nonetheless, efficiency improvements in SPR's forecasts are reasonably consistent with the multi-sector forecasts.

For the 2023 IASR, AEMO has applied SPR's forecast of efficiency savings as the most likely outcomes across sectors. The total efficiency saving applied to electricity consumption across the modelled scenarios is shown in Figure 32, comparing to the 2021 IASR forecasts.

Figure 32 Forecast energy efficiency savings, all scenarios, 2022-23 to 2053-54 (TWh per annum)



Note: The *2021 Step Change* scenario is mostly hidden behind the 2021 *Hydrogen Superpower* scenario forecast.

In the 2023 forecasts, there is greater dispersion of outcomes across scenarios compared to the 2021 forecasts. Where previously the *2021 Hydrogen Superpower* scenario followed a similar trajectory as the *2021 Step Change* scenario, the new *Green Energy Exports* scenario is more broadly distinguished from *Step Change* and has the highest level of investment in energy efficiency due to a combination of faster economic growth and the most aspirational policy settings to meet stronger carbon budgets.

Compared to previous estimates, the updated efficiency savings incorporated the following key changes:

- The inclusion of market-led or autonomous energy efficiency improvement to account for changes in cost and performance of technology, consumer preferences, and relative energy prices, that are not policy-driven.
- Savings from the GEMS/E3 program[101] were significantly reduced based on updated modelling by the Department of Climate Change, Energy, the Environment and Water (DCCEEW). In all scenarios an allowance was made for future expansion to GEMS from 2030 onwards, contributing to the rise in projections from the mid-2040s. This allowance does not apply to the *Reduced Energy Efficiency* sensitivity.

[101] See https://www.energyrating.gov.au/industry-information/energy-efficiency-initiatives/equipment-energy-efficiency-program.

- The introduction of a 'whole-of-home' annual energy budget as part of code changes in NCC2022[102] is anticipated to encourage electrification (particularly of hot water) for homes that cannot access rooftop PV and resulted in allocation of some negative residential energy efficiency savings for electricity.
- There is less spread in revised forecasts of savings from NCC in commercial buildings, particularly between *Step Change* and *Progressive Change* where faster build rate assumptions in *Progressive Change* are offset by more optimistic code changes in *Step Change*. This results in total savings in *Progressive Change* being higher than the 2021 IASR *Slow Change*.
- State schemes are assumed to be phased out at various points in the forecast horizon (Victoria in 2025, South Australia[103] in 2030, and New South Wales in 2050), per current legislation. In the interim, the expansion to the ESS[104] in New South Wales alongside an improved method for modelling the Victorian Energy Upgrades (VEU)[105] program temper the changes from GEMS and NCC described above. Revised data for VEU further shows the program to support replacement of electrical appliances with gas appliances, compared to electrification effects included in the 2022 forecasts.
- Assumption of new "hypothetical" national policy measures starting as early as 2025 and ramping up from the mid-2040s contribute to the increase in efficiency savings towards the end of the forecasting period.

The *Reduced Energy Efficiency* sensitivity forecasts a similar trajectory to the *Step Change* scenario until 2030, when the lack of policy expansion results in lower savings forecasts than *Step Change*.

3.3.12 Appliance uptake forecast

Input vintage	July 2023
Source	• Department of Industry, Science, Energy and Resources (DISER), *2021 Residential Baseline Study for Australia and New Zealand for 2000 – 2040*, available at www.energyrating.gov.au • Economic forecasts (see Section 3.3.8)
Updates since Draft IASR	Forecasts have been updated based on new projections of energy use by residential appliances and equipment from the RBS2.0 study by DISER. Forecasts also incorporate updated household disposable income forecasts from OEA.

The forecast of residential electricity consumption utilises appliance indices as a metric of the change in household electricity use by appliances and equipment, on a per connection basis. Outcomes from the 2021 Residential Baseline Study[106] (RBS, 2021) by the then Department of Industry, Science, Energy and Resources (DISER)[107] informed AEMO's estimates of changes to the level of electricity demanded per household for each NEM region. The total consumption relies on the number of appliances per appliance category, their usage hours, their capacity and size.

The dispersion across the scenarios is derived by applying a per capita Household Disposable Income (HDI) index (forecast with the economic projections described in Section 3.3.8) relative to the moderate economic

[102] See https://ncc.abcb.gov.au/editions/ncc-2022.

[103] See https://www.energymining.sa.gov.au/industry/energy-efficiency-and-productivity/retailer-energy-productivity-scheme-reps.

[104] See https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard/energy-savings-scheme.

[105] See https://www.esc.vic.gov.au/victorian-energy-upgrades-program.

[106] DISER, *2021 Residential Baseline Study for Australia and New Zealand for 2000 – 2040*, at https://www.energyrating.gov.au/industry-information/publications/report-2021-residential-baseline-study-australia-and-new-zealand-2000-2040.

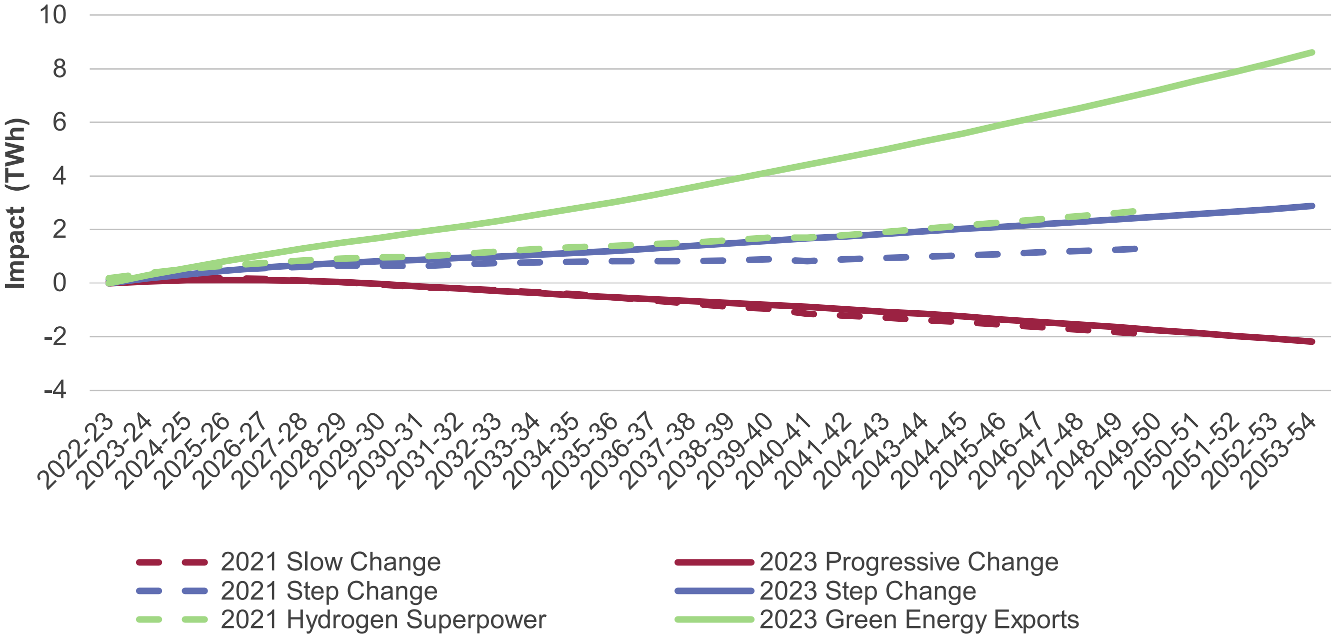
[107] From 1 July 2022, the climate change and energy functions that previously sat with DISER have transferred to the Department of Climate Change, Energy, the Environment and Water (DCCEEW).

scenario. Trajectories for beyond 2040, when the RBS study ends, have been guided by extrapolation of past trends and moderated for the likelihood of reaching maximum thermal comfort limits per household. Refer to Appendix A5 of the *Electricity Demand Forecasting Methodology* for further details.

Impacts on household electricity usage from improvements in equipment energy efficiency and switching from gas to electric devices are considered separately as part of the energy efficiency forecast (see Section 3.3.11) and electrification (see Section 3.3.5) forecasts respectively.

Figure 33 shows the impact of appliance uptake on residential consumption forecasts in the 2023 scenarios. Compared to the previous 2021 IASR, which had used 2015 RBS outcomes, the updated trajectories incorporating revised historical product sales data demonstrate higher growth across heating, cooling, and base appliance types. Space conditioning services are projected to be stronger due to higher stock levels of air-conditioner ducted and (to a lesser extent) non-ducted devices. This growth is partially offset by lower usage of electric resistive heaters given the higher use of space conditioning devices. For base household appliances, the updated forecast includes higher rates of LED installation, more charging for battery devices, greater use of electric water heaters, televisions, and clothes washing machines.

Figure 33 Forecast residential appliance uptake trajectories, consumption change relative to base year (2023), 2022-23 to 2053-54



3.3.13 Electricity price indices

Input vintage	June 2023
Source	• Australian Competition and Consumer Commission (ACCC) *Inquiry into the National Electricity Market – November 2022 report* available at https://www.accc.gov.au/about-us/publications/serial-publications/inquiry-into-the-national-electricity-market-2018-2025/inquiry-into-the-national-electricity-market-november-2022-report • DNSP annual pricing proposals to the AER, available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs • Network Service Provider Determination proposals to the AER, available at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements • AER *Default market offer prices 2023-24* available at https://www.aer.gov.au/retail-markets/guidelines-reviews/default-market-offer-prices-2023%E2%80%9324/final-decision • Essential Services Commission (ESC) *Victorian Default Offer price review 2023-24* available at https://www.esc.vic.gov.au/electricity-and-gas/prices-tariffs-and-benchmarks/victorian-default-offer/victorian-default-offer-price-review-2023-24 • Electricity futures pricing available via subscription service from https://www.asxenergy.com.au • AEMO internal wholesale price forecasts • Transmission costs from the 2022 ISP's optimal development path
Updates since Draft IASR	Retail price trends updated using latest data from ACCC and AER reports/submissions, together with electricity futures pricing from ASX Energy and internal modelling to provide forecasts for wholesale price forecasts and transmission costs.

Electricity prices are assumed to influence consumption through short-term behavioural changes (such as how electricity devices are used or energy consumption is managed), and longer-term structural changes (such as decisions to invest in CER).

Figure 34 shows the current retail price index, compared with the 2021 IASR forecasts. These were formed from bottom-up projections of various retail price components, including wholesale costs, network costs, environmental costs, and retail costs and margins. The retail price structure follows the Australian Energy Market Commission (AEMC) *Residential Electricity Price Trends* report series[108].

Previously, short-term wholesale price forecasts were based on the AEMC's *Residential Energy Price Trends* report, however this publication has not been updated since 2021. For the 2023 IASR, short-term wholesale price forecasts - are based on electricity futures pricing from ASX Energy[109] which is a publicly available dataset and is also used for the AER's Default Market Offer and the ESC's Victorian Default Offer. Long term price estimates reflect the changing mix of generation capacity forecast in AEMO's 2022 ISP. Other components of the residential price structure were updated with reference to the publications listed in the sources above.

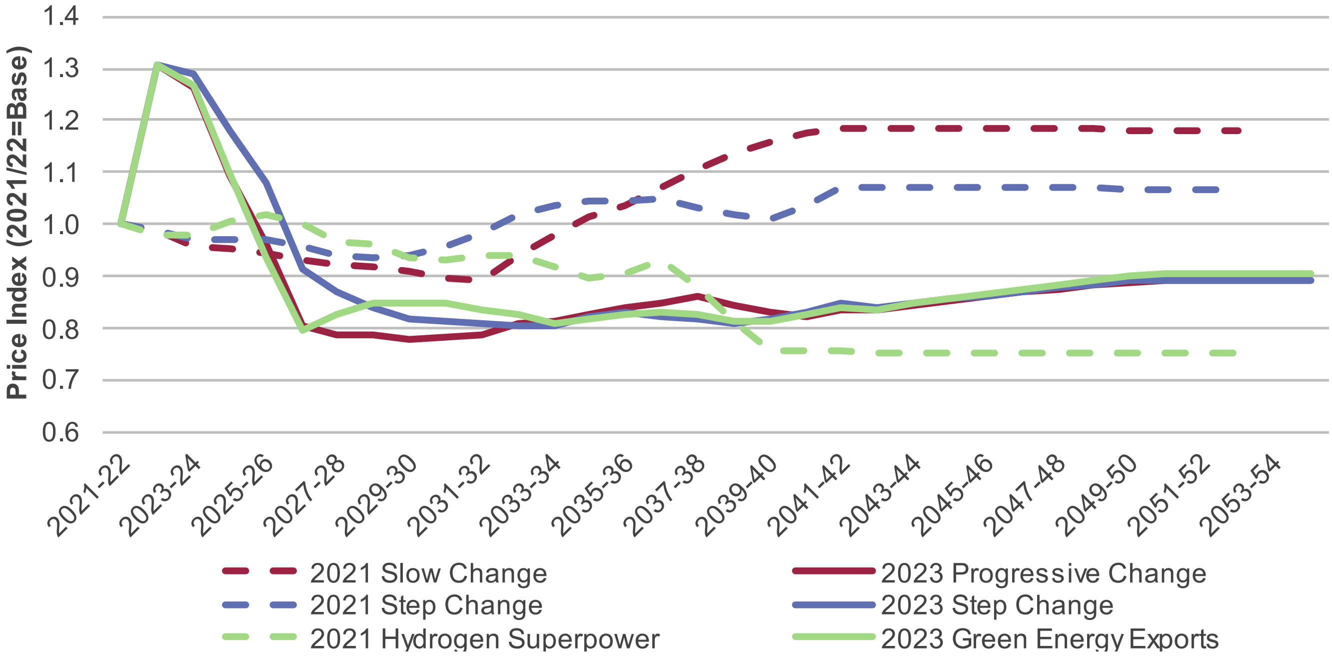
The resultant price index presented below depicts minor differences between the 2023 IASR scenarios, reflecting:

- A narrower band of long term forecast wholesale prices, and
- Offsetting increases and decreases in network and wholesale prices (for example, scenarios with higher network prices had correspondingly lower wholesale prices).

[108] AEMC, Residential Electricity Price Trends, at https://www.aemc.gov.au/market-reviews-advice/. The structure is also consistent with the Australian Energy Regulator's *Default Market Offer* and the Essential Services Commission's *Victorian Default Offer*.

[109] At https://www.asxenergy.com.au.

Figure 34 NEM residential retail price index, and compared to 2021 IASR forecast (connections weighted)



Consumption forecasts also consider the price elasticity of demand, which may be defined as the percentage change in demand for a 1% change in price. A negative price elasticity of demand indicates a decrease in consumption in response to a price increase, or an increase in consumption in response to a price decrease.

Since the Draft IASR, AEMO has reviewed the available literature on price elasticity and considered whether the existing elasticity values should be updated. AEMO concluded that the recent – and compounded – increases in energy prices warranted further analysis and consultation before updating price elasticity values. The previous elasticity coefficients, which are described below, therefore are retained in these forecasts.

For residential loads, the price response is influenced by the appliance type. Baseload appliances (such as refrigerators, washing machines, ovens/microwaves, and lighting) are assumed to be price inelastic, and therefore have a price elasticity of zero. Weather-sensitive appliances (such as heating and cooling appliances) on the other hand have a price elasticity of demand of -0.10 for all scenarios.

Businesses are expected to respond to price more readily than residential customers, so the price elasticity of demand assumption varies by scenario from -0.05 to -0.15.

Table 19 provides the price elasticities of demand that are included in the 2023 IASR scenarios.

Table 19 Price elasticities of demand for various appliances and sectors

Project	*Green Energy Exports*	*Step Change*	*Progressive Change*
Residential **Baseload appliances**	0	0	0
Residential **Weather sensitive appliances**	-0.10	-0.10	-0.10
Business **All load components**	-0.15	-0.10	-0.05

3.3.14 Demand side participation (DSP)

Input vintage	June 2023
Source	Historical meter data analysis and information submitted to the DSP Information portal in April 2023.
Updates since Draft IASR	• Current levels and committed/planned changes updated after summer 2022-23 to reflect most recent information. • Target levels to be maintained.

AEMO's forecast approach considers DSP explicitly in its market modelling, meaning that demand forecasts reflect what demand would be in the absence of DSP to avoid double counting.

AEMO estimates the current level of DSP using information provided by registered participants in the NEM through AEMO's DSP Information portal (DSP IP), supplemented by historical customer meter data. DSP responses are estimated for various price triggers and AEMO assumes the 50th percentile of observed historical responses is a reliable, central estimate of the likely response when the various price triggers are reached, as documented in AEMO's *Demand Side Participation Forecast Methodology*[110].

In accordance with this methodology, AEMO uses existing and committed DSP only for the ESOO, representing the current level discussed above with adjustments for committed changes to DSP as reported to AEMO through the DSP IP, or through policy targets with supporting legislation implemented. The DSP forecast includes Wholesale Demand Response (WDR) contributions based on the WDR dispatch data. WDR estimates are calculated as a weighted average response of dispatched WDR for each price trigger.

For long-term planning studies like the ISP, the quantity of DSP is grown to meet a target level by the end of the outlook period. The target level is defined as the magnitude of DSP relative to maximum demand and linearly interpolated between the beginning and ends of the outlook period. It is based on a review of international literature and reports of demand response potential (primarily in the United States[111] and Europe[112]) which indicated that the adopted (high) level of 8.5% of operational maximum demand is a reasonable upper estimate for growth in DSP. This growth will cater for a wide range of growth drivers, both technology-driven and from policy schemes (such as WDR).

The settings for the 2023 IASR scenarios are provided in Table 20 below, driven by the following:

- The *Green Energy Exports*[113] scenario is assumed to have high growth in DSP, representing a future with highly engaged consumers who, in addition to embracing CER technologies, also value the savings from being part of orchestrated DSP programs over the convenience of fixed-tariffs and un-controlled demand.
- The *Step Change* scenario is assumed to have moderate growth in DSP, reflecting the moderate economic growth and technology-led change.
- The *Progressive Change* scenario has the lowest assumed growth in DSP (maintaining the current penetration into the future) due to the relatively poor economic outlook and damped uptake of new technologies because of ongoing supply chain issues.

[110] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/demand-side-participation/final/demand-side-participation-forecast-methodology.pdf.

[111] See FERC's "A National Assessment of Demand Response Potential" (at https://www.ferc.gov/sites/default/files/2020-05/06-09-demand-response_1.pdf) validated against DSP uptake statuses across the United States (from https://www.ferc.gov/industries-data/electric/power-sales-and-markets/demand-response/reports-demand-response-and).

[112] See https://www.sia-partners.com/en/news-and-publications/from-our-experts/demand-response-study-its-potential-europe.

[113] Note that the DSP does not include the flexibility provided by electrolysers, which is modelled separately.

For New South Wales, the now committed New South Wales Peak Demand Reduction Scheme (PDRS[114]) policy will create a financial incentive to reduce electricity consumption during peak times[115]. AEMO includes this scheme in all scenarios, resulting in a DSP forecast which increases over time. The PDRS has been applied from 2022-23 with the target growing to 10% of forecast peak demand by 2029-30 and then staying flat. The DSP forecast assumes that 25% of the PDRS target will be delivered through energy efficiency and battery storage initiatives rather than through DSP, which are components accounted for separately in AEMO's forecasts. For any year in New South Wales, whichever target value is higher between PDRS and regular DSP growth will be used. It should be noted that the PDRS is only available in Summer.

Table 20 Mapping of DSP settings to scenarios

Scenario	*Green Energy Exports*	*Step Change*	*Progressive Change*
DSP growth target overall	High growth to reach 8.5% of peak demand by 2050 and then stays flat.	Moderate growth to reach 4.25% of peak demand by 2050 and then stays flat.	No change from current levels of DSP (0% growth).
New South Wales PDRS	Starting 2022-23 with target growing to 10% of peak demand by 2029-30 and then stays flat. Summer only.	Starting 2022-23 with target growing to 10% of peak demand by 2029-30 and then stays flat. Summer only.	Starting 2022-23 with target growing to 10% of peak demand by 2029-30 and then stays flat. Summer only.

3.4 Existing generator and storage assumptions

3.4.1 Generator and storage data

Input vintage	July 2023
Source	Participant survey responses
Updates since Draft IASR	Updated based on July 2023 Generation Information update

AEMO's Generation Information page[116] publishes data on existing, committed, and anticipated generators and storage projects (size, location, capacities, seasonal ratings, auxiliary loads, full commercial use dates and expected closure years), and non-confidential information provided to AEMO on the pipeline of future potential projects. This information is updated quarterly, with the most recently available information adopted for each of AEMO's publications (and clearly identified in each publication). The 2023 IASR Assumption Workbook includes details from the July 2023 publication, which will be used for the 2023 ESOO and 2024 ISP (unless material changes are observed during the course of the ISP modelling).

The resource availability for existing, committed, and anticipated variable renewable energy (VRE) generation is modelled using half-hourly generation profiles as described in Section 3.6.2. Timings for generator closures and their application in AEMO's forecasting and planning approaches is described in Section 3.4.4.

[114] See https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard/peak-demand-reduction-scheme#:~:text=The%20Peak%20Demand%20Reduction%20Scheme,during%20hours%20of%20peak%20demand.

[115] This is for the state of New South Wales only. The NEM region of New South Wales also includes the Australian Capital Territory, so adjustments are made to ensure the target reflects the New South Wales state demand only.

[116] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

3.4.2 Technical and other cost parameters (existing generators and storages)

Input vintage	July 2023
Source	Various, see below
Updates since Draft IASR	Updated based on July 2023 Generation Information and Clean Energy Regulator's Electricity sector emissions and generation 2021-22.

AEMO has sourced the operating and cost parameters of existing generators and storages from several different sources, including AEMO internal studies[117]. They include:

- AEMO's Generation Information page.
- GHD, 2018-19 AEMO Costs and Technical Parameter Review.
- Aurecon, 2022 Costs and Technical Parameter Review.
- AEP Elical, 2020 Assessment of Ageing Coal-Fired Generation Reliability.
- Generator surveys.
- Clean Energy Regulator, Electricity sector emissions and generation 2021-22.
- Specific adjustments to the above sources if required, based on confidential or non-confidential engagement with specific generators or developers.

The specific parameters obtained from these sources are summarised in Table 21 below.

Table 21 Sources for technical and cost parameters for existing generators

Source	Technical and cost parameters used in AEMO's inputs and assumptions
AEMO's Generation Information page	• Maximum capacities • Seasonal ratings (10% probability of exceedance (POE) summer, typical summer and winter) • Auxiliary loads • Reserves • Commissioning and retirement dates
GHD *2018-19 AEMO Costs and Technical Parameter Review* (primarily for existing generators)	• Heat rates • Maintenance rates • Fixed and variable operating and maintenance costs • Ramp rates • Minimum up and down time
Aurecon *2022 Costs and Technical Parameter Review* (primarily for new entrant generators but also referred to for some existing generators)	• Heat rate curves used for calculating complex heat rates • Heat rates • Fixed and variable operating and maintenance costs • Ramp rates • Minimum stable levels
Generator surveys	• Forced outage rates • Refinements to fixed and variable operating and maintenance costs for coal-fired generation
AEP Elical *2020 Assessment of Ageing Coal-Fired Generation Reliability*	• Assessment of forward-looking coal-fired generator reliability

[117] Consultant reports and data books from GHD, Aurecon and AEP Elical are available at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

Source	Technical and cost parameters used in AEMO's inputs and assumptions
AEMO internal studies	• Complex heat rates, informed by Aurecon and GHD • Minimum stable levels • Ramp rates for coal-fired generation (using the 90th percentile of non-zero ramp rates bid into the market by each unit). • Minimum and maximum capacity factors
Clean Energy Regulator, *Greenhouse and energy information by designated generation facility 2021-22*	• Scope 1 emission intensity for existing generators
DCCEEW, *2022 Australian National Greenhouse Accounts Factors*	• Emission factor for biomass

The specific assumptions on the parameters documented in the above table are contained in the 2023 IASR Assumptions Workbook.

Capacity outlook model assumptions in the ISP

In long-term planning studies, AEMO applies assumptions related to operational characteristics of plant to project future investment needs. Actual limits and constraints that would apply in real-time operations will depend on a range of dynamic factors which may not be reasonable to incorporate without simplification to more static assumptions.

The relative coarseness of the capacity outlook models requires that some operational limitations are applied using simplified representations such as minimum stable levels or capacity factor limitations to represent technical constraints and power system security requirements. This helps ensure that relatively inflexible generators, such as coal-fired generators, are not dispatched in a manner that exceeds their technical capability, or that would not be commercially viable. The current view of these operational limits is described in the accompanying 2023 IASR Assumptions Workbook, but they are also an outcome of the iterative market modelling process and may be refined during the ISP, as described in the ISP Methodology.

Minimum stable levels for existing generators are based on AEMO analysis of historical generation and operational experience. Minimum stable levels for new entrant generators are sourced from Aurecon.

In the ESOO, station-level auxiliary rates are applied based on the information provided in the Generation Information survey. This information is kept confidential. For the ISP and other publications, technology aggregated auxiliary rates are used so that they may be published in the accompanying 2023 IASR Assumptions Workbook while continuing to protect the confidentiality of information provided by participants.

Additional properties used in time-sequential modelling in the ISP

Additional technical limitations may be incorporated in the time-sequential models, including:

- Minimum up time and down times.
- Complex heat rate curves.
- Unit commitment optimisation and minimum stable levels, if the model granularity warrants the additional complexity. For hourly or half-hourly modelling purposes, these optimisation limits are inappropriate for any peaking plants, as this may restrict modelled dispatch in the models that is not representative of real-time operation capabilities in sub-half-hourly dispatch periods.

Further details on the implementation of these technical limitations can be found in AEMO's ISP Methodology[118].

Adjustment to the biomass emission factor

Compared with the 2021 IASR, the biomass emission factor has been reduced, because this is already captured in the total emissions in the land use sector where the biomass originates. This is consistent with the treatment of biomass as a special case in the 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories[119]. Instead of emission factors from GHD, AEMO applies the estimated Scope 1 emission factor for biomass from the Australian National Greenhouse Accounts Factors[120].

3.4.3 Generator unplanned outage rates

Input vintage	June 2023
Source	Generator surveys, AEP Elical 2020, and Aurecon 2022 Cost and Technical Parameter Review
Updates since Draft IASR	Unplanned outage rates were updated with latest data in May 2023 as part of data collection process for the ESOO. The updates were presented to the FRG in June 2023.

For the 2023 ESOO, AEMO collected information from all generators on the timing, duration, and severity of unplanned outages, via its annual survey process. This includes information on historical outages, and (for selected participants) outage projections across the 10-year ESOO forecast period. This data was used to calculate the probability of full and partial unplanned outages in accordance with the *ESOO and Reliability Forecasting Methodology*[121]. For small peaking plants and hydro generator technology types, technology aggregates are applied to individual stations to smooth the impact of outlying years. Where participants have provided outage rate projections, AEMO has adopted these in agreement with station owners/operators.

Outage modelling assumptions for existing generators for ESOO and other reliability purposes

Long duration unplanned outages

As described in the *ESOO and Reliability Forecast Methodology*[122], AEMO models outages with a duration longer than five months (long duration outages) from historical outage data from 2010-11 to 2022-23, prior to calculation of the expected unplanned outage rate. For the 2023 ESOO, AEMO used an extended historical period of all available data (13 years) to determine the (unplanned) long duration outage rates for each region and technology class.

The long duration outages used in 2023 ESOO modelling, and in other reliability assessments such as Medium Term Projected Assessment of System Adequacy (MT PASA) and Energy Adequacy Assessment Projection (EAAP), are shown in Table 22.

[118] See https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/isp-methodology.

[119] For further details see Section 2.3.3.4 at https://www.ipcc-nggip.iges.or.jp/public/2019rf/pdf/2_Volume2/19R_V2_2_Ch02_Stationary_Combustion.pdf.

[120] At https://www.dcceew.gov.au/sites/default/files/documents/national-greenhouse-accounts-factors-2022.pdf.

[121] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/reliability-forecasting-guidelines-and-methodology-consultation/final/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

[122] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/reliability-forecasting-guidelines-and-methodology-consultation/final/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

Table 22 Existing generators – long duration outages

Fuel type/technology	Long duration outage rate (%)	Mean time to repair (hours)
All coal	0.90%	5,622
OCGT	0.77%	2,562
Hydro	0.10%	2,870
Other gas and liquid	0.49%	6,441

OCGT: Open cycle gas turbine.

Unplanned outage rate trajectories (excluding long duration outages)

The first year unplanned outage rates assumed in the 2023 ESOO were based on participant-provided information and projections for each technology (see Table 23).

Table 23 Unplanned outage assumptions (excluding long duration outages) for 2023-24 year

Technology	Full unplanned outage rate (%)	Partial unplanned outage rate (%)	Partial derating (% of capacity)	Mean time to repair – full (hours)	Mean time to repair – partial (hours)
Brown coal	7.75	11.56	17.91	90.05	12.20
Black coal NSW	6.31	31.46	16.60	157.62	33.97
Black coal QLD	6.75	12.86	25.16	185.00	56.42
OCGT	7.21	1.12	9.99	44.08	106.48
Small peaking plant*	9.58	0.32	33.70	150.20	189.52
Hydro	5.11	1.71	15.18	38.10	473.44
Closed cycle gas turbine (CCGT) & gas-fired steam turbine	5.04	1.66	15.21	61.19	40.35
Batteries	1.84			26.05	

*Small peaking plants are generally classified as those less than 150 MW in capacity, or with a very low and erratic utilisation

The 10-year projections for the equivalent full unplanned outage rate[123] of all technology aggregates are shown in Figure 35, Figure 36 and Figure 37, with and without the effect of long duration outages. The annual equivalent unplanned outage rate is affected by changes to assumed reliability and retirements of generators over the horizon. To protect the confidentiality of the individual station-level information used, unplanned outage trajectories are provided for the first 10 years of the horizon for technology aggregates only. Due to the small number of coal plants in later years, all regions have been further aggregated to an 'all coal' value to protect confidentiality.

[123] Where equivalent full unplanned outage rate = Full outage rate + partial outage rate x average partial derating.

Figure 35 Equivalent full unplanned outage rate projections for coal-fired generation technologies

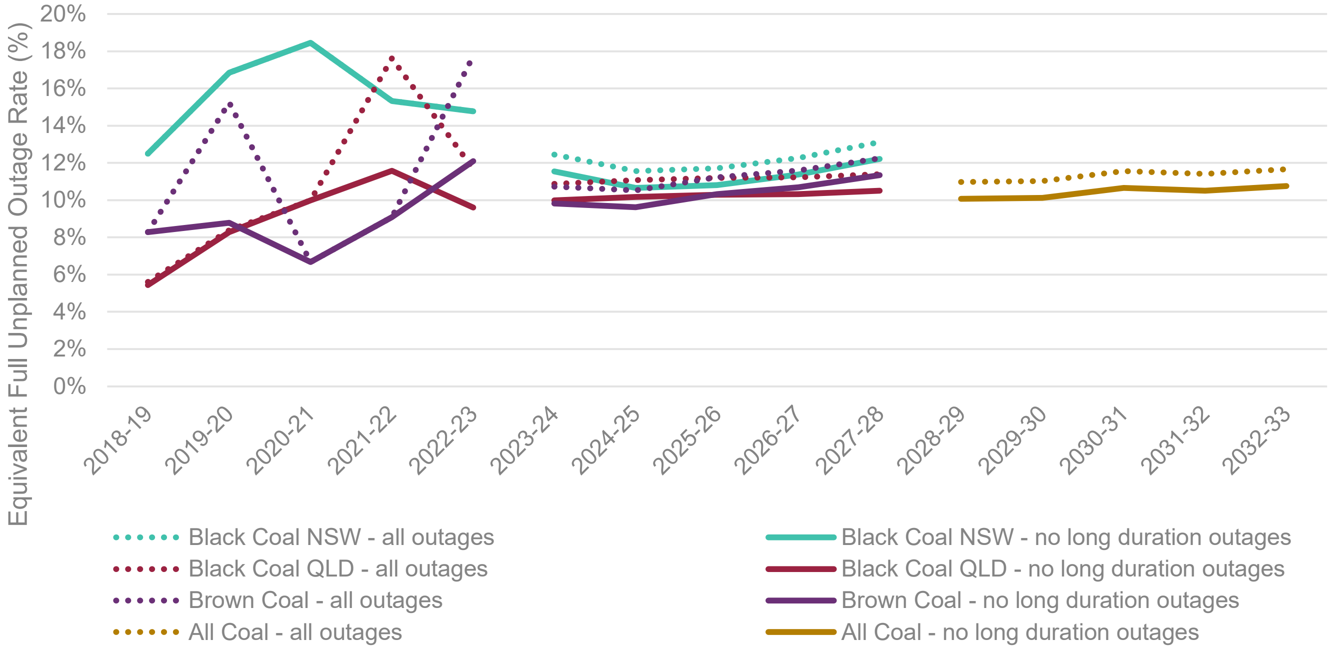


Figure 36 Equivalent full unplanned outage rate projections for OCGT, CCGT and steam turbine generation technologies

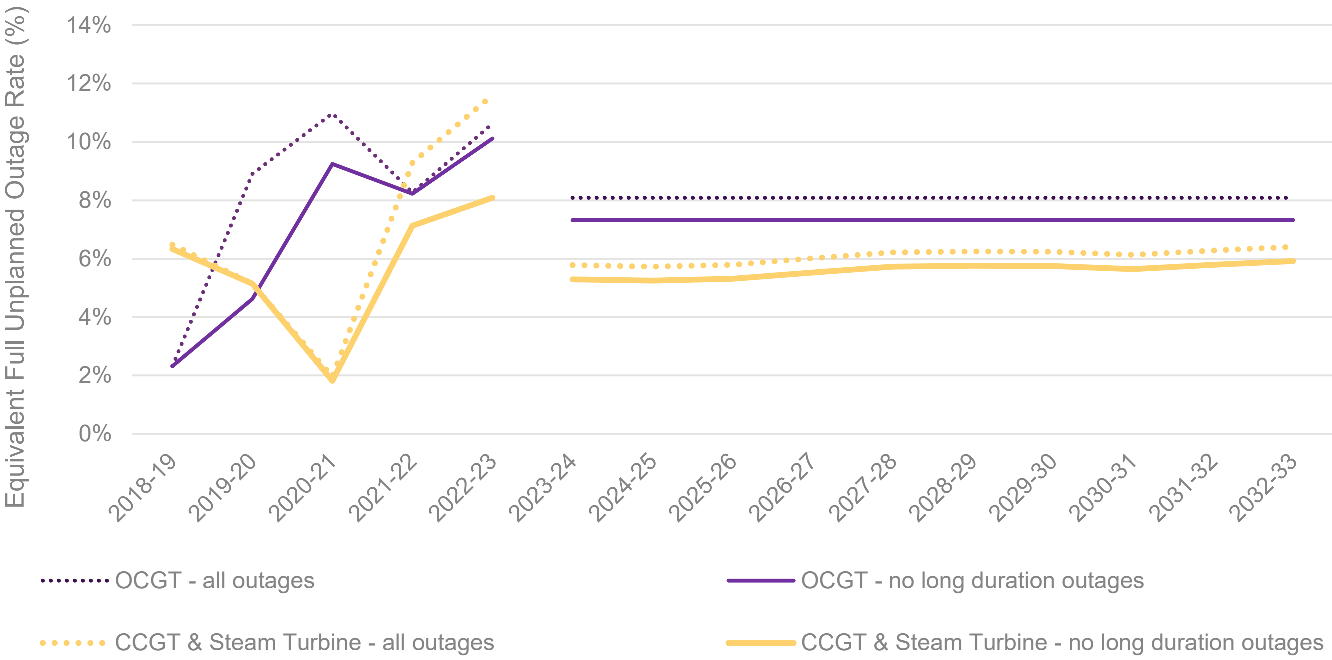
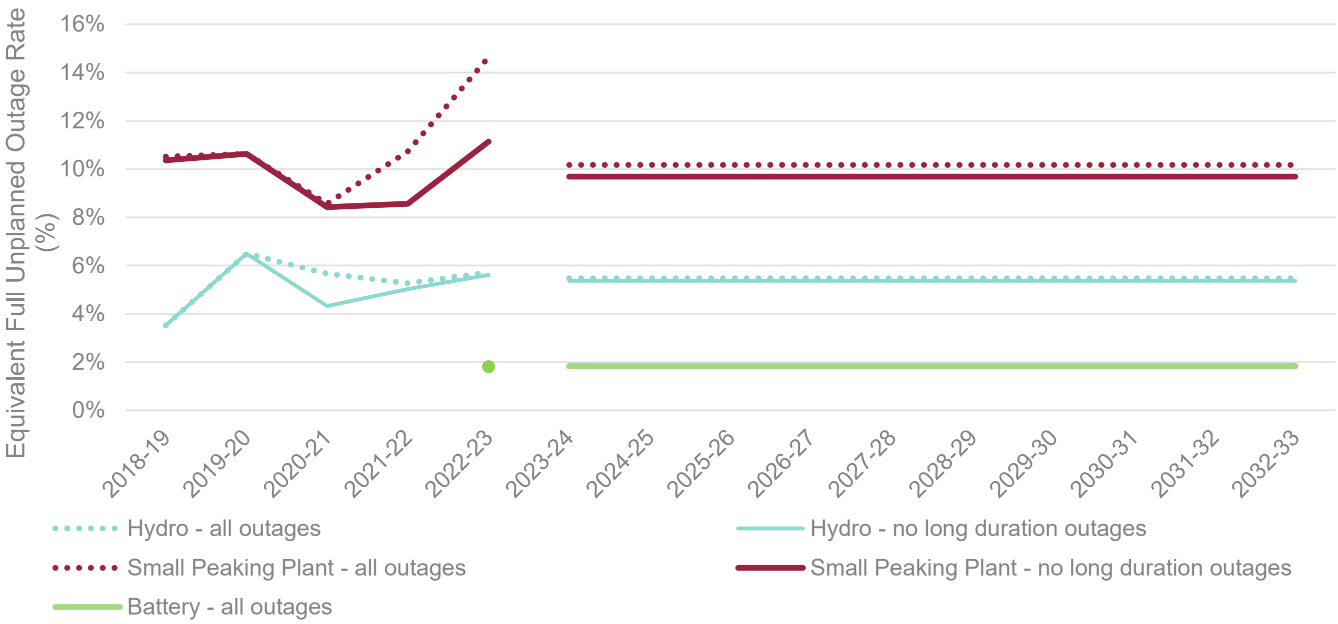


Figure 37 Equivalent full unplanned outage rate projections for small peaking plant, hydro and battery technologies



Outage modelling assumptions for existing generators for ISP purposes

For ISP purposes, the forced outage rate assumptions, which incorporate long duration outages, are held constant past the first 10 years. Although reliability may degrade as plant ages and nears retirement, any accuracy of this trend beyond 10 years is difficult to implement, particularly when timing of generation withdrawal may be dynamic. It is a level of complexity that AEMO does not consider warranted, as it is not expected to introduce a material difference to ISP outcomes. More information on treatment of outage rates across AEMO's modelling is provided in the ISP Methodology[124].

New entrant generation outage assumptions for all modelling purposes

The equivalent full forced outage rate (EFOR) for new entrants is provided by Aurecon. Calculations from Aurecon follow the formulas defined in IEEE std 762 and source data is based on indicative industry values by technology, like contractual or operational availability for onshore wind and solar. For new coal generation, Aurecon's EFOR is equally divided between full and partial outage/derating. Long duration outages are not applied to new entrant technologies.

[124] At https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/isp-methodology.

3.4.4 Generator retirements

Input vintage	• Retirement costs: June 2022 • Retirement dates: July 2023
Source	• Generation Information • GHD 2018
Updates since Draft IASR	Expected closure years and closure dates have been updated to reflect the most recent data collection. AEMO engaged with generator participants but no further information on retirement costs was able to be provided.

For existing generators, AEMO applies the expected closure year as provided by participants and published through AEMO's Generation Information[125] page as a latest retirement date, as follows:

- In ESOO, MT PASA and EAAP, expected closure years are applied consistent with participant-provided information.
- In the ISP, retirements may be brought forward ahead of the expected closure year if it reduces overall system costs, as described in Section 2.4.1 of the ISP Methodology. As discussed in more detail in that document, retirements may take place earlier than expected due to explicit decarbonisation or policy constraints.

For reference, a "closure date" has the meaning specified in NER 2.10.1(c1) which specifies the date a generator will cease to supply electricity in the market, while an "expected closure year" is the year in which a generator expects to cease to supply electricity (as per NER 2.2.1(e) (2A)). This tends to include only projects that are scheduled to close in the near term, over the next few years or so, and is published within the Generating Unit Expected Closure Year subset of the Generation Information page.

As discussed in the ISP Methodology, if a generator has reported its closure date (as opposed to its expected closure year) then earlier retirement of that unit is not considered. AEMO's approach therefore recognises the increased accuracy of closure date submissions, thereby locking these dates in across all analysis, rather than contemplating alternative economics-triggered closure timings.

Retirement costs by generation technology have been provided by GHD and are presented in the accompanying 2023 IASR Assumptions Workbook. A number of technologies (biomass, solar thermal, offshore wind) do not have a retirement cost estimate. Given the development lead times of these technologies (generally greater than six years) and the economic life (generally greater than 25 years), retirement costs would be incurred beyond the end of the ISP modelling horizon, even if built as soon as possible. Retirement costs incorporate the cost of decommissioning, demolition, and site rehabilitation and repatriation, excluding battery storage technologies where disposal cost data is not known.

[125] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

3.4.5 Hydro modelling

Input vintage	June 2023
Source	Inflows – hydro operators, considering insights regarding long-term rainfall trends from the Electricity Sector Climate Information (ESCI) project[126].
Updates since Draft IASR	Hydro scheme inflows have been updated based on data received from participants in April and June of 2023.

Hydro scheme inflows

AEMO models each of the large-scale hydro schemes using inflow data for each generator, with aggregation of some run-of-river generators.

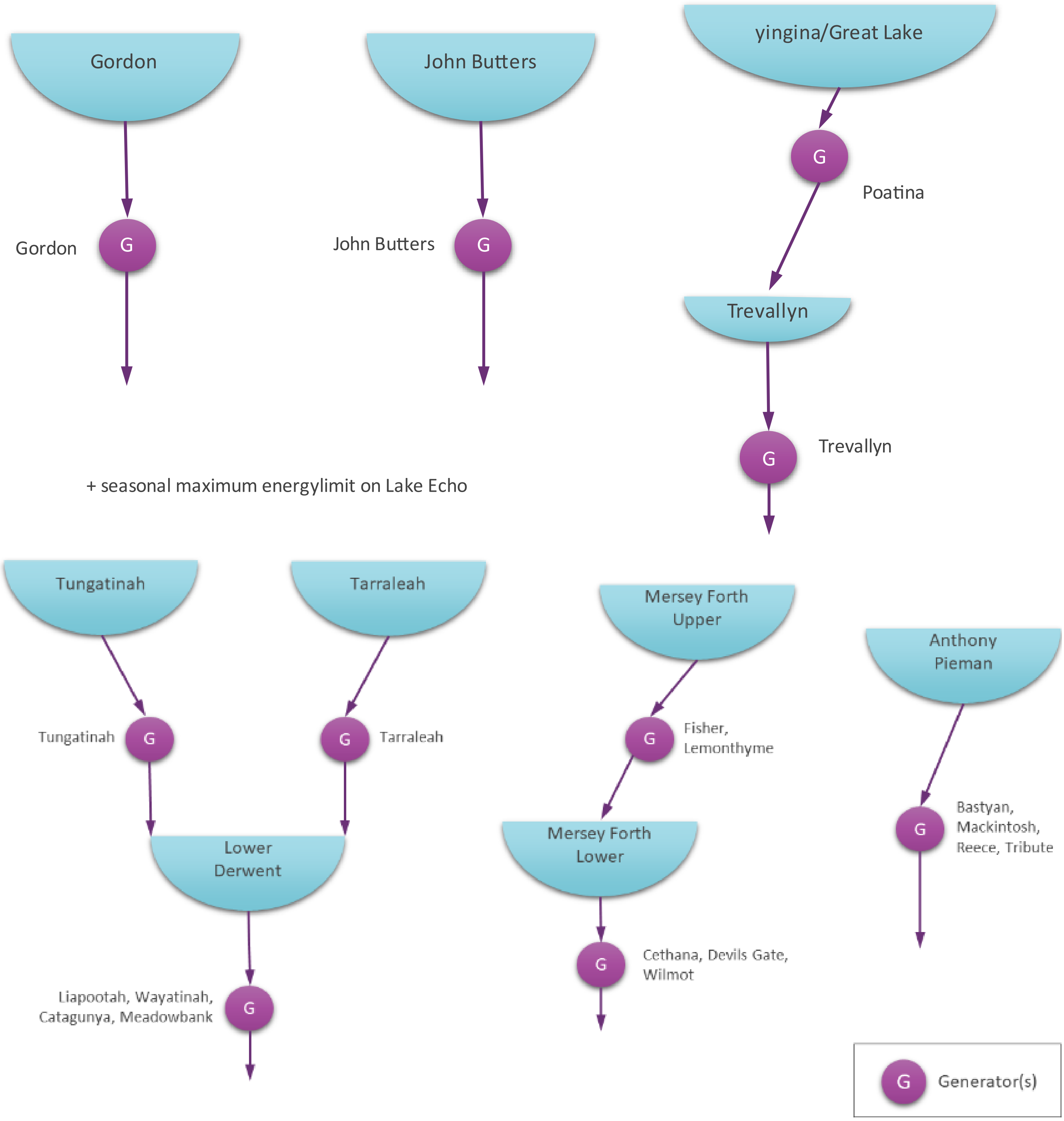
Tasmanian hydro scheme

AEMO's approach to modelling the existing Tasmanian hydro schemes relies on a 10-pond[127] topology designed to capture different levels of flexibility associated with the different types of storage outlined above (see Figure 38).

[126] ESCI information available at https://www.climatechangeinaustralia.gov.au/en/projects/esci/.

[127] The capacity outlook model may aggregate long-term storages together to reduce simulation time.

Figure 38 Hydro Tasmania scheme topology



Mainland hydro scheme

Some of the Victorian hydroelectric generators are modelled using maximum annual capacity factor constraints on each individual generator; these are West Kiewa and Bogong-Mackay[128]. The model schedules the electricity

[128] These generators are fed from a very large storage (Rocky Valley Dam), which effectively means they have an annual energy supply from rain and snow that they can use flexibly throughout the year. Annual capacity factor constraints are therefore most appropriate to constrain the generation from these units.

production from these generators across the year such that system costs are minimised within this energy constraint.

Other hydroelectric generators in Victoria and Queensland, as well as the Snowy scheme, are represented by physical hydrological models, describing parameters such as:

- Maximum and minimum volume.
- Initial storage volume.
- Monthly reservoir inflow rates reflecting historical inflows.

Monthly storage inflows used in market modelling studies can be found in the 2023 IASR Assumptions Workbook.

Figure 39 presents a representation of the topology currently modelled for the Snowy scheme.

Figure 39 Snowy Hydro scheme topology

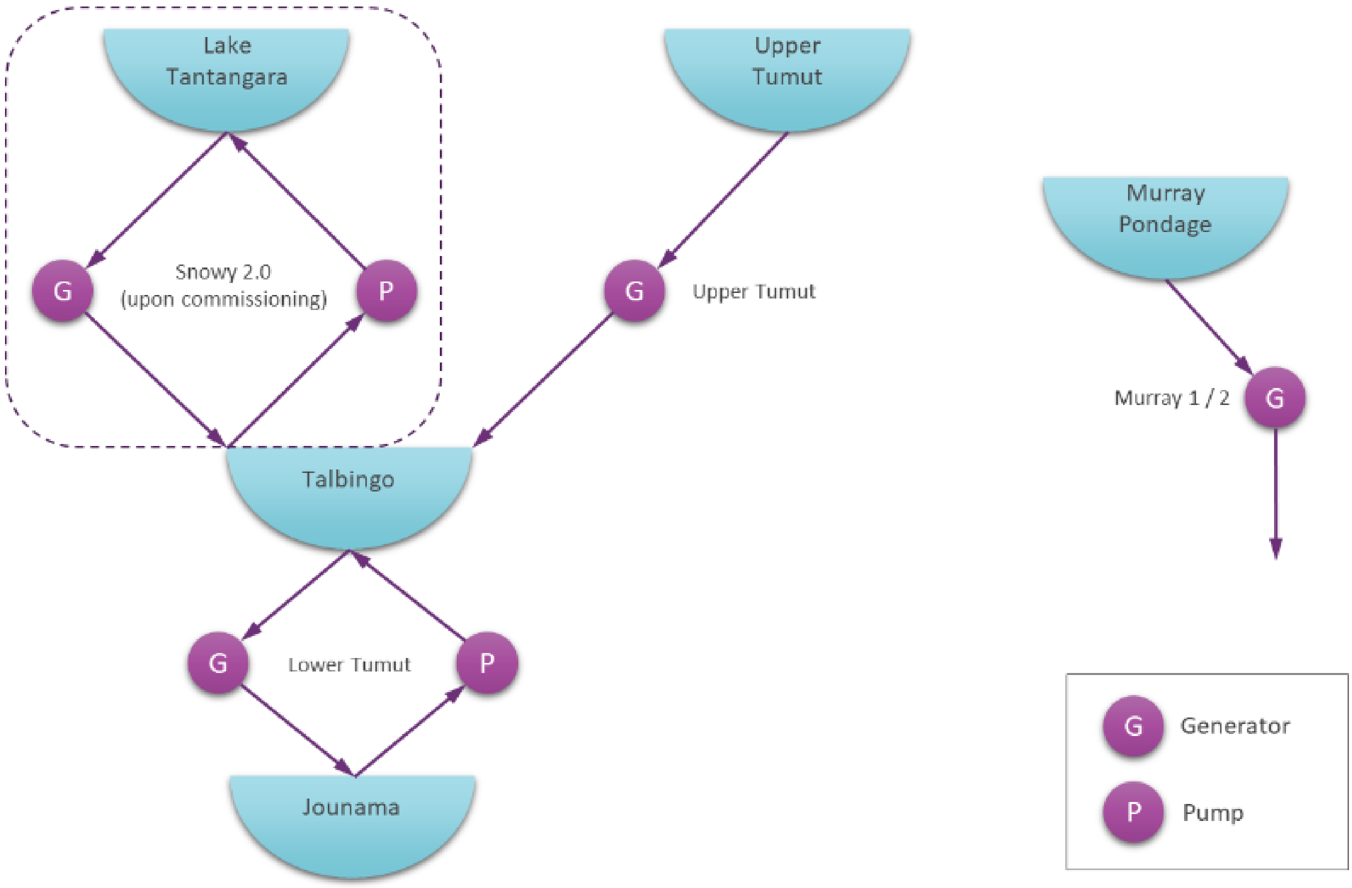
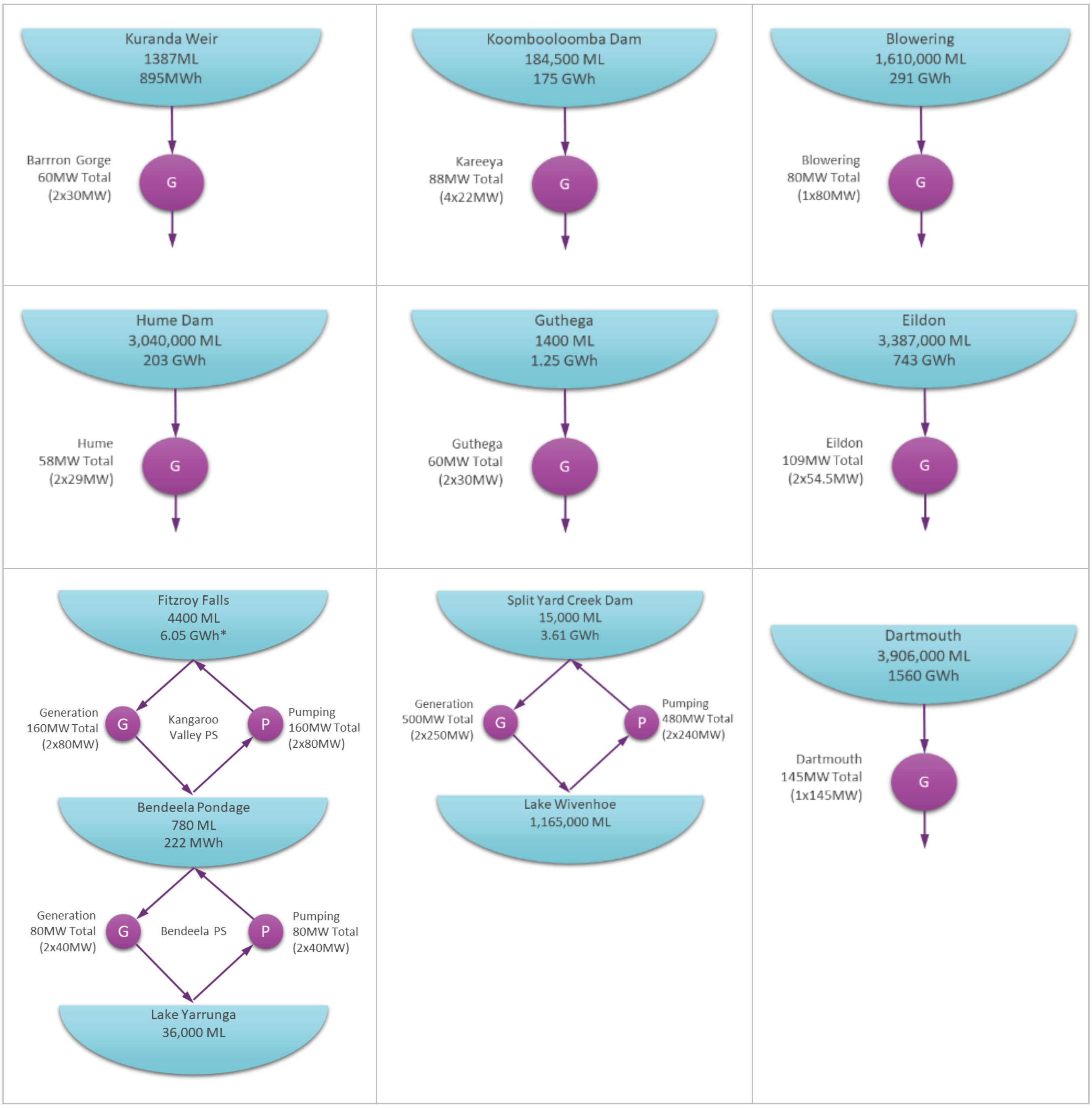


Figure 40 provides graphical representations of the other hydrological models used in the market simulations, as well as the registered capacity of the adjoining generating units[129].

[129] Storage capacities are defined in megalitres (ML).

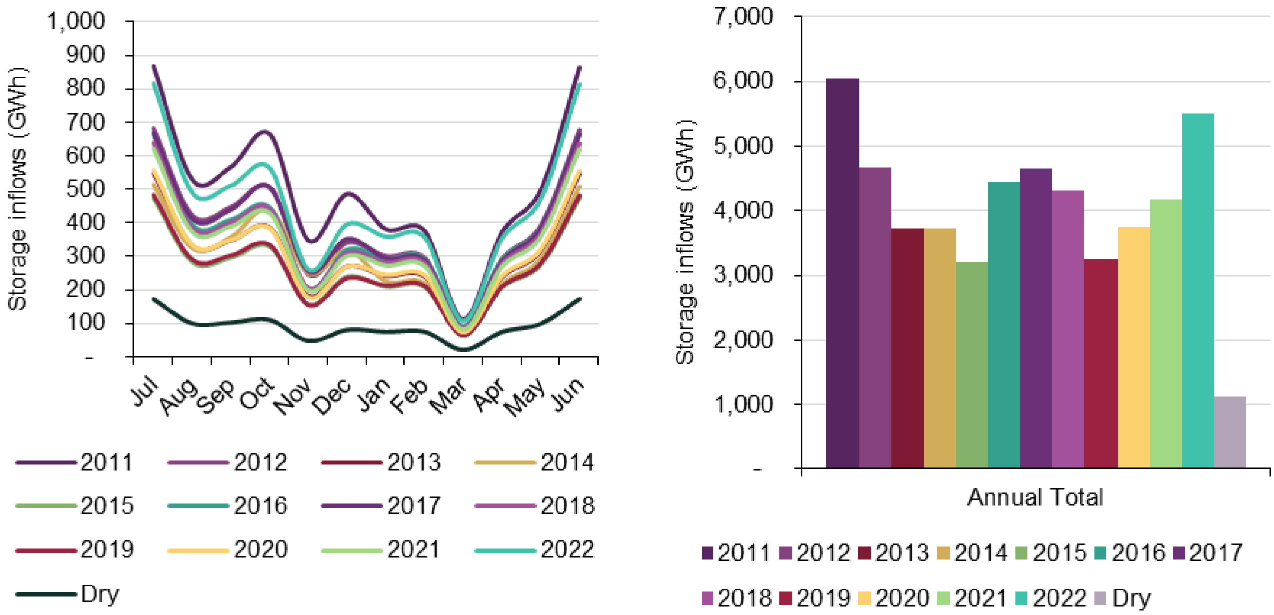
Figure 40 Hydro scheme topologies of other existing hydro power stations



*Energy storage at Fitzroy Falls includes full drop through both power stations.

The 2023 IASR Assumptions Workbook provides the annual and seasonal variation in hydro inflows for key hydro schemes. An example of this is shown in Figure 41 below, for Snowy Hydro.

Figure 41 Hydro inflow variability across reference weather years – Snowy Hydro



Australia-specific climate information on regional changes in long-term average rainfall over time has been estimated through close collaboration with CSIRO and the BoM as part of the Electricity Sector Climate Information (ESCI) project, sponsored by the Federal Government[130].

Streamflow change factor projection information was provided to AEMO as part of the ESCI project for 220 different natural streams in Australia. AEMO grouped many of these natural streams into three different areas based on their proximity to existing hydro generators, and the statistical stability of the change factor projections. The projections represent the median of an ensemble of streamflow projections and have been scaled to reflect the inherent climate narratives relevant to each scenario.

The median hydro change factor projections are shown in Table 24 for the *Step Change* scenario, as an example. Other scenario hydro climate factors are available in the 2023 IASR Assumptions Workbook.

Table 24 Median hydro climate factors, *Step Change* scenario

Region	2020-21	2030-31	2040-41	2050-51
North Queensland	0%	0%	0%	0%
Southern Queensland, New South Wales, Victoria, and South Australia	-2.0%	-5.0%	-4.9%	-5.3%
Tasmania	-0.8%	-2.0%	-1.2%	-0.4%

[130] See https://www.climatechangeinaustralia.gov.au/en/projects/esci/.

3.5 New entrant generator assumptions

3.5.1 Committed and anticipated projects

Input vintage	July 2023
Source	Participant survey responses
Updates since Draft IASR	Updated to incorporate the July 2023 Generation Information.

New generator or storage developments that are announced to market are assessed against commitment criteria published in AEMO's Generation Information page[131]. The commitment criteria cover five areas of a project's development, covering:

- Land/site acquisition.
- Contracts for major components.
- Planning and other approvals.
- Financing.
- Construction.

To classify the commitment status of generators or storages, AEMO uses information provided by both NEM participants and project proponents. In reliability assessments, some projects are subject to delays to manage the impact of commissioning risks in the short to medium term, whereas the ISP assumes that projects are delivered on schedule so that any infrastructure needed to extract the full value of these projects for consumers can be considered as part of the whole-of-system plan. The key classifications are defined as follows:

- **In Commissioning** are those projects that have meet the requirements of the first commissioning hold point (typically at least 30% capacity commissioned).
  - For reliability and ISP assessment purposes: Projects 'in commissioning' are modelled as becoming fully available at the Full Commercial Use Date (FCUD) submitted by the project proponent.
- **Committed projects** are projects that have fully met all commitment criteria but have not yet met the requirements of their first commissioning hold point.
  - For reliability assessment purposes: 'Committed' projects are included in the modelling at six months after the FCUD submitted by the project proponent.
  - For ISP assessment purposes: 'Committed' projects are assumed to proceed at the FCUD submitted by the project proponent.
- **Committed* projects** are those that are highly likely to proceed, satisfying land, finance and construction criteria plus either planning or contracts criteria. Progress towards meeting the final criteria is also evidenced and construction or installation has also commenced.
  - For reliability assessment purposes: Committed* projects are included in the modelling at six months after the FCUD submitted by the product proponent.

[131] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

  - For ISP assessment purposes: 'Committed*' projects are assumed to proceed at the FCUD submitted by the project proponent.
- **Anticipated projects** are those projects that are likely to proceed, have demonstrated progress towards meeting at least three of the commitment criteria and have updated their submission to AEMO in the previous six months.
  - For reliability assessment purposes:
    - To reflect the uncertainty in the commissioning of these projects, anticipated projects which have provided an expected commissioning date are assumed to become fully available at the latest date of either: one year after the date provided by the project proponent, or the first day after the T-1[132] year for Retailer Reliability Obligation (RRO) purposes.
    - Anticipated projects which are not yet sufficiently progressed to provide an expected commissioning date are assumed to become fully available on the first day after the T-3[133] year for RRO purposes.
  - For ISP assessment purposes:
    - Anticipated projects for which an expected commissioning date has been provided are assumed to proceed at the FCUD submitted by the project proponent.
    - Anticipated projects for which an expected commissioning date has not been provided are assumed to become fully available two years after the publication of the IASR (that is, July 2025 for the purposes of this IASR), subject to technology development lead time assumptions.
- **Proposed projects** are those projects that have not progressed sufficiently to meet the requirements of an Anticipated or Committed project.
  - Proposed projects are not considered explicitly in AEMO's reliability or ISP assessments, but may be considered in sensitivities if relevant.

Further details are available in the Reliability Forecasting Methodology Final Report[134].

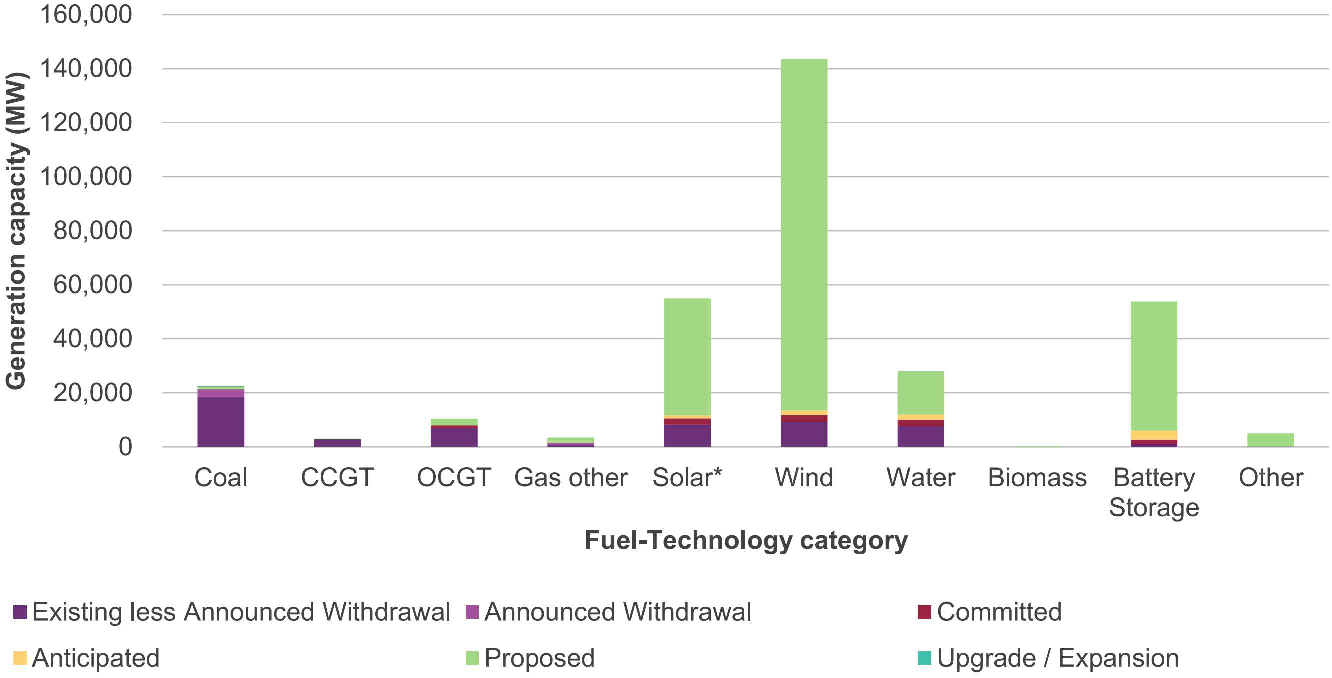
The 2023 IASR uses the Generation Information as at July 2023. A summary of existing, committed, and anticipated projects included in that release is provided in Figure 42 below.

[132] T-1 refers to reliability assessments one year out. For example, for a reliability assessment conducted in August 2023, the T-1 period refers to the 2024-25 financial year.

[133] T-3 refers to reliability assessments three years out. For example, for a reliability assessment conducted in August 2023, the T-3 period refers to the 2026-27 financial year.

[134] See Section 2.7 at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/reliability-forecasting-guidelines-and-methodology-consultation/final/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

Figure 42 Generation and storage projects in July 2023 Generation Information page



In this figure, Committed* projects are included within the 'Committed' category, and projects in commissioning are included within the 'Existing less Announced Withdrawal' category.

AEMO's modelling will reflect the most up-to-date information available at the time it commences and will incorporate new updates if material where possible. Each publication will note what version of the Generation Information was used in the assessment.

3.5.2 Candidate technologies

Input vintage	July 2023
Source	• CSIRO: *GenCost 2022-23 Final report* • Aurecon: *2022 Costs and Technical Parameters Review* • GHD: *2018-19 Costs and Technical Parameters Review*
Updates since Draft IASR	Renamed biomass generation – electricity and heat to reflect stakeholder feedback.

For the 2024 ISP's capacity outlook modelling, a reduced list of technologies is considered based on technology maturity, resource availability, and energy policy settings.

Table 25 below presents the list of technologies that will be used in 2023-24 publications.

Table 25 List of generation and storage technology candidate

List of technologies for consideration in the 2024 ISP	Commentary
CCGT – with CCS	–
CCGT – without CCS	–
OCGT – without CCS, Small unit size	–
OCGT – without CCS, Large unit size	–

List of technologies for consideration in the 2024 ISP	Commentary
Hydrogen-based reciprocating engines	Based on Aurecon's 2022 Costs and Technical Parameters Review, AEMO will instead model hydrogen-based reciprocating engines, instead of hydrogen-based OCGTs, given the former's lower relative capital and O&M costs, as well as their higher relative efficiency.
Lithium-Ion battery storage	AEMO includes storage sizes from 1 to 8 hours in its models. No geographical limits will apply to available battery capacity given its small land footprint.
Solar PV – single axis tracking	–
Solar thermal central receiver with storage (15 hr)	The storage component will be increased from 8 hours to 15 hours. Additionally, in response to stakeholder feedback, the behaviour of this technology will be modified to place greater emphasis on generating at peak and night times.
Wind – onshore	–
Wind – offshore (both fixed and floating)	Since the 2022 ISP, candidate offshore REZs have been updated for the 2023 IASR. Additionally, both fixed and floating offshore wind turbine structures will be considered as distinct candidate options, with consideration for the ocean depth of the offshore REZ. More information is available in Section 3.9.
Biomass generation – electricity and heat	Previous stakeholder feedback on technologies considered within *GenCost 2022-23 Final report*[A] has suggested the need to pair heat and electricity production. In response, biomass generators in *GenCost 2022-23 Final report* and the ISP now includes both power generation and process heat. AEMO's capacity outlook modelling does not consider heat demand or location explicitly so any build decisions will be solely driven by power needs.
Pumped hydro energy storage (PHES)	AEMO includes eight-, 24-, and 48-hour PHES options across the NEM. Six and 12-hour PHES options are consolidated into an eight-hour option to reflect likely future PHES developments across the NEM. This also aligns with the New South Wales Infrastructure roadmap. These options are supplemented by announced projects where appropriate, for example the 20-hour Cethana project in Tasmania, which is included as a specific option with its own build cost and limit and deducted from the capacity available in Tasmania. This portfolio of candidates complements deep storage initiatives (such as the committed Snowy 2.0 and the anticipated Borumba Dam), and existing traditional hydro schemes.

A. At https://www.csiro.au/en/research/technology-space/energy/energy-data-modelling/gencost.

The following technologies are excluded from modelling considerations to keep problem size computationally manageable:

- New brown coal generation (with or without CCS) – given federal and state existing and contemplated policies regarding net zero emissions, including this technology would present an internal inconsistency with those policy requirements. Considering also that there are lower cost dispatchable alternatives offering greater system flexibility, investment risks for new brown coal developments are therefore assumed to be too high to be commercially viable.
- Advanced ultra-supercritical pulverised black coal (with and without CCS) – given the presence of carbon budgets across all scenarios and the existence of lower cost dispatchable alternatives, it is not expected that these technologies will be deployed and are therefore excluded.
- Reciprocating internal combustion engines – reciprocating engines fuelled by natural gas/diesel are not modelled due to their high capital cost relative to open cycle gas turbines (OCGTs), as discussed in the Aurecon 2022 Cost and Technical Parameters Review.
- Nuclear generation, including small-modular reactors – currently, Section 140A of the *Environment Protection and Biodiversity Conservation Act 1999*[135] prohibits the development of nuclear installations.

[135] At https://www.legislation.gov.au/Details/C2012C00248.

- Geothermal technologies – geothermal technologies are considered too costly and too distant from existing transmission networks to be considered a bulk generation technology option in any REZ.
- Solar PV fixed flat plate (FFP) and dual-axis tracking (DAT) technologies – while the best solar configuration depends on each individual project, single-axis tracking (SAT) generally presents greater value on a cost per energy delivered basis given current cost assumptions. Presently, announced SAT projects also provide more proposed capacity than DAT and FFP projects, and almost all recent project commitments for large-scale solar are SAT[136]. Given this preference and the relative cost advantage, AEMO models all future solar developments using SAT configuration.
- Tidal / wave technologies – this is not sufficiently advanced or economic to be included in the modelling.
- Hybrid technologies – these are not explicitly considered, but the ISP Methodology sets out how AEMO considers the benefits of co-locating VRE and storage in the assessment of potential actionable REZ augmentations.

3.5.3 Candidate technology build costs

Input vintage	July 2023
Source	• CSIRO: *GenCost 2022-23 Final report* • Aurecon: *2022 Costs and Technical Parameters Review* • Entura: *2018 Pumped Hydro Cost Modelling* • Hydro Tasmania information on Cethana project
Updates since Draft IASR	Updated to reflect CSIRO's *GenCost 2022-23 Final report*

Capital cost trajectories

AEMO's generator and storage capital cost trajectories are informed by the GenCost publication series – an annual publication of electricity generation technology cost projections conducted jointly through a partnership between CSIRO and AEMO.

To support this forecast, Aurecon provided estimates of the current capital cost of each generation technology (except for PHES) while pumped hydro energy storage cost estimates were originally sourced from a detailed Entura report on Pumped Hydro Cost Modelling[137]. CSIRO uses these current capital cost estimates in the GALLM model to produce capital cost forecasts that are a function of global and local technology deployment.

GenCost estimates include consideration of global demand for each technology, which relates to, among other things, international policy and renewable targets. Since the 2021 IASR, the GenCost scenarios have evolved to better reflect the uncertainty in the speed of global emissions reduction, which improves the alignment with AEMO's scenarios, and consideration of current supply-chain pressures.

The build cost projections are given for three *GenCost 2022-23 Final report* scenarios: "*Global NZE by 2050*", "*Global NZE post 2050*" and "*Current Policies*". These scenarios are described in greater detail in CSIRO's *GenCost 2022-23 Final report*. AEMO maps the 2023 IASR scenarios to the *GenCost 2022-23 Final report* scenarios based on the fit of the narratives against each other, as shown in Table 26.

[136] Based on November 2022 Generation Information, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[137] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Report-Pumped-Hydro-Cost-Modelling.pdf.

Table 26 Mapping AEMO scenario themes to the *GenCost 2022-23 Final report* scenarios

ISP scenario	*GenCost 2022-23 Final report* scenario	Explanation
Progressive Change	*Current Policies**	Consistent with current commitments to the Paris Agreement, leading to the lowest global emissions reduction ambition and a 2.5°C warming future.
Step Change	*Global NZE post 2050*	Consistent with global action to limit temperature rises to less than 2°C, and with industrialised countries targeting net zero emissions by 2050.
Green Energy Exports	*Global NZE by 2050*	The most ambitious global emissions reduction scenario, consistent with limiting temperature rises to less than 1.5°C.

* While *Progressive Change* does increase its emissions reduction ambition, achieving net zero emission domestically by 2050, the scenario also delays significant action to align with a higher warming future at a global scale and is not consistent with a "well below 2°" target.

Figure 43, Figure 44 and Figure 45 present a comparison of *GenCost 2022-23 Final report*'s *Global NZE post 2050* compared with GenCost 2021-22's *Global NZE post 2050* build cost projections (excluding connection costs) for selected technologies. Cost projections for each technology and scenario are available in the accompanying 2023 IASR Assumptions Workbook.

Compared to last estimates, the resulting cost projections see a significant increase over the next few years due to the current inflationary pressure especially for wind and storage technologies. As these impacts ease, costs converge closer to previous estimates in the longer term.

As detailed in the accompanying Aurecon report[138], there has been a substantial movement in capital cost assumptions compared to last year for a number of technologies. For example, onshore wind estimates have increased by 35%, and battery costs have increased by up to 20-35%.

Increases in current cost estimates are primarily driven by supply chain cost pressures, as discussed in more detail in Aurecon's report. These pressures in turn are the result of elevated construction costs due to labour shortages, steep rises in metal prices flowing through to markets, elevated shipping costs, or rising fuel prices amongst other factors. At the same time, more technology specific factors also play a role, such as increased lithium carbonate prices, or global competition for key components and technologies impacting wind turbine prices.

In recognition of the current inflationary cycle and the resulting cost pressures, CSIRO has modified their modelling approach in *GenCost 2022-23 Final report* to better account for this influence. Taking Aurecon's and Entura's figures as a starting point, *GenCost 2022-23 Final report* now applies 'basket-of-costs' factors over the period to 2023-24 (or more detailed projected cost information where available, such as for onshore wind, solar PV, batteries and electrolysers). These basket-of-costs factors take into consideration projected CPI, imported equipment, domestic equipment, and labour indices.

Following stakeholder feedback, the impact of supply chain constraints under the *Global NZE by 2050* and *Global NZE post 2050* scenarios are expected to last until 2029-30 when strong technology development is expected to occur. From that point, costs are expected to return to the normal trajectory had there not been cost pressures. Under the *Current Policies* scenario where there is less growth in technology deployment expected, the impact of pressured supply chains is expected to last only until 2026-27, after which the cost projections are largely driven by global technology deployment. Costs are interpolated between the values for 2023-24 and the normal trajectory in either the 2026-27 or 2029-30, depending on the scenario.

Additionally, projections have been adjusted to recognise the fundamental scarcity of land and easements following stakeholder feedback. Projections will be using locational cost factor published in the report by Mott

[138] At https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

Macdonald underpinning figures in AEMO's Transmission Cost Database for the land and easement component of the project cost.

More information on methodology adjustments from GenCost 2021-22 to *GenCost 2022-23 Final report* can be found in the *GenCost 2022-23 Final report*.

Figure 43 2022 vs 2023 *Global NZE post 2050*: build cost trajectories forecasts for wind and large-scale solar

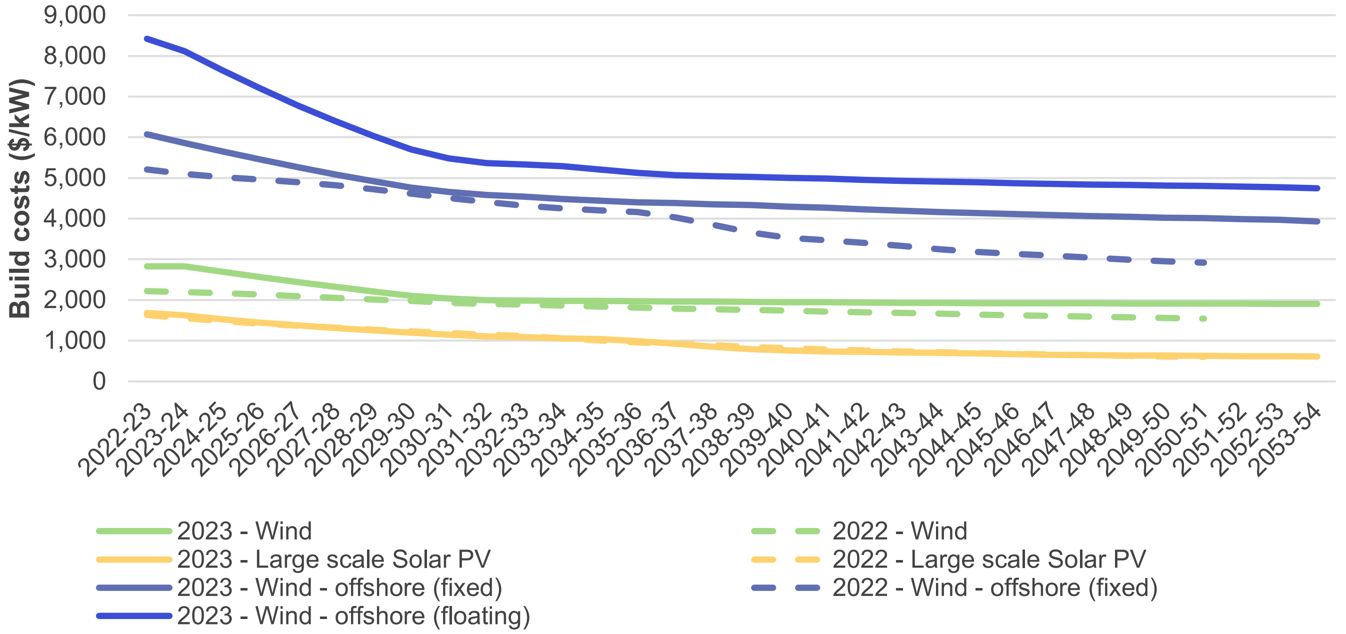


Figure 44 2022 vs 2023 *Global NZE post 2050*: build cost trajectories forecasts for gas and hydrogen

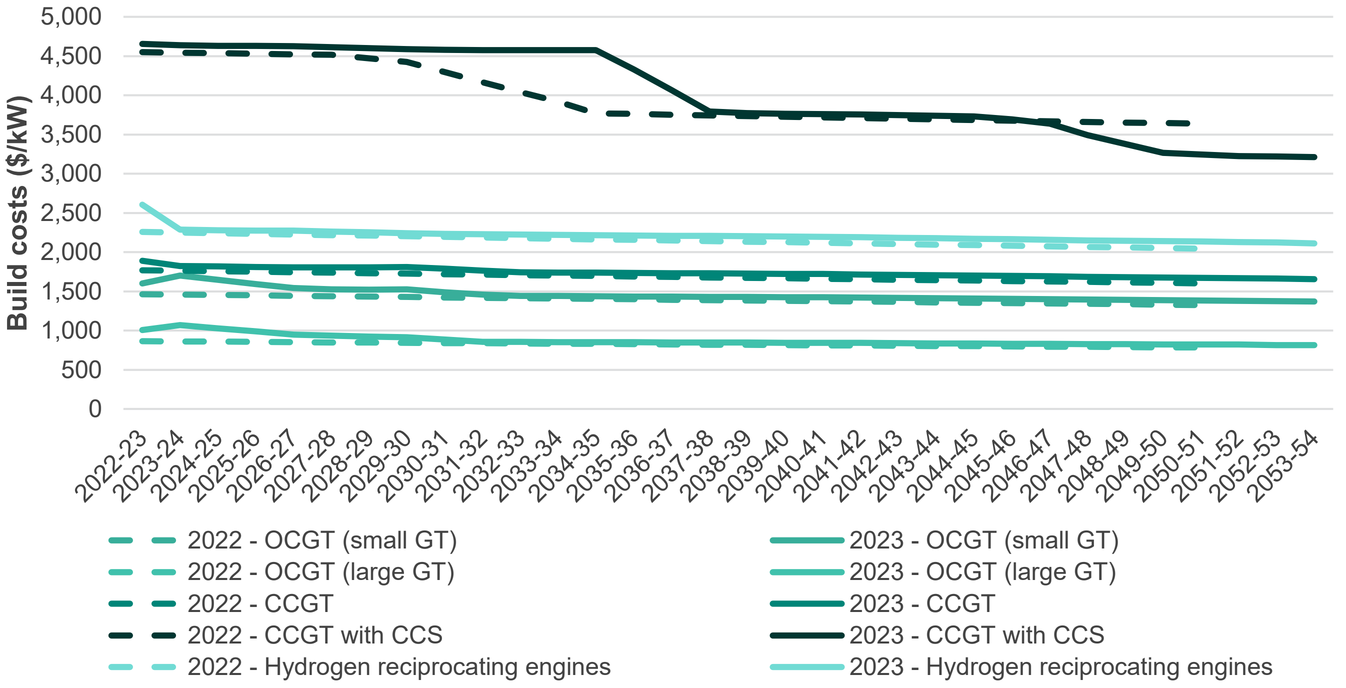
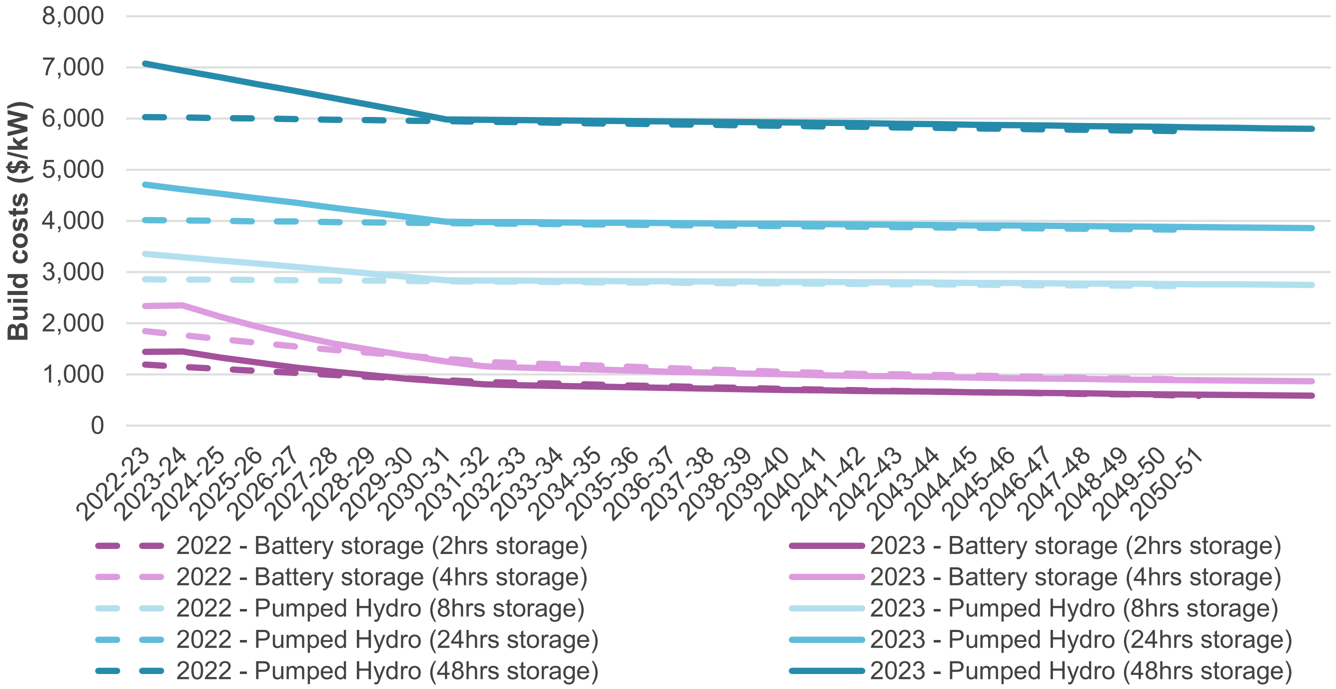


Figure 45 2022 vs 2023 *Global NZE post 2050*: build cost trajectories forecasts for selected storage technologies



In *GenCost 2022-23 Final report*, current costs (a key input to develop the projections) represent current contracting costs or costs demonstrated to have been incurred for projects completed in the current financial year and does not represent quotes for potential projects or project announcements.

It should also be noted that when comparing *GenCost 2022-23 Final report*'s capital costs in $/kW with Aurecon, the latter do not include the cost of land in its presentation of $/kW capital costs, whereas this is included by *GenCost 2022-23 Final report*, and therefore by AEMO[139].

Capital costs are not applied for existing, committed, and anticipated projects as these projects are included in all ISP development pathways, including the counterfactual, and therefore the calculation of net market benefits are not influenced by these project costs.

Locational cost factors

Input vintage	July 2023
Source	• *GHD: 2018-19 Costs and Technical Parameters Review* • *Aurecon: 2022 Costs and Technical Parameters Review* • AEMO revisions
Updates since Draft IASR	Locational cost factor adjustment for the land component of the generation cost is based on the easement and property cost adjustment factors taken from the Mott MacDonald transmission cost database update final report[140].

[139] Build costs from GenCost are then weighted by regional costs factors (see the following section) where AEMO considers Aurecon's cost of land and other locational influences.

[140] At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/2023-teor/mott-macdonald-transmission-cost-database-update-final-report.pdf?la=en.

To estimate the capital costs of technologies developed in different locations, cost zones are attributed to each generation and storage candidate. Each cost zone in each region has a specific set of locational cost factors which provides multiplicative scalars to the cost components (equipment, fuel connection, land and development, and installation) of each generation and storage technology type.

Table 27 captures breakdown of technology cost components which are informed by updated data from *GenCost 2022-23 Final report*. Compared to figures published in the AEMO's *2022 Forecasting Assumptions Update*[141], there has been an increase in the ratio of equipment cost for batteries, onshore wind, and biomass on account of the new configuration, as discussed in the above section.

These factors do not capture site-specific aspects of costs that are only known when detailed feasibility investigations have been implemented. If site-specific cost information on particular projects becomes available, AEMO may shift to adopting these values as appropriate.

Table 27 Technology cost breakdown ratios

Technology	Equipment costs	Fuel connection costs	Cost of land and development	Installation costs
OCGT (small gas turbine)	61%	5%	8%	26%
OCGT (large gas turbine)	59%	9%	8%	25%
CCGT	62%	3%	8%	27%
CCGT with CCS	63%	2%	8%	27%
Hydrogen reciprocating engines	55%	0%	8%	37%
Biomass	55%	0%	8%	37%
Battery storage (1 hr storage)	82%	0%	5%	13%
Battery storage (2 hrs storage)	83%	0%	4%	13%
Battery storage (4 hrs storage)	85%	0%	2%	13%
Battery storage (8 hrs storage)	85%	0%	1%	13%
Large-scale solar PV	57%	0%	6%	38%
Solar thermal (15 hrs Storage)	74%	0%	1%	25%
Wind – onshore	73%	0%	2%	24%
Wind – offshore (fixed)	69%	0%	2%	29%
Wind – offshore (floating)	69%	0%	2%	29%

Cost zones (low, medium, and high) consider regional labour costs and access to ports, roads and rail, but ignore localised environmental, geological, and social drivers which require site-by-site assessments and are difficult to predict. They also exclude cost premiums that may arise if multiple projects are simultaneously competing for scarce resources across the construction supply chain. The primary source of these is the GHD 2018-19 review, which has been updated following stakeholder feedback for the 2021 IASR and in this 2023 IASR.

In particular, on the back of stakeholder feedback, AEMO revised the cost zones such that the lowest cost zones in each region have equivalent cost factors. Normalising these factors means that they reflect the impact of proximity to major infrastructure and workers. The primary source of these factors is the GHD 2018-19 review.

[141] At https://aemo.com.au/-/media/files/major-publications/isp/2022-forecasting-assumptions-update/final-2022-forecasting-assumptions-update.pdf.

As a result of stakeholder feedback that highlighted the inconsistencies with the treatment of locational cost factors for transmission projects, AEMO has adopted the locational cost factors for the land and development cost component from the Mott Macdonald report[142] that feeds into AEMO's Transmission Cost Database.

Table 28 and Figure 46 present the estimated NEM locational cost factors. The accompanying 2023 IASR Assumptions Workbook provides additional details of these cost factors, including the resulting regional technology cost adjustment factors.

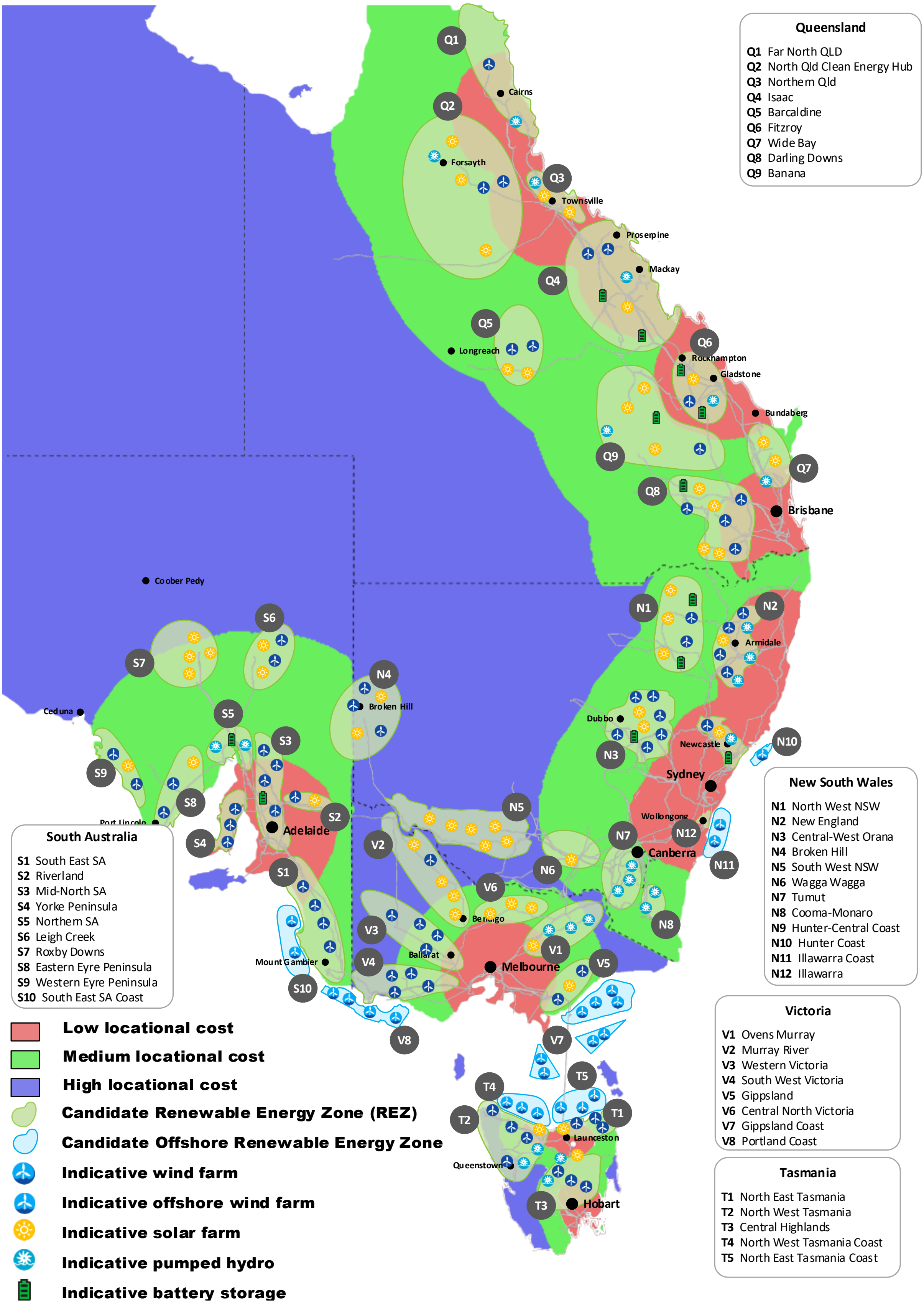
Table 28 NEM locational cost factors

Region	Cost zone	Equipment costs (%)	Fuel connection costs (%)	Cost of land and development (%)	Installation costs (%)	O&M costs (%)
New South Wales	Low	100	100	100	100	100
	Medium	105	107	79	110	108
	High	110	116	21	120	117
Queensland	Low	100	100	100	100	100
	Medium	105	110	49	115	112
	High	110	121	21	131	125
South Australia[A]	Low	100	100	100	100	100
	Medium	105	110	33	115	112
	High	110	120	17	129	124
Tasmania	Low	100	100	100	100	100
	Medium	105	107	72	110	109
	High	110	114	64	121	117
Victoria	Low	100	100	100	100	100
	Medium	103	103	69	103	103
	High	105	105	36	105	105

A. There are some differences between the South Australia values applied here when compared to the Mott Macdonald update to AEMO's Transmission Cost Database. Further information is available in Mott Macdonald's report on the update, https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation.

142 At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/2023-teor/mott-macdonald-transmission-cost-database-update-final-report.pdf?la=en.

Figure 46 Locational cost map



† The REZ boundaries for N5 , N9 and N12 are indicative and aligned with the draft declaration for these REZs.

Locational cost factors for pumped hydro

In line with all other new entrant technologies, sub-regional locational cost factors are applied to PHES options. Unlike those for other technologies, locational cost factors for PHES have been derived based on the relative cost of the natural resource and geology available within each location for PHES development. These factors do not capture site-specific aspects of costs that are only known when detailed feasibility investigations have been implemented. The factors have been sourced from the Entura report and remain consistent with the 2021 IASR. If site-specific cost information on particular projects becomes available, AEMO may shift to adopting these values as appropriate.

Table 29 presents the locational cost factors for PHES. Tasmanian facilities[143] are at least approximately 25% lower cost than Victorian alternatives, and the cost advantages of pumped hydro in Tasmania increases for deeper storage sizes.

Table 29 Pumped hydro energy storage locational cost factors

ISP sub-region	Region	PHES: 8hrs	PHES: 24hrs	PHES: 48hrs
Northern Queensland (NQ)	Queensland	1.01	0.88	0.86
Central Queensland (CQ)	Queensland	1.01	0.88	0.86
Gladstone Grid (GG)	Queensland	not applicable*	not applicable*	not applicable*
South Queensland (SQ)	Queensland	1.11	0.96	0.88
Northern New South Wales (NNSW)	New South Wales	0.88	0.82	0.62
Central New South Wales (CNSW)	New South Wales	1.02	1.08	1.12
South New South Wales (SNSW)	New South Wales	1.04	1.00	0.91
Sydney, Newcastle, Wollongong (SNW)	New South Wales	not applicable*	not applicable*	not applicable*
Victoria (VIC)	Victoria	1.00	1.00	1.00
Central South Australia (CSA)	South Australia	1.35	1.67	not applicable*
South East South Australia (SESA)	South Australia	not applicable*	not applicable*	not applicable*
Tasmania (TAS)	Tasmania	0.75	0.62	0.46

*Pumped hydro energy storage of this depth in this sub-region is not a credible candidate.

3.5.4 Storage-specific assumptions

Input vintage	July 2023
Source	• Aurecon: *2022 Costs and Technical Parameters Review* • CSIRO: *GenCost 2022-23 Final report* • Entura: *2018 Pumped Hydro Cost Modelling* • Hydro Tasmania information on Cethana project
Updates since Draft IASR	Updated to reflect final assumptions from Aurecon, which includes revisions based on stakeholder feedback. The pumped hydro options have been consolidated to reflect proposed projects and improve alignment with the New South Wales Electricity Infrastructure Roadmap and Queensland governments plans for PHES in south-east Queensland.

[143] These factors apply only to generic Tasmanian projects, as specific cost assumptions are used for the Cethana project.

AEMO includes a range of storage options in assessing the future needs of the power system. Storage expansion candidates in each region include PHES, large-scale batteries, concentrated solar thermal (CST), and embedded battery systems within AEMO's CER forecasts.

Pumped hydro energy storage (PHES) build limits

AEMO applies build limits for pumped hydro expansion candidates based on sub-regional estimates detailed by the 2018 Entura report[144], modified where appropriate to reflect the latest generator development announcements in Generation Information (or announced government development policies).

AEMO has adjusted the limits to consider proposed projects across NEM regions since the publication of the Entura report. AEMO has subtracted the generation capacity of these projects from the relevant original limit, while maintaining Entura's sub-regional breakdown.

The pumped hydro energy storage sub-regional limits are shown in Table 30.

Table 30 Pumped hydro sub-regional limits (in MW of generation capacity)

ISP sub-region	Region	PHES: 8hrs	PHES: 24hrs	PHES: 48hrs
Northern Queensland (NQ)	Queensland	1,250	278	111
Central Queensland (CQ)	Queensland	1,000	5,000	89
Gladstone Grid (GG)	Queensland	-	-	-
South Queensland (SQ) +	Queensland	1,750	-	300
Northern New South Wales (NNSW)	New South Wales	1,275	500	500
Central New South Wales (CNSW)	New South Wales	1,750	235	83
South New South Wales (SNSW)*	New South Wales	2,500	583	167
Sydney, Newcastle, Wollongong (SNW)	New South Wales	-	-	-
Victoria (VIC)	Victoria	2,700	700	400
Central South Australia (CSA)	South Australia	698	200	-
South East South Australia (SESA)	South Australia	-	-	-
Tasmania (TAS)^	Tasmania	1,625	1,200	371

+ The South Queensland limits do not include Borumba Dam (2GW), which will be modelled as a specific project.
* Total value excludes the contribution of Snowy 2.0.
^ For Tasmania, this capacity does not include the Cethana project (750 MW).

The following considerations have been made in determining the pumped hydro sub-regional limits:

- New South Wales PHES limits are based on 24 energy projects shortlisted for potential development as part of the New South Wales Government Pumped Hydro Roadmap[145]. The limits have been further adjusted to provide sufficient capacity to reflect five projects that have been awarded funding under the New South Wales Pumped Hydro Recoverable Grants Program[146].
- Tasmanian PHES limits have been informed by analysis of the detailed project information within the Entura report, provided by contributors to the report (but not published). This data avoids misinterpretation of projects

[144] Entura, Pumped Hydro Cost Modelling, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Report-Pumped-Hydro-Cost-Modelling.pdf.

[145] See https://www.energy.nsw.gov.au/nsw-plans-and-progress/major-state-projects/pumped-hydro-roadmap#-pumped-hydro-roadmap-.

[146] See https://www.nsw.gov.au/media-releases/pumped-hydro.

that may not be mutually exclusive and is aligned reasonably with Tasmanian PHES submissions to Generation Information.

- Where applicable, PHES limits have been adjusted above Entura estimates to ensure proposed projects in Generation Information submissions can be accommodated. For example, the limit for 24-hour PHES in Central Queensland has been adjusted to include the announced Pioneer-Burdekin Pumped Hydro Project[147].

Batteries

Large-scale battery expansion candidates are modelled with fixed power to energy storage ratios, but with flexibility to charge and discharge to achieve the optimal outcome for the system within the fixed power to energy storage ratio limit.

Assumptions for battery storages of 1-hour, 2-hour, 4-hour, and 8-hour duration depths are based on data provided by Aurecon in its final 2022-23 report. Battery storage degradation, which Aurecon indicates is 1.8% annually, has been factored in by reducing the storage capacity of all battery storage by 16% which is an estimate of the average storage capacity over the battery life of 20 years, after taking into account this degradation and estimated operating levels.

AEMO's technology cost assumptions consider the usable storage capacity in defining project costs as sourced from Aurecon, and its modelling assumes a minimum and maximum state of charge of 0% and 100% respectively.

Exact storage locations are identified considering the storage needs of REZ and regional developments through time-sequential dispatch and power flow modelling, using AEMO internal expertise to determine suitable locations where transmission costs may be offset by locating storage.

Solar thermal technology

AEMO models new entrant solar thermal generators as a central tower and receiver with thermal storage. Based on previous stakeholder feedback reflected in CSIRO's Draft *GenCost 2022-23 Final report*, the capacity of the thermal storage component has been updated from eight hours to 15 hours.

AEMO's capacity outlook modelling for the 2022 ISP used static discharge traces to represent operation. Stakeholder feedback has suggested modifications to the assumed operation of this technology are needed, charging during sunlight hours and discharging at night. AEMO has modified the static discharge traces to reflect this behaviour, such that they are optimised to discharge at night and during periods of high demand. If reasonable adoption of the technology occurs, subsequent simulations will include it as a controllable storage object to better represent its operation.

[147] See https://qldhydro.com.au/projects/pioneer-burdekin/.

3.5.5 Other technical and cost parameters for new entrants

Input vintage	July 2023
Source	• Aurecon: *2022 Costs and Technical Parameters Review* • CSIRO: *GenCost 2022-23 Final report* • Entura: *2018 Pumped Hydro Cost Modelling* • Hydro Tasmania information on Cethana project
Updates since Draft IASR	No update since the Draft 2023 IASR

Technical and other cost parameters for new entrant generation and storage technologies include:

- Unit size and auxiliary load.
- Seasonal ratings.
- Heat rate.
- Scope 1 emission factors.
- Minimum stable load.
- Fixed and variable operating and maintenance costs.
- Maintenance rates and reliability settings.
- Lead time, economic life, and technical life.
- Storage parameters (including cyclic efficiency and maximum and minimum state of charge).

Details of these parameters are published in the 2023 IASR Assumptions Workbook as well as in the supporting material from Aurecon.

For new entrant generators (that is, generators that are not existing, and developed in the forecast horizon), the technical life of each asset is enforced, such that new capacities will be decommissioned at the end of their respective technical lives. Replacement may not require a 'greenfield' solution (a 'brownfield' redevelopment may be appropriate for some assets), but technology improvements often mean that much of the original engineering footprint of a project may require redevelopment. Given that a brownfield solution would likely require site-by-site assessments and a more bespoke approach, AEMO applies no discount to asset redevelopments, with costs consistent with new entry greenfield developments. Likewise, there is no requirement for a retired generator to be replaced locally (except for if a policy setting required a local response to meet a renewable energy target, for example), so a retirement could be effectively replaced at another NEM location, if that minimises costs.

The technical life assumed for new wind and solar projects is 30 years. This assumption has been validated through the November 2022 Generation Information dataset, which shows that, on average, committed VRE projects have submitted a technical life (reflecting the time between commissioning date and the expected closure year) of 29 years (solar projects) and 26 years (wind projects). AEMO considers this an appropriate and supportive benchmark of the assumption.

3.6 Fuel and renewable resource assumptions

3.6.1 Fuel prices

Gas prices

Input vintage	July 2023
Source	ACIL Allen Consulting
Updates since the Draft 2023 IASR	New gas price forecasts based on feedback received on Draft 2023 IASR, to reflect gas price cap and Mandatory Code of Conduct

To address stakeholder feedback received during the 2023 Draft IASR consultation process, and AEMO's own recognition that the draft forecasts were yet to consider recent government pricing policy, AEMO sourced updated natural gas price forecasts from ACIL Allen in July 2023. These forecasts consider the impact of the Federal Government's mandatory Code of Conduct (Code). The Code[148] was published in July 2023, and includes a reasonable pricing framework extending the existing gas price cap of $12/GJ for wholesale gas contracts and for non-urgent transactions (outside three days) at the Gas Supply Hubs. Small producers (less than 100 PJ per year) supplying the domestic market are exempt from the pricing rules, whilst other producers can apply for conditional exemptions. The Code is subject to a review commencing 1 July 2025.

The gas price forecasts consider fundamental inputs such as forecast gas production costs from existing and upcoming fields, reserves, infrastructure and pipelines, in addition to international gas prices, oil prices and measures of the domestic economy. The forecasts are also based on assumptions about the influence of international prices on east coast gas prices through LNG netback pricing, and the local level of competition. The Australian Domestic Gas Supply Mechanism (ADGSM) reforms commenced 1 April 2023 and are designed to make the ADGSM more responsive to domestic gas shortfalls, while protecting established long-term contracts. The effect of the ADGSM reforms and the Heads of Agreement with east coast gas exporters are considered in the gas price forecasts.

Figure 47 compares industrial gas price forecasts at Melbourne across the scenarios against forecasts presented in the 2021 IASR, as well as the 2023 Draft IASR. All other regions are provided in the 2023 IASR Assumptions Workbook. For the *Step Change* scenario, Figure 48 demonstrates the relationship between regions. More information on the derivation of these forecasts is provided in the ACIL Allen report[149].

[148] See https://www.energy.gov.au/government-priorities/energy-markets/gas-markets/mandatory-gas-code-conduct.

[149] At https://aemo.com.au/en/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

Figure 47 Forecast industrial gas prices by scenario – Melbourne, 2023 to 2054 ($AUD/GJ)

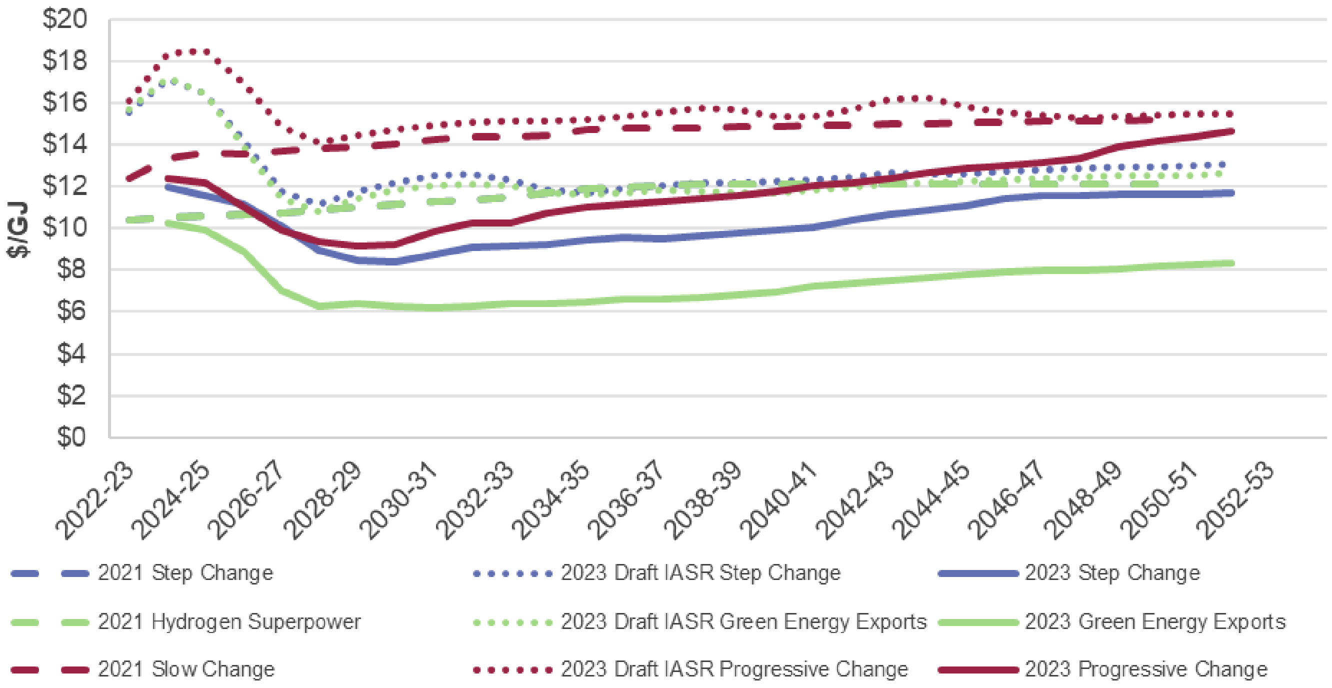
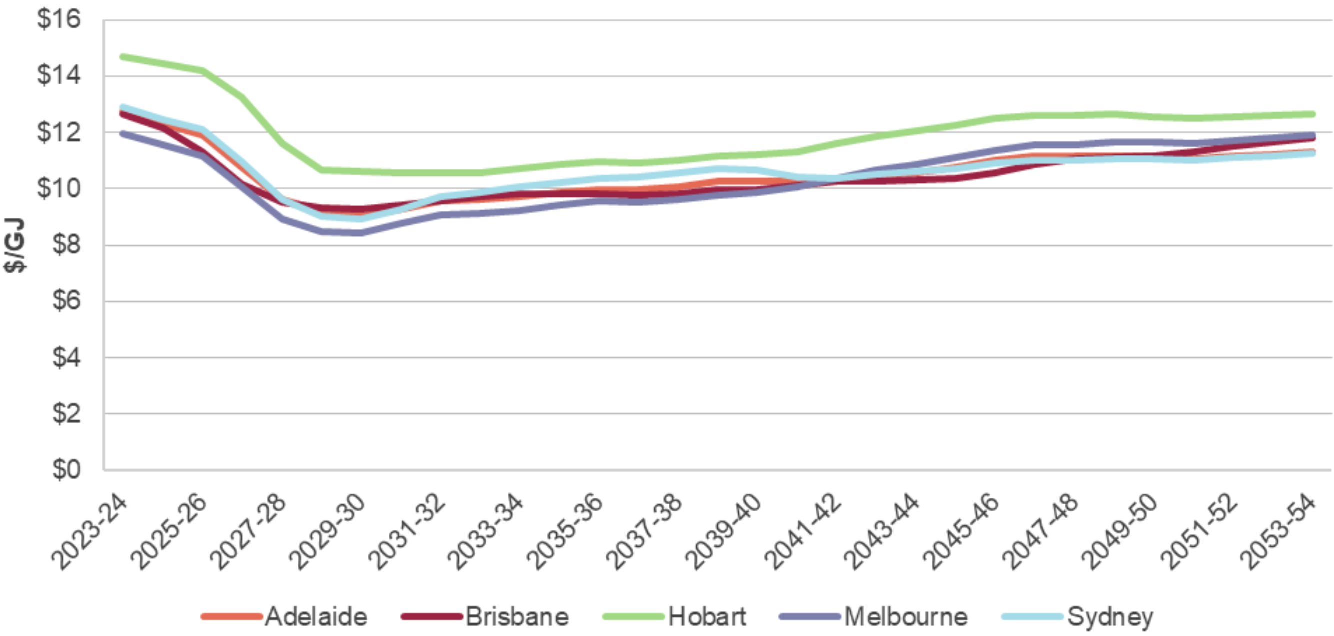


Figure 48 Forecast industrial gas prices by location – *Step Change*, 2023 to 2054 ($AUD/GJ)



Both figures feature a high initial price, reflecting the current global economic conditions. The near-term price has reduced in comparison to the 2023 Draft IASR forecasts, reflecting the impact of the Federal Government's Mandatory Code of Conduct and gas price cap. Following this, the price forecasts decline to a minimum in the late

2020s, largely driven by a forecast reduction in LNG netback prices[150]. Gas prices in the long term are forecast to increase slightly, a result of the competing effects of decreasing supply and increasing production cost.

The scenarios differ based on longer-term underlying costs of supply for each scenario, as well as international oil prices.

These gas price forecasts assume that new gas production becomes available when required, and makes no assumptions around access to finance for new gas developments. They also reflect the marginal cost for new wholesale gas supply in each region.

The gas prices associated with each gas-powered generator are provided in the 2023 IASR Assumptions Workbook. The costs include regional pricing, considering the supply options and the relevant cost of pipeline transmission.

Coal prices

Input vintage	July 2023
Source	Wood Mackenzie and OEA
Updates since Draft IASR	Forecasts updated based on feedback received on the 2023 Draft IASR, to reflect coal price cap

AEMO engaged external consultant OEA to provide a forecast for Newcastle export thermal coal prices for each scenario. The unprecedented volatility in international energy commodities during 2022 had a strong influence on coal prices for electricity generation. In late 2022, the New South Wales and Queensland Governments agreed to implement temporary coal price caps of $125 per tonne for power stations as part of the Federal Government's Energy Price Relief Plan.

The coal price forecasts provided by OEA have been updated in this 2023 IASR to reflect the $125 per tonne price cap until 30 June 2024. The export price forecast is used to establish the domestic equivalent cost for black coal generators in Queensland and New South Wales, depending on their level of export price exposure.

Not all coal generators are exposed to export pricing dynamics, particularly if they operate from captive mines, or are not using export or near-export grade black coal. Coal generators not considered exposed to the export markets (for example the Victorian brown coal fleet) use Wood Mackenzie's 2021 coal price forecasts[151].

The coal price forecasts are provided in more detail in the 2023 IASR Assumptions Workbook.

[150] See https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/lng-netback-price-series.

[151] Price forecasts do not consider any announced generator closures.

Figure 49 Forecast coal prices for existing generators in New South Wales, *Step Change*, 2023 to 2054 ($AUD/GJ)

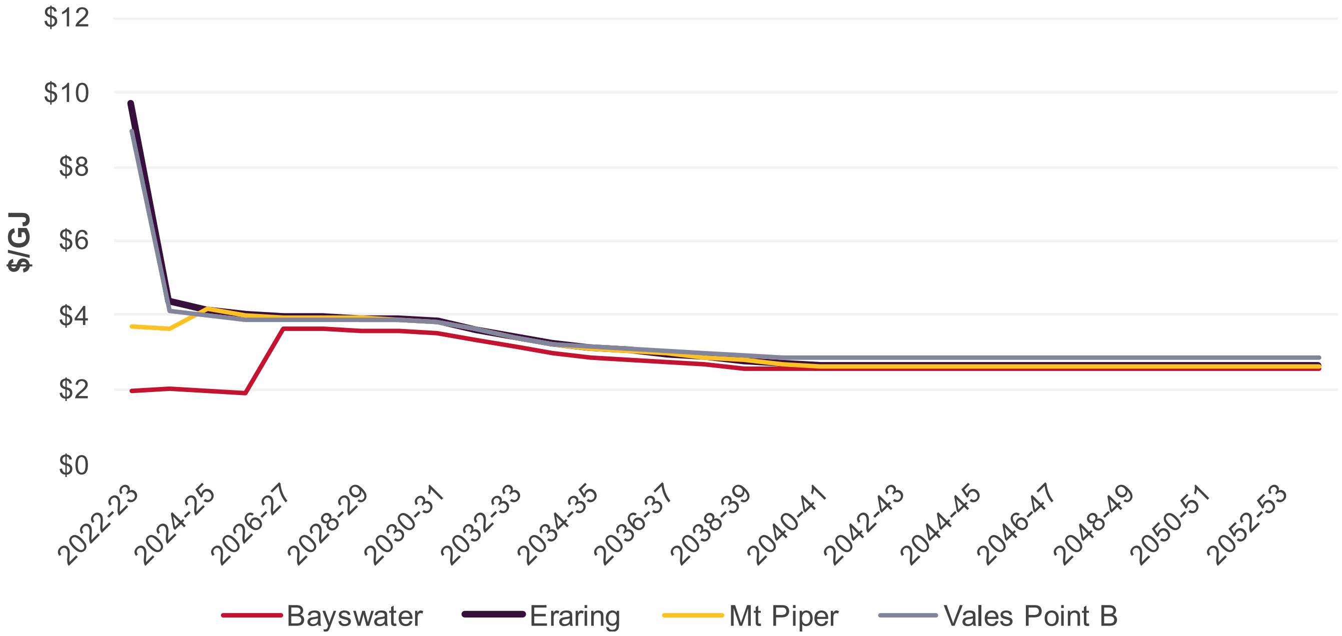
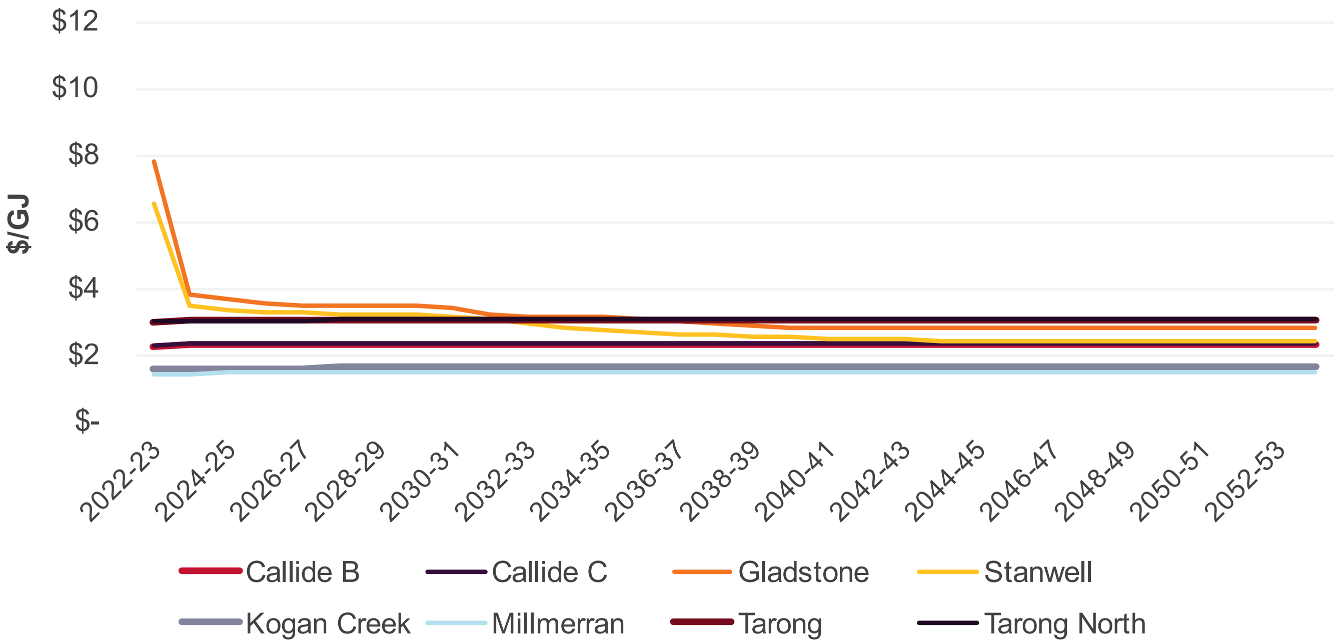


Figure 50 Forecast coal prices for existing generators in Queensland – *Step Change*, 2023 to 2054 ($AUD/GJ)



3.6.2 Renewable resources

Input vintage	July 2023
Source	• Solcast irradiance and PV output analysis • BoM • AEMO SCADA data • Other relevant reanalysis providers
Updates since Draft IASR	Updated to include the 2022-23 reference year, updates to REZ boundaries, change in wind speed reanalysis provider, and feedback received on the Draft 2023 IASR.

Renewable resource quality and other weather variables are key inputs in the process of producing generation availability profiles for solar and wind generators. Resource quality data and other weather inputs are updated annually to include the most recent reference years. This data is obtained from several sources, including:

- Wind speed (at a relevant hub height) from ERA5[152] reanalysis data from European Centre for Medium-Range Weather Forecasts.
- Solar irradiance reanalysis data from Solcast.
- Temperature and ground-level wind speed observation data from the BoM.
- Historical generation and weather measurements from SCADA data provided by participants.

AEMO uses resource-to-power conversion models to estimate VRE generation as a function of meteorological inputs, and calibrates this to historical production levels for existing wind farms. Wind generation availability modelling, for example, uses an empirical machine learning model to estimate generator output as a function of wind speed and temperature, capturing the impacts of high wind and high temperature events observed in historical data. Participant information on generator capabilities during summer peak demand temperatures are overlayed on top of these models. Further detail on how AEMO estimates half-hourly generation availability profiles for existing, committed and anticipated VRE generators is provided in the *ESOO and Reliability Forecast Methodology*[153].

For new entrant VRE generators, AEMO represents onshore wind resource quality in each REZ in two tranches representing high and medium quality sites, based on an assessment of all available datapoints that are considered suitable for wind development. AEMO represents solar resource quality based on an assessment of solar resource at a selection of existing and proposed solar generation sites within each REZ.

Following stakeholder feedback received during the 2022 ISP, AEMO has implemented methodological improvements with regards to how representative wind and solar sites in each REZ are selected. The changes place greater consideration on the suitability of sites for the development of new entrant VRE generators, and may impact the representation of REZ resource quality if high or low quality sites are considered unsuitable. Capacity factors representing the resource potential for each REZ and technology using this new methodology are provided in the 2023 IASR Assumptions Workbook. The methodology was further detailed and consulted on in the 2024 ISP Methodology.

AEMO also continues to explore potential challenges regarding the operability of a NEM that is predominantly operated from renewable generators, particularly during long periods of dark and still conditions that would lower

[152] At https://www.ecmwf.int/en/forecasts/dataset/ecmwf-reanalysis-v5.

[153] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/esoo-and-reliability-forecast-methodology-document-2022.pdf.

renewable generation output. AEMO recognises that geographic and technological diversity are key means to lower the impact of extreme conditions in this regard, however it is possible that weather extremes will still impact the resilience of a renewable energy system and increase the magnitude of extreme demand conditions as well, beyond that which is already considered in AEMO's forecasting approach which passes through forecast average temperature rise over time.

In the 2024 ISP AEMO will explore adaptations to historical weather conditions to increase the frequency of weather extremes, as a means to simulate potential growth in weather extremes affecting electricity demands and/or renewable generation.

Wind and solar resource quality for each REZ is shown below in Figure 51 and Figure 52 respectively.

Figure 51 Wind resource quality map – average wind speed (m/s) at hub height

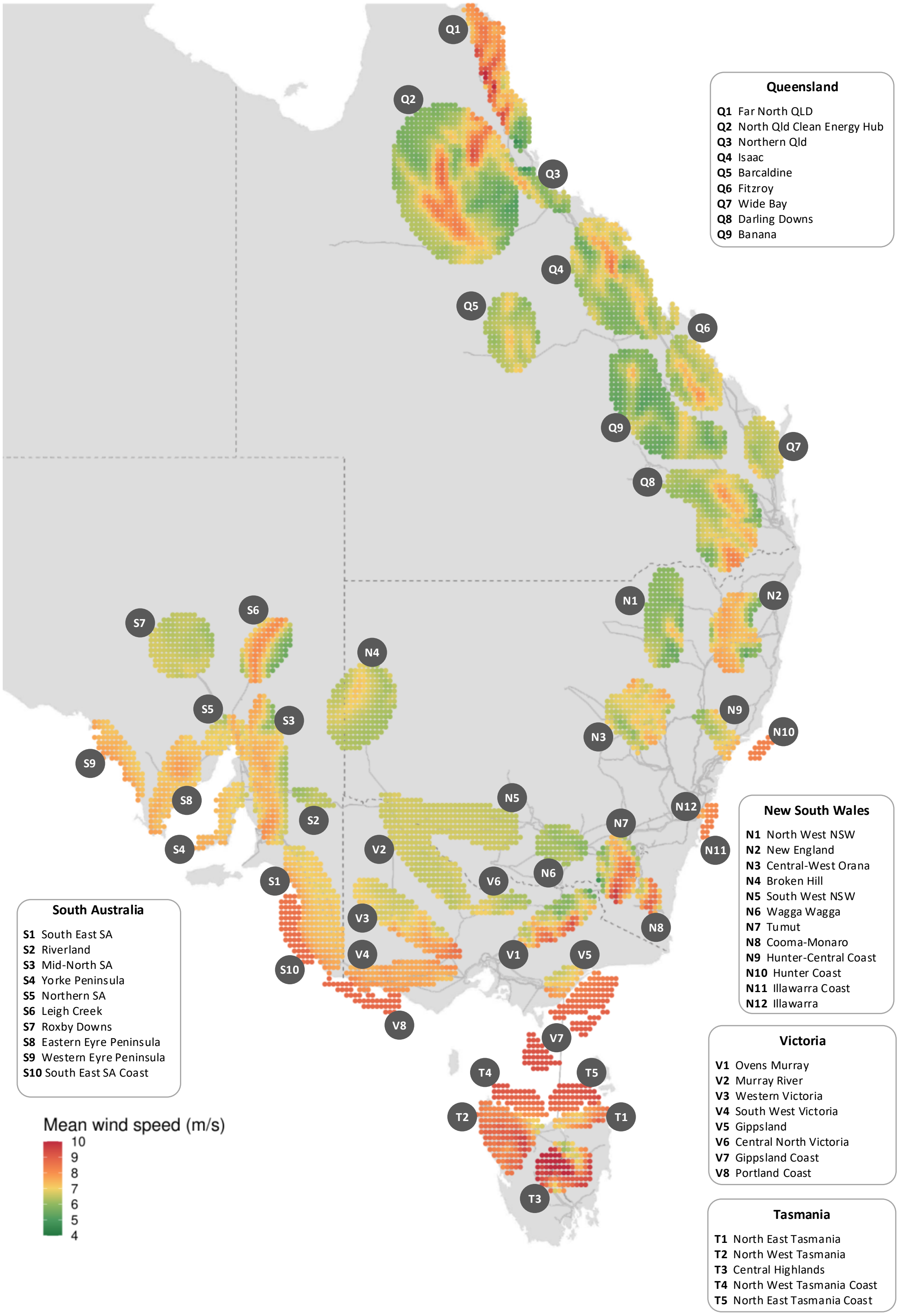
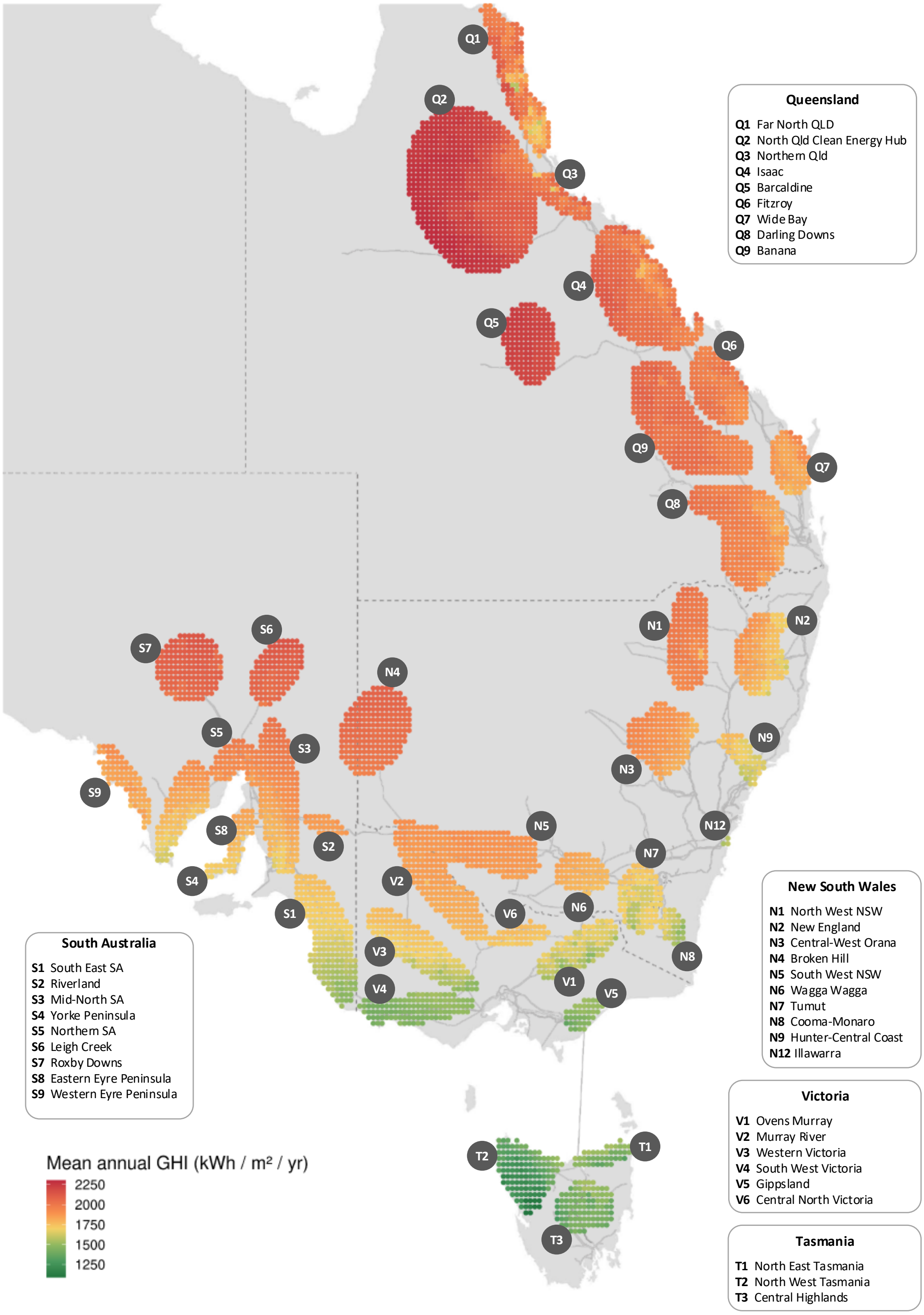


Figure 52 Solar resource quality map – average annual global horizontal irradiance (GHI) (kWh / m² / year)



3.7 Financial parameters

3.7.1 Discount rate

Input vintage	June 2023
Source	Synergies Economic Consulting and OEA
Updates since Draft IASR	A confidential survey of empirical cost of capital from across NEM stakeholders were conducted to ascertain the proposed discount rates. The survey suggests that the proposed central discount rates are appropriate, but a higher upper bound for discount rate is recommended. A new lower bound discount rate based on the latest AER revenue determination for a TNSP is also reflected.

The AER's Cost Benefit Analysis Guidelines[154] state that the discount rate in the ISP is "*required to be appropriate for the analysis of private enterprise investment in the electricity sector across the NEM*", and that it should promote competitive neutrality across investment options. For this reason, AEMO uses the same rate as both the discount rate for costs and benefits (to calculate the net present value) and the weighted average cost of capital (WACC) for annualising capital costs across all generation and transmission investments.

For the 2022 ISP, AEMO engaged Synergies Economic Consulting to provide discount rate assumptions, which is a WACC-based estimate reflecting an average investor view about required return on investments in the NEM. For the Draft 2023 IASR, Synergies Economic Consulting was again engaged to provide updated discount rate estimates and to reflect economic developments and changes in financial parameter settings since the 2022 ISP.

Following stakeholder feedback on the Draft 2023 IASR, AEMO engaged OEA to survey developers in the NEM regarding their cost of capital to gather additional input, including evidence on the suitability of Synergies proposed discount rates. OEA found that there is anecdotal and empirical evidence that suggest that the central discount rate proposed by Synergies is reasonable and similar to those faced by developers in the NEM. A report about the survey and the results is detailed in the accompanying report from OEA.

Table 31 below presents the values in this final 2023 IASR to be used in the 2024 ISP, as well as the Draft 2023 IASR and 2022 ISP values for comparison.

Table 31 Pre-tax real discount rates

	Lower bound	Central estimate	Upper bound
2022 ISP	2.0%	5.5%	7.5%
Draft 2023 IASR	4.0%	7.0%	9.0%
2023 IASR	3.0%	7.0%	10.5%

AEMO will base the lower bound rate on the most recent AER determination, *Final decision: Transgrid transmission determination 1 July 2023 to 30 June 2028*[155], which the AER set to be 3.04%. This is consistent with discretionary guidance in the AER's CBA Guidelines. The upper bound is inflated from the Draft 2023 IASR from 9% to 10.5%, matching the insights from the OEA survey results. Given that it is not possible to accurately forecast the level of return that private investors will target over the long term, the use of sensitivity analysis (as was applied in the 2022 ISP) is an important approach to reduce the risks of under- or over-investment due to this assumption.

[154] At https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

[155] Attachment 3, Rate of Return, at https://www.aer.gov.au/system/files/AER%20-%20Transgrid%202023-28%20-%20Final%20Decision%20-%20Attachment%203%20Rate%20of%20return%20-%20April%202023.pdf.

3.7.2 Value of customer reliability

Input vintage	December 2022
Source	• AER: 2019 Values of Customer Reliability Review • AER Values of Customer Reliability – Annual adjustment – December 2022
Updates since the Draft 2023 IASR	VCR updated to reflect AER December 2022 update.

Values of Customer Reliability (VCRs) are usually expressed in dollars per kilowatt-hour [kWh]) and reflect the value different customer types place on reliable electricity supply. VCRs are used in cost-benefit analysis to quantify market benefits arising from changes in involuntary load shedding when comparing investment options.

In accordance with the AER's Cost Benefit Analysis Guidelines, AEMO is required to use the AER's most recent VCRs at the time of publishing the ISP Timetable. The AER releases annual updates to its VCRs based on the Consumer Price Index for that year, with the most recent adjustment coming in December 2022[156]. AEMO has applied these adjustments to the customer load-weighted state VCRs that were published by the AER in December 2019[157] and used for the 2022 ISP; the current VCRs are summarised in Table 32 below.

Table 32 AER Values of distribution and transmission customer load-weighted VCR by state

	New South Wales	Victoria	Queensland	South Australia	Tasmania
VCR ($/MWh)	49,216	48,152	46,774	50,513	37,578

3.8 Climate change factors

The changing climate has an impact on a number of aspects of the power system, including consumer demand response to changing temperature conditions, and generation and network availability. The impact of reduced precipitation on dam inflows is described in Section 3.4.5. The following sections describe other impacts considered in AEMO modelling.

As described in Section 3.6.2, AEMO recognises that a changing climate may also lead to greater potential challenges in maintaining the operability of a NEM that is predominantly reliant on intermittent generation for its electricity production, particularly during long periods of dark and still conditions that would lower renewable generation output. AEMO recognises that geographic and technological diversity are key means to lower the impact of extreme conditions in this regard, however it is possible that weather extremes will still impact the resilience of a renewable energy system and increase the magnitude of extreme demand conditions as well, beyond that which is already considered in AEMO's forecasting approach which passes through forecast average temperature rise over time (as described in the following section).

In the 2024 ISP AEMO will explore adaptations to historical weather conditions to increase the frequency of weather extremes, as a means to simulate potential growth in weather extremes affecting electricity demands and/or renewable generation.

[156] At https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability/update-0.

[157] See Table 5.22 at https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf.

3.8.1 Temperature change impacts

Input vintage	January 2019 (CMIP5)
Source	BoM, CSIRO, ESCI (see ClimatechangeinAustralia.gov.au)
Updates since Draft IASR	No update since the 2021 IASR

AEMO incorporates climate change temperature change factors in its demand forecasts and transmission line thermal ratings in forecasting models where constraints are applied. For demand, AEMO adjusts historical weather outcomes to apply in future years based on the outcomes projected by forecast climate models. Climate data is collected from ESCI data published on the CSIRO and BoM's website Climate Change in Australia[158]. For more information on this, see Appendix A.2.3 of the Electricity Demand Forecasting Methodology[159].

For transmission line ratings, AEMO applies the most relevant temperature rating available for the equipment for the projected weather outcome. At present, AEMO applies seasonal ratings for most regions, as published in the transmission equipment ratings[160], except for Victoria where forecast dynamic line ratings are available for some transmission lines for application in the reliability forecasting models.

Climate Change in Australia and ESCI data projects gridded daily minimum and maximum temperatures for each global climate model (GCM) for each of the RCP pathways (outlined in Section 3.2). Data is selected for the closest available RCP to the scenario specification. Climate science considers that warming over the next 20 years or so is largely locked in from historical emissions and therefore adjustments do not vary substantially between scenarios to 2050. Where the physical impacts associated with the RCP's referenced in the scenario narrative are not available, results are scaled between available RCPs (often just 4.5 and 8.5) to reflect the likely outcome.

Figure 53 shows the change to summer maximum temperature anomaly ranges expected for Southern Australia under two atmospheric greenhouse gas concentrations relevant to the scenario definitions[161]. The figure uses the lighter shaded lines to demonstrate uncertainty between climate models as represented by the 90th and 10th percentiles, however, shows a high level of agreement in the median (solid line) towards increasing temperatures in AEMO modelling timeframes for the emissions scenarios included.

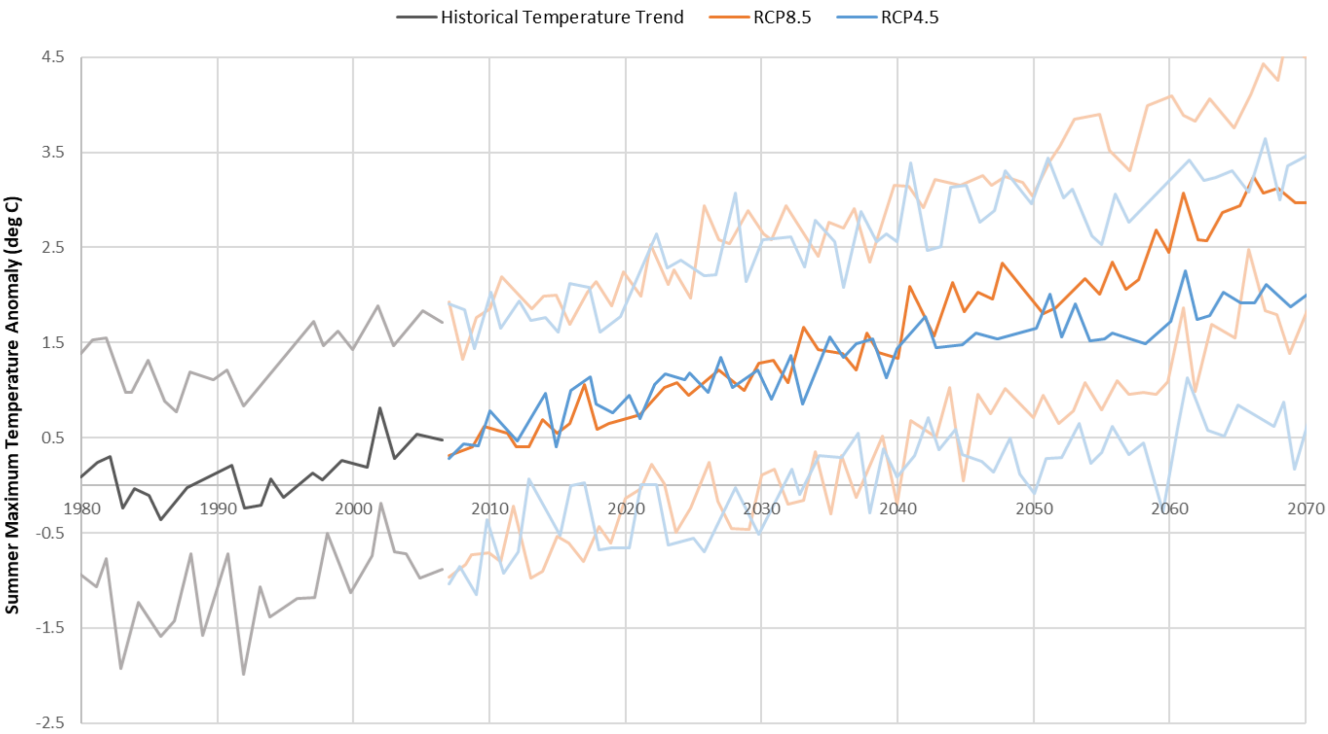
[158] At https://www.climatechangeinaustralia.gov.au/en/climate-projections/explore-data/data-download/station-data-download/.

[159] At https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-demand-forecasting-methodology/final-stage/electricity-demand-forecasting-methodology.pdf.

[160] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/network-data/transmission-equipment-ratings.

[161] Data sourced from www.climatechangeinaustralia.com.au.

Figure 53 Southern Australia summer maximum temperature anomaly



3.9 Renewable energy zones (REZs)

REZs are areas where clusters of large-scale renewable energy can be developed using economies of scale. REZs may include onshore and offshore areas and will be subject to jurisdictional land and environmental planning approval processes. With the relevant government support, AEMO could trigger REZ Design Reports to require the local TNSP to explore and report on any technical, economic or social issues that will need to be addressed for the REZ to be a valuable, sustainable and welcome development. However, most states are currently exploring state-based development schemes in preference to REZ design reports. AEMO will coordinate with jurisdictions as REZ plans develop, to ensure planning alignment.

An efficiently located REZ can be identified by considering a range of factors, primarily:

- The quality of its renewable resources, diversity relative to other renewable resources, and correlation with demand.
- The cost of developing or augmenting transmission connections to transport the renewable generation produced in the REZ to consumers.
- Its proximity to load, and the network losses incurred to transport generated electricity to load centres.
- The critical physical must-have requirements to enable the connection of new resources (particularly inverter-based equipment) and ensure continued power system security.

REZ candidates were initially developed in consultation with stakeholders for the 2018 ISP and used as inputs to the ISP model. To connect renewable projects beyond the current transmission capacity, additional transmission infrastructure will be required (for example, increasing thermal capacity, system strength, and developing robust control schemes). Since the 2018 ISP, the REZ candidates have been continuously refined through the 2020 ISP and the 2022 ISP consultation process. AEMO now makes another evolution to the candidate REZs.

This section describes the parameters around REZs that will be used as inputs for the 2024 ISP. These parameters are:

- Geographic boundaries – Section 3.9.1.
- Resource limits – Section 3.9.3.
- Transmission limits – Section 3.9.4.
- REZ augmentations and network costs – Section 3.9.5.

3.9.1 REZ geographic boundaries

Input vintage	July 2023
Source	AEMO – based on 2018 DNV-GL report, ISP workshops, consultation with TNSPs and jurisdictions, and written feedback to the 2018 ISP, 2020 and 2022 ISP
Updates since Draft IASR	Updated in response to the New South Wales and Federal Government declaration. The following revisions have been made: • Offshore REZ boundary changes for Gippsland Coast and Hunter Coast • Additional REZ in New South Wales called Illawarra

REZ candidates are geographic areas that indicate where new renewable energy generation might be developed using economies of scale. These were initially developed through consultation to the 2018 ISP and subsequently updated through 2020 and 2022 ISP consultation.

Geographic Information Systems (GIS) data

GIS data defining the candidate REZ boundaries is available on the 2023 IASR consultation page[162] .When accessing this data, please note:

- Only candidate REZ boundaries have been provided, not any GPS data for assets owned by third parties (for example, generation and network data).
- The GIS data for candidate REZs is approximate in nature. The polygons were derived by replicating the candidate REZ illustration (see Figure 54).
- As the REZ polygons are approximate in nature, they should not be used to determine whether a project is within or outside of a candidate REZ.

In some cases, jurisdictional REZ plans are still under development and boundaries may not have been identified. Where updated REZ boundaries are available, AEMO will update its GIS data accordingly.

Candidate REZ identification

Ten development criteria were used to identify candidate REZs[163]:

- **Wind resource** – a measure of high wind speeds (above 6 m/s).

[162] See https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

[163] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Multi-Criteria-Scoring-for-Identification-of-REZs.pdf.

- **Solar resource** – a measure of high solar irradiation (above 1,600 kW/m^2).
- **Demand matching** – the degree to which the local resources correlate with demand.
- **Electrical network** – the distance to the nearest transmission line.
- **Cadastral parcel density** – an estimate of the average property size.
- **Land cover** – a measure of the vegetation, waterbodies, and urbanisation of areas.
- **Roads** – the distance to the nearest road.
- **Terrain complexity** – a measure of terrain slope.
- **Population density** – the population within the area.
- **Protected areas** – exclusion areas where development is restricted.

Using the resource quality and development criteria with feedback received throughout the 2018, 2020 and 2022 ISP consultation, AEMO has 44 candidate REZs for inclusion in the 2024 ISP – three more than in the 2022 ISP.

Changes since the 2022 ISP

Based on AEMO analysis and recent feedback from existing and intending TNSPs and state and federal governments, the following changes to the 2022 ISP REZs have been made:

- A new candidate offshore REZ in the vicinity of North East Tasmania – North East Tasmania Coast REZ – has been added to assess the potential benefits of this new zone.
- A new candidate REZ – Hunter-Central Coast REZ – has been added to assess the benefits of this new zone. The REZ boundaries are aligned with the indicative geographical area defined in Schedule 1 of the draft Hunter-Central Coast REZ declaration[164].
- AEMO has aligned the boundaries for the Gippsland Coast REZ to the area published in the Commonwealth Notice of proposal[165] to declare an area – Bass Strait off Gippsland.
- AEMO has aligned the boundaries for the Portland offshore REZ to the area published in the Commonwealth-Offshore renewable energy infrastructure area proposal[166]l.
- A new candidate REZ has been added – the Illawarra REZ was formally declared by the Minister for Energy in New South Wales on 27 February 2023[167]. The REZ boundaries are aligned with the indicative geographical area defined in New South Wales Department of Planning, Industry and Environment publication[168].

AEMO acknowledges that the Queensland Government has recently released a draft REZ roadmap which identifies potential areas where REZ transmission will connect to the existing shared transmission network. AEMO will continue to engage with the Queensland Government as its REZ roadmap is developed.

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164 At https://www.energyco.nsw.gov.au/sites/default/files/2022-09/hcc-rez-draft-order-declaration.pdf.

165 Department of Climate Change, Energy, the Environment and Water, Notice of proposal to declare an area – Bass Strait off Gippsland, at https://www.dcceew.gov.au/sites/default/files/documents/Notice%20of%20Proposal%20to%20Declare%20-%20Gippsland.pdf.

166 Department of Climate Change, Energy, the Environment and Water- Offshore renewable energy infrastructure area proposal: Southern Ocean Region off Victoria and South Australia, https://consult.dcceew.gov.au/oei-southern-ocean

167 EnergyCo, Illawarra Renewable Energy Zone, at https://www.energyco.nsw.gov.au/ilw-rez.

168 Illawarra Renewable Energy Zone geographic area at https://www.energyco.nsw.gov.au/sites/default/files/2023-01/ilw-rez-methodology-geographic-area.pdf.

Modelling renewable energy without REZs

When determining the economic benefits of a development path, AEMO must compare system costs against a counter-factual where no transmission is built. In this counter-factual, transmission that expands the capacity of REZs will generally not be allowed.

To conduct this analysis, it will become necessary to model renewable generation connecting to areas with existing network hosting capacity, but which may also have lower quality resources. For this reason, resource limits, resource quality, and network capacity are also determined for areas of the network that have existing hosting capacity, or where generation retirement is expected to result in additional network capacity. These areas are known as “non-REZs”. These lower quality resource areas are included in all scenarios, not just the counterfactual studies. This ensures the ISP’s capacity outlook model can determine the optimal trade-off between development of high-quality renewable resources in REZs, with associated network build, compared to developing lower quality resources in areas with spare hosting capacity.

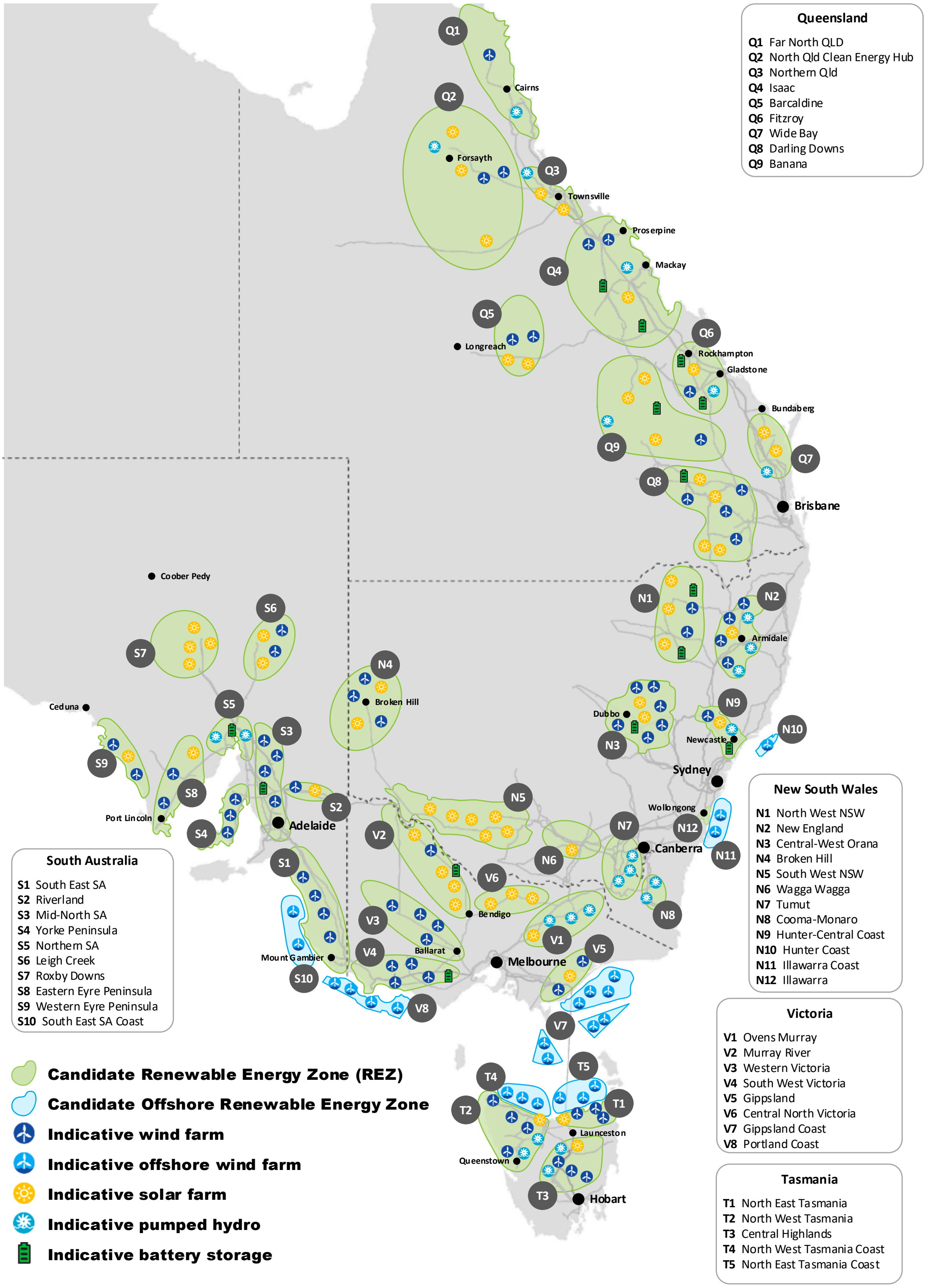
The following changes are made for non-REZs since the 2022 ISP:

- Reduced the area of the non-REZs to align with the location of 500 kV transmission line infrastructure, and excluded the area which has now been included in the new Hunter-Central Coast REZ. The assumed capacity factors for resources in the non-REZs have also been adjusted, to reflect the adjusted land area boundaries.
- Updated the connection cost for wind and solar in non-REZ areas to include assets to connect the new generation through a switching station, as well as additional line length for the connection. This change better reflects the differing infrastructure that can be assumed to be available between REZs and non-REZs. Section 3.9.5 provides information about updates to transmission and generator connection costs.
- An increase to the land use penalty factor for non-REZ areas to reflect the high density of land use in the non-REZ areas and consequent assumed difficulty in acquiring the necessary land access and planning approvals for new generation.

3.9.2 Candidate REZ geographic boundaries

Figure 54 shows the geographic locations of REZ candidates. The location of generation symbols is illustrative only – these symbols do not reflect the location of actual projects or the location where projects should be developed.

Figure 54 Renewable energy zone map



† The REZ boundaries for N5, N9 and N12 are indicative and aligned with the New South Wales Government's draft declaration for these REZs.
* AEMO has aligned the boundaries for the Gippsland Coast REZ and Hunter Coast REZ to the areas published in the Commonwealth Notice of proposal.

3.9.3 REZ resource limits and social licence

Input vintage	July 2023
Source	AEMO. Resource limits were derived by AEMO based on 2018 DNV-GL report, ISP workshops, consultation with TNSPs and jurisdictions, and written feedback to the 2018 ISP, 2022 ISP and Draft 2023 IASR.
Updates since Draft IASR	In response to feedback to the Draft IASR, the following revisions have been made: • Fixed offshore wind turbine structure revised from 60m to 70m depth • The allowable offshore REZ area revised from 90% to 80%

REZ resource limits reflect the total available land for renewable energy developments, expressed as installed capacity (MW). The availability is determined by existing land use (for example, agriculture) and environmental and cultural considerations (such as national parks), as well as the quality of wind or solar irradiance.

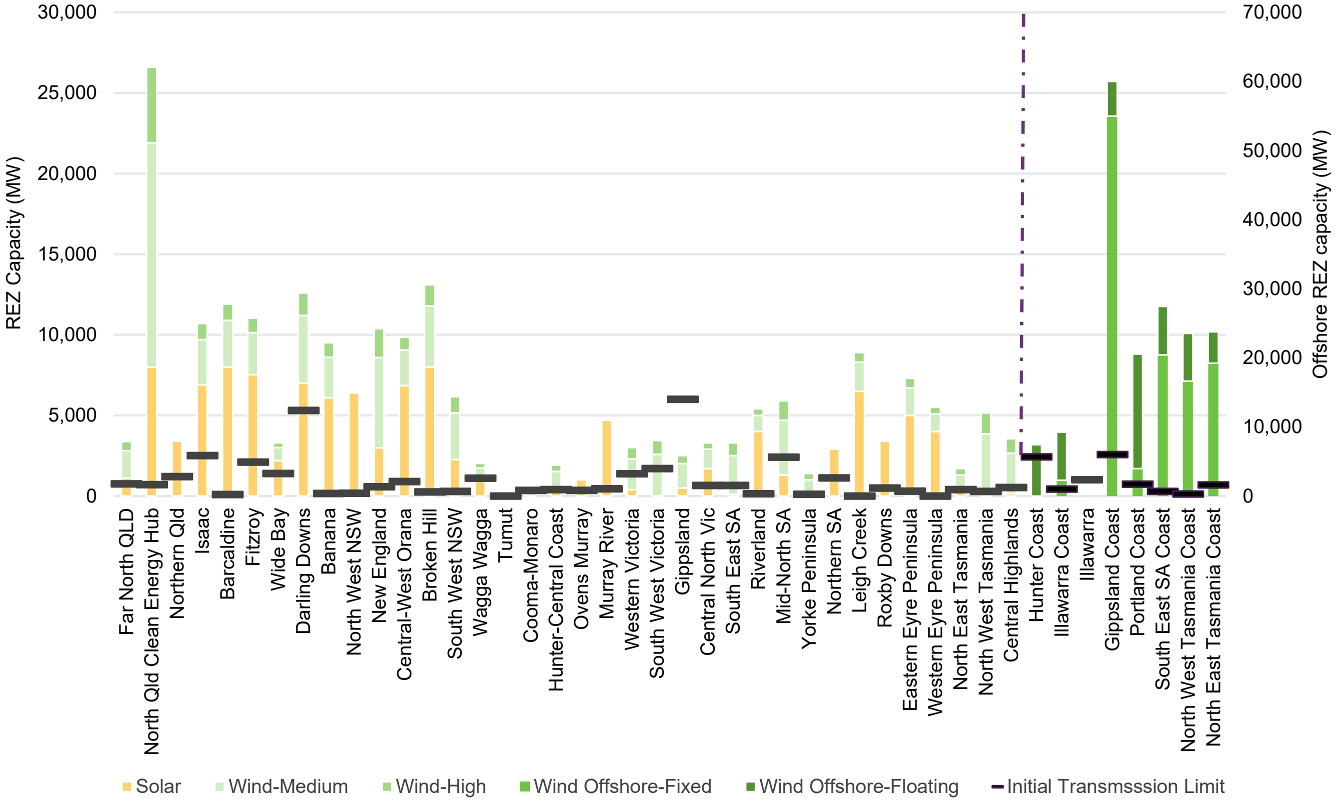
AEMO adjusts REZ resource limits when the boundary of a REZ changes or when appropriate evidence becomes available from localised consultation and studies. As desktop studies and stakeholder engagement have already been completed to prepare the existing REZ resource limits, AEMO expects that any further changes will need to be based on localised evidence as REZ projects are developed and delivered.

AEMO made the following changes since the 2022 ISP:

- In the 2022 ISP, AEMO updated the REZ boundaries for the South West New South Wales REZ aligned with geographical area of the SWNSW REZ in Schedule 1 of the draft REZ declaration under the NSW EII Act. For this final 2023 IASR, all relevant parameters are now aligned with the update to the geographical area including the update of the resource limit.
- Included resource limits for Hunter-Central Coast REZ and Illawarra REZ.
- Updated the resource limits for offshore REZs. See the section on offshore wind resource limits below for more information.

The updated resource limits are shown in Figure 55 and provided in detail in the 2023 IASR Assumptions Workbook.

Figure 55 REZ resource limits and Initial transmission limits



Note: Offshore REZ capacities use right axis scale. The dotted purple line is to separate offshore and onshore REZs.

Onshore wind farm resource limits

Maximum REZ wind generation resource limits were initially calculated based on a DNV-GL[169] estimate of:

- Typical wind generation land area requirements.
- Land available that has a resource quality of high (in the top 10% of sites assessed), and medium (in the top 30% of sites assessed, excluding high quality sites), and an assumption that only 20% of this land area will be able to be utilised for wind generation, considering competing land and social limitations.

These resource limits have evolved during the 2020 ISP and 2022 ISP to incorporate input from TNSPs, changes to REZ geographic boundaries, and increased connection interest, and to include existing, committed, committed* and anticipated generation in each REZ[170] (see Section 3.5.1 for more information on classification of generation projects). No changes are made to the existing REZs resource limits for the 2023 IASR as the latest updates to the committed and anticipated generation, since July 2021, within each REZ are accounted for within the market modelling by summation of generation in each REZ and subtracting this from the total resource limit. The resource limits are shown in Figure 55, and are further detailed in the 2023 IASR Assumptions Workbook.

[169] Multi-Criteria-Scoring-for-Identification-of-REZs DNV-GL, 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Multi-Criteria-Scoring-for-Identification-of-REZs.pdf.

[170] AEMO, NEM Generation Information July 2021, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2021/nem-generation-information-july-2021.xlsx.

Solar farm resource limits

Maximum REZ solar generation resource limits (both CST and PV) have been calculated based on:

- Typical land area requirements for solar PV.
- An assumption that only 0.25% of the approximate land area of the REZs will be able to be used for solar generation. This allocation is significantly lower than wind availability, as solar farms have a much larger impact on alternative land use than wind farms, which require reasonable distance between wind turbines.

The initial resource limits were adjusted in the 2020 ISP and 2022 ISP to incorporate input from TNSPs, changes to REZ geographic boundaries, and increased connection interest, and to include existing, committed, committed*, and anticipated generation in each REZ[160].

No changes are made to the existing REZ resource limits for the 2024 ISP, as the latest updates to the committed and anticipated generation within each REZ since July 2021 are accounted for in the market modelling by summation of generation in each REZ and subtracting this from the total resource limit. The resource limits are shown in Figure 55 and are further detailed in the 2023 IASR Assumptions Workbook.

Offshore wind resource limits

After considering announced projects and stakeholder feedback, AEMO included six candidate offshore REZs for the 2022 ISP. These zones were broadly located based on public information on offshore wind projects. To further enhance the modelling of offshore wind, AEMO made the following changes from the 2022 ISP for offshore REZs:

- Included an additional offshore REZ for the North East Tasmania Coast, based on participant feedback.
- Updated the boundaries for Gippsland Coast offshore REZ , Hunter Coast offshore REZ and Portland Coast REZ, to align with the areas identified by the Federal Government[171] for offshore wind development.
- Specified resource limits for each offshore REZ for both fixed and floating offshore wind turbine structures, considering the ocean depth of the offshore REZ (see Table 33).

Table 33 Offshore REZ resource limits

Offshore REZ	Resource limits – fixed structures (MW)	Resource limits – floating structures (MW)	REZ area (km^2)
N10 – Hunter Coast	0	7,416	1,854
N11 – Illawarra Coast	2,288	6,940	2,307
V7 – Gippsland Coast	54,996	5,000	14,999
V8 – Portland Coast	3,948	16,596	4,482
S10 – South East South Australia Coast	20,428	7,032	6,865
T4 – North West Tasmania Coast	16,624	6,912	5.884
T5 – North East Tasmania Coast	19,212	4,544	5,939

[171] DCCEEW, Notice of Proposal to Declare an Area Bass Strait off Gippsland, Victoria, at https://www.dcceew.gov.au/sites/default/files/documents/Notice%20of%20Proposal%20to%20Declare%20-%20Gippsland.pdf, and

-DCCEEW, Portland Coast Offshore renewable energy infrastructure area proposal: Southern Ocean Region off VIC and SA at https://consult.dcceew.gov.au/oei-southern-ocean; and

-DCCEEW declaration, Area in the Pacific Ocean off the Hunter declared suitable for offshore wind at https://www.dcceew.gov.au/energy/renewable/establishing-offshore-infrastructure/hunter

The maximum offshore REZ wind generation resource limit in Table 33 was calculated based on:

- Assumed turbine capacity density of 5 MW/km^2.
- Allowing for 80% of the offshore REZ area to be developed.
- Fixed offshore wind turbine structures assumed to be built up to a depth of 70 meters.
- Floating offshore wind turbine structures are assumed at a depth above 70 meters but less than 1,000 meters.

Land use penalty factors in REZs allow for increases in resource limits.

Land use reviews with governments indicate that the expansion of REZs is likely to become constrained by social licence factors, as opposed to purely on land availability (although varying between REZs).

In the 2022 ISP, AEMO applied an additional land use penalty factor of $0.25 million/MW to all new VRE build costs in a REZ, which applies only if generation is modelled above the original REZ total resource limits. This penalty factor was applied to capture the expected increase in land costs or difficulties in obtaining land.

For the 2024 ISP, the land use penalty factor is $0.29 million/MW.

By using the REZ land-use penalty factor, AEMO can model a staged increase in land costs, reflecting more complicated arrangements required for planning approvals and engagement with community and traditional landowners as more renewable generation goes into a REZ.

It is vital that developers and TNSPs identify key stakeholders and commence engagement on land and access as early as possible for AEMO's assessments of future REZ potential. This includes engagement with communities, title holders, and Traditional Owners. Early indications of sensitivities in proposed future REZ areas will assist in the assessment of potential expansion opportunities or limits, thereby improving the projections of future potential in the ISP candidate paths.

Even with a land use penalty factor, an upper land use limit is also applied to the REZ resources. For the 2022 ISP, this was based on 5% of land area within a REZ for wind resources, and 1% of land area for solar resources – which will also be applied for the 2024 ISP.

The land area within a REZ can be found in the 2023 IASR Assumptions Workbook.

Social licence

'Social licence' is commonly used to refer to local community acceptance of new infrastructure development. The efficient and effective transition of the energy sector will rely on both government and the energy industry understanding and delivering the community's ambition and needs for the future power system, both broadly in the community, and in the places that host new development. Conversely, a lack of social licence could lead to significant project delays and increased cost.

AEMO will include input and feedback from external stakeholders in its overall consideration of social licence matters. This will include feedback from the Advisory Council on Social Licence, established by AEMO to better understand social licence issues facing the energy transition and to provide input on community sentiment and social licence issues, risks, opportunities, and pathways forward.

The Council's establishment gives effect to recommendations in the ISP Consumer Panel Report on the *Draft 2022 ISP*, which called for AEMO to place a greater emphasis on social licence risks associated with the ISP's implementation and for AEMO to "take a leadership role amongst the many stakeholders that will need to be involved"[172]. In addition, greater insights on social licence matters would benefit AEMO in the execution of its role more generally, beyond its ISP work. This includes in its role contributing to energy policy and actions to support the energy transition. The ISP is an engineering and economic options assessment. AEMO uses three ways to quantify social licence in the economic modelling:

- **Transmission network augmentation costs and generator connection costs** – social licence consideration may require longer routes, additional landowner compensation and consideration for under grounding of some overhead components. Additional cost can also include the cost associated with engagement activities with land holders and communities.
- **Project lead time** – understanding the community concerns early can assist in reducing project delays at implementation phase but require additional activities and time during early phases of the project.
- **Land use-penalty factors** – a reflection that REZ development is likely to be limited by social licence rather than renewable resources (see above).

AEMO consulted on transmission augmentation cost, generator connection costs and project lead times in the 2023 *Transmission Expansion Options Report* consultation.

3.9.4 REZ transmission limits

Input vintage	July 2023
Source	Based on the 2023 *Transmission Expansion Options Report* and feedback to the 2023 ISP Methodology consultation
Updates since Draft IASR	Updated Queensland REZ group constraint based on transmission augmentation option, addition of South East South Australia limit.

Individual REZ transmission limits

Network studies were undertaken to identify REZ transmission limits of the existing network. In the 2022 ISP, following feedback to the ISP Methodology consultation, REZ transmission limits were updated to reflect total transmission limits rather than surplus hosting capacity. The REZ transmission limit is expressed as an inter-temporal generation constraint. The purpose of the constraint is to limit the generation dispatch up to the transmission limit which can be increased when it is economically optimal.

Where flows across the transmission limit in a REZ are affected by generation, AEMO applies a generation constraint to reflect this dependency within the REZ. This was consulted on through the 2023 ISP Methodology.

Compared to the 2021 IASR, the following changes were made to transmission limits and generation constraints:

- Where significant change in transmission limits is noted for seasonal ratings, separate limits are specified. This has impacted limits for North West Tasmania, Central Highlands, Murray River, Western Victoria and Central North Victoria REZs.
- Limits are now provided for new REZs including Hunter-Central Coast REZ, Illawarra REZ and North East Tasmanian Coast REZ.

[172] ISP 2022 Consumer Panel. *Report on AEMO's Draft 2022 Integrated System Plan.* February 2022. Page 12. At https://aemo.com.au/-/media/files/major-publications/isp/2022/isp-consumer-panel-report-on-draft-2022-isp.pdf?la=en.

- The South West New South Wales REZ modelling has been updated to consider the updated REZ boundary. The existing voltage stability transmission limit that now includes generation outside of N5 (in the vicinity of Darlington Point) is accounted for by including these generators in a separate transmission limit (Table 35).
- Western Victoria REZ, V3, is modelled as a V3 East and V3 West limit to reflect the different network limits associated with generation groups within this REZ (Table 35).
- Gippsland transmission limits now include terms to account for Basslink, Marinus Link and coal and gas generation impacts (see SEVIC1 in Table 34).
- South East South Australia REZ transmission limit is now modelled as a sub-region flow limit, and also now has a new limit modelled to take into account the Tailem Bend solar farms.
- Darling Downs REZ transmission limit now includes terms to account for to Queensland – New South Wales Interconnector (QNI), Central Queensland (CQ)-Southern Queensland (SQ) and local coal, gas generation impacts and the anticipated project of Borumba pumped hydro (see SWQLD1 in Table 34).

In some cases, offshore REZ resources are anticipated to connect through to the transmission network via an onshore REZ. These resources will all be modelled within the individual REZ transmission limit for the onshore REZ.

Table 34 REZ transmission limit constraints

Transmission constraint	REZ	Co-efficient	Constraint terms	Transmission-limited total build (MW)
SEVIC1	Gippsland	1	Gippsland REZ generation (onshore and offshore)	6,000
		1	Basslink and Marinus Link flow	
		1	Existing South East Victoria coal and gas generation (Loy Yang A, Loy Yang B, Yallourn, Jeeralang, Bairnsdale, Valley Power)	
SWQLD1	Darling Downs	1	Darling Downs REZ generation	5,300
		1.5	New South Wales to Queensland interconnector flow (QNI)	
		-0.3	Central Queensland to South Queensland flow	
		0.6	Existing South West Queensland coal and gas generation (Tarong, Tarong North, Kogan Creek, Darling Downs, Braemar)	
		1.5	Millmerran coal generation	
		0.5	Borumba Pumped Hydro	
S1-TBMO	South East SA	0.3	South East South Australia to Central South Australia flow	350
		1	Tailem Bend Solar Farm stages 1 & 2	

Secondary transmission limits within a REZ

Where there are significant transmission limits that apply to only a subset of generation within a REZ, a secondary transmission limit can be modelled. It is noted that the inclusion of an additional limit can significantly impact on simulation complexity. These are only included where impacts are deemed significant, such as where existing generation are already seeing network congestion.

Table 35 REZ secondary transmission limits

REZ	Constraint terms	Transmission constraint	Transmission limit (summer peak/summer typical/winter reference) in MW
N5 (Existing)	Existing SWNSW Solar Generation: • Limondale 1 & 2 Solar Farm • Sunraysia Solar Farm • Coleambally Solar Farm • Finley Solar Farm • Darlington Point Solar Farm • Hillston Sun Farm • Darlington Point BESS • Riverina BESS 1 & 2	SWNSW1	550/550/550
V3 (East)	Existing V3 wind generation east of Ballarat: • Elaine Wind Farm • Mt Mercer Wind Farm • Moorabool Wind Farm • Yaloak South Wind Farm • Yendon Wind Farm New generation in V3 (East)	V3-EAST	600/600/800
V3 (West)	Existing V3 wind generation west of Ballarat: • Ararat Wind Farm • Bulgana Wind Farm • Challicum Hills Wind Farm • Crowlands Wind Farm • Kiata Wind Farm • Murra Warra Wind Farm stage 1 & 2 • Waubra Wind Farm New generation in V3 (West)	V3-WEST	780/780/980

Group constraints

The transmission network is a complex and interconnected system. Transmission flows are influenced by generation and system services across multiple locations. Within AEMO's capacity outlook model, simplifications are needed to represent the power system to keep the optimisation problem tractable, which may rely on flow limits being influenced by single REZ outcomes.

To address this need, "group constraints" are applied. These constraints combine either the generation from more than one REZ, or the generation within a REZ with the power flow along a flow path, to reflect network limits that apply to multiple areas of the power system. Table 36 below shows the group constraints that apply in the capacity outlook model. These have been developed by considering the limits observed from power system analysis, and in consultation with TNSPs.

Based on AEMO analysis and recent feedback from existing and intending TNSPs, the following changes to the REZ group constraints have been made since the 2021 IASR:

- Removed group constraints for NQ1 and NQ3 as these constraints are now represented as sub-regions with flow paths (see Section 3.10.1).
- With the inclusion of a new sub-region in Northern Queensland (NQ, see Section 3.10.1), the NQ2 group constraint has been updated to incorporate the flow on the flow path NQ-CQ as opposed to generation in Q1,

Q2 and Q3. By updating this constraint, the constraint captures more system conditions, such as demand in Northern Queensland.

- A new group constraint in Southern Queensland to capture the network limits with additional generation in the Q7 (Wide Bay REZ) and generation in Central and Northern Queensland. AEMO proposes to use the flow on CQ-SQ instead of generation in each REZ within Central and Northern Queensland sub-region.
- A new group constraint called Southern Queensland and South West Queensland has been created to capture the impact of the intended super grid transmission network on the outputs of Q7 (Wide Bay REZ).
- An increase in the NSA1 transmission-limited total build to reflect the Davenport – Cultana 275 kV line uprating project[173], which is expected to be completed in 2024-25.

Table 36 REZ group transmission constraints

Generator/REZ ID/ Flow path	Generator / REZ name/Flow path name	Group constraint name	Transmission-limited total build (MW) (summer peak/summer typical/winter reference)
NQ-CQ	Northern Queensland – Central Queensland	NQ2	2,500/2,500/2,750
Q4	Isaac		
Q5	Barcaldine		
-0.5 x CQ-SQ	Central Queensland – Southern Queensland	SQ1 (Before Queensland SuperGrid)	1,400/1,400/1,400
Q7	Wide Bay		
Q7	Wide Bay	SQ1 (After Queensland SuperGrid)	5,700/5,700/5,700
0.42*Q8	Darling Downs		
-0.82*CQ-SQ	Central Queensland – Southern Queensland		
0.75*BPH	Borumba Pumped Hydro		
0.51*Q8_Coal	Existing South West Queensland coal and gas generation (Tarong, Tarong North, Kogan Creek, Darling Downs, Braemar)		
VIC-SA	Heywood Interconnector	SWV1	1,700/1,700/1,700
V4	South West Victoria		
V8	Portland Coast		
S3	Mid-North SA	MN1[B]	2,400/2,400/2,400[C]
0.5 x S4[A]	Yorke Peninsula		
S5	Northern SA		
S6	Leigh Creek		
S7	Roxby Downs		
S8	Eastern Eyre Peninsula		
S9	Western Eyre Peninsula		
0.5 x S5	Northern SA	NSA1[C]	1,125/1,125/1,125
S8	Eastern Eyre Peninsula		
S9	Western Eyre Peninsula		
T1	North East Tasmania	NET1	1,600/1,600/1,600

173 ElectraNet, Network Capability Incentive Parameter Action Plan, Revenue proposal 2023-24 to 2027-28, at https://www.aer.gov.au/system/files/ENET012%20-%20ElectraNet%20-%20Attachment%2010%20-%20Appendix%20A%20NCIP%20Action%20Plan%20-%2031%20January%202022.pdf.

Generator/REZ ID/ Flow path	Generator / REZ name/Flow path name	Group constraint name	Transmission-limited total build (MW) (summer peak/summer typical/winter reference)
T5	North East Coast Tasmania		

A. Only 50% of the renewable energy developed in the Yorke Peninsula contributes to this transmission constraint.
B. MN1 and NSA group constraints are removed in the *Green Energy Exports* scenario due to location of new load for hydrogen production. If large hydrogen load is developed in South Australia, depending on the location, these constraints may either have electrolyser demand terms added, or constraint removed depending on the year they are committed.
C. Mid-North Transmission-limited total build (MW) shown does not include additional limitations in the underlying 132 kV network. A minor network augmentation is required to remove the 132 kV network limitations to enable this full network capacity.

Modifiers due to committed and anticipated transmission augmentations

This section focuses on REZ transmission limit uplifts due to committed and anticipated transmission augmentations. REZ transmission limits can change due to either:

- Flow path augmentations – a flow path is the portion of the transmission network used to transport significant amounts of electricity across the backbone of the interconnected system. When flow paths traverse REZs, flow path upgrades can improve a REZ's access through the shared transmission network.
- REZ network augmentations – the REZ network connects renewable generation in areas where large-scale renewable energy can be developed using economies of scale. REZ network augmentations increase, at an efficient cost, transmission access from the REZ to the NEM shared transmission network.

Committed and anticipated network augmentation projects may increase REZ transmission limits. The REZ transmission modifiers as a result of committed and anticipated network augmentations are presented in the 'Build limits' tab of the Final 2023 Inputs and Assumptions Workbook. Committed and anticipated transmission augmentation projects are defined in sections 3.10.3 and 3.10.4.

3.9.5 REZ augmentations and network cost

Input vintage	July 2023
Source	AEMO internal – Based on the Transmission Cost Database and TNSP data
Updates since Draft IASR	Transmission Cost Database update and the 2023 *Transmission Expansion Options Report* consultation

Following stakeholder feedback to the 2020 ISP, AEMO developed the 2021 *Transmission Cost Report* to improve the accuracy and transparency of costs used in the 2022 ISP. For the 2024 ISP, AEMO has published the *Transmission Expansion Options Report* with an expanded scope, including:

- Transmission augmentation options for flow paths and for REZs including:
  - A description of the network option.
  - The expected increase in transfer capacity/network capacity.
  - For REZs, any modifiers due to flow path augmentations.
  - The project cost, including the class of estimate and associated accuracy.
  - Project lead time, including consideration for community engagement and establishment of social licence.
- REZ connection costs.
- System strength remediation costs.

3.10 Network modelling

This section describes inputs and assumptions relating to the transmission network. The inputs and assumptions are grouped into the following categories:

- **ISP sub-regions** – the power system is modelled in different ways depending on the analysis being performed. A 12 sub-region structure is used to improve the granularity of optimisations that were previously assessed across five regions.
- **Existing network capacity** – this section summarises the existing capacity of the transmission network with relation to transferring power between sub-regions.
- **Committed transmission projects** – these projects are included in all scenarios. Once a project meets five criteria, the projects are classified as committed and will be modelled in all scenarios.
- **Anticipated transmission projects** – major transmission projects that are in the process of meeting three of the five commitment criteria are classified as anticipated. The treatment of anticipated transmission projects can vary depending on the type of modelling being performed (see Section 3.10.4).
- **Transmission capability with committed and anticipated projects**– increased transmission capability from committed and anticipated projects are captured and assessed in the ISP.
- **Flow path augmentation options** – this was consulted on through the Draft 2023 *Transmission Expansion Options Report* and included transmission upgrades that were not committed or anticipated, which will be assessed in the 2024 ISP.
- **Transmission augmentation costs** – the costs of transmission augmentation options and the building blocks used to estimate new augmentations as the need may arise. This was updated and consulted on through the Draft 2023 *Transmission Expansion Options Report*.
- **Preparatory activities** – the 2022 ISP triggered preparatory activities for six future ISP projects. The relevant TNSPs provided the costs, lead times and preliminary designs for these projects.
- **Non-network options** – AEMO considers potential non-network options alongside network solutions to develop an efficient power system strategy.
- **Loss flow equations** – loss flow equations are used to reflect the energy lost when transferring energy between regions
- **Marginal loss factors (MLFs)** – these values are used to reflect network losses and the marginal pricing impact of bids from a connection point to the regional reference node.
- **Transmission line unplanned outage rates** – forced outage rates of inter-regional transmission elements are critical inputs for AEMO's reliability assessments.

3.10.1 ISP sub-regions

Input vintage	December 2022
Source	AEMO internal – prepared for the 2022 ISP and adjusted and consulted on through the 2021 and 2023 IASR
Updates since Draft IASR	None - stakeholders supported the structure proposed in the Draft IASR

The power system is modelled in different ways depending on the analysis being performed. AEMO represents the network topology and reference nodes in different ways. The network can be represented as either a regional or sub-regional topology:

- In the regional topology, each of the five NEM regions is represented by a single reference node. In this topology, all loads are placed at the respective regional reference nodes, with generation represented across the power system considering the REZ transmission limits and group constraints described previously.
- The sub-regional topology breaks down some of the NEM regions into smaller sub-regions. In this topology, the regional load and generation resources are appropriately split between the different sub-regions. Flow path transmission constraints are added to reflect the capability of the network.

AEMO has made the following changes to the sub-regional topology since the 2022 ISP:

- **Separating Central and Northern Queensland (CNQ) into two sub-regions** – AEMO further divided the CNQ sub-region from the 2022 ISP into a Northern Queensland (NQ) sub-region and a Central Queensland (CQ) sub-region for the purpose of improving the modelling of network losses across Queensland.
- **South Australia region** – AEMO divided the South Australia region into two sub-regions, South East South Australia (SESA) and Central South Australia (CSA). The new sub-regional model will assist to better capture network limitations between SESA and Victoria and across South Australia.

Table 37 lists all the regions and sub-regions to be used in AEMO studies (and their corresponding reference nodes). The nodes in **bold** are those used as reference nodes in the regional topology.

Table 37 NEM regions, ISP sub-regions, reference nodes and REZs

NEM region	ISP sub-region	Reference node	REZs
Queensland	Northern Queensland (NQ)	Chalumbin 275 kV	Q1, Q2 and Q3
	Central Queensland (CQ)	Broadsound 275 kV	Q4, Q5 and Q6
	Gladstone Grid (GG)	Calliope River 275 kV	-
	South Queensland (SQ)	**South Pine 275 kV**	Q7, Q8 and Q9[A]
New South Wales	Northern New South Wales (NNSW)	Armidale 330 kV	N1 and N2
	Central New South Wales (CNSW)	Wellington 330 kV	N3 and N9
	South NSW (SNSW)	Canberra 330 kV	N4, N5, N6, N7 and N8
	Sydney, Newcastle, Wollongong (SNW)	**Sydney West 330 kV**	N10 and N11
South Australia	Central South Australia (CSA)	**Torrens Island 66 kV**	S2, S3, S4, S5, S6, S7, S8 and S9
	South East South Australia	South East 132 kV	S1 and S10
Tasmania	Tasmania (TAS)	**George Town 220 kV**	T1, T2, T3, T4 and T5
Victoria	Victoria (VIC)	**Thomastown 66 kV**	V1, V2, V3, V4, V5, V6, V7 and V8

Note: Bold reference nodes are those used for whole of region modelling, for example in the ESOO. In such studies, all regional loads are represented at the regional reference nodes.
A. Q9, in scenarios with large hydrogen export development, will lie within CQ

Capacity outlook model representation

In the 2022 ISP, AEMO used a 10-area sub-regional model for capacity outlook modelling. For the 2024 ISP, AEMO is using a 12-area sub-regional model. The sub-regional model provides more granular information on key intra-regional transmission limitations and augmentations which are not well approximated by interconnectors and REZ limits. The sub-regional representation and flow paths are presented and described in Figure 56 and Table

38. For each flow path, AEMO models the alternating current (AC) and direct current (DC) interconnectors separately, which can result in multiple parallel flow paths.

Figure 56 ISP sub-regional model

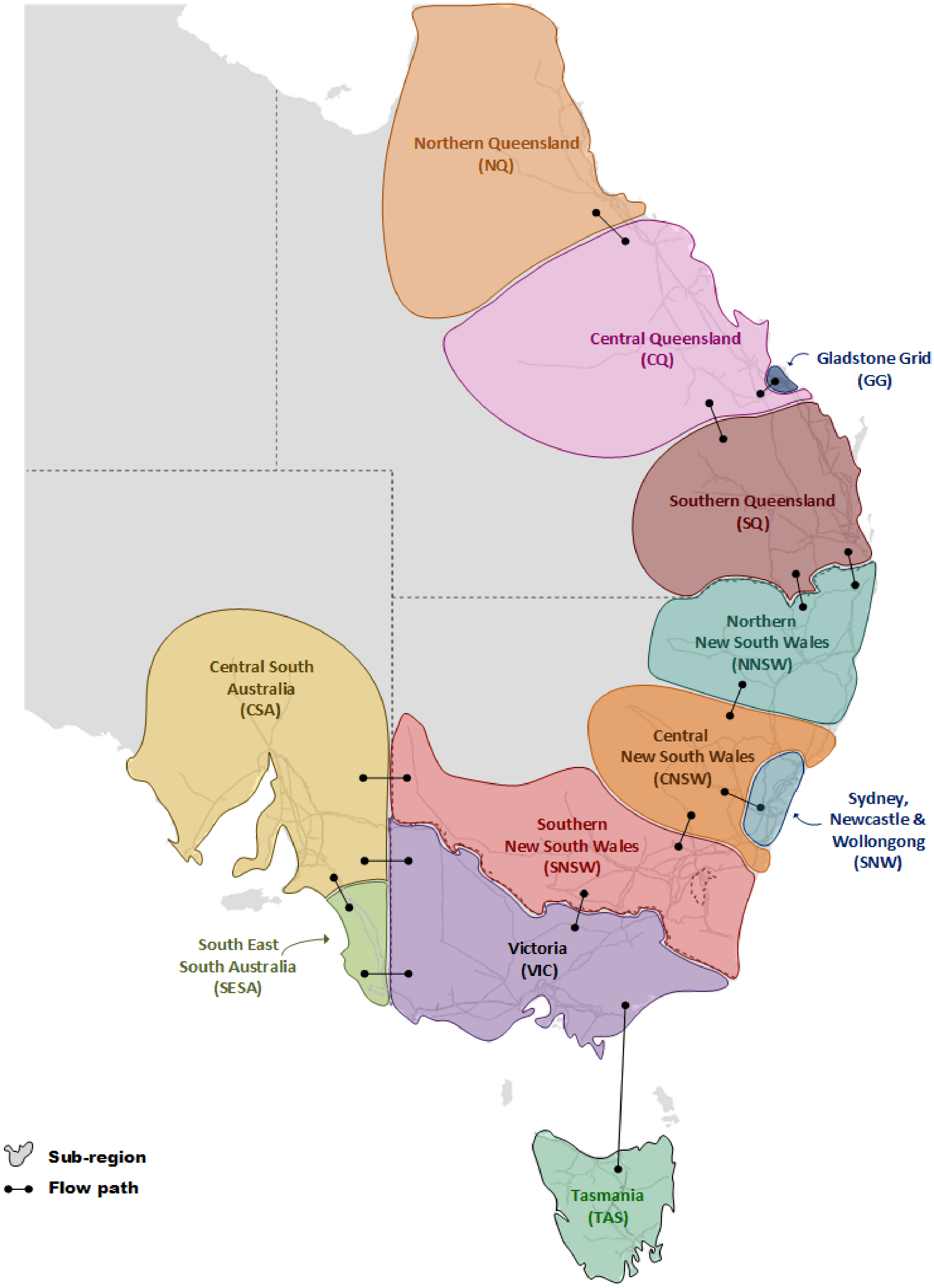


Table 38 Existing network flow path representation between sub-regions

Flow path definition	Inter-zonal flow path (forward direction of power flow)
CQ-NQ	Strathmore – Ross 275 kV (2 circuits) Strathmore – Haughton River 275 kV (1 circuit) Strathmore – Clare South 132 kV (1 circuit) King Creek – Clare South 132 kV (1 circuit)
CQ – GG	Bouldercombe – Calliope River 275 kV (1 circuit) Raglan – Larcom Creek 275 kV (1 circuit) Calvale – Wurdong 275 kV (1 circuit) Gin Gin – Calliope River 275 kV (2 circuits) Teebar Creek – Wurdong 275 kV (1 circuit)
SQ – CQ	Woolooga – Teebar Creek 275 kV (1 circuit) Woolooga – Gin Gin 275 kV (2 circuits) Halys – Calvale 275 kV (2 circuits)
NNSW – SQ (QNI)	Dumaresq – Bulli Creek 330 kV (2 circuits)
NNSW – SQ (Terranora)	Terranora – Mudgeeraba 110 kV (2 circuits)
CNSW – NNSW	Muswellbrook – Tamworth 330 kV (1 circuit) Liddell – Tamworth 330 kV (1 circuit) Hawks Nest tee – Taree 132 kV line (1 circuit) Stroud – Taree 132 kV line (1 circuit)
SNSW – CNSW	Crookwell – Bannaby 330 kV (1 circuit) Yass – Marulan 330 kV (1 circuit) Collector – Marulan 330 kV (1 circuit) Capital – Kangaroo Valley 330 kV (1 circuit) Yass – Cowra 132 kV (2 circuits)
CNSW – SNW	Wallerawang – Ingleburn 330 kV (1 circuit) Wallerawang – Sydney South 330 kV (1 circuit) Bayswater – Sydney West 330 kV (1 circuit) Bayswater – Regentville 330 kV (1 circuit) Liddell – Newcastle 330 kV (1 circuit) Liddell – Tomago 330 kV (1 circuit) Bannaby – Sydney West 330 kV (1 circuit) Marulan – Avon 330 kV (1 circuit) Marulan – Dapto 330 kV (1 circuit) Kangaroo Valley – Dapto 330 kV (1 circuit) Stroud – Brandy Hill 132 kV (1 circuit) Stroud – Tomago 132 kV (1 circuit) Hawks Nest tee – Tomago 132 kV (1 circuit) Singleton – Rothbury 132 kV (1 circuit which is normally open)
VIC – SNSW	Murray – Upper Tumut 330 kV (1 circuit) Murray – Lower Tumut 330 kV (1 circuit) Wodonga – Jindera 330 kV (1 circuit) Red Cliffs – Buronga 220 kV line (circuit) Jindabyne – Guthega 132 kV (1 circuit) Geehi Dam – Guthega 132 kV (1 circuit)
SNSW – CSA	Buronga – Bundy 330 kV (2 circuits)
VIC – SESA (Heywood)	Heywood – South East 275 kV (2 circuits)
VIC – CSA (Murraylink)	Red Cliffs – Monash HVDC cable
SESA - CSA	Black Range – Tailem Bend 275 kV (2 circuits) Keith – Tailem Bend 132 kV (1 circuit)
TAS – VIC	George Town – Loy Yang HVDC cable

Representation of load and generation within each of the sub-regions is presented in the table below. Sub-region loads are represented at the Sub-region Reference Node. The Reference Node for each sub-region is located close to the sub-region's major load centre, except in North and Central Queensland where the nodes have been selected to capture intra-regional loss equations.

Table 39 Load and generation representation within the sub-regional model

Sub-region	Sub-region Reference Node	Load and generation representation
Northern Queensland (NQ)	Chalumbin 275 kV	All load and generation including and north of Ross, Haughton River and Clare South.
Central Queensland (CQ)	Broadsound 275 kV	All load and generation including and north of Calvale, Gin Gin and Teebar Creek substations, except load and generation in GG and NQ sub-regions.
Gladstone Grid (GG)	Calliope River 275 kV	All load and generation at Calliope River, Boyne Island, Larcom Creek and Wurdong substations.
South Queensland (SQ)	South Pine 275 kV	All Queensland load and generation except load and generation in CQ, GG and NQ sub-regions.
Northern New South Wales (NNSW)	Armidale 330 kV	Within New South Wales, all load and generation including and north of Tamworth substation.
Central New South Wales (CNSW)	Wellington 330 kV	Within New South Wales, all load and generation including and west of Wallerawang and Wollar substations. Load and generation at Bayswater, Liddell and Muswellbrook substations. Load and generation at Bannaby, Avon and Dapto substations.
South New South Wales (SNSW)	Canberra 330 kV	Within New South Wales, all load and generation including and south of Gullen Range, Marulan and Kangaroo Valley substations. All load and generation in South West New South Wales.
Sydney, Newcastle and Wollongong (SNW)	Sydney West 330 kV	All New South Wales region load and generation except CNSW, SNSW and NNSW sub-regions load and generation.
Victoria (VIC)	Thomastown 66 kV	All load and generation within Victoria.
Central South Australia (SA)	Torrens Island 66 kV	All load and generation within South Australia except SESA sub-region load and generation.
South East South Australia (SESA)	South East SA 132 kV	All load and generation south of Tailem Bend within South Australia.
Tasmania (TAS)	George Town 220 kV	All load and generation within Tasmania.

Detailed transmission constraint representation for time-sequential models

In the ESOO, and where required in the ISP time-sequential models, AEMO applies a more detailed transmission representation. The NEM transmission network is represented using detailed transmission constraint equations over a regional topology, similar to what is used in the NEM Dispatch Engine (NEMDE). These constraints:

- Consider the NEM's network at 220 kV or above, and other transmission lines under this voltage level that run parallel to the network at 220 kV or above.
- Calculate the network flow capability (intra- and inter-regional) and the available generator output capacity in every dispatch interval of the model.
- Are constantly updated to reflect changing power system conditions and outages.
- Are modified to cater for different transmission development pathways and scenarios assessed in an ISP.

3.10.2 Existing transmission capability

Input vintage	July 2023
Source	AEMO internal supplemented by advice from TNSPs via joint planning
Updates since Draft IASR	Updated following the Draft 2023 Transmission Expansion Options Report. Transfer limits have been split into three system conditions that align with the approach to modelling generation capacity. Historical transfer performance was reviewed, and power flow studies undertaken by AEMO and TNSPs.

Transfer capability across the transmission network is determined by thermal capacity, voltage stability, transient stability, small signal stability, frequency stability and system strength. It varies throughout the day with generation dispatch, load and weather conditions. In time-sequential market modelling, limits are represented through network constraint equations. For capacity outlook modelling, notional transfer limits between the regions or sub-regions are represented at the time of maximum demand in the importing region or sub-region.

AEMO made the following changes since the 2021 IASR:

- Inclusion of flow path limits between Central Queensland (CQ) and Northern Queensland (NQ).
- Inclusion of flow path limits between South East South Australia (SESA) and Central South Australia (CSA).
- Revision of flow path limits between Tasmania (TAS) and Victoria (VIC) regions aligned with current operational advice.

The 2023 IASR notional transfer limits are in Table 40. They reflect current assessments and may change as further power system analysis is undertaken, or as the sub-regional representation is refined. Interconnector transfer capabilities are a subset of this information, and are listed in the 2023 IASR Assumptions Workbook.

Table 40 Notional transfer capabilities between the sub-regions of the existing network (December 2022)

Flow paths (forward power flow direction)	Forward direction capability (MW)			Reverse direction capability (MW)			Comments
	Summer peak	Typical summer	Winter reference	Summer peak	Typical summer	Winter reference	
CQ – NQ	1,200	1,200	1,400	1,200	1,200	1,400	New flow path added for 2024 ISP.
CQ – GG	700	700	1,050	750	750	1,100	No changes to 2022 ISP.
SQ – CQ	1,100	1,100	1,100	2,100	2,100	2,100	The maximum power transfer from CQ to SQ grid section is limited by transient or voltage stability following a Calvale to Halys 275 kV circuit contingency. It is assumed Powerlink establishing new substation at Karana Downs for teeing both Blackwall – Rocklea 275 kV lines to South Pine. The maximum transfer capability from SQ to CQ is limited by thermal capacity of the Palmwoods – South Pine 275 kV line following a credible contingency.
NNSW – SQ (“QNI”)	685	745	745	1,205	1,165	1,170	No changes to 2022 ISP. This transfer limits assumes the full capacity provided by QNI minor project expected in mid-2023. Queensland to New South Wales transfer limit is influenced by generation output from Sapphire Wind Farm. For peak demand, typical summer and winter reference conditions Sapphire wind

Flow paths (forward power flow direction)	Forward direction capability (MW)			Reverse direction capability (MW)			Comments
	Summer peak	Typical summer	Winter reference	Summer peak	Typical summer	Winter reference	
							dispatch assumed to be 33%, 50% and 50% respectively.
NNSW – SQ ("Terranora")	0	50	50	130	150	200	No changes to 2022 ISP.
CNSW – NNSW	910	910	910	930	930	1,025	No changes to 2022 ISP. This transfer limits assumes the full capacity provided by QNI minor project.
SNSW – CNSW	2,700	2,700	2,950	2,320	2,320	2,590	No changes to 2022 ISP. For flow from SNSW to CNSW, Snowy 2.0 generation or pump load is <= 660.
CNSW – SNW	6,125	6,125	6,225	6,125	6,125	6,125	CNSW to SNW transfer limits updated. This limit has been formulated for the DLT model and should not be used for other applications. AEMO will work closely with EnergyCo and Transgrid to further refine this limit, which is expected to increase, for the final 2023 IASR. See the 2023 IASR Assumptions Workbook for more details CNSW-SNW transfer limit improvement with Waratah Super Battery (WSB) with a SIPS and associated minor network augmentation and Central West Orana Transmission Link. Power is not expected to frequently flow from SNW to CNSW since the major load centre is SNW. For DLT modelling, a transfer limit of 6,125 MW is assumed for this limit, and will be reviewed if it becomes material
VIC – SNSW	870	1,000	1,000	400	400	400	No changes to 2022 ISP. VIC-SNSW transfer limits assumes the full capacity provided by VNI Minor. Victoria SIPS with 250 MW battery storage in western side of Melbourne raises the thermal capacity of Victoria – New South Wales interconnector. Victoria – SNSW transfer limit during summer peak periods reduces to 250 MW from 400 MW on conclusion of the VNI SIPS agreement 31 March 2032. For flow from SNSW to VIC, Snowy 2.0 generation or pump load is <= 660.
VIC – SESA ("Heywood")	650	650	650	650	650	650	No changes to 2022 ISP. Heywood interconnector currently operates at 600 MW forward capability and 550 MW reverse capability. AEMO and ElectraNet work towards to release the transfer capability to its designed capability of 650 MW in both directions.
VIC – CSA (Murraylink)	220	220	220	100	200	200	No changes to 2022 ISP.
SESA – CSA	650	650	650	650	650	650	New flow path added for 2024 ISP.
TAS – VIC	462	462	462	462	462	462	In 2022 ISP, 478 MW applied in both directions. 462 MW transfer in both directions is sourced from Market bids.

Committed and anticipated projects may increase the capability of flow paths or result in new flow paths. The flow path uplift factors and new flow paths as a result of committed and anticipated project are presented in the 'Network capability' tab of the 2023 IASR Assumptions Workbook.

3.10.3 Committed transmission projects

Input vintage	July 2023
Source	AER and TNSPs – AER's approval of Contingent Project Application and advice from TNSPs on the status of projects meeting the commitment criteria
Updates since Draft IASR	• New South Wales Waratah Super Battery Network Augmentations and SIPS Control • Victoria South West REZ minor Augmentations

AEMO applies the five-criteria definition of a committed project from the AER's regulatory investment test[174]; specifically, a committed transmission project must meet all the following criteria:

- The proponent has obtained all required planning consents, construction approvals and licences, including completion and acceptance of any necessary environmental impact statement.
- Construction has either commenced or a firm commencement date has been set.
- The proponent has purchased/settled/acquired land (or commenced legal proceedings to acquire land) for the purposes of construction.
- Contracts for supply and construction of the major components of the necessary plant and equipment (such as transmission towers, conductors, terminal station equipment) have been finalised and executed, including any provisions for cancellation payments.
- Necessary financing arrangements, including any debt plans, have been finalised and contracts executed.

This final 2023 IASR applies the committed projects listed in the Transmission Augmentation Page[175], June 2023 release. For further details on these projects please see the 2023 IASR Assumptions Workbook or the Transmission Augmentation Page.

Some projects currently categorised as anticipated (see Section 3.10.4) may become committed before ISP modelling commences. AEMO intends to update this list of committed projects if a project becomes committed during the development of the ISP.

3.10.4 Anticipated transmission projects

Input vintage	July 2023
Source	AER and TNSPs – AER's approval of Contingent Project Application and advice from TNSPs on the status of projects meeting the commitment criteria
Updates since Draft IASR	• Queensland CopperString 2032 • Victoria Koorangie Energy Storage

[174] At https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20-%2025%20August%202020.pdf.

[175] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

Anticipated transmission projects are transmission augmentations that are not yet committed but are highly likely to proceed and could become committed soon. AEMO applies the criteria set out in the AER's regulatory investment test to determine anticipated projects. These projects must be in the process of meeting three out of the five committed project criteria (described in 3.10.3). Such projects could be network or non-network augmentations and could be regulated or non-regulated assets.

The Reliability Forecasting Methodology[176] defines which categories of transmission projects are included (considered to be committed) in reliability assessments. This may include anticipated projects that have received regulatory approval and minor upgrades that are not subject to the RIT-T but judged to be committed for reliability assessment purposes. For ISP modelling, anticipated projects will be included in all scenarios.

Generally, transmission projects will be classified as anticipated once they have passed a contingent project application or similar funding approval. AEMO intends to update the status of anticipated projects if any other project becomes committed during the development of the ISP.

The final 2023 IASR applies the anticipated projects listed in the Transmission Augmentation Page[177], June 2023 release. For further details on these projects please see the 2023 IASR Assumptions Workbook or the Transmission Augmentation Page.

3.10.5 Flow path augmentation options

Input vintage	July 2023
Source	AEMO, 2022 ISP, TNSP
Updates since Draft IASR	2023 *Transmission Expansion Options Report* consultation and through further TNSP engagements

Flow paths are a feature of power system networks, representing the main transmission pathways over which bulk energy is shipped. They are the portion of the transmission network used to transport significant amounts of electricity across the backbone of the network to load centres. Flow paths change as new interconnection is developed, or as a result of shifting large amounts of generation into new areas (such as in the case of major REZ development).

Flow path augmentation options represent new network and non-network options to increases the transfer capability between ISP sub-regions. Each option is a candidate to be built during capacity expansion modelling. While many flow path augmentation options increase REZ network capacities, distinct options to expand the network capacity within individual REZs are modelled through a separate process, outlined in Section 3.9.

When identifying flow path augmentation options across ISP sub-regions to connect REZs and pumped hydro storage, AEMO considers credible options including the following technologies:

- High voltage alternating current (HVAC) technology.
- High voltage direct current (HVDC) technologies.
- Virtual transmission lines (using grid-scale batteries).

[176] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines/forecasting-and-planning-guidelines.

[177] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

AEMO has consulted on flow path augmentation options, including the capacity gained and lead time to deliver the project, through the 2023 *Transmission Expansion Options Report*. Please see Section 3.9.5 for more details.

3.10.6 Transmission augmentation costs

Input vintage	July 2023
Source	• Actionable projects: RIT-T data with factors applied • Projects with Preparatory activities: TNSP cost data, cross check with AEMO's Transmission Cost Database • Future projects: AEMO's Transmission Cost Database
Updates since Draft IASR	The 2023 *Transmission Expansion Options Report*

For the 2022 ISP, AEMO engaged independent expert consultant GHD to develop a new Transmission Cost Database for use by AEMO in developing cost estimates. It comprised a Cost and Risk Databook and cost estimation tool. To reflect the latest changes in the market, AEMO engaged expert consultant Mott MacDonald to update the Transmission Cost Database. The updated Transmission Cost Database includes:

- Cost and risk data which aligns with latest changes in market costs.
- The latest transmission project information and escalation factors.

3.10.7 Preparatory activities

Input vintage	June 2023
Source	TNSPs
Updates since Draft IASR	Received preparatory activities from the following TNSPs: • ElectraNet • Powerlink • Transgrid • AEMO (Victorian Planner)

Preparatory activities[178] are intended to improve the conceptual design, lead time, location and cost estimates for transmission projects. The ISP may require preparatory activities for some future ISP projects. Future ISP projects are projects which address an identified need, form part of the ODP, and may be actionable ISP projects in the future.

While TNSPs must commence preparatory activities as soon as practicable for actionable ISP projects, an ISP may specify whether preparatory activities must be carried out for future ISP projects and the timeframes for carrying out those activities.

To allow the outcomes of these preparatory activities to inform development of the ISP, AEMO may request that relevant TNSPs provide a report on preparatory activities for specific future ISP projects. These are typically projects which may become actionable ISP projects, but more detailed information is required, such as improved cost estimates, network designs, and initial appraisal of land considerations. This initial high-level design and costing in the preparatory activities report is necessarily approximate, as the detailed requirements for robust costings and plant design will not have been undertaken – this would require much more extensive work, including detailed Geotech land surveying and engagement on the route and necessary planning approvals.

[178] See definition in NER 5.10.2 and NER 5.22.6(c)-(d).

Preparatory activities are not the same as early works, because preparatory activities remain essentially a desktop exercise.

The projects for which preparatory activities are currently required to be performed by TNSPs are outlined in the following table. The TNSP preparatory activities report are published on the AEMO website.

Table 41 Preparatory activities

Project	Indicative timing	Responsible TNSP(s)
South East South Australia REZ expansion (Stage 1)	2025-26 to 2045-49	ElectraNet
Darling Downs REZ Expansion (Stage 1)	2025-26 to 2047-48	Powerlink
Mid-North South Australia REZ Expansion	≥ 2028-29	ElectraNet
QNI Connect (500 kV option)	2029-30 to 2036-37	Powerlink and Transgrid
QNI Connect (330 kV option – New South Wales scope)		Transgrid
South West Victoria REZ Expansion	≥ 2033-34	AEMO (Victorian Planner)

For preparatory activities requested and received in response to the 2020 ISP, AEMO escalated the costs from the previous preparatory activities received.

3.10.8 Non-network options

Input vintage	July 2023
Source	Previous projects, stakeholder submissions
Updates since Draft IASR	None

Non-network options are defined in the NER (Chapter 10, glossary) as a means by which an identified need can be fully or partly addressed other than by a network option. In the ISP, AEMO considers potential non-network options alongside network solutions to develop an efficient power system strategy. Depending on their relative costs and benefits, the capital costs of large network augmentation could be deferred or avoided by delivering a non-network solution.

Non-network options include a range of technologies, for example:

- Generation investment (including embedded or large-scale).
- Storage technologies (such as battery storage and pumped hydro).
- Demand response.

As per Section 3.4.3 of the CBA Guidelines, prior to the Draft ISP, AEMO is required to:

- undertake early engagement with non-network proponents to gather information in relation to non-network options; and
- if there are any credible non-network options identified through early engagement and joint planning, but not included in a TAPR, include these in its process for selecting development paths.

The Draft IASR invited submissions for proposals from non-network proponents, however no responses were received. AEMO continues to welcome submissions regarding non-network options. A formal notice requesting submissions for non-network options[179] will be published alongside the Draft ISP.

3.10.9 Network losses

Input vintage	March 2023
Source	AEMO *Marginal Loss Factors Report* 2023-24 Financial Year and internal processes
Updates since Draft IASR	• Updated in line with AEMO's *Marginal Loss Factors Report published in March 2023* • For existing network intra-regional loss factor equations, loss equations and proportioning factors, the final 2023 IASR Assumptions Workbook has been updated • For future augmentation options, the final 2023 *Transmission Expansion Options Report*

This section describes the inter-regional loss flow equations, interconnector MLF equations, and interconnector loss proportioning factors for use in studies such as the ISP and ESOO. While the sub-regional model does split some regions into smaller sub-regions, inter-regional losses will continue to be modelled across regional boundaries – consistent with the design of the NEM.

Inter-regional loss equations, loss factor equations and proportioning factors

Inter-regional loss equations are used to determine the amount of losses on an interconnector for any given transfer level. These are used to determine net losses for different levels of transfer between regions so NEMDE or AEMO's capacity expansion model and time-sequential market model can ensure the supply-demand balance includes losses between regions.

Inter-regional loss factor equations describe the variation in loss factor at one regional reference node (RRN) with respect to an adjacent (RRN. These equations are necessary to cater for the large variations in loss factors that may occur between RRNs as a result of different power flow patterns. This is important in minimising the distortion of economic dispatch of generating units.

Interconnector loss proportioning factors are used to separate the inter-regional losses into the amount belonging to each of the two regions.

The existing network inter-regional loss equations, loss factor equations and proportioning factors are sourced from the *Marginal Loss Factors for the 2023-24 Financial Year*[180] report and are presented in the 'Network losses' tab of the 2023 IASR Assumptions Workbook

For committed and anticipated projects that impact interconnector flows, the inter-regional loss equations, loss factor equations and proportioning factors are updated.

Intra-regional loss and loss factor equations

AEMO models intra-regional loss equations to capture the change in network losses as more generation connects to capture declining MLFs as large generation is developed in parts of the network remote from demand centres.

[179] NER 5.22.12

[180] At https://aemo.com.au//media/files/electricity/nem/security_and_reliability/loss_factors_and_regional_boundaries/2023-24-financial-year/marginal-loss-factors-for-the-2023-24-financia-year-pdf.pdf?la=en.

AEMO has identified Northern Queensland as being remote from load centres under all scenarios except *Green Energy Exports*, based on insights from the 2022 ISP's *Hydrogen Superpower* scenario outcomes. AEMO has made the following changes compared to the 2022 ISP model:

- Removed the MLF penalty factors applied to Far North Queensland and Queensland Clean Energy Hub in all scenarios except the *Green Energy Exports* scenario.
- Used the sub-regional model to capture the network losses, through intra-regional equations, between the Northern Queensland, Central Queensland and Southern Queensland sub-regions for all scenarios except the *Green Energy Exports* scenario.

The 2023 IASR Assumptions Workbook 'Network losses' factors tab' captures the intra-regional loss factor equations.

3.10.10 Marginal loss factors (MLFs)

Input vintage	March 2023
Source	AEMO *Marginal Loss Factors Report* 2023-24 Financial Year and internal processes
Updates since Draft IASR	Updated in line with AEMO's 2023-24 *Marginal Loss Factors Report*

Network losses occur as power flows through transmission lines and transformers. Increasing the amount of renewable energy connected to the transmission network remote from load centres will increase network losses. As more generation connects in a remote location, the power flow over the connecting lines and on the AC system increases, and so do losses.

Electrical losses are a transport cost that need to be priced and factored into electrical energy prices. MLFs are used to adjust the price of electricity in a NEM region, relative to the RRN, in a calculation that aims to recognise the relationship between a generator's output and the energy that is actually delivered to consumers. The NEM uses marginal costs as the basis for setting spot prices in line with the economic principle of marginal pricing. The spot price for electrical energy is determined, or is set, by the incremental cost of additional generation (or demand reduction) for each dispatch interval. Consistent with this, the marginal loss is the incremental change in total losses for each incremental unit of electricity. The MLF of a connection point therefore represents the marginal losses to deliver electricity to that connection point from the RRN.

In dispatch and settlement in the NEM, the local price of electricity at a connection point is equal to the regional price multiplied by the MLF. A renewable generator's revenue in the NEM wholesale market is directly scaled by its MLF, through both electricity market transactions and any revenue derived from large-scale renewable generation certificates (LGCs) created if accredited under the LRET.

MLFs are an outcome of applying the methodology described in AEMO's Forward-Looking Transmission Loss Factors, and are updated every financial year with the publication of AEMO's *Marginal Loss Factors Report*. AEMO updated the MLFs to reflect the latest available version of this report. Where a committed or anticipated generator does not have an MLF calculated in the *Forward-Looking Transmission Loss Factors* report, a 'shadow' generator is used. This is a generator which is located electrically close to the generator in question, and where possible, is the same technology. This same concept is applied to generic new entrant generators.

See the 'Marginal Loss Factors' tab in the 2023 IASR Assumptions Workbook.

3.10.11 Transmission line unplanned outage rates

Input vintage	June 2023
Source	AEMO Network Outage Schedule and other AEMO sources
Update process	Updated in June 2023 as part of data collection process for the ESOO

AEMO models some outages on a limited selection of transmission flow paths that are required for inter-regional power transfer. Information is collected on the timing, duration, and severity of the transmission outages to inform transmission unplanned outage rate forecasts. Table 42 shows the rates and method used in the 2023 ESOO, consistent with the *ESOO and Reliability Forecast Methodology*. Transmission line unplanned outage rates apply only to some reliability modelling. The ISP capacity outlook modelling does not include transmission outage rates, given their low probability.

Table 42 Inter-regional transmission flow path outage rates

Flow path	Unplanned outage rate (%)		Mean time to repair (hours)		Outage rate method
	Single credible contingency	Reclassification	Single credible contingency	Reclassification	
Liddell – Muswellbrook – Tamworth – Armidale – Dumaresq – Bulli Creek (QNI)	0.19%	1.40%	14.5	4.3	Annual static
Murraylink	0.07%	Not applicable	12.4	Not applicable	Annual static
Mortlake – Heywood – South East (Victoria-South Australia))	0.09%	0.01%	7.8	4.7	Annual static
Basslink	5.39%	Not applicable	213.9	Not applicable	Annual static

3.11 Power system security

Planning studies focus on the reliability and security of the future power system under system normal conditions and following the first credible contingency, including the continued availability of various system services to be able to restore the power system to a secure operating state within 30 minutes following a contingency.

New generation and transmission investments may change the scale and location of services needed for power system security. A changing mix of technologies from synchronous units and inverter-based resources[181] (IBR) developments create both challenges and opportunities for planning the future power system.

Planning assumptions for power system security are applied when developing the ISP, given the uncertainty regarding the future operation of synchronous generating units, emerging technology and new innovations that enable IBR to provide sought-after system services, demand levels, regulatory change, operational measures, and other emerging security issues.

As the system evolves, and once detailed models are available, comprehensive studies will be required to improve the accuracy of operating requirements and limits advice.

[181] IBR include wind farms, solar PV generators, and batteries. They do not have moving parts rotating in synchronism with the grid frequency, but instead are interfaced to the power system via power electronic converters which electronically replicate grid frequency.

AEMO's *Power System Requirements* document[182] describes power system security services in more detail, and the capabilities of various technologies to supply these services.

This section describes the inputs and assumptions made for the following power system security issues:

- Synchronous unit commitment assumptions.
- System strength requirements and cost.
- Inertia requirements.
- Other system security limits.

3.11.1 Synchronous unit commitment assumptions

Input vintage	December 2022
Source	AEMO internal
Updates since Draft IASR	None – stakeholders agreed to the draft structure

As IBR penetration increases, the number of large synchronous generating units online is reducing and encroaching on system security limits. AEMO expects that the power system security services traditionally provided by thermal power stations will be provided from alternative sources as coal-fired generation capacity is withdrawn from the market. When forecasting generation dispatch, AEMO will therefore assume a synchronous generating unit commitment requirement for each region of the NEM that declines over time. This reflects the fact that operation with low or no synchronous generating units in a region will need to be a staged process.

Ultimately, AEMO assumes that the requirement to maintain a minimum dispatch of coal-fired generators will end[183]. In practice, the pace at which unit commitment requirements reduce will depend on the pace of the energy transition, the delivery of services such as system strength services, as well as the uplift in operational tools and practices described in the Engineering Framework[184].

As unit commitment requirements decline, it is expected that power system security services will be delivered by increased interconnection, increased presence of pumped hydro generators, advanced inverters, and expected levels of synchronous condensers being installed (or retrofitted to existing synchronous generators). AEMO uses the following planning assumptions for unit commitment requirements:

- **New South Wales, Queensland and Victoria** – for these regions, which have a predominance of coal-fired power generation, AEMO applies a 'half-life' approach and assumes that the number of units required will halve every two years from 2025-26 for the *Progressive Change* and *Step Change* scenarios. For the *Green Energy Exports* scenario, AEMO assumes that the number of units will halve under the planning assumption every year to align with the with rapid and widespread transformation of the economy and rapid decarbonation assumed in this scenario.
- **South Australia** – a unique assumption is needed to reflect the progress in transforming the power system in recent years. In South Australia, AEMO and ElectraNet have already been actively considering an approach to

[182] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power-system-requirements.pdf.

[183] Long-term power system security assumptions are used for the purpose of assessing reliability and the economics of development plans. Detailed limits advice is required before changing operational practices.

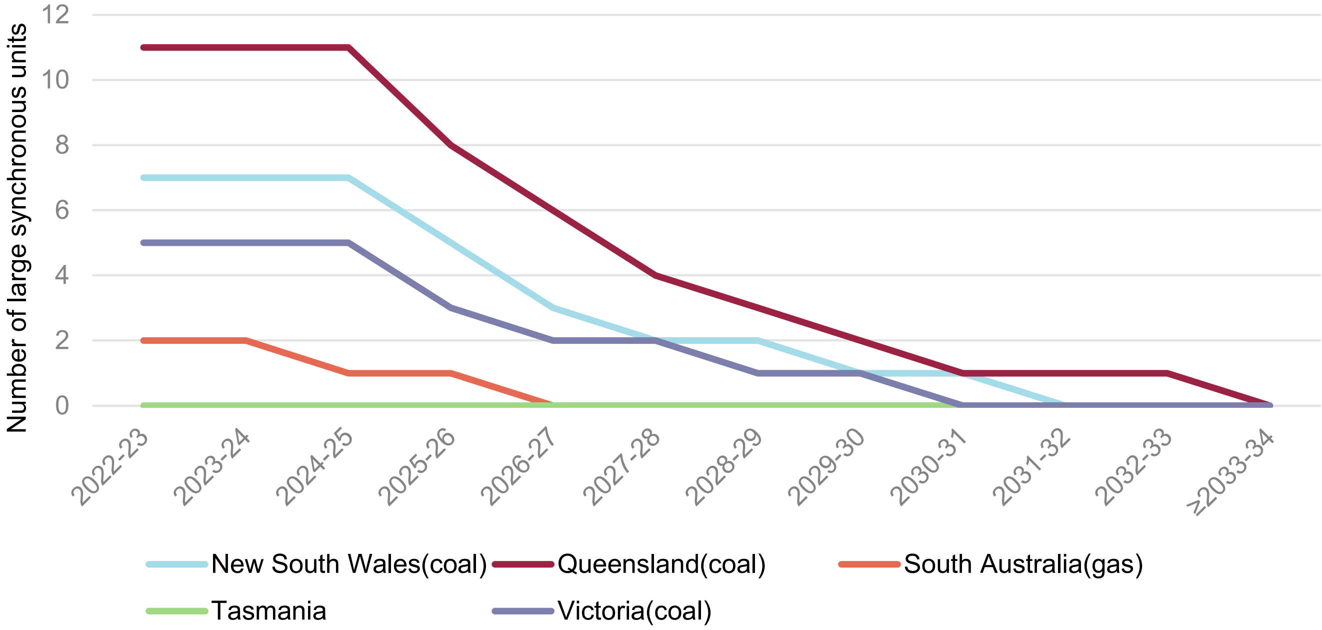
[184] See https://aemo.com.au/initiatives/major-programs/engineering-framework.

reducing the minimum synchronous machine requirement[185]. In addition, there are no remaining coal-fired units in South Australia. For all scenarios, AEMO applies the 'half-life' approach for gas-fired units in South Australia from the 2022-23 financial year[186].

- **Tasmania** – AEMO does not use a fixed assumption for unit commitment in Tasmania, because the region has a large number of small, distributed hydroelectric generators and a large number of combinations of machines that can be used for power system security purposes. No manual constraints need be applied for modelling Tasmania as many of the generators can be operated in synchronous condenser mode when required.

Figure 57 and Figure 58 provide the unit commitment assumptions for New South Wales, Queensland, South Australia and Victoria derived from these approaches. These assumptions are developed for the purpose of planning studies and should not be used for operational advice.

Figure 57 New South Wales, Queensland, South Australia, Tasmania and Victoria projected unit commitment requirements, all scenarios except *Green Energy Exports*, 2022-23 to 2033-34



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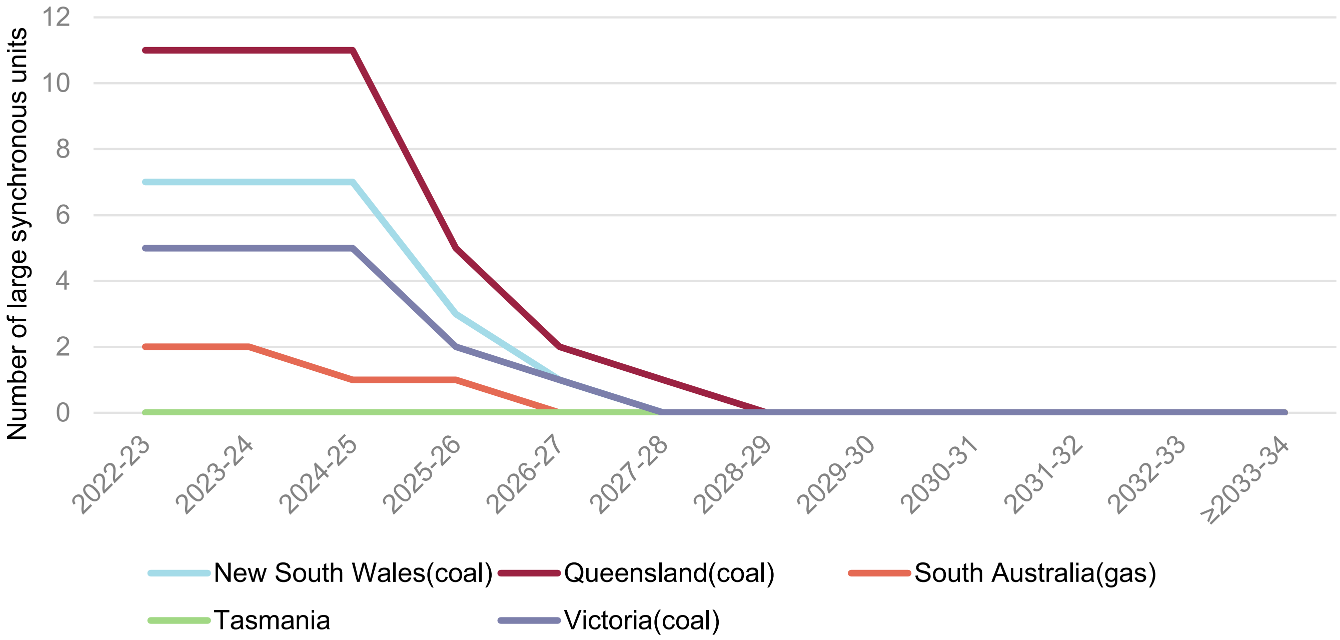
185 Stakeholder engagement materials relating to synchronous generator requirements in South Australia are at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/related-resources/operation-of-davenport-and-robertstown-synchronous-condensers.

186 As for other regions, this assumption is for planning and market modelling purposes only. Real-time operations will depend on limit advice.

Figure 58 New South Wales, Queensland, South Australia, Tasmania and Victoria projected unit commitment requirement, *Green Energy Exports* scenario, 2022-23 to 2029-30



3.11.2 System strength requirements and cost

Input vintage	July 2023
Source	AEMO internal
Updates since Draft IASR	• Existing system strength standards for the NEM are provided at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning and may be further updated following the release of AEMO's annual *System Strength Report* (or subsequent updates to requirements in response to changing circumstances) • The final 2023 IASR Assumptions Workbook has been updated with latest system strength remediation cost • Costs to deliver the efficient level of system strength have been provided through the *Transmission Expansion Options Report*

The increasing integration of IBR across the NEM has implications for the engineering design of the future power system. As clusters of IBR connect in close proximity, more system strength will be needed, and TNSPs will need to ensure a basic level of fault current across their networks.

Key aspects of system strength (discussed in AEMO's white paper *System Strength Explained*[187]) include steady state voltage management, voltage dips, fault ride-through, power quality and operation of protection.

The system strength rules have recently been amended to a new framework under the AEMC's final determination on the efficient management of system strength on the power system[188]. Under the previous rule, AEMO was required to determine the fault level requirements across the NEM and identify whether a fault level shortfall was likely to exist at the time or in the coming five years. From 1 December 2022, AEMO declared a system strength standard for each system strength node in the NEM, against which the local System Strength Service Providers (SSSPs) must provide services to meet the full requirement starting from 1 December 2025.

[187] At https://aemo.com.au/-/media/files/electricity/nem/system-strength-explained.pdf.

[188] See https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system.

The new system strength requirements comprise a minimum three phase fault level requirement at each system strength node, and an IBR forecast that sets the efficient level of system strength against which the SSSP must ensure a stable voltage waveform. The revised System Strength Requirements Methodology[189] defines the process AEMO must apply to set these standards.

For the efficient level of system strength, AEMO incorporates a $/kW value in the ISP modelling for the system strength services provided to enable connection and operation of IBR within REZs. AEMO engaged expert consultant Mott MacDonald to update the Transmission Cost Database, which was used for the 2020 and 2022 ISP (see Section 3.10.6 for more details). AEMO used the updated Transmission Cost Database to develop cost estimates for system strength service provision for the efficient level, for use in the 2024 ISP. These cost estimates were consulted on through the *Transmission Expansion Options Report*.

AEMO updates the system strength requirements annually[190]. AEMO's System Strength Requirements Methodology details the fault level calculation method to be used, and defines the system strength nodes and requirements for each region. The ISP uses the most up-to-date minimum fault level requirements for each node. The fault level requirements are calculated by deriving minimum fault levels from electromagnetic transient (EMT) studies that determine the minimum synchronous generator combinations required to be online in each NEM region.

3.11.3 Inertia requirements

Input vintage	December 2022
Source	AEMO
Updates since Draft IASR	Existing inertia requirements for regions of the NEM when islanded are provided at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning and may be further updated following the release of AEMO's annual *Inertia Report* (or subsequent updates to requirements in response to changing circumstances)

Inertia allows the power system to resist large changes in frequency arising from an imbalance in power supply and demand due to a contingency event. Forecast inertia is continuing to decline across the NEM as synchronous generator behaviour changes, penetration of IBR increases, and minimum demand projections decline.

AEMO is required to assess and publish the minimum threshold level of inertia and the secure operating level of inertia for each NEM region when it is islanded, and to assess shortfalls over the coming five-year period. AEMO's process for assessing these requirements is outlined in AEMO's Inertia Requirements Methodology and AEMO's assessments for each region are published at least annually on AEMOs website[191].

Shortfall declarations are not an outcome of the ISP process, but an outcome of the separate annual Inertia Report. For the ISP inertia assessments, AEMO will use the updated inertia requirements published on AEMO's website.

AEMO considers that the rise of IBR will provide viable alternatives to the inertia sources traditionally provided from synchronous generators, although the complete replacement of traditional synchronous inertia with IBR remains to be demonstrated at scale. In addition, given the inter-relationship between inertia and frequency, a

[189] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf.

[190] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

[191] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

number of ongoing regulatory reforms in the NEM relating to frequency services and requirements can be expected to affect the assessment of inertia requirements in the future.

3.11.4 Other system security limits

Input vintage	July 2023
Source	AEMO internal and TNSP limits advice
Updates since Draft IASR	None- Stakeholders have agreed to the current structure.

In NEMDE, a series of network constraint equations control dispatch solutions to ensure that intra-regional network limitations are accounted for. The time-sequential model used in long-term planning studies contains a subset of the NEMDE network constraint equations to achieve the same purpose. This subset of network constraint equations is included in the ISP model to reflect power system operation within other security limits. In addition to system strength and inertia limits which are considered above, these include:

- Voltage stability – for managing transmission voltages so that they remain at acceptable levels after a credible contingency.
- Transient stability – for managing continued synchronism of all generators on the power system following a credible contingency.
- Oscillatory stability – for managing damping of power system oscillations following a credible contingency.
- Rate of change of frequency (RoCoF) – for managing the rate of change of frequency following a credible contingency.

The effect of committed transmission and generation projects on the network is implemented in NEMDE as modifications to the network constraint equations that control power flow. The methodology for formulating these constraints is in AEMO's Constraint Formulation Guidelines[192].

Other system security limits may need to be applied on a case-by-case basis as more information becomes available, for example to ensure frequency control services or to account for non-credible contingencies in some cases such as the trip of double-circuit interconnectors.

3.12 Hydrogen infrastructure

Input vintage	July 2023
Source	CSIRO: *GenCost 2022-23 Final report* Queensland Government: 'Enabling Queensland's hydrogen production and export opportunities' ARUP: Australian hydrogen hub study report 2019
Updates since Draft IASR	Hydrogen from SMR removed and replaced with electrolyser hydrogen. PEM Cost has been updated to reflect *GenCost 2022-23 Final report*.

[192] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource.

This section outlines key inputs and assumptions related to hydrogen production technologies, as well as infrastructure needs where potential for development of hydrogen domestic and export production locations are explored within ISP modelling.

Hydrogen demand assumed across scenarios is discussed in Section 3.3.6.

Hydrogen production technologies

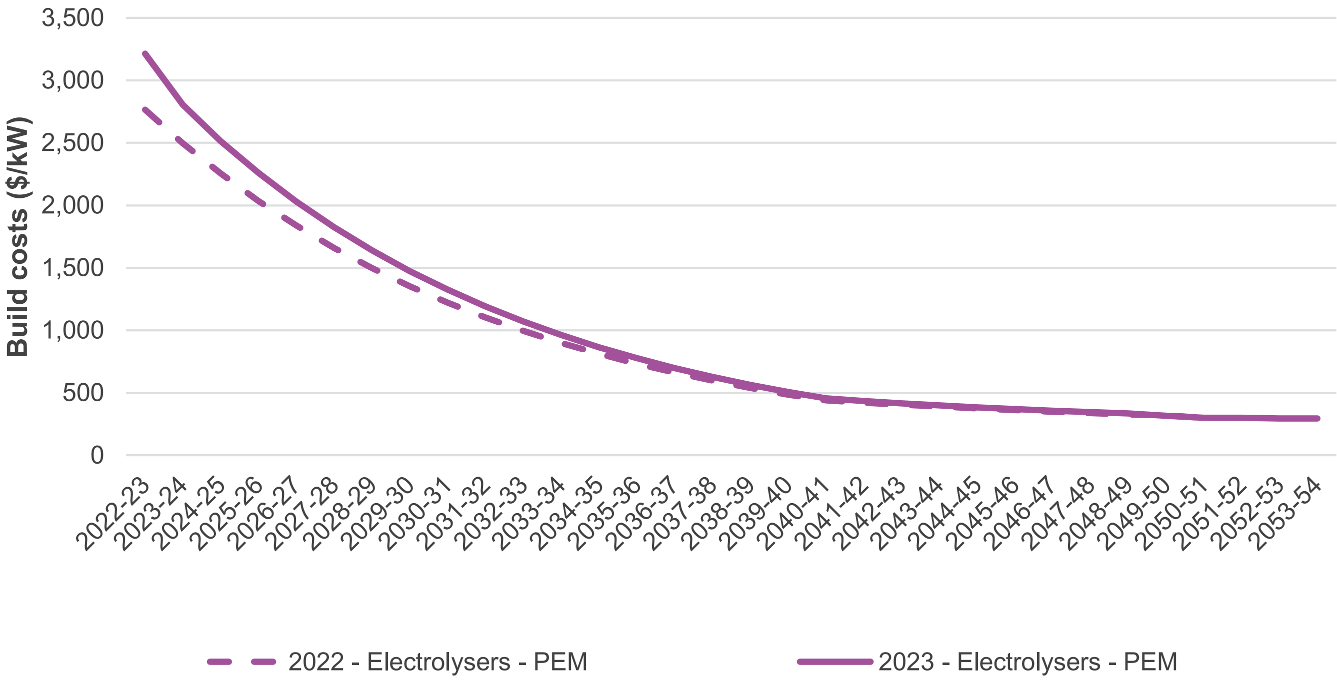
To produce hydrogen, AEMO's forecasts include production potential from electrolysis only. Electrolysis uses electricity to split water molecules into hydrogen and oxygen. If this electricity is sourced from renewable generation it creates "green hydrogen". Proton exchange membrane (PEM) technology is most commonly proposed for development in the NEM, and AEMO's forecasts apply this technology choice.

PEM characteristics

Figure 59 below presents the capital cost projections for new PEM installations as forecast in *GenCost 2022-23 Final report* for its Global NZE post 2050 scenario, compared to GenCost 2021-22 projections. Relative to the 2021-22 forecasts, there has been an increase in hydrogen electrolysers cost in early years, driven by significant cost pressures factored in *GenCost 2022-23 Final report*. See Section 3.5.3 for more detail on these cost adjustments, as well as detail on scenario mappings between the *GenCost 2022-23 Final report* and final 2023 IASR scenarios.

Cost projections for PEM electrolysers for each scenario are available in the accompanying 2023 IASR Assumptions Workbook.

Figure 59 Forecast build cost trajectories for electrolysers (PEM), 2022 vs 2023 Global NZE post 2050 scenario



Electrolysers can be operated flexibly, providing capacity to ramp up and down rapidly, potentially even providing fast frequency response in a similar way to electrochemical batteries. AEMO models PEM electrolysers as fully flexible, with a minimum baseload component (subject to the economic consequences of such operation, which may increase total costs to deliver the volume of hydrogen targeted in the scenario).

For the 2021 IASR, the baseload operating level of the electrolyser was set at 10% of total demand, even when the electrolyser is not producing hydrogen. Reported performance from the Energiepark Mainz facility in Germany indicates a baseload of 4.5%[193]. AEMO assumes a baseload of 4.5% for domestic-focused electrolysers, and 2% for larger-scale export-focused electrolysers, in line with 2022 ISP assumptions.

3.12.1 Hydrogen infrastructure needs

There are two main potential large-scale hydrogen supply pathways, both of which require bulk transport of energy from the source to the consumer. The main difference is the location of the conversion; that is, whether the bulk transport occurs using electrons (with electrolysers and a water source located at the consumer) or molecules (with electrolysers and a water source located at the VRE source).

AEMO has reviewed external studies on the optimal choice of pathway, and notes a lack of consensus, due to the dependence on many project parameters. The ISP model is currently configured to transport electrons via electricity transmission, with electrolysers located at export ports or close to domestic electrical load centres. No change to this configuration has been adopted for this 2023 IASR and 2024 ISP, but AEMO may examine the impacts of this pathway choice in future iterations.

Electrolyser location

Ten hydrogen export ports were initially selected from 30 hydrogen hubs identified in ARUP's Australian Hydrogen Hubs report to the COAG Energy Council[194]. An additional candidate port has been added at Mackay in Queensland, to align with the recent Queensland Government report into hydrogen export opportunities[195] and provide sufficient granularity across the state to reflect the ISP model sub-regions.

Table 43 lists the candidate hydrogen export ports (shown in Figure 60) that provide a geographic spread with access to REZ and port infrastructure. These candidate ports will be considered as options in the ISP modelling.

Table 43 Candidate hydrogen export ports

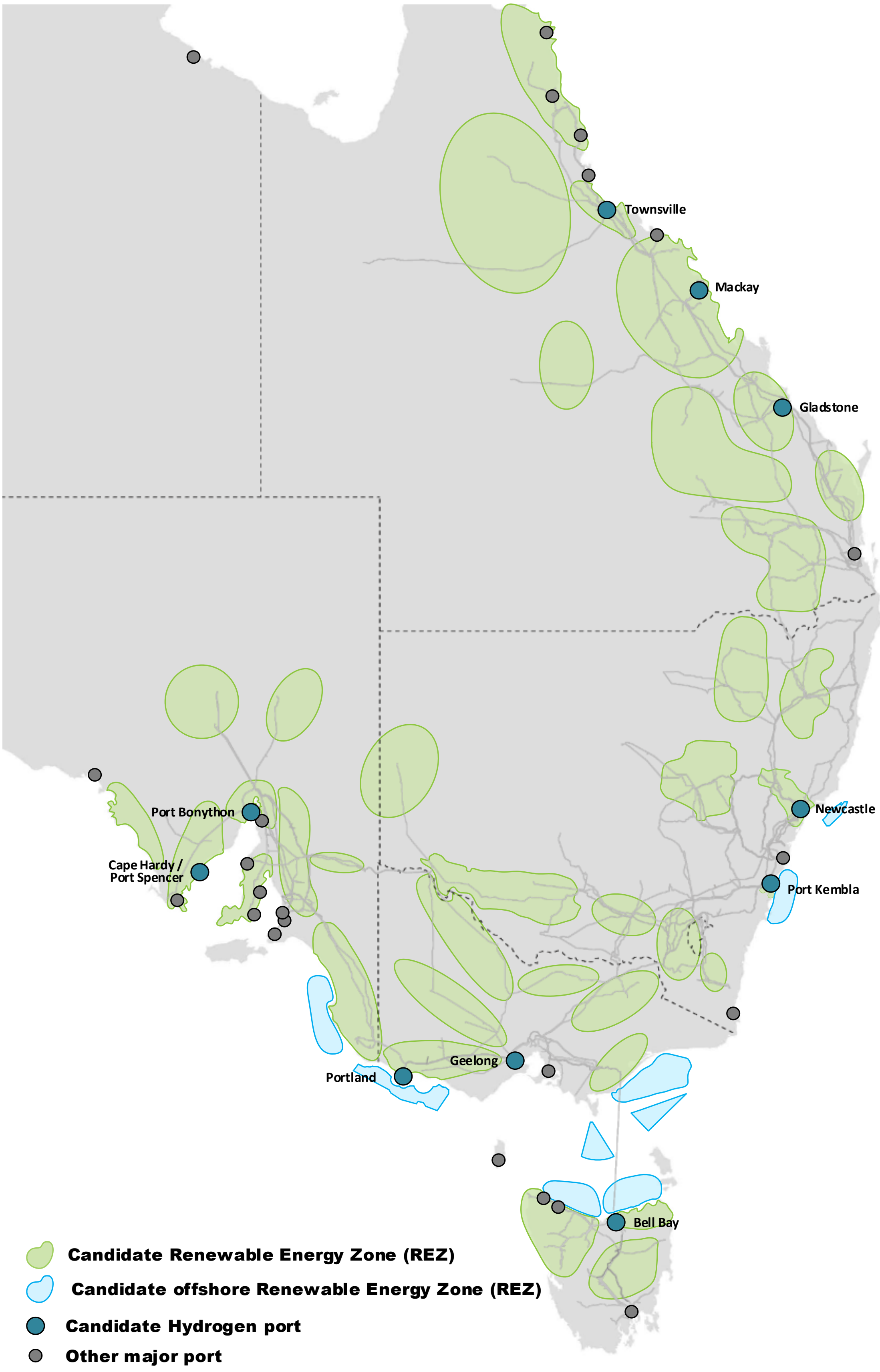
NEM region	Potential port location
New South Wales	Newcastle, Port Kembla
Queensland	Gladstone, Townsville, Mackay
South Australia	Port Bonython, Cape Hardy/Port Spencer
Tasmania	Bell Bay
Victoria	Geelong, Portland

[193] Kopp, M., Coleman, D., Stiller, C., Scheffer, K., Aichinger, J., Scheppat, B. et al. (2017), "Energiepark Mainz: Technical and economic analysis of the worldwide largest Power-to-Gas plant with PEM electrolysis", International Journal of Hydrogen Energy, Vol. 42, Issue 52.

[194] At https://www.dcceew.gov.au/sites/default/files/documents/nhs-australian-hydrogen-hubs-study-report-2019.pdf.

[195] Queensland Government. 'Enabling Queensland's hydrogen production and export opportunities'. Oct 2022, at https://www.epw.qld.gov.au/__data/assets/pdf_file/0017/33191/enabling-qld-hydrogen-opportunities-report.pdf.

Figure 60 Candidate hydrogen export ports



Water supply

For the 2024 ISP, water is assumed to be available, and is not a limiting factor affecting electrolyser operations, since all sites are assumed to be coastal. Water is not a costed component of electrolyser operation within the ISP modelling, although some export ports may require desalination. AEMO recognises that further analysis may be needed in future to validate the availability of water resources.

3.13 Employment factors

Input vintage	November 2022
Source	Rutovitz, J., Langdon., R, Mey, F., Briggs, C. (2022) *The Australian Electricity Workforce for the 2022 Integrated System Plan: Projections to 2050*. Prepared by the Institute for Sustainable Futures for RACE for 2030
Updates since Draft IASR	None

The demand for skilled labour in the electricity sector is forecast to double from approximately 44,000 in 2023 to over 80,000 by 2050 in the *Step Change* scenario from the 2022 ISP[196]. This growth will challenge engineering, procurement and construction (EPC) firms and regional communities as well as individual workers, particularly if there are boom-and-bust cycles or if workers and contractors are engaged project-to-project. With proactive planning, this challenge could represent an opportunity.

This section outlines the employment factors that will be used to estimate the workforce requirements needed to implement the ISP. The focus on workforce requirements in this estimation is focused on infrastructure development requirements; it does not include the workforce requirements to deliver electrification developments or other factors affecting the evolution of the consumer load in the energy transition.

A *Constrained Supply Chains* sensitivity will be included in the 2024 ISP to explore the costs and benefits of reducing the volatility of employment demand (see Section 2.3.1).

Generation and storage

Employment factors are applied to the capacity of generation and storage build to estimate workforce requirements. Employment factors reduce over time in proportion with technology costs (see Section 3.5.3) to reflect productivity improvements.

[196] See https://aemo.com.au/-/media/files/major-publications/isp/2022/supporting-materials/the-australian-electricity-workforce-for-the-2022-isp.pdf.

Table 44 Generation and storage employment factors

Technology	Construction time	Construction/ installation	Manufacturing		O&M	Fuel
			Total	On-shore		
	Years	Job-years / MW			Jobs / MW	Jobs / GWh
Black coal	5	11.1	5.4	3.32	0.22	0.04
Brown coal	5	11.1	5.4	3.32	0.22	0.01
Mid-merit gas	2	1.3	0.9	0.38	0.14	0.07
Peaking gas & liquids	2	1.3	0.9	0.38	0.14	0.11
Wind (onshore)	2	2.7	1.6	0.38	0.22	0.00
Wind (offshore)	3	1.4	5.3	0.38	0.08	0.00
Utility-scale PV	1	2.1	3.9	0.09	0.11	0.00
Rooftop PV	1	5.2	3.6	0.15	0.16	0.00
Utility-scale batteries	1	0.6	0.6	0.09	0.04	0.00
Distributed batteries	1	5.3	0.6	0.09	0.27	0.00
Pumped hydro	4	7.2	3.5	0.70	0.08	0.00
Hydro	5	7.4	3.5	2.21	0.14	0.00

Note: AEMO may apply employment estimates for individual projects where the information is available.

Transmission

Employment factors are applied to transmission build to estimate workforce requirements. Because transmission construction is relatively mature, employment factors for transmission development do not reduce over time.

Table 45 Transmission employment factors

Transmission build	Construction/ installation
Transmission line: single circuit	0.66 job-years/km
Transmission line: double circuit	3.68 job-years/km
Transmission (other)	1.85 job-years/$million

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A2. Supporting material

In addition to the 2023 IASR Assumptions Workbook, Table 46 documents additional information related to AEMO's inputs and assumptions.

Table 46 Additional information and data sources

Organisation	Document/source	Link
AEMO	Generation Information	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information
AEMO	AEMO's Transmission Cost Database	https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation
AEMO	2023 GSOO Stakeholder Surveys and gas supply input data	https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2023/2023-gsoo-gas-statement-of-opportunities-supply-data.zip?la=en
AEP Elical	2020 Assessment of Ageing Coal-Fired Generation Reliability	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/aep-elical-assessment-of-ageing-coal-fired-generation-reliability.pdf
AER	Values of Customer Reliability (VCR)	https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability/update-0
Aurecon	2022 Costs and Technical Parameter Review	Report: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/aurecon-2022-cost-and-technical-parameter-review.pdf Workbook: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/aurecon-2022-cost-and-technical-parameters-review--workbook.xlsb
OEA	2022 Commodities Scenario Forecast	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/bis-oxford-economics-2022-23-commodities-scenario-forecasts-report.pdf
OEA	2022 Macroeconomic forecasts	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/bis-oxford-economics-2022-macroeconomic-outlook-report.pdf
CSIRO and CWC	2022 Multi-sector modelling	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-climateworks-centre-2022-multisector-modelling-report.pdf
CSIRO	*GenCost 2022-23 Final report*	https://www.csiro.au/en/research/technology-space/energy/energy-data-modelling/gencost
CSIRO	2022 Projections for solar PV and battery systems	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-2022-solar-pv-and-battery-projections-report.pdf
CSIRO	2022 Electric Vehicle Projections	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/csiro-2022-electric-vehicles-projections-report.pdf
Energy Networks Australia	RIT-T Handbook	https://www.energynetworks.com.au/resources/fact-sheets/ena-rit-t-handbook-2020/
Entura	Pumped Hydro cost modelling	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Report-Pumped-Hydro-Cost-Modelling.pdf
GHD	2018-19 AEMO Costs and Technical Parameter Review	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/9110715-rep-a-cost-and-technical-parameter-review---rev-4-final.pdf
Green Energy Markets	Projections for solar PV and stationary energy battery systems	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/gem-2022-solar-pv-and-battery-projection-report.pdf

Organisation	Document/source	Link
ACIL Allen	ACIL Allen Gas Price Forecasts	Report: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios Workbook: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios
Synergies	Updating the 2022 discount rate	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/synergies-updating-the-2022-discount-rate.pdf
OEA	Cost of Capital Survey 2023	https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios
Wood Mackenzie	Wood Mackenzie 2021 Coal Prices	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/Wood-Mackenzie-Draft-Coal-cost-projections-2020.pdf

A3. Abbreviations

Acronym	Meaning
ABS	Australian Bureau of Statistics
AC	alternating current
ACCC	Australian Competition and Consumer Commission
ACCU	Australian carbon credit unit
ADGSM	Australian Domestic Gas Supply Mechanism
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APS	Announced Pledges Scenario (IEA 2021 World Energy Outlook)
BCA	Building Code of Australia
BEV	battery electric vehicle
CBA Guidelines	Cost Benefit Analysis Guidelines (AER)
CBD	Commercial Building Disclosure
CCGT	closed cycle gas turbine
CCS	carbon capture and storage
CDP	candidate development pathway
CEFC	Clean Energy Finance Corporation
CER	consumer energy resources
CNQ	Central and Northern Queensland
CNSW	Central New South Wales
Consultation Report	*IASR Consultation Summary Report*
CQ	Central Queensland
CSA	Central South Australia
CSG	coal seam gas
CST	concentrated solar thermal
CWC	ClimateWorks Centre
DAC	direct air capture
DAT	dual-axis tracking
DC	direct current
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DISER	Department of Industry, Science, Energy and Resources
DNSP	distribution network service provider
DSP	demand-side participation
DSP IP	DSP Information portal
E3	Equipment Energy Efficiency
EAAP	Energy Adequacy Assessment Projection
EFOR	equivalent full forced outage rate
EMT	electromagnetic transient

Acronym	Meaning
EPC	engineering, procurement and construction
ESC	Essential Services Commission
ESCI	Electricity Sector Climate Information
ESOO	*Electricity Statement of Opportunities*
ESS	Energy Savings Scheme
ETI	Energy Transitions Initiative
EV	electric vehicle
FBT	fringe benefits tax
FCUD	Full Commercial Use Date
FFP	fixed flat plate
FRG	Forecasting Reference Group
GCM	global climate model
GEM	Green Energy Markets
GEMS	Greenhouse and Energy Minimum Standards
GG	Gladstone Grid
GHI	global horizontal irradiance
GIS	Geographic Information Systems
GSOO	*Gas Statement of Opportunities*
GSP	gross state product
GW	gigawatt/s
GWh	gigawatt hour/s
HVAC	high voltage alternating current
HVDC	high voltage direct current
IASR	*Inputs, Assumptions and Scenarios Report*
IBR	inverter-based resources
IEA	International Energy Agency
IIO	Infrastructure Investment Opportunities
ISP	*Integrated System Plan*
kV	kilovolt/s
kW	kilowatt/s
kWh	kilowatt hour/s
LPG	liquefied petroleum gas
LRET	Large-scale Renewable Energy Target
LTESA	Long-Term Energy Service Agreement
LULUFC	via land use, land use change and forestry
MLF	Marginal loss factor
MT PASA	Medium Term Projected Assessment of System Adequacy
$MtCO_2$-e	million tons of carbon dioxide equivalent
MVR	mechanical vapour recompression
MW	megawatt/s
MWh	megawatt hour/s

Acronym	Meaning
NABERS	National Australian Built Environment Rating System
NCC	National Construction Code
NDC	Nationally Determined Contribution
NEM	National Electricity Market
NEO	National Electricity Objective
NEPS	National Energy Performance Strategy
NER	National Electricity Rules
NEVA	*National Electricity (Victoria) Act 2005*
NIM	net interstate migration
NOM	net overseas migration
NNSW	Northern New South Wales
NQ	North Queensland
NSP	network service provider
NSW EII Act	*New South Wales Electricity Infrastructure Investment Act 2020*
NZE	Net Zero Emissions (IEA 2021 World Energy Outlook scenario)
OCGT	open cycle gas turbine
ODP	optimal development path
OEA	Oxford Economics Australia
PDRS	Peak Demand Reduction Scheme
PEM	proton exchange membrane
PHES	pumped hydro energy storage
PHEV	plug-in hybrid electric vehicle
PJ	Petajoule/s
POE	probability of exceedance
PTIP	Priority Transmission Infrastructure Project
PV	photovoltaic
PVNSG	PV non-scheduled generation
QEJP	Queensland Energy and Jobs Plan
QNI	Queensland – New South Wales Interconnector
QRET	Queensland Renewable Energy Target
QREZ	Queensland Renewable Energy Zone
RBS	Residential Baseline Study
RCP	Representative Concentration Pathway
REES	Retailer Energy Efficiency Scheme
RET	Renewable Energy Target
REZ	renewable energy zone
RIT-T	regulatory investment test for transmission
RoCoF	rate of change of frequency
RRO	Retailer Reliability Obligation
SAT	single-axis tracking
SDG	Sustainable Development Goal

Acronym	Meaning
SDS	Sustainable Development Scenario (IEA 2021 World Energy Outlook)
SESA	South East South Australia
SIPS	System Integrity Protection Scheme
SNSW	South New South Wales
SNW	Sydney, Newcastle and Wollongong
SPR	Strategic Policy Research
SPS	Stated Policies Scenario (IEA 2021 World Energy Outlook)
SQ	South Queensland
SSSP	System Strength Service Provider
STC	small-scale technology certificate
STEPS	Stated Policies Scenario (IEA 2021 World Energy Outlook)
TNSP	transmission network service provider
TOU	time of use
TRET	Tasmanian Renewable Energy Target
TWh	terawatt hour/s
UNFCCC	United Nations Framework Convention on Climate Change
V2G	vehicle to grid
V2H	vehicle to home
VCR	Value of Customer Reliability
VEU	Victorian Energy Upgrades
VPP	virtual power plant
VRE	variable renewable energy
VRET	Victorian Renewable Energy Target
WACC	weighted average cost of capital
WDR	Wholesale Demand Response
WEO	World Energy Outlook