Draft 2023 Inputs, Assumptions and Scenarios Report

December 2022

Draft report for consultation

For use in Forecasting and Planning studies and analysis

Important notice

Purpose

AEMO publishes this Draft 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	16/12/2022	Initial release

Executive summary

Background

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

Publication of this draft 2023 *Inputs, Assumptions and Scenarios Report* (Draft 2023 IASR) commences formal consultation on the scenarios, inputs and assumptions proposed for use in AEMO's 2023-24 forecasting and planning activities, including the 2024 ISP. The Draft 2023 IASR also provides detail on the process by which any inputs and assumptions will be updated and consulted on prior to modelling commencing, to mitigate risks associated with data latency and maintain publication relevance.

The details provided in the 2023 IASR are critical to AEMO's forecasting and planning publications, and also to relevant Regulatory Investment Test for Transmission (RIT-T) assessments undertaken by transmission network service providers (TNSPs) under the ISP framework.

Notice of Consultation: Invitation for written submissions

AEMO is committed to continued engagement on the content of this Draft 2023 IASR in the interests of increasing transparency, and utilising stakeholder feedback for the benefit of energy consumers and the energy sector. The commitment to engagement is also consistent with the principles outlined in the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines.

Feedback is welcome on all report content, and AEMO has included 'Matters for Consultation' as a guide. Feedback will be particularly helpful where views are accompanied by supporting information. AEMO requests that, where possible, submissions should provide evidence that support any views or claims that are put forward.

Submissions should be sent via email to forecasting.planning@aemo.com.au and are required by Thursday 16 February 2023.

Consultation process to date

Preliminary stakeholder input throughout 2022 has helped shape how the proposed scenarios in the Draft 2023 IASR build on the substantial stakeholder engagement undertaken for the 2021 IASR scenarios, adopted in the 2022 ISP.

In January 2022, the Forecasting Assumptions Update (FAU) consultation included a request for feedback on the role of gas in scenarios. In July 2022, a scenarios webinar gathered extensive stakeholder input on scenarios. The webinar results were discussed in an August webinar and published online[1]. Stakeholder attendees at Forecasting Reference Group (FRG) meetings throughout 2022 also provided early perspectives on their views of the inputs of relative importance, and on preliminary forecasting components and assumptions.

[1] Webinar presentations and recordings available at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/opportunities-for-engagement.

Proposed scenarios

The use of scenario planning is an effective practice when planning in highly uncertain environments, particularly through disruptive transitions. Scenarios are a critical aspect of forecasting, enabling the assessment of future risks, opportunities, and development needs in the energy industry. Scenarios therefore 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 a scenario planning approach coupled with cost-benefit analysis to determine economically efficient ways to provide reliable and secure energy to consumers through the energy transition.

While some scenarios may be more likely than others, no single scenario is expected to be the definitive version of the future that will occur, and understanding the potential benefits or regrets of developments across the scenario collection is valuable when investing in the face of uncertainty.

The proposed scenarios in this Draft 2023 IASR reflect a similar scenario collection to the 2021 IASR scenarios, applied in the 2022 ISP, with some key adjustments. Since the 2022 ISP, political commitments have accelerated to provide new mechanisms to achieve increasing levels of energy sector transformation, with a common goal of increasing the pace of decarbonisation. Broadly speaking, the scenarios in this Draft 2023 IASR explore pathways and paces of decarbonisation to achieve the various targets, with opportunities to accelerate further if greater ambition was sought. As such, the proposed scenarios continue to provide a broad range of futures to inform regulatory network and non-network investment purposes, including both the ISP and RIT-Ts, that may test the risks of under- and over-investment in a balanced manner.

In developing the proposed scenarios, AEMO has focused on the principles that scenarios should remain broad, distinct, internally consistent, and plausible, and take into consideration the guidance provided in the AER's cost benefit analysis (CBA) guidelines.

The proposed scenarios explore critical dimensions and uncertainties affecting the energy sector. Key uncertainties include:

- The health and evolution of the Australian economy, and the impact to the transformation of the energy sector and energy consumers, including the scale and pace of electrification of Australia's industrial, manufacturing, mining and transportation sectors (and others), and the supply chains that support it.
- The pace, scale and orchestration of consumer energy resources (CER), which comprise small-scale embedded generation and storage technologies, such as residential and commercial 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 export 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.

Like the 2022 ISP, AEMO proposes to apply four scenarios to its scenario planning approach to examine a plausible range of variations in the pace and directions of the transition. These updated scenarios include consideration of various commitments that extend the social, political and technological ambition than some scenarios in the 2021 IASR. AEMO's proposed scenario collection therefore include scenario names with greater connection to the climate outcomes.

AEMO is seeking stakeholder feedback on the scenarios, including the scenario names that will be used in the 2024 ISP. AEMO considers this amended scenario collection provides logical extension to the 2021 IASR collection, used in the 2022 ISP and other planning assessments, and provides greater transparency for stakeholders through this Draft 2023 IASR.

- ***1.5°C 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. Higher economic growth internationally (and locally) increases global demand for green energy, enabling greater development of green energy exports domestically (particularly green hydrogen exports via ammonia and other energy-intensive manufacturing that utilise hydrogen such as green steel). Compared to the 2021 IASR *Hydrogen Superpower* scenario, NEM-connected hydrogen production is lower, although export demand will still be a significant driver of energy sector investments, and domestic opportunities to utilise green energy sources are high.
- ***1.8°C Orchestrated 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. Like the 2021 *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. The scenario also reflects growing ambition and interest in developing hydrogen production opportunities to support new domestic loads.
- ***1.8°C Diverse Step Change*** – explores key variations on the 2021 *Step Change* scenario. This scenario also targets achieving a scale of transformation to meet Australia's contribution to limit global temperature rise to below 2°C compared to pre-industrial levels. In this scenario, consumers continue to invest in CER including electrified transportation, but hesitate to embrace the technologies and shared control required to orchestrate these assets. With less orchestration occurring, the ability to rely on these investments to operate the power system securely is reduced and the overall scale and contribution of consumers to the energy transformation is therefore lower, requiring greater action and diversified investments from utilities. As such, greater investment in methods to decarbonise the gas sector is deployed, with biomethane blending reducing the emissions intensity of molecular energy use, enabling a greater alternative to electrification for some gas commercial and industrial customers that are best supported by traditional molecular sources of energy.
- ***2.6°C Progressive Change*** – explores the challenges of meeting Australia's current Paris Agreement commitment of 43% emissions reduction by 2030 amid economic circumstances that are more challenging. As such, the scenario reflects an extension on the 2021 *Progressive Change* scenario regarding decarbonisation, combined with slower economic growth fundamental compared to 2021's *Slow Change* scenario. National and state-based policy commitments necessitate continued energy sector investments, but industrial loads are at greater risk given economic and high energy costs persisting globally. Higher technology costs and supply chain challenges relative to other scenarios slow the pace of change beyond current policies.

The *Slow Change* scenario as 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 this Draft 2023 IASR, a majority of stakeholders supported the *Slow Change* scenario's removal.

While scenarios are fundamental to AEMO's forecasting and planning approach, a key role exists for sensitivity analysis to explore uncertainties around key assumptions. AEMO proposes complementing the scenario collection with a range of sensitivities, such as:

- **Higher and lower discount rate** sensitivities, given the volatility of financial markets in the last year, with the timing and magnitude of a return to 'equilibrium' financial parameters remaining uncertain.
- An **offshore wind** sensitivity, to reflect the uncertainty regarding the implementation and pathway to develop this emerging technology domestically. The sensitivity will at least meet the targets specified in the Victorian Government's directions paper on the establishment of an offshore wind industry.
- A **smoothed infrastructure** sensitivity, exploring the costs and benefits of lower levels of volatility of employment demand.

Inputs and assumptions

This Draft 2023 IASR describes in detail the current inputs and assumptions in relation to:

- Policy settings, including settings that reflect carbon emissions constraints.
- Energy consumption forecasting components, including CER.
- Generation and storage assumptions affecting existing assets, and new entrant technologies, including capital cost projections and fuel price assumptions.
- Renewable energy zone (REZ) assumptions.
- Transmission modelling assumptions.
- Assumptions related to other power system security inputs.
- Financial and economic parameters.
- Gas modelling inputs, and assumptions relating to hydrogen production and hydrogen demand.
- Employment factors that will be used to estimate the workforce requirements needed to implement the ISP.

This Draft 2023 IASR:

- Describes the source of each input assumption and documents the most up-to-date information available,
- Details how and when any of the inputs and assumptions will be updated (if not already updated for this Draft 2023 IASR), and
- Explains the proposed approach for stakeholder engagement on further feedback on any updates.

This Draft 2023 IASR is supported by associated data artefacts, published on AEMO's website[2] with this report. These include the Draft 2023 Inputs and Assumptions Workbook, which provides more detail for the inputs and assumptions under construction for use in 2023-24 forecasting, modelling and planning processes and analysis.

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

Next steps

After receiving submissions by 16 February 2023, AEMO will facilitate a workshop to discuss the key issues raised by stakeholders, focusing discussions on inputs and assumptions referenced most frequently across the submissions. This workshop will also seek feedback on the relative likelihood of the scenarios. Further opportunities for engagement on inputs and assumptions are outlined throughout this report.

AEMO will continue to engage with governments to further understand the detail of various policy initiatives for inclusion, to ensure that policies are sufficiently developed to enable AEMO to identify relevant impacts on the power system, consistent with NER 5.22.3(b). As public policy is a key dimension of all scenarios, it is essential that AEMO receives all relevant detail prior to the finalisation of the IASR in July 2023.

While this report does not solely focus on the input variables and parameters for the purposes of the ISP, these inputs, assumptions and scenarios are a key input to the ISP. AEMO's ISP Timetable[3] has details on major milestones in the ISP development process and upcoming events, and AEMO's website details how to get involved in the 2024 ISP, including upcoming consultation on the ISP Methodology.

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

Contents

1 Introduction

AEMO develops several 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 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. 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, dynamic roadmap over a planning horizon of at least to 2050, optimising net market benefits while managing the risks associated with change. AEMO published the inaugural ISP for the NEM in 2018, and publishes 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, relying on scenario assumptions that are documented in the *Inputs, Assumptions and Scenario Report* (IASR).

This document, the draft version of the IASR, serves to circulate those foundations for formal stakeholder feedback, ultimately supporting appropriate transparency of planning assumptions, and increasing stakeholder understanding and acceptance of critical planning outcomes to support the energy sector's transition.

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[4].

Providing transparency of key forecasting and planning inputs and assumptions, as well as providing clear definitions and rationales for the planning scenarios that will assess future energy system needs, is essential to

[4] 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.

support stakeholders' understanding and decision-making during the energy transition. AEMO's publications such as this Draft 2023 IASR and its various forecasting and planning methodologies are therefore critical.

The National Electricity Rules (NER)[5] require AEMO to develop, consult and publish the IASR in accordance with the Australian Energy Regulator's (AER) Forecasting Best Practice Guidelines[6]. Consistent with these Guidelines, AEMO is following a "single stage process", publishing this Draft 2023 IASR for stakeholder feedback.

In preparing this Draft 2023 IASR, AEMO has sought to offer stakeholders the opportunity to understand and comment on elements of the inputs, assumptions and scenarios at preliminary development stages.

In the case of inputs and assumptions, this engagement has occurred most frequently through engagement opportunities using the Forecasting Reference Group (FRG)[7]. Since January 2022, AEMO has used the FRG to seek feedback on topics of interest for consideration in the Draft 2023 IASR and on preliminary forecasts of key components, such as macro-economic conditions, consumer energy resources (CER), demand-side participation (DSP), and forward-looking generator forced outage rates.

The draft scenarios presented in this Draft 2023 IASR are an update of those deployed in the 2022 ISP, and incorporate early stakeholder feedback provided in two webinars, as shown in Table 1[8]. These scenarios essentially rely on the scenarios developed and used for the 2022 ISP, which included an extensive consultation process conducted in developing the 2021 IASR.

Table 1 Stakeholder engagement on the 2023 IASR

Activity	Date
Scenarios webinar 1	13 July 2022
Scenarios webinar 2	31 August 2022
Release of Draft IASR	16 December 2022
Draft IASR webinar	2 Feb 2023
Consumer advocates verbal submission session	9 Feb 2023
Submissions close on Draft IASR	16 February 2023

This Draft 2023 IASR documents the current draft of inputs, assumptions and scenarios, including information that has recently been updated, and other information that is interim and will be further updated during continued engagement ahead of the finalisation of the 2023 IASR in July 2023. In the following sections, Table 2 lists the inputs and assumptions and their current status, and Table 3 lists the forward plan for engagement for those that require continued development ahead of the final 2023 IASR.

Details on how to engage with AEMO during this consultation period is provided on AEMO's website[9], including methods to register your interest and attendance at relevant webinars.

[5] NER cl.5.22.8(a)

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

[7] More information about the FRG, including all meeting presentations and papers, is available at https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg.

[8] Presentations and recordings of these 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.

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

Continued engagement on interim assumptions

Some of the inputs described in the Draft 2023 IASR have key dependencies, and therefore cannot be updated ahead of this publication. Others represent assumptions that are gathered directly from relevant stakeholders or historical measurements, and therefore are not subject to as significant stakeholder consultation.

Where updated input assumptions are not yet available, the annual Draft IASR provides insights and seeks feedback on the previous year's assumptions to help inform the update of that input. For the purpose of this Draft 2023 IASR, these are referred to as interim inputs.

The FRG provides an opportunity for stakeholders to engage in the continued development of relevant inputs in a timely manner and gives AEMO flexibility to consult on the latest information available ahead of inclusion in the final 2023 IASR. The FRG is a monthly meeting, open to all stakeholders, that focuses on facilitating constructive discussion on matters relating to gas and electricity forecasting and market modelling. It is an opportunity for stakeholders to validate assumptions, share expertise, and explore new approaches to addressing the challenges of forecasting in a rapidly changing energy industry.

Table 2 classifies each input and assumption by the following definitions:

- **Interim** – an input that has not been materially updated since the 2021 IASR or the 2022 Forecasting Assumptions Update, but is intended to be updated before the release of the final 2023 IASR. Where inputs are interim, the forward plan column indicates the planned timing and mechanism of consultation.
- **Draft** – an input that is considered final unless AEMO receives sufficient evidence to change it as part of this Draft 2023 IASR consultation.
- **Current view** – an input or assumption which is regularly updated in a standardised process to reflect the most up-to-date observations; for example, meter demand data, or the continued development of new generation projects that are included within AEMO's Generation Information data set, or even environmental and energy policies that AEMO considers meet NER 5.22.3(b). The final 2023 IASR published in July 2023 will document the status of these inputs and assumptions at that time and their intended application in the 2023 ESOO and the draft 2024 ISP.

The information in Table 2 is correct at time of publishing; please check AEMO's website for updates[10].

Table 2 Status and update process for key inputs and assumptions

Input	Status	Forward plan for updating inputs and assumptions
Policy and emissions reduction settings		
Public policy settings	Current view	Contingent on changes in status of federal and state government policy. The criteria for inclusion are outlined at the beginning of Section 3.1.
Emissions and climate assumptions	Current view	Contingent on changes in status of international agreed targets on emission reductions and climate change more broadly. Criteria for inclusion are the same as those outlined at the beginning of Section 3.1.
Consumption and demand historical and forecasting components		
Historical demand data	Current view	Data is continuously updated.
Historical weather data	Current view	Data is continuously updated.

[10] At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/opportunities-for-engagement.

Input	Status	Forward plan for updating inputs and assumptions
Historical other non-scheduled generation	Current view	Data is continuously updated.
Historical regional transmission and distribution network losses	Current view	To be updated once AER data is received in April-June 2023.
Climate change factors	Draft	Any further updates will be based on feedback on this Draft 2023 IASR.
Distributed photovoltaics (PV)	Draft	**Capacity** was updated through consultancy, FRG discussion on draft forecast took place in September 2022. Any further updates will be based on feedback on this Draft 2023 IASR. **Normalised generation** to be updated through ongoing data service provider.
Electric storage uptake and virtual power plant (VPP) aggregation	Draft	Was updated through consultancy, presentation to FRG on preliminary forecast took place in September 2022. Any further updates will be based on feedback on this Draft 2023 IASR.
Electric and fuel-cell vehicles	Draft	Was updated through consultancy, presentation to FRG on preliminary forecast took place in September 2022. Any further updates will be based on feedback on this Draft 2023 IASR.
Electrification of other sectors	Draft	Was updated through consultancy, presentation to FRG on preliminary forecast took place in September 2022. Any further updates will be based on feedback on this Draft 2023 IASR.
Fuel switching and alternative gas production	Draft	Was updated through consultancy, presentation to FRG on preliminary forecast took place in September 2022. Any further updates will be based on feedback on this Draft 2023 IASR.
Economic and population, including connections	Draft	Was updated through consultancy, presentation to FRG on preliminary forecast took place in August 2022. Any further updates will be based on feedback on this Draft 2023 IASR.
Energy efficiency	Draft	Was updated through consultancy, presentation to FRG on preliminary forecast took place in September 2022. Any further updates will be based on feedback on this Draft 2023 IASR.
Appliance uptake	Interim	To be updated using Forecasting Methodology. Scheduled for FRG discussion in May 2023.
Electricity prices	Interim	To be updated based on internal wholesale price forecasts and Australian Energy Market Commission's (AEMC's) *Residential Electricity Price Trends* report. Scheduled for FRG discussion in May 2023.
Large industrial load forecasts	Current view	Large industrial load forecasts will be sourced via participant surveys conducted in April 2023 to use latest information possible. Scheduled for FRG discussion in May 2023.
Demand side participation	Interim	To be updated based on an analysis of 2022-23 summer behaviour and supported by the DSP Information Portal. The portal is updated by all market participants in April 2023. Growth rates for part of the scenario settings, outlined in Section 3.3.15. Scheduled for FRG discussion in May 2023.
Existing generator and storage assumptions		
Generation and storage data	Current view	New generation and storage developments sourced from AEMO's Generation Information survey, updated quarterly. The July 2023 update will be used for 2023 ESOO and draft 2024 ISP modelling.
Technical and cost parameters	Draft	Any further updates will be based on feedback on this Draft 2023 IASR and CSIRO's draft GenCost 2022-23 consultation. This IASR reflects updates from AEMO's Generation Information, Aurecon's 2022 Costs and Technical Parameter Review, and the CER's Electricity sector emissions and generation 2020-21.
Generator operating limits	Current view	Based on analysis of historical generation, this may nevertheless be adjusted during ISP modelling based on more granular modelling outcomes which could be fed back into the capacity outlook models.
Forced outage rates	Draft	To be updated through data collection process from generators conducted annually in March-April. Scheduled for FRG Consultation in June 2023.
Generator retirements	Current view	Retirement dates are sourced through AEMO's Generation Information data collection process and are updated to reflect latest information provided. The July 2023 update will be used for 2023 ESOO and draft 2023 ISP modelling.
Hydro inflows	Current view	Hydro inflow information based on information provided by participants which will be updated to reflect 2022-23 inflows when available.

Input	Status	Forward plan for updating inputs and assumptions
Climate change factors	Current view	Any further updates will be based on feedback on this Draft 2023 IASR
New entrant generator assumptions		
Candidate technology options	Draft	Any further updates will be based on feedback on this Draft 2023.IASR and CSIRO's draft GenCost 2022-23 consultation.
Technology build costs	Draft	Any further updates will be based on feedback on this Draft 2023 IASR and CSIRO's draft GenCost 2022-23 consultation.
Locational cost factors	Draft	Any further updates will be based on feedback on this Draft 2023 IASR.
Other technical and cost parameters	Draft	Any further updates will be based on feedback on this Draft 2023 IASR.
Storage modelling	Draft	Any further updates will be based on feedback on this Draft 2023 IASR.
Fuel assumptions		
Gas prices	Draft	Was updated through consultancy, presentation to FRG on preliminary forecast took place in October 2022. Any further updates will be based on feedback on this Draft 2023 IASR.
Coal prices	Draft	Was updated through consultancy, presentation to FRG on preliminary forecast took place in October 2022. Any further updates will be based on feedback on this Draft 2023 IASR.
Biomass and liquid fuel prices	Draft	Any further updates will be based on feedback on this Draft 2023 IASR.
Financial parameters		
Discount rate	Draft	Was updated through consultancy. Any further updates will be based on feedback on this Draft 2023 IASR.
Value of Customer Reliability	Current view	Information as per December 2019 AER calculation with 2020 and 2021 annual adjustments.
Renewable energy zones (REZs)		
REZ geographic boundaries	Draft	Any further updates will be based on feedback on this Draft 2023 IASR., and potentially in response to government policy.
REZ resource limits	Draft	Any further updates will be based on feedback on this Draft 2023 IASR.
REZ transmission limits	Draft	Any further updates will be based on feedback on this Draft 2023 IASR.
REZ augmentation and network costs	Interim	To be updated through the Transmission Expansion Report consultation in May 2023 (see Section 3.9.4).
Transmission		
ISP sub-regions	Draft	Any further updates will be based on feedback on this Draft 2023 IASR.
Existing transmission capacity	Current view	Based on historical data and network capability assessment.
Committed transmission projects	Current view	Sourced from TNSPs/AER and updated as information is available.
Anticipated transmission projects	Current view	Sourced from TNSPs and updated as information is available.
Flow path augmentation options	Interim	To be updated through the 2023 Transmission Expansion Report consultation (see Section 3.9.4).
Transmission augmentation costs	Interim	To be updated through the 2023 Transmission Expansion Report consultation (see Section 3.9.4).
Inputs from preparatory activities	Current View	To be updated using information provided by TNSPs in June 2023, via preparatory activities (see Section 3.10.7).
Non-network options	Draft	Any further updates will be based on feedback on this Draft 2023 IASR and the 2023 Transmission Expansion Report consultation
Network losses	Current View	Existing network inter-regional loss factor equations, loss equations, proportioning factors and generator marginal loss factors (MLFs) to be updated from AEMO's annual Region and Marginal Loss Factor Reports published in April 2023. These values may change further as the

Input	Status	Forward plan for updating inputs and assumptions
		power system evolves. Any changes to these numbers will updated in accordance with the ISP Methodology.
	Draft	Updates to existing network intra-regional MLF equations, and loss equations and proportioning factors to be updated based on feedback to the Draft 2023 IASR.
	Interim	Future inter-regional/intra-regional loss factor equations, loss equations and proportioning factors to be consulted on through the 2023 Transmission Expansion Report consultation.
Network losses – MLF	Current View	To be updated from AEMO's annual Region and Marginal Loss Factor Reports published in April 2023. These values may change further as the power system evolves. Any changes to these numbers will updated in accordance with the ISP Methodology.
Transmission line failure rates	Interim	To be updated based on data collected in March/April 2023 for the 2023 ESOO. Scheduled for FRG consultation in June 2023.
Power system security		
Synchronous unit commitment assumptions	Draft	Any further updates will be based on feedback on this Draft 2023 IASR.
System strength requirements and costs	Current view	Existing system strength requirements are updated as required and are published in the annual System Strength Report on AEMO's website.
	Interim	Application of the new system strength standards will be consulted through the ISP Methodology. System strength costs will be consulted on through the 2023 Transmission Expansion Report.
Inertia requirements	Current view	Existing inertia requirements are updated as required and are published in the annual Inertia Report on AEMO's website.
Other	Current view	Sourced by TNSP limit advise and the corresponding constraint equation information in AEMO's market management system.
Gas system assumptions		
Pipeline capacities	Current view	Sourced annually in Q4 from GSOO stakeholder surveys.
Production facility capacities	Current view	Sourced annually in Q4 from GSOO stakeholder surveys.
Gas storage facility operational capabilities (including injection and withdrawal rates, and storage capacity)	Current view	Sourced annually in Q4 from GSOO stakeholder surveys.
Reserves and resources estimates by resource category (2P, 2C and prospective)	Current view	Sourced annually in Q4 from GSOO stakeholder surveys.
Gas field production costs	Current view	Sourced annually in Q4 from consultancy.
Gas expansion candidate build costs	Draft	Any further updates will be based on feedback on this Draft 2023 IASR.
Hydrogen assumptions		
Hydrogen demand	Draft	Any further updates will be based on feedback on this Draft 2023 IASR.
Hydrogen supply	Draft	Any further updates will be based on feedback on this Draft 2023 IASR.
Hydrogen infrastructure needs	Draft	Any further updates will be based on feedback on this Draft 2023 IASR.
Employment factors		
Generation and storage	Draft	Any further updates will be based on feedback on this Draft 2023 IASR.
Transmission	Draft	Any further updates will be based on feedback on this Draft 2023 IASR.

* The methodology is described in detail in AEMO's Market Modelling methodology, applied to the ISP, available at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/market-modelling-methodology-paper-jul-20.pdf.

Stakeholder engagement plan

Table 3 below summarises upcoming consultations on inputs and assumptions[11]. This information is correct at time of publishing; please check AEMO's website for updates.

Table 3 Upcoming consultation processes (monthly overview)

Month	Consultation format	Inputs / assumptions / scenarios or relevant methodology
December 2022	Draft 2023 IASR Publication and submission window opening	All
January 2023	Webinar	Transmission cost database
February 2023	IASR webinar	Opportunity for stakeholders to ask any questions about the Draft 2023 IASR, before the consultation is closed and stakeholder submissions are analysed. Register here to attend the Draft 2023 IASR public webinar.
March 2023	Publish Draft ISP Methodology	ISP Methodology
	FRG discussion	Energy efficiency forecasts
May 2023	Draft Transmission Expansion Report and submission window opening	Network augmentation options (including REZs and flow path augmentations options), network augmentation network capacity gain, project lead time and project costs including system strength remediation costs, connection costs and network augmentation costs
	Transmission Expansion Report Webinar	Network augmentation options (including REZs and flow path augmentations options), network augmentation network capacity gain, project lead time and project costs including system strength remediation costs, connection costs and network augmentation costs
	FRG discussion	Appliance uptake and retail prices
	FRG discussion	Demand side participation
June 2023	ISP Methodology workshop	ISP Methodology
	FRG Consultation	Forced outage rates
	Publish ISP Methodology	ISP Methodology
July 2023	Publish final Transmission Expansion Report	Network augmentation options (including REZs and flow path augmentations options), network augmentation network capacity gain, project lead time and project costs including system strength remediation costs, connection costs and network augmentation costs
	Publish final 2023 IASR	All

FRG forward plan, and therefore the specific timing of the FRG items listed above, is subject to change. See the current forward plan at https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg.

Call for submissions on the Draft 2023 IASR

The publication of this Draft 2023 IASR commences the process of formal consultation on AEMO's key forecasting and planning inputs, assumptions and scenarios. Stakeholders are invited to submit written feedback on any issues presented within, or related to, this publication. For example, if stakeholders consider that the scenario collection currently proposed does not adequately capture the range of uncertainties that materially impact supply and demand in the NEM, opportunity still remains for stakeholders to suggest additional distinct, plausible and internally consistent scenarios, or scenario amendments, through written submissions.

Further consultation will continue throughout the first half of 2023, particularly on those input assumptions which are yet to be updated, including regarding AEMO's Transmission Expansion Report. The final inputs, assumptions

[11] This summary is correct at the time of publishing, but the detailed live version of the engagement calendar can be found on the ISP 2022 webpage.

and scenarios that will be applied in the Draft 2024 ISP and the 2023 ESOO will be documented in the final 2023 IASR in July 2023.

Stakeholders are invited to provide further input through a written submission to the questions outlined in this report. Submissions need not focus on each question and are not limited to the specific consultation questions contained in each chapter.

Submissions should be sent via email to forecasting.planning@aemo.com.au and are required to be submitted by 5:00 pm Melbourne time on Thursday 16 February 2023.

AEMO asks that submissions provide evidence that support any views or claims that are put forward.

Stakeholders should identify any parts of their submissions that they wish to remain confidential and explain why the information provided is confidential. AEMO may still publish that information if it is otherwise authorised to do so, for example if the information is found to be available in the public domain, but will advise the stakeholder before doing so.

Following the completion of the submission window, AEMO will publish a summary of the issues raised across the submissions, and outline how feedback is being addressed. Following the completion of the updates to inputs and assumptions, AEMO will publish a final version of the IASR in July 2023.

A webinar is scheduled for 2 February 2023. This webinar is designed as an opportunity for stakeholders to ask AEMO staff any questions that have arisen in their review of the Draft 2023 IASR before the deadline for written submissions two weeks later.

Verbal submissions from energy consumer advocates will be accepted on 9 February 2023.

All current and future stakeholder engagement opportunities for the 2024 ISP will be listed 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 are a critical aspect of forecasting, enabling the assessment of future risks, opportunities, and development needs in the energy industry. Scenarios therefore 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 a scenario planning approach coupled with cost-benefit analysis to determine economically efficient ways to provide reliable and secure energy to consumers through the energy transition.

While some scenarios may be more likely than others, no single scenario is expected to be the definitive version of the future that will occur and understanding the potential benefits or regrets of developments across the scenario collection is valuable when investing in the face of uncertainty. In reliability assessments a central scenario is selected from this scenario collection (typically being that which is considered most likely), enabling critical evaluation of that particular scenario's future needs to maintain reliability, while other scenarios provide insights regarding the spread of reliability risks in the energy transition, and opportunities for addressing them.

The proposed scenarios in this Draft 2021 IASR have regard to the guidance provided in the Cost Benefit Assessment (CBA) Guidelines to examine future supply and demand conditions to value investments within an uncertain environment. This Draft 2023 IASR consultation seeks feedback on the scenarios themselves. AEMO will engage with stakeholders further on the scenario likelihoods, prior to finalising the 2023 IASR, or prior to applying those weightings in the 2023 ESOO or Draft 2024 ISP.

Major sectoral uncertainties have been identified through insights developed in the 2022 ISP, including:

- The health and evolution of the Australian economy, and the impact to the transformation of the energy sector and energy consumers, including the scale and pace of electrification of Australia's industrial, manufacturing, mining and transportation sectors (and others), and the supply chains that support it.
- The pace, scale and orchestration of consumer energy resources (CER), which comprise small-scale embedded generation and storage technologies, such as residential and commercial 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 export 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 proposed set of scenarios, and having regard to the AER's Cost Benefit Analysis Guidelines (CBA Guidelines)[12], 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.

[12] See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable.

- **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 The scenario development process

The scenarios contained in this Draft 2023 IASR reflect fundamental similarities 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. Early engagement with stakeholders provided feedback that retaining and evolving existing scenarios in planning the energy transition is preferred, relative to alternatives which would develop entirely new scenarios. Scenario longevity, where appropriate, allows for increased comparison of modelling outcomes and insights to support stakeholder decision-making. For example, the ISP Consumer Panel noted that there "may be value in seeking to retain the same scenarios for at least two ISPs"[13]. AEMO has sought to minimise change to this Draft 2023 IASR scenario collection, while still ensuring that the scenarios provide meaningful purpose considering the principles outlined above and maintain maximum relevance by updating and adjusting the collection to reflect the evolution of social, technological, and political change.

Also consistent with stakeholder feedback in AEMO's early engagement, AEMO has considered that some changes to the scenario collection are necessary. For example, the *Slow Change* scenario from the 2021 IASR described a potential world with low social and political appetite for decarbonisation. Following Australia's commitment to a 43% emissions reduction target by 2030, planning for a *Slow Change* is no longer consistent with the policy settings. Other changes are explained in each scenario description.

2.2 Scenario narratives and descriptions

AEMO's scenarios examine the future needs of the power system, and the investments required to support the energy transition to net zero emissions. The scenarios reflect current and likely future trends in energy consumption, consumer energy investments, and technology costs, and includes all policies that meet the relevant requirements (see Section 3.1).

Since releasing the 2021 scenarios, social, policy and technology developments have shifted, and need to be reflected in the 2023 scenarios. Maintaining the scenario collection as it was developed in 2021 is not appropriate for all scenarios.

AEMO's revised set of scenarios maintains fundamental themes described in the 2021 scenario collection, but reflect reduced uncertainty regarding the degree of decarbonisation that the energy transition should plan to achieve, particularly since Australia's commitment to net zero emissions by 2050, and updated commitments to the Paris Agreement.

The draft 2023 scenarios reflect ongoing developments and the evolved thinking of AEMO and stakeholders on the 2021 IASR scenarios.

[13] 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.

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 2021 IASR, AEMO deferred considering the likelihood of the scenarios until the development of the Draft 2022 ISP, thereby ensuring that the latest market, social and political information informed the scenario likelihoods.

AEMO again proposes to defer the consideration of scenario likelihood to a future time closer to when these inputs and assumptions will be deployed in AEMO publications, and will engage with stakeholders via a Delphi Panel or similar approach to ascertain the appropriate new weightings for these scenarios at that time.

AEMO is seeking stakeholder feedback on the scenarios, including the scenario names that will be used in the 2024 ISP. AEMO considers this amended scenario collection provides logical extension to the 2021 IASR collection, used in the 2022 ISP and other planning assessments, and provides greater transparency for stakeholders through this Draft 2023 IASR.

2.2.1 *1.5°C Green Energy Exports*

A scenario with rapid and widespread transformation of the economy to achieve a temperature rise limited to 1.5°C. Consumer investments are high, and global demand for green energy contributes to a strong green energy export economy.

Scenario purpose

To understand the implications and needs of the power system experiencing rapid change to decarbonise and support the broader emissions reduction objectives of the economy, realising relatively more of Australia's renewable generation potential than other scenarios, to support green energy exports, and to increase domestic use of green energy in various forms (for example, increasing local manufacturing opportunities).

This scenario represents a world with 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, low emissions energy support domestic energy consumers as well as international customers, supplementing declining exports of traditional emissions-intensive resources.

There is a high degree of electrification and energy efficiency investments across many sectors. The transport sector in particular rapidly embraces electric and hydrogen-fuelled options to decarbonise both light and heavy vehicle fleets, with the strongest level of change to electrify the transport sector than other scenarios.

The energy transition in Australia is embraced quickly by consumers, supported by commensurate actions globally, with consumer investments in distributed energy resources (including electrified vehicles), and energy efficient homes. A mixture of electrified and molecular energy options enables consumers of all types (residential, commercial and industrial) to decarbonise efficiently.

2.2.2 *1.8°C Orchestrated Step Change*

A scenario with strong consumer investments in consumer energy resources, successful deployment of orchestration technologies to take greatest advantage of these resources, and rapid overall transformational investment to decarbonise the economy, leading to a temperature rise below 2°C.

Scenario purpose

To understand the needs in the power system to support strong decarbonisation of the electricity sector, enabling other sectors to electrify their current energy activities, while consumers continue to invest strongly in CER, with high success in orchestrating these consumer investments.

This scenario includes a global step change in response to climate change, supported by technology advancements and strong consumer support of the transition. Domestic and international action increases to achieve the objectives of the Paris Agreement, to limit the global temperature rise to well below 2°C compared to pre-industrial levels, although achieving 1.5°C is not realised (unlike the *1.5°C Green Energy Exports* 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.

Rapid transformation of the energy sector is enabled by cost reductions for battery storage and variable renewable energy (VRE), which enables higher consumer investments in those consumer resources. Consumer preferences and manufacturing strategies lead to high uptake of electrified vehicles, and internal combustion engine [ICE] vehicles are eventually removed from roads entirely.

Continued advancements in digital technologies, and innovative business models, facilitate a growing role for consumers to manage energy use efficiently and provide flexibility to the energy system. Aggregators develop successful virtual power plant (VPP) value propositions, which are popular with existing battery owners, and spur on additional battery uptake. Sustainability has a very strong focus, with consumers, corporations, developers, and government supporting the need to reduce the collective energy footprint by adopting greater energy efficiency measures.

Electrification is high in this scenario. Industry decarbonises manufacturing and other industrial activities. Consumers switch from gas to electricity to heat their homes. The scale of energy efficiency improvement is high in this scenario, with changes in building design, smart appliances, and digitalisation helping consumers manage energy use. The assumed scale of NEM-connected hydrogen production is limited, significantly less availability than the *1.5°C Green Energy Exports* scenario, and only limited export facilities are connected to the NEM.

As with all scenarios, economic utilisation of land-use sequestration offsets may offer a means to manage sectors or specific industries that are harder to decarbonise.

2.2.3 *1.8°C Diverse Step Change*

A scenario with modest consumer investments, lesser successes in providing consumer appetite for and/or economic stimulation of orchestration of these investments, yet still rapid overall transformational investment to decarbonise the economy, leading to a temperature rise below 2°C.

Scenario purpose

To understand the needs in the power system to support strong decarbonisation of the electricity sector, while other solutions are adopted to reduce emissions across the energy landscape and provide consumers with a more diverse set of early options to lower emissions. This scenario also explores power system impacts of reduced availability of orchestrated consumer energy investments.

Like the *1.8°C Orchestrated Step Change* scenario, this scenario likewise includes a global step change in response to climate change, supported by technology advancements and strong consumer support of the transition. Current state and federal environmental pledges lead to sufficient action to at least achieve Australia's current Paris Agreement commitments, although (like the *1.8°C Orchestrated Step Change* scenario) achieving 1.5°C is not realised.

The scenario utilises a broad mix of technologies to reduce emissions, including greater investments outside of the electricity sector. The costs of VRE and storage technologies continue to fall and are increasingly competitive with existing fossil-fuelled generation. Investments in CER are less significant than *1.8°C Orchestrated Step Change*, and CER orchestration reflects only a moderate level, as consumer preferences and economic stimulation is lower in this scenario. The use of electrified transport and energy efficiency are still strong contributors to a changing energy landscape.

One of the ways initial diversity is achieved is through greater investments in green gases (such as biomethane), strengthening the role of the gas network during the transition and slowing the pace of electrification investments outside the transport sector.

2.2.4 *2.6°C Progressive Change*

A scenario with more challenging economic conditions affecting energy consumers' actions to decarbonise the economy, which achieves current domestic and global policy objectives, but slows further progression and leads to a global temperature rise above 2°C.

Scenario purpose

To understand the needs in the power system with lesser growth in electricity consumption, due to lower economic, population, and electrification outcomes. 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 includes lower assumed forecast economic growth than historical trends. It follows a slower global recovery from the COVID-19 pandemic, and ongoing disruptions affecting international energy markets and associated supply chains. The challenging economic conditions lead to the greatest relative risk to industrial load closures across the scenarios.

More muted technology cost reductions affecting consumer energy devices, lower disposable incomes, lesser population growth and EV supply chain issues (as well as slower vehicle replacement cycles) contribute to lesser relative uptake of consumer energy resources (household photovoltaic [PV] systems, batteries and EVs).

Investment in alternative heating appliances to transition away from gas is also slowed in the short to medium term, due to challenging economic conditions.

Lower economic activity reduces total energy requirements, lowering the investments required to achieve the necessary carbon reduction relative to other scenarios.

Renewable energy development trends continue to be driven by current market and policy settings.

Global progress towards net zero ambitions is in line with currently announced policies and ambitions, and Australia delivers on its commitment to a 43% reduction of emissions by 2030, and net zero by 2050.

Matters for consultation

- **Does the draft 2023 IASR scenario collection adequately enable AEMO to sufficiently test the risks of over-and under-investment in the power system in the *Integrated System Plan*?**
- **Do the scenario names provide improved clarity regarding their drivers and potential use?**

2.3 Comparing to the 2021 IASR scenarios

The draft 2023 IASR scenarios reflect ongoing market and policy developments and the evolved thinking of AEMO and stakeholders on the 2021 IASR scenarios, which were used in the 2022 ISP.

AEMO has adjusted the scenario collection, removing *Slow Change* in response to updated policy that will deliver a faster pace of decarbonisation than was considered in the scenario; this decision has been supported during early engagement with stakeholders. Policy developments have narrowed the range of scenarios, in turn allowing greater granularity to be incorporated in the scenario assessed as most likely in the 2022 ISP. Two variations of the *Step Change* scenario have been developed – the *1.8°C Orchestrated Step Change* scenario and the *1.8°C Diverse Step Change* scenario will allow further examination of the impact of more or less CER and its orchestration and differences in availability of biomethane that delays some electrification.

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

- The ***1.5°C Green Energy Exports* scenario** refines the 2021 *Hydrogen Superpower* scenario, again reflecting very strong decarbonisation activities to limit temperature increase to 1.5°C, resulting in rapid transformation of Australia's energy sectors and a strong shift towards electrification. Higher economic growth domestically and internationally and global demand for green energy enables high green energy exports (particularly green hydrogen and green steel). The scale of hydrogen production in the NEM is lower than in the 2021 *Hydrogen Superpower* scenario, more in line with current energy exports in the NEM; nonetheless, the export demand will still be a significant driver of energy sector investments.
- The ***1.8°C Orchestrated Step Change* scenario** remains very similar to the 2021 *Step Change* scenario, with strong action on climate change to limit temperature increase to well below 2°C, targeting 1.8°C. It once

again features highly engaged energy consumers, with high CER investments that are efficiently orchestrated to play a key role in decarbonising Australia's economy. Like in 2021 *Step Change*, strong electrification across all sectors where practical is forecast.

- The ***1.8°C Diverse Step Change* scenario** is most similar to the 2021 *Step Change* scenario, with strong action to achieve Australia's 43% emissions reduction target by 2030, and sufficient action to limit temperature rise to well below 2°C, targeting 1.8°C. The decarbonisation investments spread to the gas sector in this scenario, with biomethane blending reducing the emissions intensity of molecular energy use, and slowing and reducing the electrification of some commercial and industrial gas customers. Unlike *1.8°C Orchestrated Step Change*, consumers are less able and/or willing to adopt sophisticated communication technologies to unlock energy device orchestration, lowering the size and overall flexibility of CER.
- The ***2.6°C Progressive Change* scenario** features slower economic growth and load risks (similar to the 2021 *Slow Change* scenario), and only modest technology cost change (reflecting the 2021 *Progressive Change* scenario). The scenario still anticipates strong decarbonisation investments to meet national and state-based policy, including Australia's 43% emissions reduction target by 2030, yielding a significantly faster pace of transition than the 2021 *Slow Change* scenario.

2.4 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 Draft 2023 Inputs and Assumptions Workbook.

Table 4 Key parameters, by scenario

Parameter	*1.5°C Green Energy Exports*	*1.8°C Orchestrated Step Change*	*1.8°C Diverse Step Change*	*2.6°C 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	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	Moderate economic growth, moderate coordination	Slower economic growth, lesser coordination
Australian economic and demographic drivers	Higher (partly driven by green energy)	Moderate	Moderate	Lower
DER uptake (batteries, PV and EVs)	Higher	Higher	Moderate	Lower
Consumer engagement such as VPP and DSP uptake	Higher	Higher	Moderate	Lower
Energy Efficiency	Higher	Higher	Moderate	Lower
Hydrogen use	Faster cost reduction. High production for domestic and export use	Allowed	Allowed	Allowed
Hydrogen blending in gas network^	Unlimited	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	7.5% blending target for reticulated gas by 2030 and 10% by 2035	Allowed, but no specific targets to introduce it

Parameter	*1.5°C Green Energy Exports*	*1.8°C Orchestrated Step Change*	*1.8°C Diverse Step Change*	*2.6°C Progressive Change*
Supply Chain barriers	Less challenging	Moderate	Moderate	More challenging
Global/domestic temperature settings and outcomes	Applies RCP 1.9 where relevant (~ 1.5°C)	Applies RCP 2.6 where relevant (~ 1.8°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	NZE	SDS	APS	STEPS

^ Hydrogen blending of the gas network will need to accommodate the technical requirements of transmission and distribution pipelines, as well as the capabilities of connected gas appliances. Higher blends than ~10% may require appliance change and/or switches to dedicated hydrogen transmission pipelines.

Matters for consultation

- **Are the scenarios plausible and internally consistent?**

2.5 Sensitivities

The four core scenarios described above have been designed to capture a range of possible and plausible futures and will underpin assessments of the development needs of the NEM, as well as the inherent over- and under-investment risk to consumers associated with these development needs.

There is inherent uncertainty around the set of inputs that make up each scenario and that underpin the modelling, which creates risks around decision-making. Sensitivities can be deployed to complement the scenario analysis and are designed to test how significant potential events or key assumptions are to influence the energy outcomes observed in the scenarios.

Sensitivity modelling allows for the testing of the resilience of modelling outcomes and candidate development paths against this uncertainty in inputs, and increases confidence in the robustness of the optimal development path and the individual actionable projects it contains. This may involve change to a single variable (most common), or multiple variables (less common, as it is then unclear in isolation which variable was the primary driver for any result variation).

The set of sensitivities AEMO proposes modelling in the 2024 ISP includes, but is not limited to:

- **Higher and lower discount rate** – these sensitivities would examine the impact on the collection of candidate development paths of an upper and lower bound discount rate around the central assumed rate, as outlined in Section 3.7.1. In the 2022 ISP the higher discount rate sensitivities showed the most significant impact on rankings.
- **Offshore wind sensitivity** – the Victorian Government released an Offshore Wind Directions paper in 2021 and an Implementation Strategy in 2022 (which is expected to be complemented by a second stage in 2023). The development of offshore wind requires federal and Victorian regulatory and legislative changes, and the timing of any legislative package is uncertain. In this Draft 2023 IASR, AEMO proposes modelling offshore wind as an eligible technology in all scenarios, and to model the development of the scale of investment to meet the targets within the Victorian paper as a sensitivity (continuing the approach applied in the 2022 ISP). AEMO will monitor and seek further input from the Victorian Government for the Final 2023 IASR about offshore wind targets, and will consider its potential inclusion subject to meeting the public policy criteria (see Section 3.1).

- **Smoothed infrastructure sensitivity** – to explore the costs and benefits of reducing the volatility of employment demand (see Section 3.13 for information on employment factors).

More details on these sensitivities can be found in the accompanying Draft 2023 Inputs and Assumptions Workbook.

'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 the energy industry securing social licence to develop the new infrastructure assets required of the future power system. Conversely, a lack of social licence could lead to significant project delays and increased total system costs.

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. For instance, alternative assumptions that reflect greater limitations and higher cost, to address social licence issues could also be considered.

Social licence, therefore, could be a theme of the scenario collection and/or be applied as sensitivity analyses to the scenarios. AEMO considers that the relationship between the scenario narratives and social licence settings is unclear, and is proposing to apply social licence considerations in sensitivity analysis.

AEMO is seeking stakeholder views on this proposed approach, and the appropriate settings and impacts that should apply in any such analyses.

AEMO will be guided by modelling outcomes when developing both the Draft 2024 ISP (and before finalising the 2024 ISP) as well as new potential policy announcements when determining any other sensitivity analyses that could provide useful insights.

Matters for consultation

- Do you consider any of the proposed sensitivities is not sufficiently relevant to be investigated in the 2024 ISP?
- Do you consider any additional sensitivities ought to be explored in the 2024 ISP?

3 Inputs and assumptions

3.1 Public policy settings

Input vintage	December 2022
Source	Various
Update process	The inclusion of policy settings in the scenarios may evolve as initiatives progress through funding and/or legislative processes.
Get involved	**Draft 2023 IASR consultation**

Policy settings constantly evolve as governments progress policy initiatives. Since the 2021 IASR was developed, and particularly 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 identified by the 2022 ISP *Step Change* scenario.

For all scenarios, AEMO applies the 'public policy criteria' set out in NER 5.22.3(b) to determine whether a policy is included. Scenarios may include parameters that expand beyond the stated intent of current policies if appropriate to reflect the scenario narrative. For a policy to be included in all scenarios, it must be sufficiently developed to enable AEMO to identify the direct or indirect impacts on the power system, and must also meet at least one of the following criteria:

- A commitment has been made in an international agreement to implement that policy.
- The policy has been enacted in legislation.
- There is a regulatory obligation in relation to that policy.
- There is material funding allocated to that policy in a budget of the relevant participating jurisdiction.
- The Ministerial Council of Energy (MCE) has advised AEMO to incorporate the policy.

The details in this section reflect AEMO's current view on various state and federal policy positions and whether they meet the public policy criteria. The objective of this Draft 2023 IASR is to identify whether commitments have been made already that satisfy these criteria, or whether there is sufficient expectation that the criteria will be met prior to finalising the 2023 IASR in July 2023 for use in the Draft 2024 ISP.

In some instances, this section outlines proposed policy settings that are yet to meet the requirements of NER 5.22.3(b). AEMO outlines in these instances why the proposed settings include the particular policy, given anticipated developments by jurisdictions to achieve the criteria.

AEMO will work with each relevant government, as needed, to gain a further understanding of each policy yet to demonstrate the appropriate conditions required, and how best to implement these in the ISP.

The major government policies explicitly considered include:

- Federal policies, including Australia's greenhouse gas emissions reduction target specified in the *Climate Change Act (2022)* (C'th), including Australia's *nationally determined contribution* to the Paris Agreement.
- Energy policies of various individual jurisdictions, including:

  - New South Wales Electricity Infrastructure Roadmap, including renewable energy and long-duration storage developments, and the Energy Security Safeguard, which includes targets for energy efficiency and peak demand reduction.
  - Various components of the Queensland Energy and Jobs Plan and the infrastructure pathway of the Queensland SuperGrid Infrastructure Blueprint that are anticipated to be part of legislation or to receive budgetary funding.
  - Tasmania's Renewable Energy Target, and its renewable energy coordination framework.
  - Various policy initiatives with state funding support to develop hydrogen industries across NEM jurisdictions, including South Australia's *Hydrogen Action Plan*.
  - Victoria's collection of policies affecting electricity, including the Victorian renewable energy and storage targets, development of offshore wind generation and the expedited framework to deliver transmission developments.
- Energy policies across federal and state jurisdictions affecting CER investments, energy efficiency, EVs and other relevant targets

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

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. This target is 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.

Underpinning the updated 2030 emissions target is the Federal Government's commitment to achieve an 82% share of renewable energy by 2030, announced in the *Powering Australia* Plan[14]. A number of elements in the Powering Australia Plan have already been legislated or allocated funding[15].

AEMO proposes to model the 43% emissions reduction target and carbon budget to 2030, as well as a net zero emissions economy (by 2050) as committed policy, included in all scenarios.

The scale of renewable energy to be developed will be an outcome influenced by the carbon budget, and various other policies across jurisdictions, and we anticipate that a share of approximately 82% as observed in the 2022 ISP *Step Change* scenario will be achieved across the scenario collection, with some scenarios potentially higher and lower as was observed in the 2022 ISP outcomes.

More detail on the forecast carbon budgets for the NEM as assumed in this Draft 2023 IASR can be found in Section 3.2.1.

[14] Available at https://www.alp.org.au/policies/powering-australia.

[15] List of progressed commitments available at https://www.energy.gov.au/government-priorities/australias-energy-strategies-and-frameworks/powering-australia.

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 are shown in Table 5.

Table 5 Economy-wide state-level emission reduction ambitions (relative to 2005 levels)

	New South Wales	Queensland	South Australia	Tasmania	Victoria
2025					28-33% reduction
2030	50% reduction	30% reduction	50% reduction	**Net zero**	45-50% reduction
2035					75-80% reduction
2040					
2045					**Net zero**
2050	**Net zero**	**Net zero**	**Net zero**		

Note: Timing of emissions reduction ambition may be rounded to the nearest 5 yearly increment, for presentation purposes

While some targets are legislated (Victoria[16] and the Australian Capital Territory[17]), implementation details by sectors need to be developed further to provide the clarity that would allow them to be included in AEMO's optimisation models.

Although AEMO proposes not to apply these as policy settings in any scenario, the breadth of AEMO's scenarios will provide sufficient variation to achieve the intent of these legislated schemes within the scenario collection.

As an example, Table 6 presents state-level emission outcomes from AEMO's multisectoral modelling (see Section 3.3.4 for more detail) compared to legislated state targets for Victoria. It demonstrates that at least the *1.5°C Green Energy Exports* scenario will achieve an emissions budget in line with the policy from an economy-wide perspective.

Table 6 Victorian emission reduction outcomes from multisectoral modelling compared to Government targets

	Status	*1.8°C Orchestrated Step Change*	Victoria targets	*1.5°C Green Energy Exports*
2025	**Legislated**	-	**28-33%**	-
2030	**Legislated**	47%	**45-50%**	66%
2035	Announced*	66%	**75-80%**	84%
2045	Announced*	80%	**100% (Net zero)**	95%

*These targets were announced as a pre-election commitment by the Victorian Government in October 2022.

[16] 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).

[17] 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.

Federal and state renewable energy policies

New South Wales Electricity Infrastructure Roadmap

In 2020, the New South Wales Government released its Electricity Infrastructure Roadmap[18] and enabling legislation, the *Electricity Infrastructure Investment Act 2020* (NSW EII Act), providing a plan to decarbonise New South Wales's electricity system reliably and affordably. The NSW EII Act sets out minimum development requirements, with existing or committed capacity at or before 14 November 2019 not contributing to the infrastructure objectives. Any generation that has progressed to committed or existing since that time is included as contributing to the objectives of the NSW EII Act.

Prior to 2030, the NSW EII Act sets out the minimum objectives of construction of generation infrastructure generating at least the same amount of electricity in a year as:

- 8 gigawatts (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 a Long Term Energy Services Agreement is 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.

For the 2022 ISP, AEMO employed a development trajectory at least as fast as the trajectory of energy generating and storage capability specified in the Consumer Trustee's 2021 Infrastructure Investment Opportunities (IIO) Report over the period until the minimum objective is met[19].

For modelling in 2023-24, AEMO proposes to again apply the requirement to at least meet the generation and storage developments of the latest IIO Report, adjusted to consider relevant new committed and anticipated projects, as well as any new specific commitments to investments to meet the NSW EII Act. Details of this trajectory can be found in the accompanying IASR Assumptions Book.

Any additional transmission investments options to meet the New South Wales objectives, that are classified as neither committed nor anticipated projects, are considered as development options for consideration using the cost-benefit analysis (CBA) framework set out in AEMO's ISP Methodology. For more information on the committed and anticipated projects applied in this Draft 2023 IASR see AEMO's Transmission Augmentation Page[20], December 2022 release

In response to the New South Wales Minister for Energy's direction[21], the New South Wales Consumer Trustee announced it will conduct a competitive tender for long-term energy services agreements (LTESAs) for firming

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

[19] The development trajectory from the IIO Report may require faster investments in some scenarios.

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

[21] See https://www.treasury.nsw.gov.au/sites/default/files/2022-08/Matt-Kean-med-rel-New-firming-tender-to-ensure-energy-reliability_0.pdf.

infrastructure[22], targeting 380 megawatts (MW) of firming. The tender is expected to commence in the second quarter of 2023, with the LTESA operational by summer 2025-26.

As the tender process for procurement of these firming resources is underway, with a clear direction under the Infrastructure Roadmap framework to procure these resources, AEMO proposes to reflect this firming tender across all scenarios.

Waratah Super Battery is also proposed to be considered an anticipated project, operating as part of the System Integrity Protection Scheme (SIPS) and delivered as a Priority Transmission Infrastructure Project (PTIP) under the NSW EII Act[23].

Queensland Energy and Jobs Plan

In September 2022, the Queensland Government released its Queensland Energy and Jobs Plan (QEJP)[24]. The QEJP identifies initiatives for the development of renewable and firming generation in Queensland including:

- Expansion of the Queensland Renewable Energy Target (QRET) to 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 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 QREZ.
- Transmission investments, at up to 500 kilovolts (kV), to build new backbone transmission connecting energy storage and renewables to load centres, including connections to Borumba PHES and Pioneer-Burdekin PHES, expanding the connection of Southern Queensland to Central Queensland, and connecting Hughenden and Townsville, unlocking more renewable generation.

AEMO recognises that the legislative settings for these key actions of the QEJP are under active development. As described in the QEJP, legislation to support QRET expansion and QREZ establishment will be prepared in 2023. As such, AEMO proposes to include these in the policy settings across all scenarios.

AEMO anticipates that sufficient budgeted funding for key firming investments will be confirmed in a similar timeframe, supporting progression of pumped hydro (Borumba Dam followed by Pioneer-Burdekin) and gas projects (starting with the Kogan Creek project). AEMO proposes to apply normal project commitment assessments to these projects from AEMO's quarterly Generation Information releases, and consider sensitivity analysis as appropriate pending each survey response.

The development of the QREZ and PHES projects will require significant transmission developments, and the QEJP has identified several transmission options up to 500 kV. AEMO will consider these as part of the

[22] 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.

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

[24] See https://www.epw.qld.gov.au/energyandjobsplan/about.

Queensland transmission options in the ISP and will consult on it through the 2023 Transmission Expansion Report.

Tasmanian Renewable Energy Target (TRET)

The TRET remains 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. The TRET remains included in all scenarios.

This policy continues to meet the appropriate criteria for commitment in the 2024 ISP.

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

The currently legislated Victorian Renewable Energy Target (VRET) mandates 40% of the region's generation 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. This target is measured against Victorian generation, including renewable CER.

AEMO understands that the updated VRET, including its various annual targets, is intended to be legislated and is sufficiently developed to enable assessment of impacts on the power system, therefore AEMO proposes to include the updated policy across all scenarios.

The Victorian Government has also pledged a target[25] 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 will 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 criteria, AEMO proposes to include the energy storage targets in its 2023-24 modelling.

In March 2022, the Victorian Government released its Offshore Wind Policy Directions Paper[26], which set targets of 2 GW of offshore wind capacity by 2032, 4 GW by 2035 and 9 GW by 2040, with first power provided by 2028. The Offshore Wind Policy Directions Paper states that the 2032 target will be finalised as the offshore wind business case is developed in 2024. The Victorian Government recently published its first Offshore Wind Implementation Statement[27].

The development of offshore wind requires federal and Victorian regulatory and legislative changes, and the timing of any legislative package is uncertain. Funding of $40 million for initial feasibility studies has been allocated with significant further financial commitment required for implementation. In this Draft 2023 IASR, AEMO proposes modelling offshore wind as an eligible technology in all scenarios, and to model the development of the scale of investment to meet the targets within the Victorian paper as a sensitivity (continuing the approach applied in the 2022 ISP). AEMO will monitor further announcements in future Offshore Wind Implementation Statements and seek input for the Final 2023 IASR in regards to offshore wind targets, in view of its potential inclusion subject to meeting the public policy criteria.

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

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

[27] At https://engage.vic.gov.au/download/document/29625.

Victoria has a legislated position via Victoria's *Climate Change Act (2017)* to reduce greenhouse gas emissions by 2050 to meet a net-zero economy, with short-term targets at five-yearly steps. This policy provides a pathway for Victoria's overall economy to reduce emissions (relative to 2005 levels) to 45-50% by 2030 (for example) and set a pre-election commitment to achieve 75-80% reductions by 2035 and reach net-zero emissions by 2045 (five years earlier than the legislation presently requires).

The Victorian Government has developed a number of pledges to outline actions and drive emission reductions. To the degree that there is sufficient clarity to be incorporated in modelling, these have been captured and are considered by AEMO's modelling. The energy sector pledge is underpinned by VRET and the Victorian Energy Upgrades (VEU) program, and the transport pledge is underpinned by a 50% zero-emission vehicles new sales by 2030 target. these policies will all be considered in the 2024 ISP. Other pledges either lack sufficient detail regarding the implementation or cannot be accurately reflected by AEMO's suite of models (such as the agriculture sector pledge), and as such are not currently included in the ISP modelling.

The Victorian pledges and other policies (including the expanded VRET and NEM-wide emissions budgets) may lead to a pace of energy-sector transformation expected from the emission reductions policy. The Draft 2024 ISP will explore this and will consider whether alternative sensitivity analyses to drive additional change to Victorian emissions outcomes are necessary (such as explicit closure or development trajectories affecting Victoria's generation mix), and the impact this may have on ISP development pathways.

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

The amendment to the NEVA in 2020 was made to facilitate expedited approval of transmission system upgrades. The NEVA enables the Minister to approve augmentations of the Victorian transmission system. For the purpose of the ISP, any order made by the Minister will be considered as an anticipated investment, and therefore included in all scenarios.

Three projects are currently supported under the NEVA and therefore considered anticipated developments – the Murray REZ non-network (increasing network capability via the Koorangie Energy Storage System, with a capacity of 125 MW[28]), the Western Victoria REZ non-network, and the Mortlake turn in. For more information on these developments, see Section 3.9.3.

Large-scale Renewable Energy Target (LRET)

The LRET is one of the two schemes under Australia's Renewable Energy Target (RET), a Federal Government policy established to ensure that 33,000 GWh of Australia's electricity would come from renewable sources by 2020. While the RET was met in September 2019, high-energy users are required to continue meeting their obligations under the scheme until 2030[29].

AEMO includes no explicit accounting for the policy in modelling, because the RET has been met and the continuing incentive it provides to construct additional VRE is minimal relative to other policies.

[28] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2022/2022-victorian-annual-planning-report.pdf.

[29] 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 Office of Hydrogen Power South Australia to deliver the Hydrogen Jobs Plan[30] which seeks to establish hydrogen production and power generation in South Australia.
- The Queensland Government has, in its Queensland Energy and Jobs Plan, allocated $20 million to coordinate and plan for renewable hydrogen hubs, including community awareness programs. It has also allocated funding to support the Central Queensland Hydrogen Project, and the Kogan Renewable Hydrogen Project[31].
- The Victorian Government has, in its 2022-23 budget, allocated almost $12 million to assist in decarbonising freight with hydrogen, and almost $7 million to develop offshore wind and hydrogen sectors[32].
- The New South Wales Government has also contributed funding to support hydrogen refuelling initiatives for freight transport (complementing the Victorian initiative above), and has allocated $150 million in grant funding to support hydrogen hubs in the state[33]. The government is also supporting the dual-fuel capability of the committed Tallawarra B Power Station.
- The Tasmanian Government is providing funding of $70 million, matching an equivalent Commonwealth allocation, to support the establishment of a green hydrogen hub at Bell Bay[34].

AEMO will work closely with each jurisdiction, and particularly with the South Australian Government considering the scale of funding explicitly budgeted in that state, to identify whether and how the various hydrogen funding packages could be included in the ISP as further details become available.

Rewiring the Nation

In October 2022, the Federal Government announced the Rewiring the Nation framework, which aims to modernise the grid and ensure the NEM's transmission network is fit for purpose and 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 transition Australia's electricity grids.

This policy has received material funding, and support for Marinus Link and Victoria – New South Wales Interconnector (VNI) West (KerangLink) has already been announced. As such, AEMO proposes to include it in all scenarios in the 2024 ISP.

AEMO will work with the Clean Energy Finance Corporation and the Department of Climate Change, Energy, the Environment and Water to gain a further understanding of the policy and how best implement it in the ISP.

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

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

32 See https://www.delwp.vic.gov.au/our-department/budget-2022-23.

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

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

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 it across all scenarios. Nuclear technology therefore is an excluded technology option.

Other policies affecting consumer demand

Distributed energy resources policies

State and federal policies contribute to supporting the development of CER, including small-scale technology certificates (STCs) and Australian carbon credit units (ACCUs). Additional policies included are listed in Table 7.

Table 7 Policies supporting CER

State	Policy	Description
NSW	The proposed **Peak Demand Reduction Scheme** [A] may offer additional revenue for batteries once installed	Included through general virtual power plant tariff and payments considerations.
VIC	**The Solar Homes Program** [B] policy 700,000 home solar systems over ten 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.
VIC	Victorian Energy Efficiency Certificates under the **Victorian Energy Upgrades program** [C] support both energy efficiency investments and CER investments.	The value of certificates is assumed to increase 2% per annum in *2.6°C Progressive Change*, 3 % in *1.8°C Diverse Step Change* and 5% in *1.8°C Orchestrated Step Change* and *1.5°C Green Energy Exports*.
ACT	The ACT government is making available an $3,500 residential subsidy ($35,000 for business) targeting deployment of 36MW of battery storage under its **Next Generation Energy Storage scheme** [D].	Minimum addition of 5000 batteries by 2023.
ACT	Pensioners who own their home are eligible for up to 50% (with a cap of $2500) of a home solar system under its **Home Energy Support** scheme [E].	Minimum addition of 5000 systems over five years.

A. See https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard/peak-demand-reduction-scheme.
B. See https://www.solar.vic.gov.au/solar-homes-program.
C. See https://www.energy.vic.gov.au/for-households/victorian-energy-upgrades-for-households.
D. See https://www.climatechoices.act.gov.au/policy-programs/next-gen-energy-storage.
E. See https://www.climatechoices.act.gov.au/policy-programs/home-energy-support-rebates-for-homeowners.

Electric vehicle policies

Numerous state and federal policies are already starting to influence the uptake of EV purchase decisions by consumers.

The *Treasury Laws Amendment (Electric Car Discount) Bill 2022* will provide fringe benefit exemption for EVs, and has only recently passed Federal parliament. While it will lower purchasing costs for some buyers, it is unclear at the time of writing of this report how effective it will be at supporting any sales targets. While many state policies have been announced, these are yet to be legislated (and often debate has centred on how to structure EV taxes as much as how to support consumers who seek to purchase EVs). Consequently, 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[35].

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) 2006, 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) 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 (NSW ESS), the Victorian Energy Upgrades (VEU) program, and the South Australian Retailer Energy Efficiency Scheme (SA REES).
- Other national schemes, such as the **Commonwealth Emissions Reduction Fund** (ERF) and the funding support available from the **Clean Energy Finance Corporation** (CEFC).

In November 2022, the Federal Government commenced consultation on the National Energy Performance Strategy (NEPS)[36] which aims to develop a framework for improving energy performance across the economy through energy efficiency and demand management. NEPS is in the early stages of consultation, and AEMO will monitor its development during the Draft 2023 IASR consultation process.

New South Wales Energy Security Safeguard

Through its established Energy Security Safeguard[37], New South Wales has a target for energy efficiency savings, both in general through the Energy Savings Scheme (ESS), and at time of peak demand through the Peak Demand Reduction Scheme (PDRS). Both are modelled, with details listed in Section 3.3.12 for energy efficiency and Section 3.3.15 for the PDRS.

Matters for consultation

- Do you have any further views on the individual policies and their proposed application?
- Do you consider any additional policies missing that you consider important to include in some or all the scenarios? If so, please provide details.

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

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

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

3.2 Emissions and climate assumptions

3.2.1 Alignment to the IEA World Energy Outlook scenarios

AEMO's scenarios have been aligned to the International Energy Agency's (IEA's) World Energy Outlook (WEO) scenarios to anchor them to global narratives on developments and policies and plausible permutations of those that aim to address current and future commitments to the Paris Agreement.

IEA's scenarios provide a global backdrop to economic and multisectoral modelling, to influence economic growth and international fuel price projections that are influenced by global conditions (including the influence of climate outcomes), and help provide context for "Australia's share" of meeting the various temperature outcomes within each scenario narrative. They also provide guidance to the multi-sectoral modelling regarding the uptake rate and limits on energy efficiency and electrification across scenarios.

IEA's 2021 WEO assessed four scenarios[38]. As IEA explains it, two of these scenarios are normative, in that they are designed to achieve a specific outcome and show a pathway to reach it. The other two scenarios are exploratory, in that they define a set of starting conditions and then see where they lead. The scenarios are summarised in Table 8.

The 2022 WEO, released in October 2022, maintained three of the 2021 scenarios (and provided guidance regarding the fourth scenario, in particular in terms of the temperature outcome).

Table 8 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 it 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 (next) shows the "ambition gap" that needs to be closed to achieve the goals agreed at Paris in 2015
Sustainable Development Scenario (SDS)	This is a normative scenario, mapping 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 SDGs. 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 (SDGs), in particular 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).

[38] See https://www.iea.org/reports/world-energy-model/understanding-weo-scenarios.

In mapping the IEA scenarios to the proposed scenarios in this Draft 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 large and significant structural changes in global energy consumption underpinning its narrative, the ***1.5°C Green Energy Exports*** scenario is most closely aligned to NZE.
- The IEA's SDS scenario is consistent with the Paris Agreement target of limiting temperature increase to well below 2ºC, which therefore logically aligns to AEMO's ***1.8°C Orchestrated Step Change*** scenario.
- AEMO's **1.8°C *Diverse Step Change*** scenario has been aligned to the IEA's APS, as the AEMO scenario utilises greater diversity of energy supplies, which is similar to the themes within APS. APS still achieves the "well below 2ºC" increase in temperature targeted by the Paris Agreement, and therefore AEMO applies the same temperature settings in the *1.8°C Diverse Step Change* and *1.8°C Orchestrated Step Change* scenarios.
- The ***2.6°C 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.

Alignment with the Relative Concentration Pathways

The IASR scenarios also map to the Relative Concentration Pathways (RCPs) framework, which represents specific trajectories of emissions and land-use and their resulting impact on temperate increases. The RCPs are used by the Intergovernmental Panel on Climate Change (IPCC) for the modelling underpinning its Sixth Assessment Report (AR6)[39]. There are multiple RCPs defined, with AEMO proposing the following mapping to its scenarios:

- AEMO's proposed ***1.5°C 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 proposed ***1.8°C Orchestrated Step Change*** and ***1.8°C Diverse Step Change*** scenarios are aligned to RCP2.6 (consistent with a temperature rise less than 2ºC by the end of the century, in line with the Paris Agreement).
- The proposed ***2.6°C Progressive Change*** scenario is aligned to RCP4.5 (consistent with a temperature rise of approximately 2.6ºC by the end of the century), which in turn is aligned with the temperature rise envisioned by the IEA's STEPS scenario, which was also mapped to *2.6°C Progressive Change*.

Mapping the IASR scenarios to climate assumptions

As outlined above, each of the scenarios proposed in this Draft 2023 IASR has been associated with a particular WEO and RCP scenario consistent with the intent of the IASR scenarios. The mapping has been summarised in Table 9, with further scenario details found in Section 2.4. The 2023 IASR scenarios have also been mapped to CSIRO's latest GenCost global scenarios discussed further in Section 3.5.3.

Overall, this frames the proposed 2023 IASR scenarios within a global context which was used to inform assumptions made by AEMO's consultants to ensure consistency in the global settings across all consultancies.

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

Table 9 Scenario mappings

2023 IASR scenario	2021 WEO scenario	RCP	GenCost (CSIRO)
1.5°C Green Energy Exports	NZE	RCP1.9	Global net-zero emissions by 2050
1.8°C Orchestrated Step Change	SDS	RCP2.6	Global net-zero emissions post 2050
1.8°C Diverse Step Change	APS	RCP2.6	Global net-zero emissions post 2050
2.6°C Progressive change	STEPS	RCP4.5	Current policies

3.3 Consumption and demand: historical and forecasting components

AEMO updates its projections of energy consumption and maximum/ minimum demand at least annually[40]. The updates are informed by stakeholder consultation through the FRG and consider a range of model inputs, including:

- DER uptake and generation/charging/discharging patterns, including the potential aggregation and coordinated charging/discharging opportunities for CER (such as through VPPs):
  - Distributed PV.
  - Battery storage.
  - EVs.
- Economic and population growth drivers, including meter connections.
- Climate.
- Large industrial loads (LILs), including for export loads such as liquified natural gas (LNG) exports (informed by stakeholder surveys).
- Energy efficiency and fuel switching, both policy-driven and in the context of possible electrification pathways.

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).

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

The *Electricity Demand Forecasting Methodology*[41] and *Gas Demand Forecasting Methodology Information Paper*[42] 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[43].

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

3.3.1 Historical demand data

Input vintage	• Live currency • June 2022 for loss data
Status	Current view
Source	• SCADA/EMMS/NMI Data • Generation Information page • AER and network operators
Update process	Continuously updated Loss data will be updated in April-June 2023

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[44].

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).

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

[42] At https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2022/2022-gas-statement-of-opportunities-methodology-demand-forecasting.pdf.

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

[44] 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.

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.

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 6 (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 (CER) and applies a solar generation model to estimate the amount of power generation at any given time. Refer to Section 3.3.6 for details. AEMO's DER Register[45] is used for validating the historical PV installation data.

3.3.2 Historical weather data

Input vintage	Live currency
Status	Current view
Source	Bureau of Meteorology (BoM)
Update process	Live data stream from the BoM

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 10.

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 10 Weather stations used in consumption, minimum and maximum demand forecasts

Region	Station name	Date range
New South Wales	Bankstown Airport AWS	January 1989 ~ Now
Queensland	Archerfield Airport	July 1994 ~ Now
South Australia	Adelaide (Kent Town)	October 1993 ~ July 2020
	Adelaide (West Terrace)	July 2020 ~ Now
Tasmania	Hobart (Ellerslie Road)	January 1882 ~ Now
Victoria	Melbourne (Olympic Park)	May 2013 ~ Now
	Melbourne Regional Office	October 1997 ~ January 2015

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

Matters for consultation

- Do you consider the use of the listed weather stations appropriate to forecast consumption and maximum/minimum demand?

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

Input vintage	November 2022
Status	• Current view
Source	• Generation Information page • Settlements data • NMI data • DER Register
Update process	Updated quarterly

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[46] 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 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 biomass-based cogeneration, or generation from landfill gas or wastewater treatment plants) in the long term. Historical capacity factors by technology type are used to forecast generation using the projected capacities.

AEMO's current view of ONSG reflects the November 2022 release of the Generation Information page and is shown in aggregate by region in Figure 1 below.

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

Figure 1 Aggregate ONSG capacity, by NEM region

3.3.4 Multi-sectoral modelling influences to demand forecasts

Input vintage	November 2022
Status	Draft
Source	CSIRO and ClimateWorks Centre
Update process	Updated by new consultant forecast in 2022

AEMO engaged consultants CSIRO and ClimateWorks Centre (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, and alternative gas uptake (such as hydrogen and biomethane). See Table 4 in Section 2.4 for key scenario parameters.

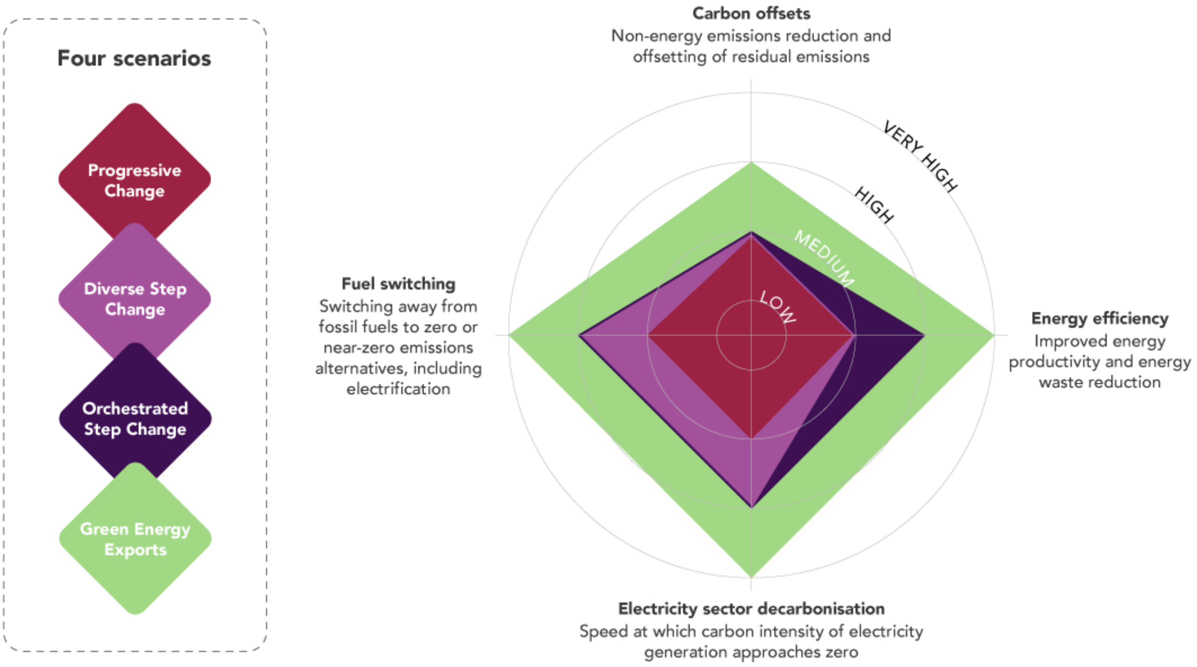
Using the CSIRO and CWC AUS-Times model, this multi-sectoral approach enables a better understanding of whole-of-economy interactions, by simultaneously considering a range of options available to meet scenario-specific temperature goals or emissions targets at the least cost. These options broadly align 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 2 illustrates the scale of utilisation of the four pillars across the scenarios.

Figure 2 Four pillars of decarbonisation, and utilisation by scenario



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

- National and NEM emissions pathways (see Section 3.2 for further details), including forecast needs for emission sequestration to provide carbon offsets.
- Fuel switching opportunities, particularly the electrification of other sectors of Australia's economy, as well as domestic consumption of hydrogen as a substitute for other energy sources, complementing any assumed export demand in the scenarios.
- Energy efficiency savings by sector, to demonstrate the investment required to improve energy productivity and offset residential and business consumption.

Table 11 describes, at a high level, the key assumptions and outcomes from the multi-sectoral modelling. Further details may be found in subsequent subsections and the CSIRO and CWC supporting report[47].

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

Table 11 Key assumptions and outcomes from the multi-sectoral modelling

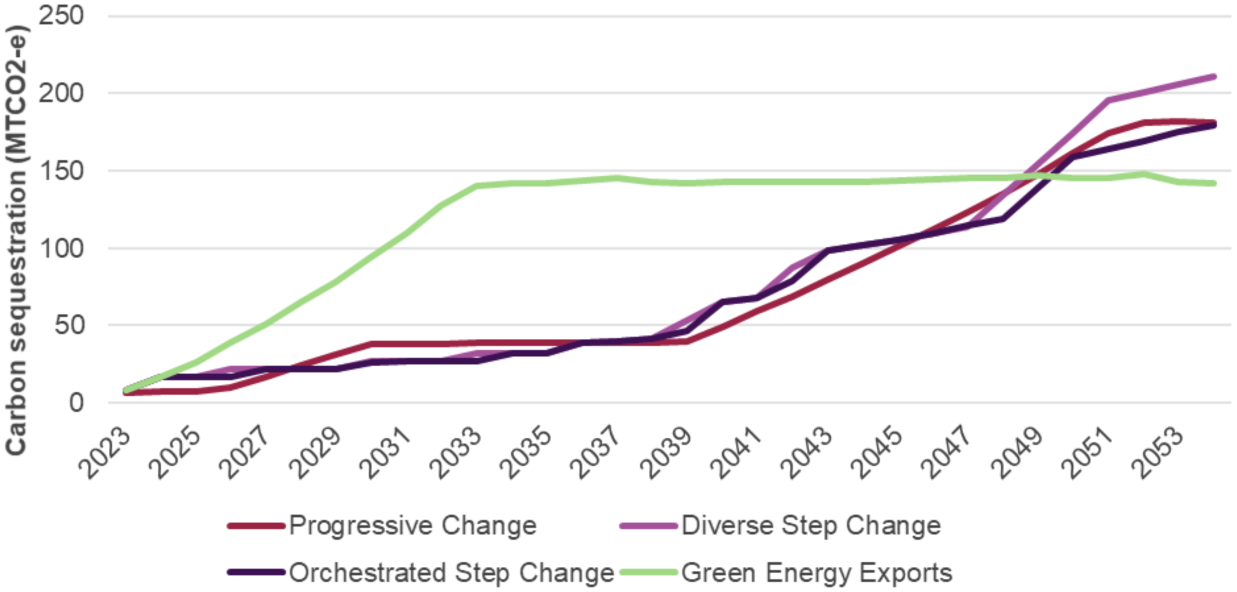
	1.5°C Green Energy Exports	*1.8°C Orchestrated Step Change*	*1.8°C Diverse Step Change*	*2.6°C Progressive Change*
Electrification (Section 3.3.5)	There is a high degree of electrification investment across many sectors, though many homes and businesses delay the switch to electricity for their heating requirements, relying instead on alternative gases (such as hydrogen and/or biomethane) to replace existing gas heating systems. The pace and scale of electrification in the residential sector is therefore similar or less than other scenarios. EV consumption is highest in this scenario, with state targets assumed to be overachieved by 15%. This scenario has the strongest amount of electrification overall – 43 terawatt hours (TWh) in 2030 and 153 TWh in 2050, owing to high rates of electrification in the industrial sector.	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 strong electrification investments reduce the emissions intensity of manufacturing and other industrial activities. This scenario has the second largest amount of electrification overall – 35 TWh in 2030 and 136 TWh in 2050.	The degree of electrification is high in the transport sector, and to a lesser extent, the industrial and residential sectors as more diverse alternative gases are available to delay electrification. Electrification of the transport sector is lower than in *1.8°C Orchestrated Step Change*, reflecting that consumers are less engaged with vehicle replacement, leading to an underachievement of various state targets by 15%. Overall, this scenario has the least amount of electrification in 2030 at 22 TWh, being most pronounced in the industrial sector. By 2050, electrification adds 116 TWh to the NEM load.	Investment in alternative heating appliances to transition away from gas is more muted due to challenging economic conditions. This scenario has a moderate amount of electrification – 24 TWh in 2030 and 98 TWh in 2050. The large increase in electrification between 2030 and 2050 is due to the uptake of electric vehicles. In this scenario state EV policies are assumed to be underachieved by 30%.
Energy efficiency (Section 3.3.10)	There is a high degree of energy efficiency investment across many sectors, the largest contributing factor being cooling loads in the commercial sector. Energy efficiency accounts for 32 TWh in 2030 and 92 TWh in 2050 of electricity savings.	The scale of energy efficiency improvement is high in this scenario, with changes in building design, smart appliances, and digitalisation helping consumers manage their energy use wisely. Energy efficiency accounts for 22 TWh in 2030 and 62 TWh in 2050 of electricity savings.	This scenario uses a broad mix of technology and there is a moderate level of consumer engagement. The scenario includes a moderate outlook for energy efficiency, accounting for savings of 18 TWh in 2030 and 55 TWh in 2050.	In this scenario, energy efficiency accounts for 17 TWh in 2030 and 51 TWh in 2050. It is the lowest across the scenarios, reflecting the impact of lower economic activity on energy demand.
Carbon sequestration across NEM states **(see below)**	To achieve 1.5°C, this scenario sees significant use of emissions sequestration, reaching 142 Mt CO_2-e/year (million tonnes of carbon dioxide equivalent per year) in 2034. Sequestration remains at that level over the period to 2050. Direct Air Capture (DAC) plays a less significant role in this scenario, beginning in 2025 but capturing a much smaller share of sequestered emissions (at most 3% over the horizon), as more early emissions savings reduces the need for long-term abatement through this technology.	This scenario reaches 26 Mt CO_2-e/year in 2030 and 65 Mt CO_2-e/year in 2040. Sequestered emissions increase at lower rate after, reaching 159 Mt CO_2-e/year in 2050. Similar to the other two scenarios, DAC starts in the late 2030s, and by 2050 account for 29% of annual sequestered emissions.	This scenario sees an increase in sequestration over the period, reaching 27 Mt CO_2-e/year in 2030. Carbon sequestration increases to 65 Mt CO_2-e/year by 2040 and sees a more rapid increase over the period to 2050, when it reaches 174 Mt CO_2-e/year. DAC begins operating in the late 2030s, and by 2050 accounts for 26% of all annual sequestered emissions.	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 begins in 2040, and by 2050 accounts for 26% of all annual sequestered emissions.

	1.5°C Green Energy Exports	*1.8°C Orchestrated Step Change*	*1.8°C Diverse Step Change*	*2.6°C Progressive Change*
Fuel switching and alternative gas production (Section 3.3.14)	Natural gas use declines quickly over the period from late 2020s to 2050. It is replaced by a combination of high electrification and high domestic hydrogen production, which is encouraged by relatively cheaper hydrogen prices (than the other scenarios) due to the significant scale of hydrogen production for export. Biomethane production is strongest overall, with a ramp up during the 2030-2040s.	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 *1.5°C Green Energy Exports* scenario.	Natural gas use declines more gradually over the period to 2050. It is replaced by a combination of electrification and hydrogen. Biomethane is assumed to be supported by subsidies, so production is higher in this scenario, with explicit blending targets. Hydrogen Exports are present but very limited compared to *1.5°C 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. It 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 offsets in the scenario narratives and in 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 3 below presents the estimated emissions captured from sequestration activities in the NEM.

Figure 3 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 11, DAC becomes technically and commercially feasible at some scale around 2040 in all scenarios. It sees a significant increase after that, capturing between around 41-46 Mt CO_2-e (million tonnes of carbon dioxide equivalent) per annum in 2050, in all scenarios but *1.5°C Green Energy Exports*.

For *1.5°C Green Energy Exports*, the scale of DAC deployment is lessened, as alternative forms of sequestration to limit emissions are required before DAC technologies are assumed to become available (thereby not requiring as much deployment of DAC in later years). This locks in emission reductions from land use in later years too, and as a result DAC does not need to scale up to the degree it does in other scenarios.

3.3.5 From 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, AEMO deployed whole-of-economy multi-sectoral modelling to inform the pace and breadth of energy transformation across the scenarios. This work was conducted with CSIRO and CWC and produced the following four key forecast outcomes:

- Carbon budgets for the Australian economy (broadly consistent with the 2021 to 2030 carbon budget defined in the *Climate Change Act (2022)*), as well as a carbon budget for the electricity sector (including a distinct budget for the NEM).
- The scale of fuel switching as industrial, commercial, and residential loads shift fuel use towards lower emissions energy sources, particularly electrification.
- The scale of energy efficiency anticipated.
- The scale of sequestration activities required to maintain the carbon budgets, from alternative land use and direct air capture.

CSIRO and CWC's detailed methodology and insights can be found in the supplementary materials to this 2023 IASR in Appendix 2.

These outcomes were identified using a model which minimises the total economic costs associated with meeting the temperature goals of each scenario, subject to physical, technological, and policy constraints, and assuming appropriate reductions in carbon intensity from technological improvement and deployment. This model considered end-use demand sectors including agriculture, mining, manufacturing, other industry, commercial and services, residential, transport (road and non-road), and land use, including forestry. See Section 3.3.4 for more information.

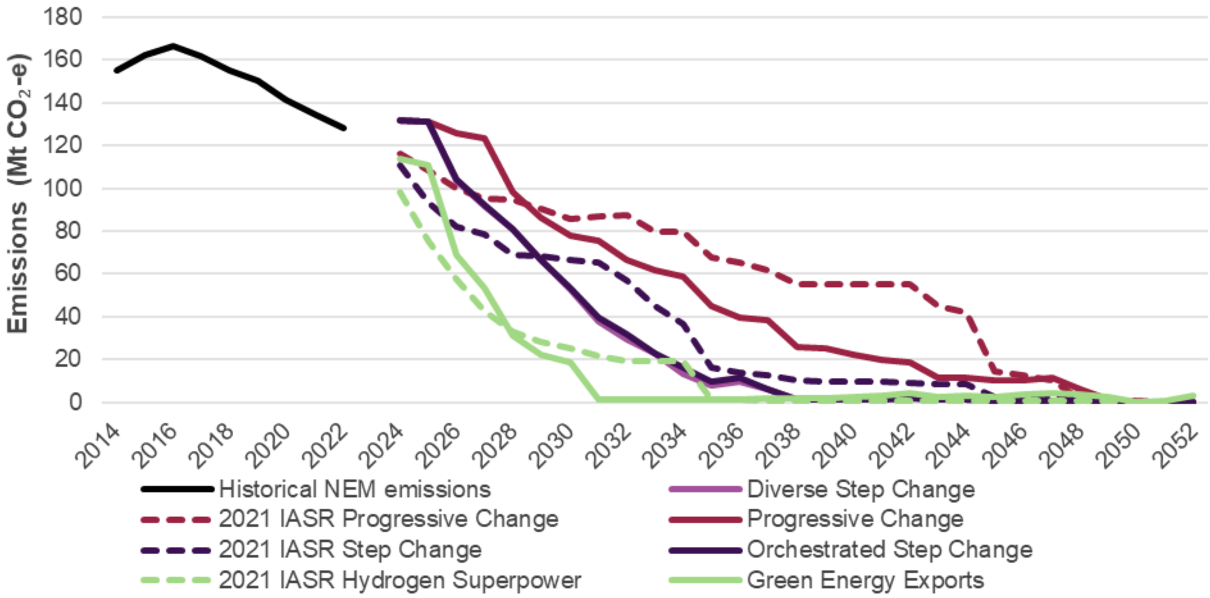
The scenarios identified alternative emissions reduction pathways consistent with the scenario narratives and targeting the variations in temperature settings for each scenario.

NEM carbon budgets

AEMO's scenarios capture both increased electrical load via electrification and the emissions trajectory that the NEM must remain within to maintain a consistent level of abatement as forecast by the multi-sector model. These emissions trajectories are then converted into carbon budgets for the NEM.

Figure 4 below presents the NEM emission trajectories produced by the latest multisectoral 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 multisectoral 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 4 NEM emission trajectories from multi-sectoral modelling



In line with the ISP Methodology[48], and as applied in the 2022 ISP, AEMO proposes to apply the aggregate NEM emissions from the multi-sectoral modelling as cumulative carbon budgets in AEMO's models. Table 12 below presents the cumulative carbon budgets that will be applied for each scenario along with comparisons to the 2021 IASR budgets that underpinned the 2022 ISP.

Table 12 NEM cumulative budgets from multi-sectoral modelling (Mt CO_2-e)

Horizon	2023-24 to 2050-51		2024-25 to 2029-30	2024-25 to 2051-52
Scenario	**2021 IASR**	**Draft 2023 IASR (for comparison)**	**As proposed: Draft 2023 IASR**	**As proposed: Draft 2023 IASR**
1.5°C Green Energy Exports	453	467	630	357
1.8°C Orchestrated Step Change	891	813	630	681
1.8°C Diverse Step Change	-	-	630	670
2.6°C Progressive Change	932*	560*	630	1,203

* The *Progressive Change* cumulative budget horizon in the 2022 ISP applied from 2030-31 to 2050-51. The current multisectoral modelling for *2.6°C Progressive Change* over the period 2030-31 to 2050-51 demonstrates a much smaller carbon budget given the tightened 2030 emissions requirements of the public policy (43% emissions reduction by 2030). This is presented for comparison purposes only.

As shown in Table 12 above, the Draft 2023 IASR carbon budgets have reduced in comparison to the 2021 IASR mainly due to the shift in the modelling horizon. When comparing the cumulative emissions budget of the 2021 and 2023 IASR modelling over the same horizon (shown by the first two numeric data columns), there is a reduction of approximately 8% in *1.8°C Orchestrated Step Change*, for example, due to lower levels of sequestration over the 2030s and 2040s onwards and energy efficiency forecasts.

Unlike in the 2021 IASR and 2022 ISP, AEMO also proposes to reflect a carbon budget to 2030, to ensure the emissions reduction stipulated in the *Climate Change Act (2022)* is at least achieved in all scenarios. 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. While the multisectoral modelling was not constrained by this target explicitly, it broadly achieved

[48] Available at https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-isp-methodology.pdf.

the minimum objective across the scenarios, although the *2.6°C Progressive Change* exceeded the requirement by approximately 77 Mt CO_2-e.

AEMO proposes to apply a commensurate carbon budget for the period 2024-25 to 2029-30 to reflect the objectives of the *Climate Change Act (2022)*. To calculate this budget, the *2.6°C Progressive Change* scenario's forecast multisectoral emissions (643 Mt CO_2-e in total over 2024-25 to 2029-30) are reduced by a pro-rata share of the total emissions that it exceeded the Act's target by (77 Mt CO_2-e), with the pro-rata share calculated on the current share of Australia's emissions attributable to electricity generation from the NEM (26% in 2021-22[49]).

AEMO proposes to model the budgets presented in the last two columns in Table 12 in the 2024 ISP, applied to the noted modelling horizons.

Across all the proposed 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 offsets is important in the scenarios, including from sequestration opportunities from the land use, land use change and forestry (LULUCF) sector[50] or DAC (see Section 3.3.4).

Matters for consultation

- Do you consider the proposed scenario alignment to the IEA scenarios appropriate?
- Do you consider the global temperature pathways proposed to be assigned to each scenario appropriate?
- Do you consider the proposed carbon budgets appropriate?

3.3.6 Electrification

Input vintage	November 2022
Status	Draft
Source	• CSIRO and ClimateWorks Australia (multi-sector modelling) • CSIRO (road transport modelling)
Update process	Updated by new consultant forecasts in 2022

Decarbonisation of the Australian economy requires fuels 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 fuels, such as hydrogen and biomethane. AEMO has therefore considered a range of electrification outcomes, with the *1.5°C Green Energy Exports* scenario adopting both a high degree of electrification and fuel-switching to hydrogen.

[49] Calculated using data from the latest National Greenhouse gas Inventory Quarterly Update at time of drafting (March 2022), at https://www.dcceew.gov.au/climate-change/publications/national-greenhouse-gas-inventory-quarterly-update-march-2022.

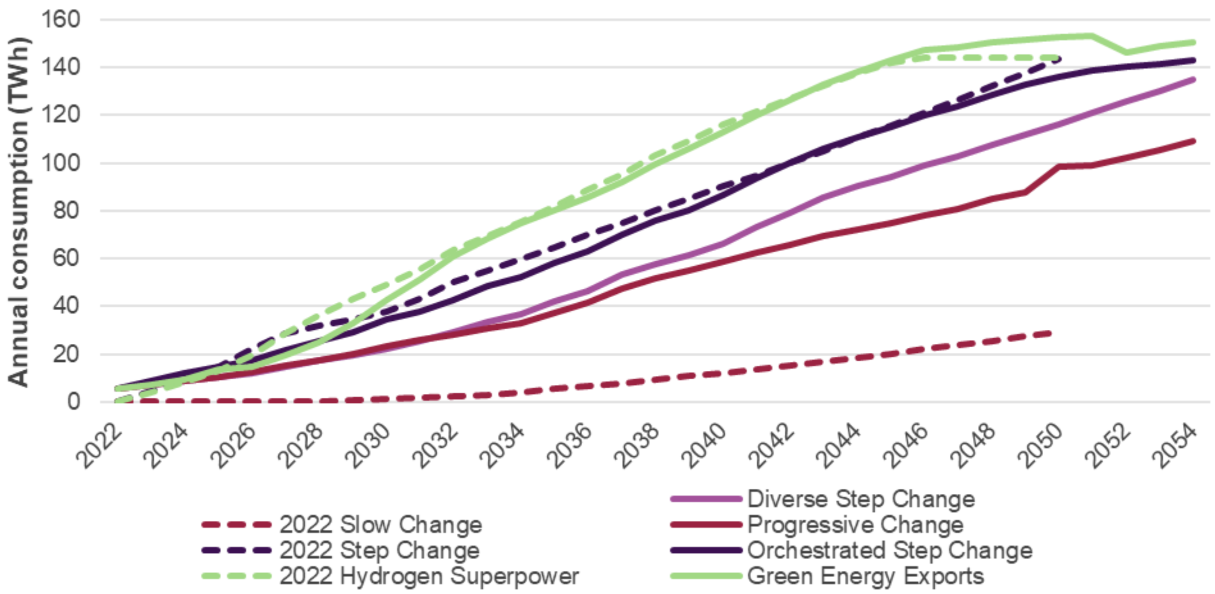
[50] LULUCF can sequester carbon via the conservation of high-carbon ecosystems, combined with increased afforestation, reforestation, and agroforestry rates, or through investment in technology-based solutions such as CCS.

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). Electrification of the transport sector is expected in all 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 investment appetite for technological advances to achieve the emissions reduction goals.

Figure 5 below shows scenario electrification forecasts, including transport. By 2050 at least 98 terawatt hours (TWh) of new electricity is required – a large proportion of the NEM's current operational consumption.

Figure 5 Total electrification forecast per scenario, including transport



The *1.8°C Orchestrated Step Change* and *1.5°C Green Energy Exports* scenarios show accelerated electrification for the residential, commercial and industrial sectors compared to the *2.6°C Progressive Change* and 1.8°C *Diverse Step Change* scenarios, although similar levels of electrification are reached by 2050. The residential sector alone has electrification in 2050 ranging from 13 TWh in the *2.6°C Progressive Change* scenario to 17 TWh in the *1.8°C Orchestrated Step Change* scenario.

Impact of electrification on daily and seasonal load shape

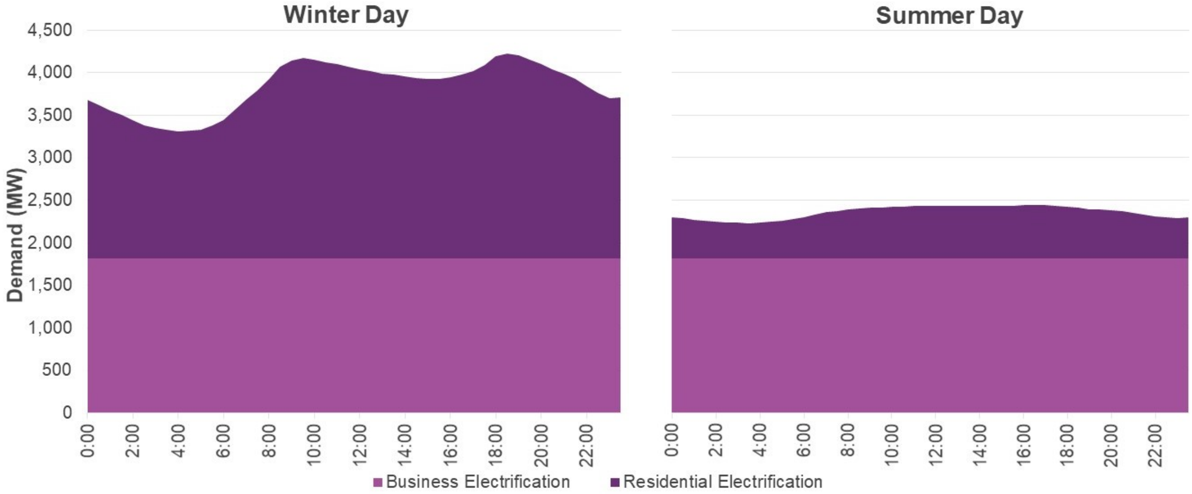
In converting non-transport electrification into half-hourly data, AEMO assumes:

- 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 6 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 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 3.3.12).

Figure 6 Example electrification daily load shape contrasting winter and summer (Victoria 2050-51, *1.8°C Orchestrated Step Change* scenario)



Matters for consultation

- Do you consider the approach to applying electrification to the load shape of residential and business consumers as reasonable?

Electrification of the transport sector

Input vintage	November 2022
Status	Draft
Source	CSIRO consultancy, incorporating data from FCAI, EVC, Origin Energy, Energex and Ergon Networks
Update process	Actuals updated to June 2022, new policies included, charge profiles updated

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. The replacement affects the scale of investment and flexibility of the NEM. Consumers' transport needs, coupled with distribution network operating modes, will contribute significantly to shaping future daily demand profiles for the NEM.

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 detailed EV model 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. These strategy documents describe how each region intends to enable adoption of EVs. Most have adopted uptake targets (50% sales share of EVs by 2030), combined with subsidies, funding for public infrastructure and 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[51].

The model also benefits from incorporation of:

- EV sales data from peak bodies and government departments, which have fed into revised actuals data for EV uptake.
- Trial data on consumer EV charging behaviour, to convenience and smart day/night profiles.
- Public charging location electricity use data, resulting in revised fast charger 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 detailed EV workbook[52]. All figures here are for the NEM, unless otherwise specified.

Relative scale of transport electrification versus other sectors

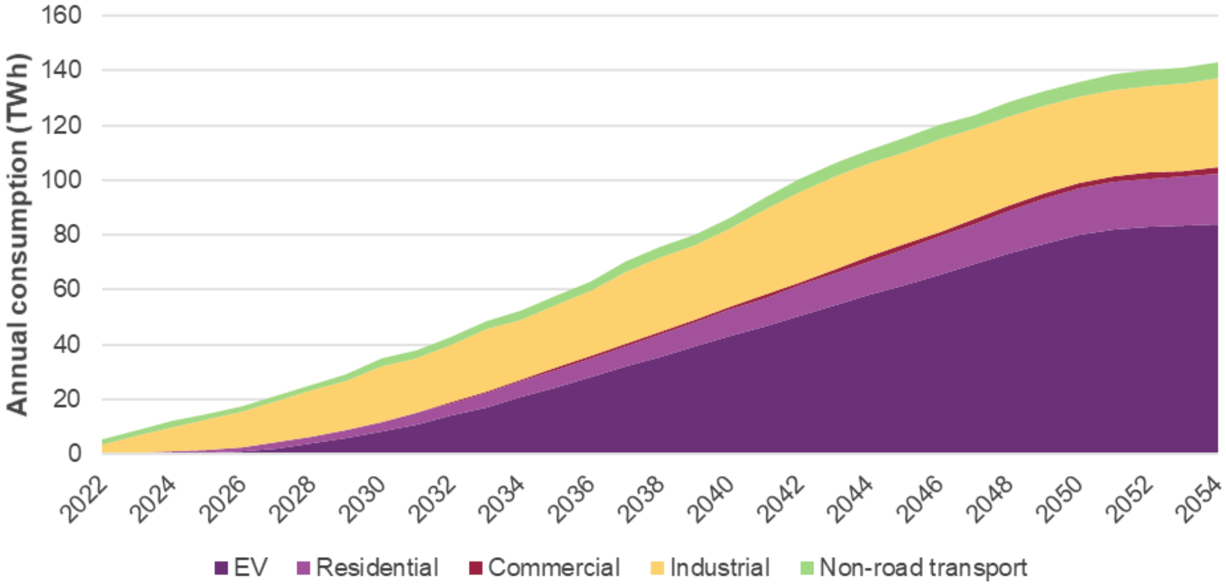
Transport electrification contributes a significant overall emissions reduction and is forecast to provide approximately half the newly electrified NEM load. The passenger and small commercial vehicle fleet is forecast to be dominated by EVs in later decades, encouraged by strengthening government policies, 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).

Figure 7 shows the scale of transport electrification against other sources of electrification in the *1.8°C Orchestrated Step Change* scenario, as an example.

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

[52] AEMO Detailed EV workbook, at https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

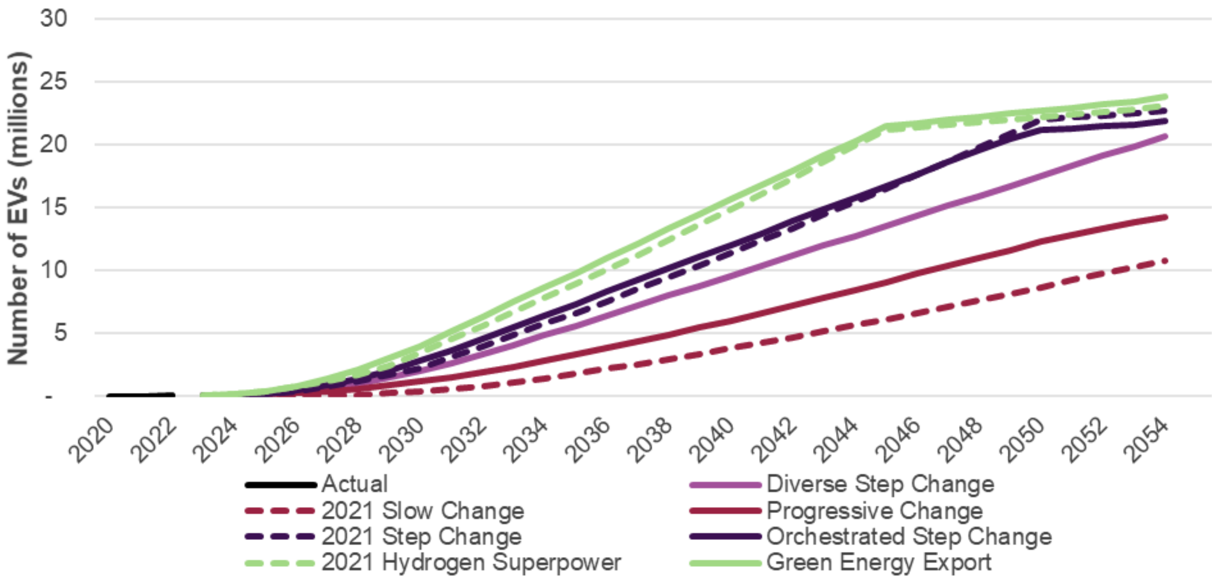
Figure 7 Contribution of EVs compared to other sources of electrification (*1.8°C Orchestrated Step Change*)



Aggregated sales data shows that the current EV fleet size (as at end June 2022) across the NEM is approximately 51,000 vehicles, representing 0.3% of the total road transport fleet. 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 continue EV production despite a global downturn in overall vehicle sales. 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 8 shows the projections for BEV and PHEV fleet size in the NEM by scenario, compared to the 2021 IASR.

Figure 8 Projected BEV and PHEV fleet size by scenario



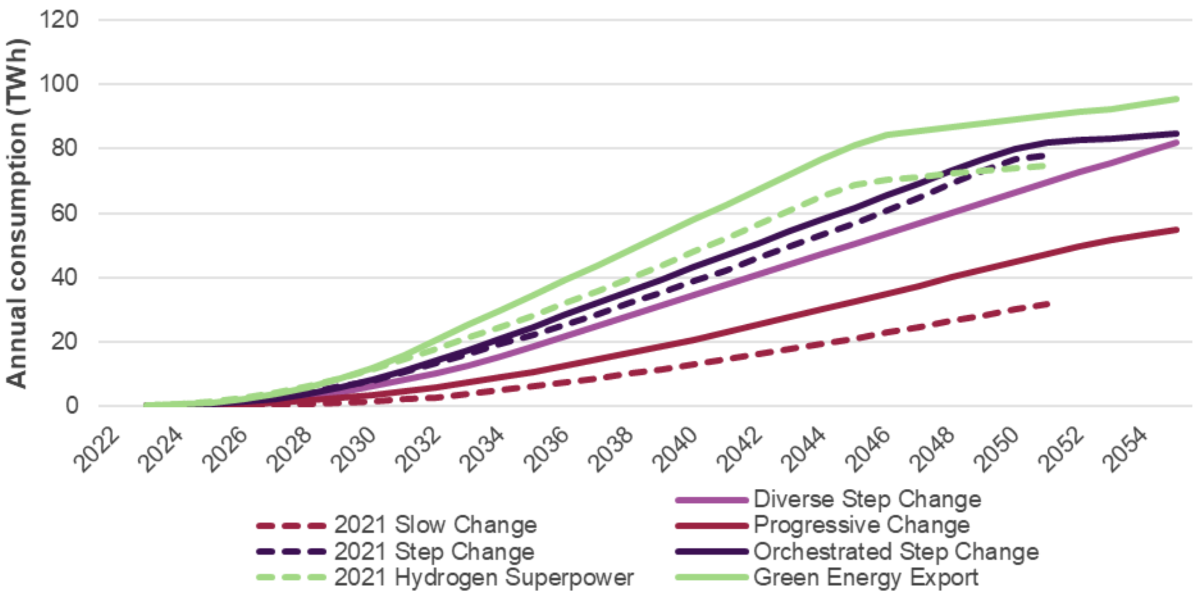
In the period up to 2030, strong sales are predicted, largely due to the introduction of a range of EV strategies by all state governments and the Federal Government, as described above. The *1.8°C Orchestrated Step Change* scenario assumes these targets are met, based on an assumed cost parity with ICE vehicles in 2027 and continued expansion of global EV production capacity. The other scenarios assume it is over- or under-achieved by varying degrees, depending on cost parity timing.

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 *1.5°C 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.

Electricity consumption from EVs

Electricity consumption from BEVs is shown in Figure 9, 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 actual uptake data, so consumption has increased by a greater percentage than the overall uptakes[53]. The projected consumption of almost 90 TWh by EVs by 2050 in the *1.5°C Green Energy Exports* scenario equates to almost half of today's total operational consumption in the NEM.

Figure 9 BEV and PHEV electricity consumption by scenario



EV daily electricity consumption patterns

While annual energy consumption by EVs is largely dependent on the uptake trajectories of the vehicle types, the instantaneous demand across the day has a wide array of contributing influences. These include consumer behaviour, EV vehicle types (including motorcycles, passenger and commercial vehicles of different sizes, trucks and buses), and charging infrastructure availability.

The vehicle charging profile types used by AEMO include a mix of static and dynamic profiles:

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

- Static profiles:
  - Convenience – at place of residence.
  - Smart daytime – driven by time of use (TOU) tariffs to reduce peaks, with a focus on daytime charging.
  - Smart night-time – driven by TOU tariffs to reduce peaks, with a focus on night-time charging.
  - Fast charging – available at public locations with dedicated infrastructure.
- Dynamic profiles:
  - 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).
  - 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.

Figure 10 shows typical convenience and fast charge profiles used in this year's modelling, compared to last year's profile. The profiles below are shown for a typical January weekday in Victoria, under the *1.8°C Orchestrated Step Change* scenario, and are normalised to 7 kilowatt hours (kWh)/vehicle/day. This is the amount of energy required to drive a medium residential vehicle the assumed average distance of 30 km/day[54].

The convenience profile for this year's modelling was informed by new data made available from a range of Australian trials, including Energex and Ergon networks, and Origin Energy[55]. The generic 2021 convenience profile peaked at almost 1.2 kilowatts (kW) per EV and was based on the observation that most chargers sold in Australia are around 7.2 kW capacity. However, the new trial data indicates dedicated high-power chargers are less common than previously believed, so a lower charging peak is considered appropriate. The profiles used in the modelling are 'after diversity' so show the expected average load per vehicle on any given weekday or weekend day. This average peak is lower than the individual charger capacity, as each vehicle may only charge once or twice a week.

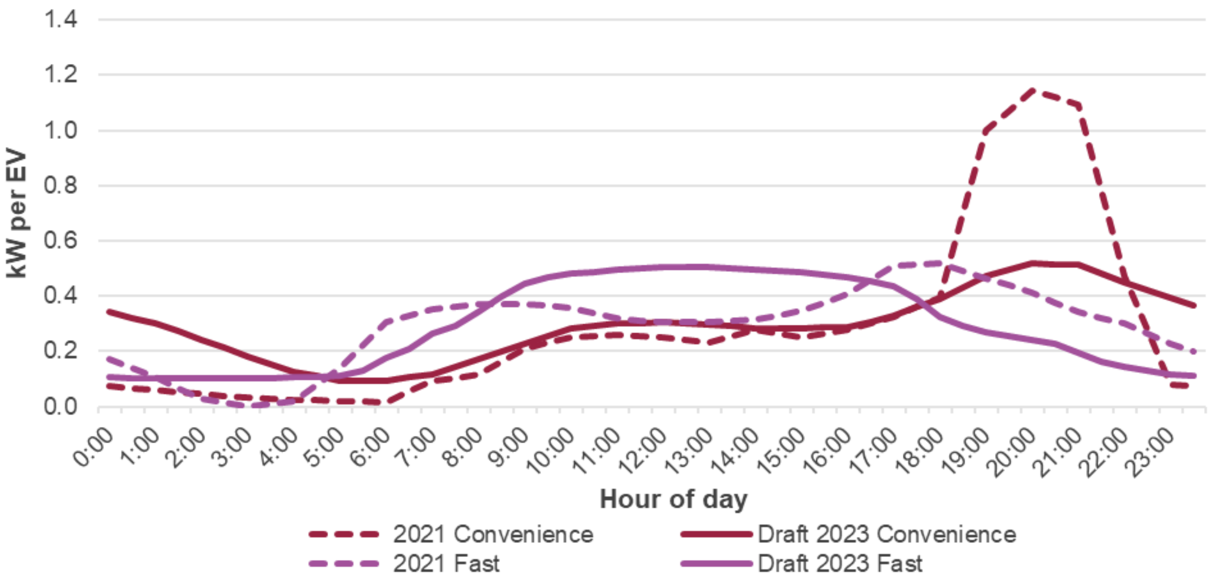
The fast charge profile used in 2021 was based on traffic movements as the best available proxy while public charging data was scarce. It showed mostly daytime demand with two peaks. For the Draft 2023 IASR, AEMO developed a new fast charge profile based on analysis of public fast charger meter data,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

[54] The assumed average daily distance travelled varies by vehicle size and type.

[55] 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 10 Normalised after diversity EV charging profiles (medium-sized residential EVs in Victoria based on a typical January weekday, 2030, *1.8°C Orchestrated Step Change* scenario)



A range of half-hourly charging profiles were developed for each vehicle type and charge profile, and vary across the months and years, to account for travel variation and yearly improvements in vehicle efficiency affecting new vehicles. There are also variations across state, and between weekdays/weekends. Most charging profiles[56] are detailed in the Detailed EV workbook published with this Draft 2023 IASR[57]. Figure 10 illustrates the change in daily profile shape for two of the charging profiles – presented on a normalised charge per vehicle, rather than the total energy consumption for all vehicles. The normalised profiles must be multiplied by the assumed consumption for a given day/month/vehicle type to arrive at a final consumption profile.

Customers are forecast to evolve their charging behaviours as charging incentives and infrastructure availability grow. Time of use tariffs and increasing uptake of dynamically controlled charging will drive a shift in consumer behaviour to more middle-of-the-day charging, with consumers benefiting from behaviours that reduce broader grid costs. Figure 11 illustrates the split of charge types in the *1.8°C Orchestrated Step Change* scenario for residential medium vehicles in New South Wales, and Table 13 provides snapshots for 2030 and 2050 to show the variation of splits assumed across the scenarios in the same state.

Further information regarding the drivers for vehicle uptake, and charging behaviours, is provided in the CSIRO report[58].

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[56] A dynamic charging profile also applies, reflecting a cohort of vehicle owners that are conscious of the prevailing daily weather conditions to change their charging behaviours based on solar generation availability. This profile is dynamic, and is not provided in the Detailed EV workbook in its Draft form.

[57] AEMO. Detailed EV workbook, at https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

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

Figure 11 Split of charging types for medium residential vehicles (NSW, 1.8°C Orchestrated Step Change)

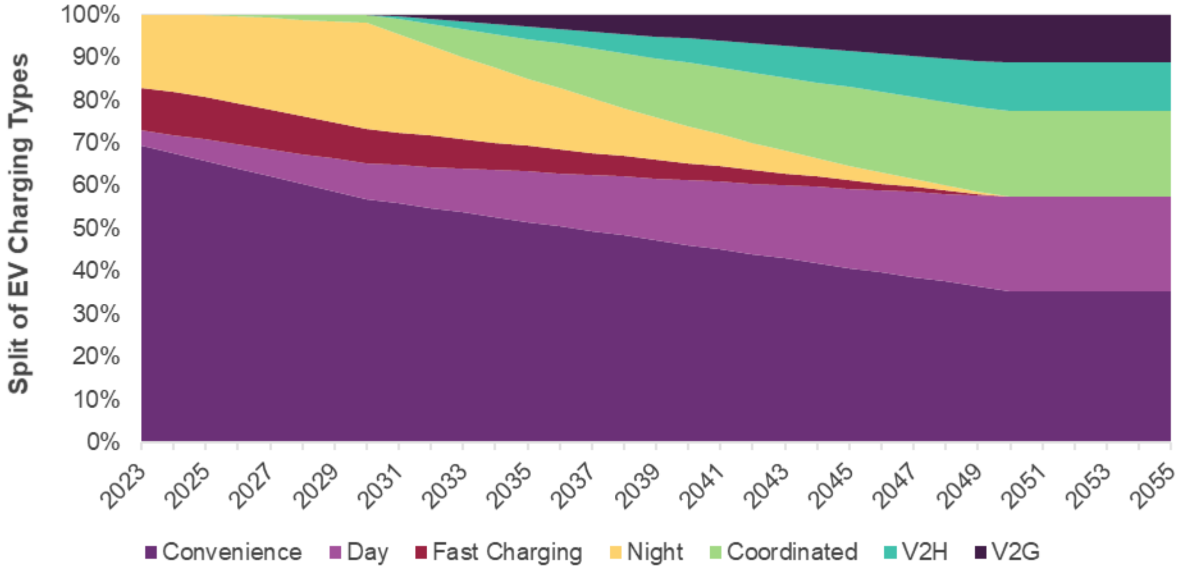


Table 13 Split of charging types for residential vehicles in NSW by scenario for 2030/2050

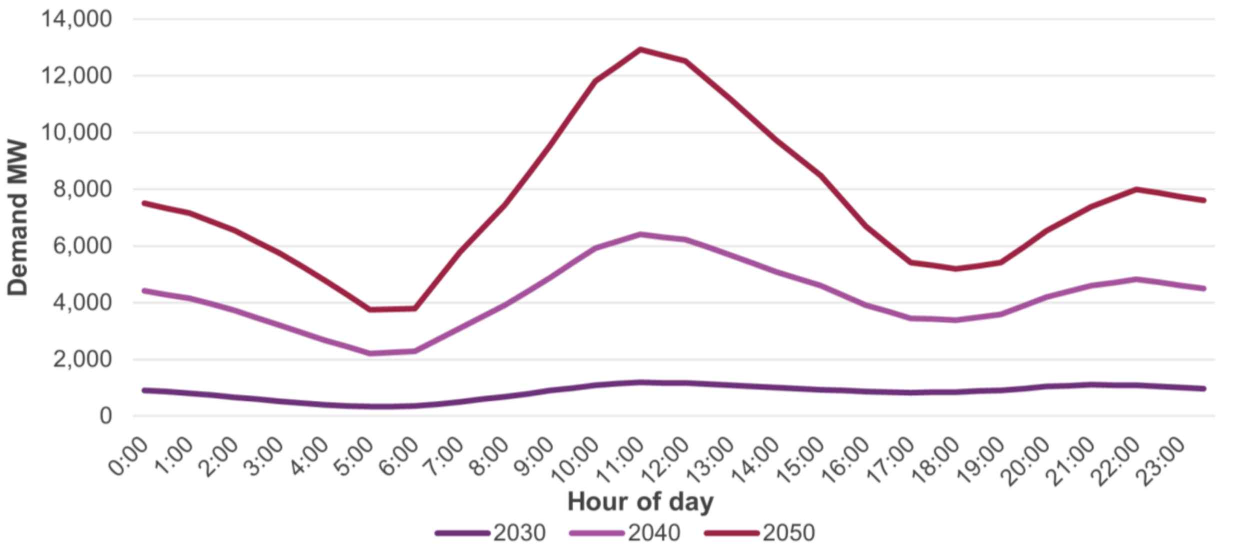
	Convenience (%)	Day (%)	Fast charge (%)	Night (%)	Coordinated (%)	V2G (%)	V2H (%)
	2030						
1.5°C Green Energy Exports	52	8	8	26	2	2	2
1.8°C Orchestrated Step Change	57	8	8	25	2	0	0
1.8°C Diverse Step Change	55	7	10	28	0	0	0
S2.6°C Progressive Change	54	6	10	30	0	0	0
	2050						
1.5°C Green Energy Exports	23	21	0	0	22	17	17
1.8°C Orchestrated Step Change	35	22	0	0	20	11	11
1.8°C Diverse Step Change	47	19	2	3	13	8	8
2.6°C Progressive Change	58	16	10	6	0	5	5

Half-hourly electricity demand was calculated by multiplying the number of vehicles by the half-hourly charging profiles weighted by the percentage of vehicles in the fleet that are allocated to each charging profile.

Figure 12 illustrates the assumed demand profile on a typical January weekday for snapshots of 2030, 2040 and 2050 for all vehicles in the NEM, across all charge profiles, for the *1.8°C Orchestrated Step Change* scenario. The profile shows twin peaks, aligned to the middle of the day and the evening, reflecting the blend across all charging profiles. The midday transport electrification peak increases from approximately 1,200 MW in 2030 to 13,000 MW in 2050, while the transport electrification evening peak increases from approximately 1,100 MW to 8,000 MW over the same period. Rising EV penetration drives growth in both peaks, although the evening peak is partly offset by assumed consumer behaviour shifting from convenience charging to time-of-use tariffs and increasing uptake of dynamically controlled charging to optimise network performance. Importantly though, with these assumed charging shifts, the charging load may be focused during daytime periods, absorbing excess solar generation when available.

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.

Figure 12 Illustrative daily demand profile for all EVs for 2030, 2040, 2050 (Based on a typical January weekday, *1.8°C Orchestrated Step Change* scenario)



Matters for consultation

- Do you consider the methods and assumptions described in this section regarding transport electrification are reasonable and provide appropriately for each scenario?
- Do you consider the change in vehicle charging load profiles (compared in Figure 10) are appropriate than the 2021 IASR profiles given they are developed from trial data, particularly for the reduced peak demand from 'convenience' charging?
- Should other factors regarding electrification be considered that may impact the consumer electricity load shape?

3.3.7 Fuel switching and alternative gas production

Input vintage	December 2022.
Status	Draft
Source	CSIRO and ClimateWorks Centre

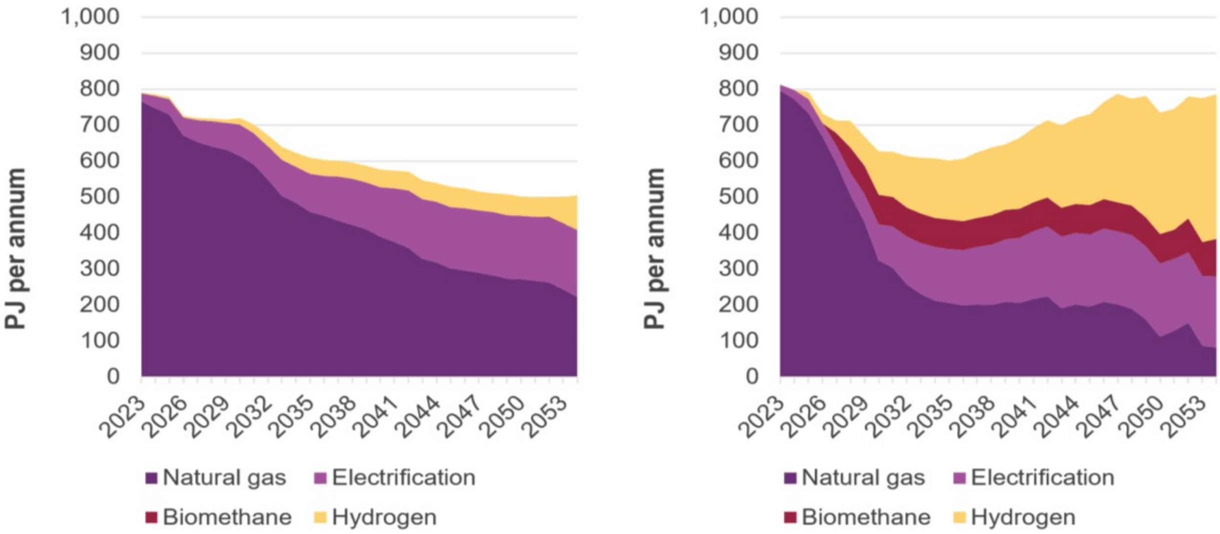
Update process	Updates of fuel switching to hydrogen and biomethane from the 2022 multi-sector modelling.

To achieve the emissions reductions targets outlined in the scenario narratives, fuel switching away from fossil gaseous fuels is required over time in all sectors. Natural gas can be substituted by electricity (discussed in Section 3.3.5), hydrogen or biomethane.

Figure 13 illustrates the fuel switching away from natural gas for the *1.8°C Orchestrated Step Change* and *1.5°C Green Energy Exports* scenarios. Note that both graphs depict end-use consumption – the electricity consumption shown is only that portion associated with electrification of natural gas use in existing and new buildings, and excludes existing electricity consumption. Electricity and hydrogen consumption for transport, and electricity and gas used for hydrogen production are also excluded. The graphs show:

- Gradually declining fossil gas use in *1.8°C Orchestrated Step Change*. Biomethane uptake is minor, due to its cost being less competitive. Electrification is the main new fuel adopted, followed by hydrogen.
- More rapidly declining fossil gas use in *1.5°C Green Energy Exports* through the late 2020s due to the influence of a much lower carbon budget. Biomethane uptake is greater, and the level of electrification is similar to *1.8°C Orchestrated Step Change*. Hydrogen production is much higher as technology cost breakthroughs are assumed for this technology in this scenario, enabling greater domestic and export demand.

Figure 13 End-use consumption from natural gas fuel-switching (*1.8°C Orchestrated Step Change* [left] and *1.5°C Green Energy Exports* [right])



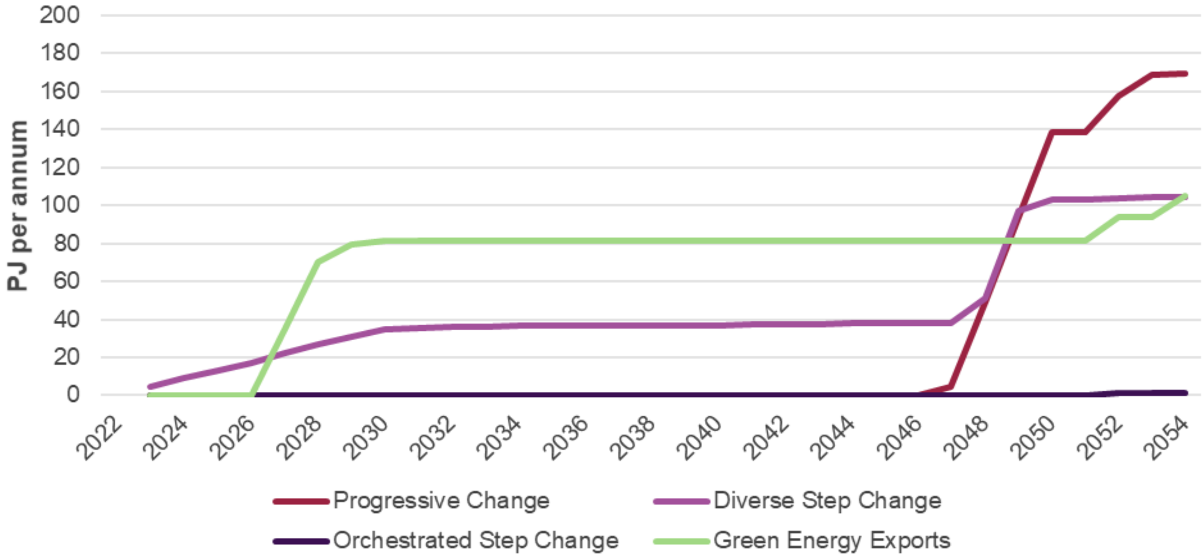
Biomethane

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.

As such, the biomethane forecast, particularly in the short to medium term, is largely assumption-driven, with *1.8°C Diverse Step Change* including an assumed minimum of 7.5%(vol) blending of biomethane into natural gas transmission and distribution by 2030, growing to 10%(vol) by 2035.

The forecast for each scenario is shown in Figure 14. Biomethane use in other scenarios has the potential to increase in the long term, as its low emissions factor can contribute to meeting net zero 2050 goals.

Figure 14 Biomethane use by scenario



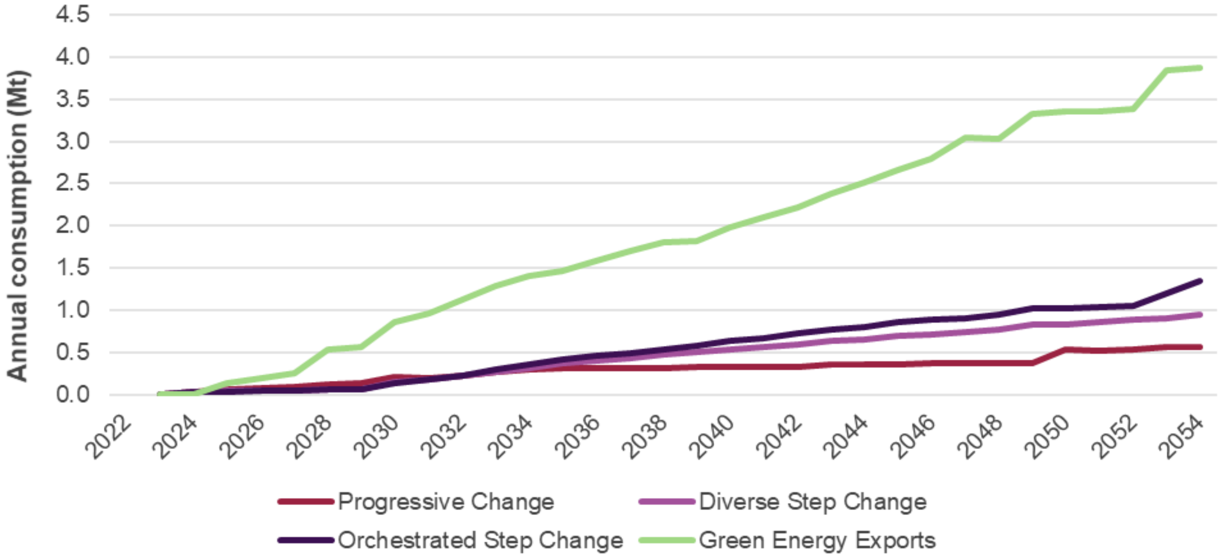
Domestic hydrogen

Significant hydrogen production announcements have been made across the eastern states of Australia, as evidenced by CSIRO's HyResource[59] listing of projects. Although every state has outlined hydrogen strategies and there are eight industrial sector projects in operation, the trajectory of capital cost reductions and uptake timing is still very uncertain.

The assumed hydrogen production for domestic use (including the transport sector) in the NEM regions is informed by the outcomes of the multi-sector modelling, where it was an endogenous variable, and is shown in Figure 15.

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

Figure 15 Domestic hydrogen consumption across NEM (all sectors, including transport)



Hydrogen uptake is lowest in *2.6°C Progressive Change*, due to lesser economic activity. *1.8°C Diverse Step Change* and *1.8°C Orchestrated Step Change* see moderate consumption of domestic hydrogen, mostly in the industry and transport sectors, despite competing with electrification and biomethane. The *1.5°C Green Energy Export* scenario has the strongest uptake, due to a high learning rate driving down costs, as hydrogen volumes are boosted by significant exports.

The model forecasts that hydrogen in residential/commercial sectors reaches 8-10% (by volume) in distribution pipelines by 2030 in all scenarios. It remains around 10% for all scenarios except *1.5°C Green Energy Exports*, where it reaches 91% hydrogen (by volume) by 2050, enabled by distribution system upgrades to hydrogen-compatible materials and appliances. The CSIRO Multi-sector Modelling report[60] notes that all scenarios assume that a 10% hydrogen blending share by 2030 (buildings and industry) can be introduced without physical modifications and with little impact on the system, consistent with near-term government aspirations and current developments (e.g., Hydrogen Park South Australia, Hydrogen Park Gladstone, HyP Murray Valley). In the Green Energy Export scenario, it is assumed that barriers and technical challenges arising from hydrogen use in appliances can be overcome and that 100% hydrogen is possible in the longer-term by 2050. This is consistent with continued upgrade of distribution pipelines from cast iron to polyethylene in Australia, and trials and demonstrations already underway in the UK.

Industrial gas supply is forecast to reach between 40-80% hydrogen (by volume) by 2050 across the scenarios, assuming that hydrogen-compatible pipelines supply industry hubs.

Export hydrogen

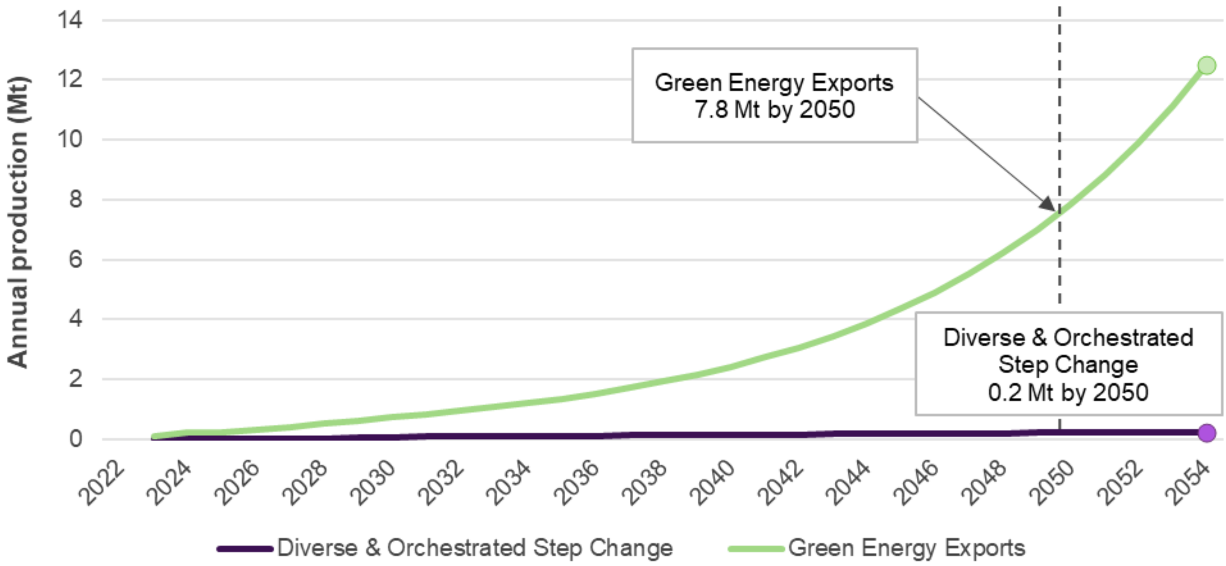
Australia is considered well placed to export green hydrogen, due to high quality renewable energy potential and a history as a reliable international energy and resource supplier. Several Australian states have developed plans for construction of *1.5°C Green Energy Exports* facilities, making use of existing and expanded port infrastructure.

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

The assumed quantities of NEM-connected export hydrogen are shown in Figure 16. Note that no export hydrogen is assumed in the *2.6°C Progressive Change* scenario.

Export hydrogen in the NEM assumed in this Draft 2023 IASR is lower than the 2021 IASR's *Hydrogen Superpower* scenario, based on an assumption that the NEM states will export their current share of the global LNG market in hydrogen by 2050, and that 50% of export hydrogen production within NEM regions will not be connected to the NEM.

Figure 16 Export hydrogen production across NEM



3.3.8 Consumer energy resources

Input vintage	November 2022
Status	Draft
Source	• CSIRO • Green Energy Markets
Update process	Updated by new consultant forecasts in 2022

CER predominantly describes consumer-owned devices that can generate or store electricity as individual units and which 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 Draft 2023 IASR, the PVNSG forecasts are included in this section. CER (including PVNSG) therefore 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) 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 14 below, with 'average' indicating a simple average of GEM and CSIRO.

Table 14 Consultant scenario mapping for CER

Scenario	*1.5°C Green Energy Exports*	*1.8°C Orchestrated Step Change*	*1.8°C Diverse Step Change*	*2.6°C Progressive Change*
PV forecast mapping	GEM	Average	Average	CSIRO
PVNSG forecast mapping	GEM	GEM	GEM	CSIRO
Battery and VPP forecasts mapping	Average	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 *2.6°C Progressive Change*, while the elevated outlook seen in GEM's forecasts best represented the ambitious assumptions of the *1.5°C Green Energy Exports* scenario. AEMO considers that averaging PV, battery and VPP forecasts for *1.8°C Diverse Step Change* and *1.8°C Orchestrated Step Change* provides a balanced view of outlooks, and maintains an appropriate relationship with the 2021 IASR forecasts.

In contrast, except for *2.6°C Progressive Change*, GEM forecasts were selected based on the simplicity of maintaining historical proportionality with PVNSG, which are affected by similar costs and revenues.

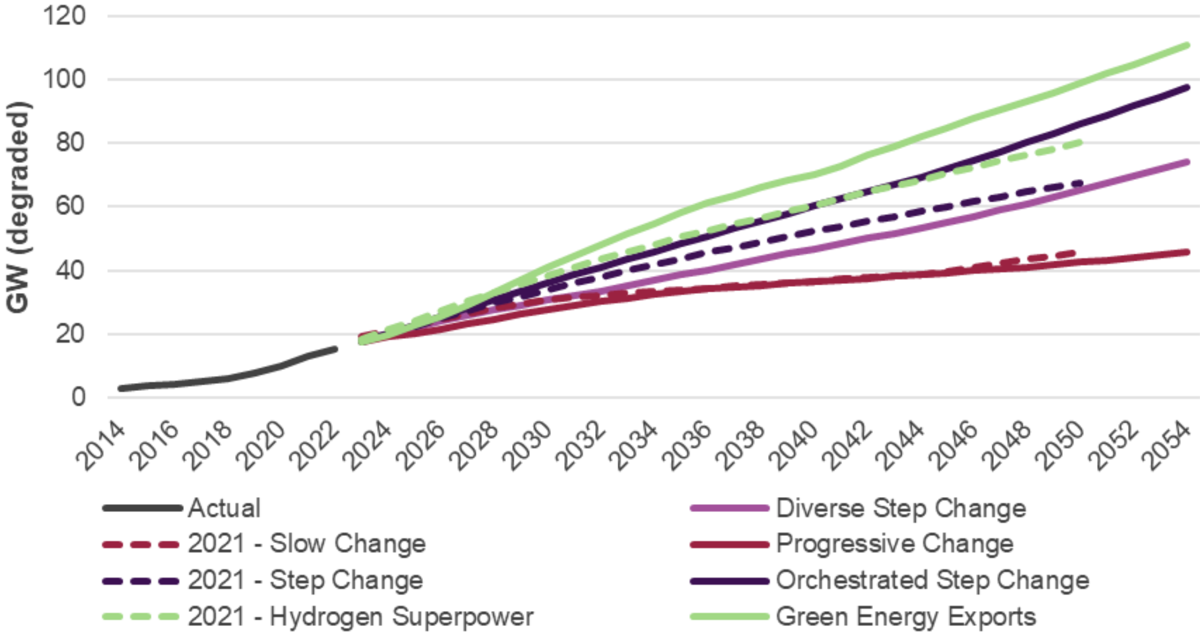
Details of assumptions underpinning each consultant's forecasts are provided in their reports that supplement this Draft IASR (see Appendix 2).

Distributed PV

Distributed PV systems, including residential and commercial rooftop PV, and larger embedded PVNSG systems, have in aggregate have seen continued growth over 2021 and 2022, with approximately 2.3 GW of new installations over the 2022 financial year, and a total NEM capacity of about 15.3 GW. By 2050, the scenarios represent a range of distributed PV penetration, with up to approximately 50% of all dwellings having PV systems installed. Considering that dwelling numbers include "attached" abodes without suitable roof spaces (including units, townhouses, and apartment complexes), that many of the suitable dwelling types will still be impeded from significantly shading, or may be limited by ownership considerations (rental premises may be less likely to invest in PV systems without alternative financial models that reward landlords for installing them), AEMO considers that this represents a significant proportion of dwellings with PV installations.

Figure 17 shows the cumulative PV capacity installed across the NEM, projected for each scenario according to the scenario mapping in Table 14. Compared to 2021, the Draft 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.

Figure 17 NEM distributed PV installed capacity (degraded)



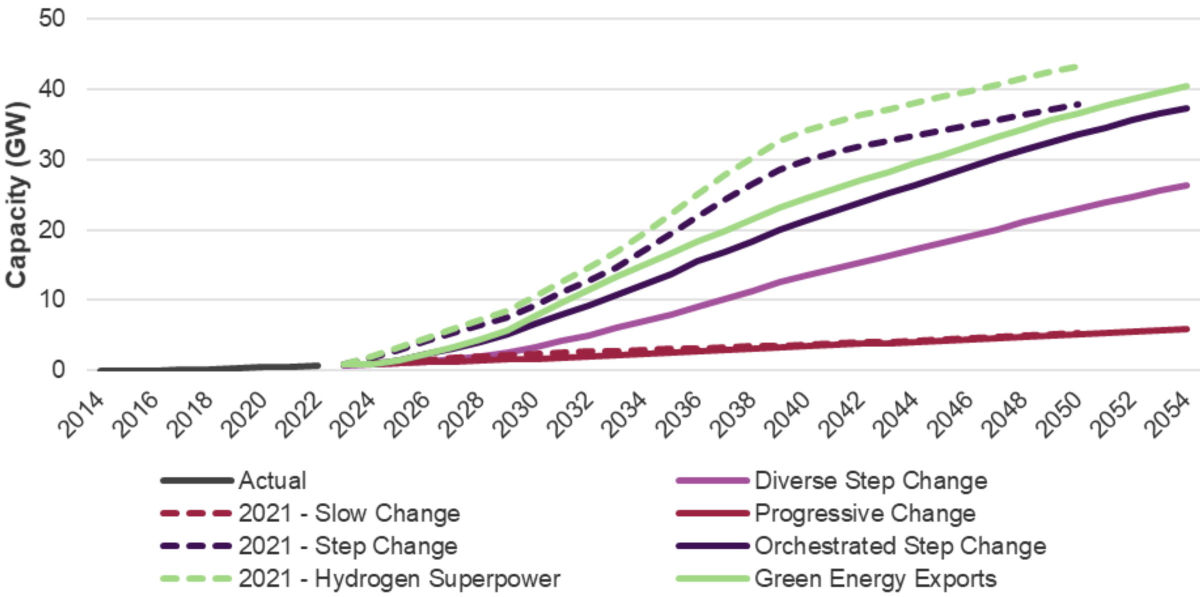
Battery storage uptake

Distributed residential and commercial battery systems have the potential to 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:

- 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
- Technical assumptions such as the energy to power ratio and the round trip efficiency. Household batteries have been modelled by CSIRO and GEM with a 2.2 and 2.5 energy to power ratio, respectively. This means that a battery could provide 2.2 hours and 2.5 hours of supply if discharging at full capacity. The ratios are static over time, reflecting established views of optimal design of consumer needs. The battery round trip efficiency, or efficiency factoring the total losses incurred over one charge-discharge cycle was assumed to be 85% and 90% by CSIRO and GEM, respectively. This technical assumption is also static over time, reflecting the technical challenges in delivering further efficiency gains.

Figure 18 shows the total forecast installed capacity of distributed batteries across the NEM for all scenarios. In the long term, the Draft 2023 IASR forecasts are moderated by a lack of improvement in technology costs, and a delay in short-term popularity reflecting lower than anticipated year-on-year growth of small-scale batteries to date.

Figure 18 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 conventional large-scale generation and storage facility, such as frequency control ancillary services (FCAS) and energy arbitrage. This is in contrast to typical household battery installations without VPP, which are configured to minimise household energy costs, or to minimise the volume of grid supplied energy.

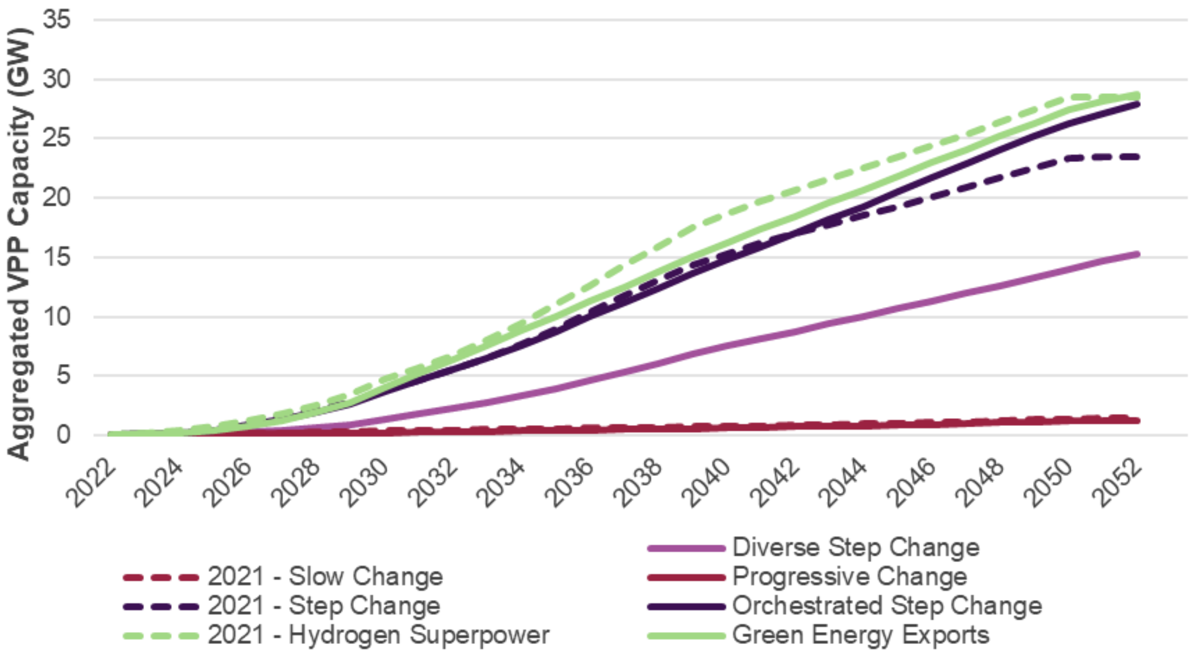
The role of consumers in developing resources that can meet, not only their household needs, but the broader needs of their community and the power system at large, will be a significant influence on the scale of transmission investments needed to maintain reliability, security and affordability through the energy transition. Consumer resources that increase load flexibility and provide reliable capacity to meet system peaks will offset other investments. Without these, additional grid-scale solutions will be needed instead to ensure a reliable and resilient power system.

The *1.8°C Diverse Step Change* and *1.8°C Orchestrated Step Change* scenarios apply key differing assumptions to these consumer resources, providing a key point of distinction between these otherwise similar scenarios. VPP aggregators offer consumers financial incentives in return for a degree of control over the battery charging and discharging profiles. AEMO sees that the availability of mutually beneficial VPP offers will increase the uptake of distributed batteries, particularly where the financial incentives support broad social accessibility, such as the reduction of up-front and ongoing consumer costs. Thus, although the *1.8°C Diverse Step Change* and *1.8°C Orchestrated Step Change* scenarios share many common assumptions, a driver for lower battery uptake in the former is the lower attractiveness of VPP offers.

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 on a small scale, VPP trials are demonstrating the potential value to the grid if deployed at scale, and the value to participating consumers.

The VPP capacity forecast in the NEM is shown in Figure 19. Assumed rates of customer adoption of VPPs have been revised downward slightly relative to the 2021 IASR forecasts, following consultation at FRG meetings.

Figure 19 Aggregation trajectories for VPP forecasts



Hosting capacity for distribution-connected CER

Conceptually, PV forecasts should include the consideration of distribution network hosting capacity limitations which may impact consumer payback and lead to a moderation of further PV uptake. This could occur through the inability of distribution networks to cater for unconstrained two-way energy flow at all times and will arise where it is uneconomic to do so. This may particularly be the case at times of coincident maximum solar irradiance as the level of penetration of CER increases. The economic investment in distribution networks to cater for increasing CER will be assessed by each distribution network service provider (DNSP) through the economic regulatory framework and may be closely linked to levels of orchestration that increase the utilisation of CER at times of greatest system value, potentially also impacting the amount of energy that would otherwise be spilt.

The projected growth in distributed batteries should be considered alongside PV uptake. Batteries, whether controlled directly by the household or by VPP, are incentivised to charge during times of peak solar radiation, and discharge when required at other times. This operation, in general, tends to reduce PV-only driven minimum load, and also tends to reduce network peak loading in general, improving the effective hosting capacity of distribution networks.

Presently AEMO does not assume that lower voltage networks will materially limit CER operation or uptake. AEMO will engage with DNSPs to validate these assumptions given distribution network investment plans. AEMO also applies differing assumptions regarding CER uptake and orchestration across the scenario collection which assists in evaluating the impact of CER on transmission investments.

Matters for consultation

- Are the assumptions which are proposed to apply affecting CER (including PVNSG) investments providing a reasonable spread of futures to evaluate the transmission-scale investments needed for the energy transition?
- Should other considerations affecting the operation and orchestration of consumer resources be considered, particularly regarding the variation between the *1.8°C Diverse Step Change* and *1.8°C Orchestrated Step Change* scenarios? Will these assumptions effectively distinguish the investment needs of transmission-scale infrastructure with greater or lesser consumer resources?
- AEMO has adopted the average of each consultant's projections regarding battery and VPP orchestration levels from GEM and CSIRO for the *1.8°C Diverse Step Change* scenario, which results in a higher uptake forecast than an alternative if adopting the lower forecast from CSIRO in isolation. Do stakeholders have any comments on the adoption of this level?

3.3.9 Economic and population forecasts

Input vintage	October 2022
Status	Draft
Source	• BIS Oxford Economics • ABS Population Series
Update process	May be updated in mid-2023 to reflect latest economic data if economic indicators suggest a clear need).

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

While the economic recovery continues to be affected by COVID-19, the successful roll-out of the vaccine has enabled overseas travel and migration to resume and restrictions on activity generally no longer dominate the social dynamic in Australia. Compared to other countries, the Australian economy has performed well due to timely monetary and fiscal policy propping up household incomes and supporting domestic consumption. Further to this, strong global commodity prices for key mining inputs contributed to the strength of the Australian economy through the pandemic.

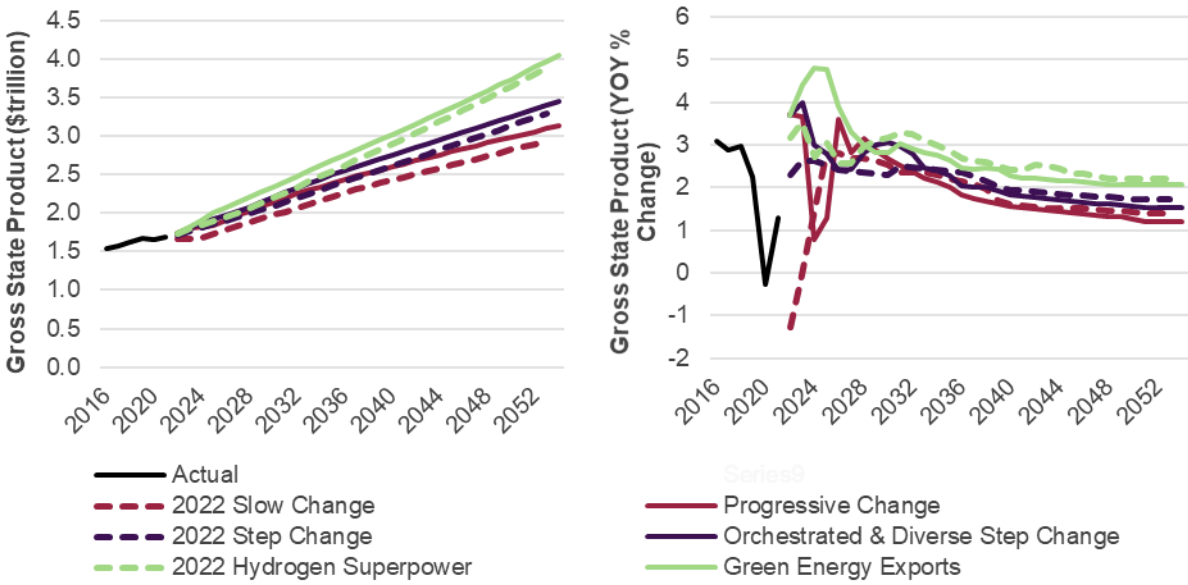
Following the economic rebound from the pandemic, pent-up global demand has outpaced supply with disruptions across many sectors. This is particularly true of energy markets, which have also been impacted by the Russia-Ukraine conflict. As a result, high inflationary pressures have been felt around the world, triggering central banks to respond by lifting interest rates earlier than previously expected, including the Reserve Bank of Australia. Additionally, labour markets have also faced shortages, and business investment is at risk of stalling given high producer input costs. Floods experienced across the NEM regions also have come at significant societal costs. Despite this, domestic recession risks are considered to remain low, and gross domestic product (GDP) is expected to return to trend over the next few years following increased growth in 2021-22.

During the pandemic, industrial production outperformed the services sector, with some sub-sectors greatly benefitting from pandemic-driven financial stimulus. More recently, growth has been limited with supply chain issues and production capacity limits constraining growth for the sector.

Australia's net zero emissions commitment will accelerate the structural change set to impact the Australian economy over the long run. During the transition to net zero emissions the mining sector is expected to continue to see strong growth, 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 driven by strong net overseas migration.

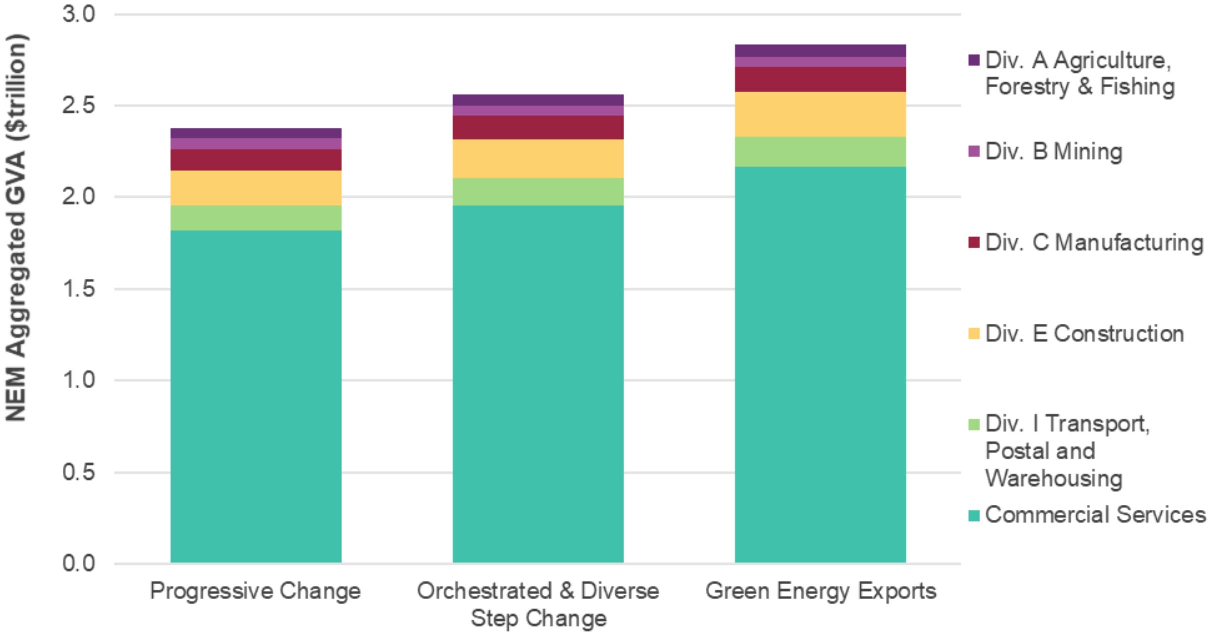
Figure 20 shows the forecast economic outcomes for gross state product (GSP) of the aggregated NEM regions, demonstrating that uncertainty across the scenarios remains, despite a higher long-term forecast. Figure 21 further provides a breakdown of the relative economic activity of each sub-sector, demonstrating the economic significance of the commercial services sector and the relative sectoral breakdowns across scenarios in 2041-42.

Figure 20 NEM aggregated gross state product



For comparison purposes, the low economic growth of *2022 Slow Change* is compared with *2.6°C Progressive Change.*

Figure 21 2041-42 NEM aggregated gross value added (by ANZSIC division)



3.3.10 Households and connections forecasts

Input vintage	December 2022
Status	Draft
Source	• ABS • BIS Oxford Economics • AEMO meter database
Update process	May be updated in mid-2023 to reflect latest economic and/or population data if relevant indicators suggest a clear need).

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

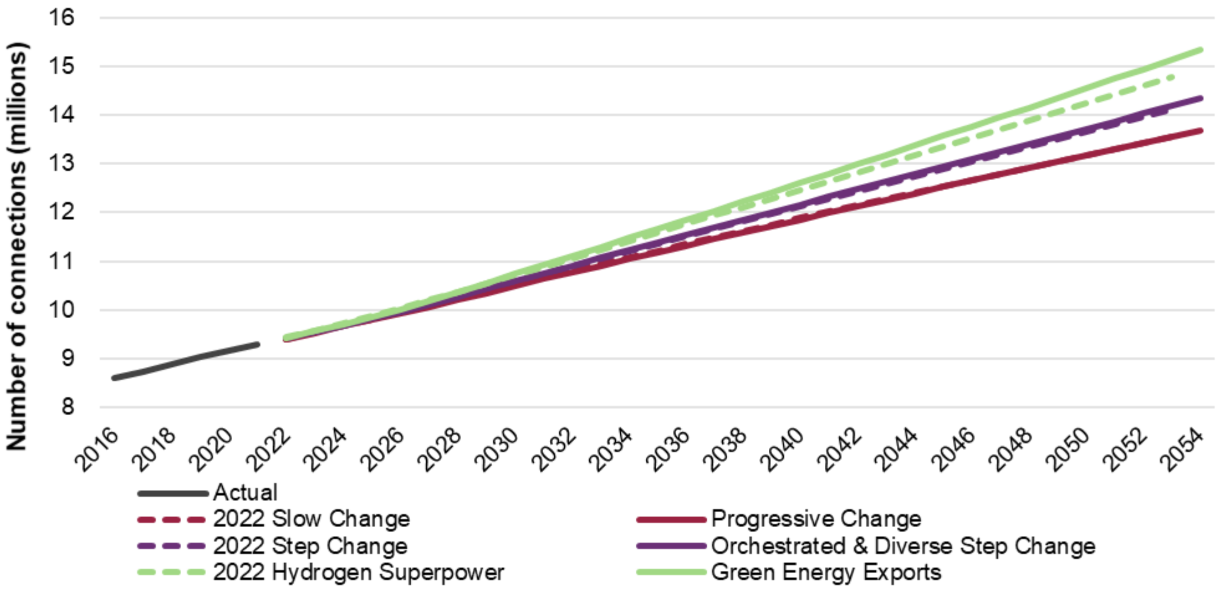
Strong economic activity and migration (described in the previous section) has a positive influence on the domestic population. The Australian population forecast is relatively unchanged compared to the 2021 projections, as past forecasts of the timing of the relaxation of border restrictions has been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

Some regional population growth variations exist, with Queensland expected to experience the strongest population growth out of the NEM regions, while Victoria is forecast to experience the weakest growth in response to historical extended COVID lockdowns.

AEMO's 2022 connections model utilises this updated population forecast in conjunction with connections numbers from AEMO's metering database to forecast the number of residential connections. In the short term, AEMO's updated forecast dips marginally lower than the 2022 forecast (down approximately 39,000 for the *1.8°C Orchestrated Step Change* and *1.8°C Diverse Step Change* scenarios by 2024-25). This is driven by a projected downturn in construction activity. Stronger growth is forecast from 2030 onwards with an additional 72,000 connections projected by 2051-52 (compared to the 2022 *Step Change* scenario, as forecast for the 2022 ESOO) which is driven by greater construction activity on the back of more favourable long term economic outcomes domestically.

Figure 22 shows the residential connections actual and forecast for all scenarios across the NEM.

Figure 22 2022 NEM residential connections actual and forecast, 2015-16 to 2053-54



Note: 2022 *Slow Change* is not visible in the chart as it follows a similar trajectory to *2.6°C Progressive Change*.

3.3.11 Large industrial loads

Input vintage	June 2022
Status	Current view
Source	• Surveys/Interviews • AEMO meter database • Distribution network service providers • Economic outlook • Media search/announcements
Update process	Will be updated in mid-2023
Get involved	**FRG discussion in May 2023**

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, considering the economic outlook based on the advice provided to AEMO by BIS Oxford Economics.

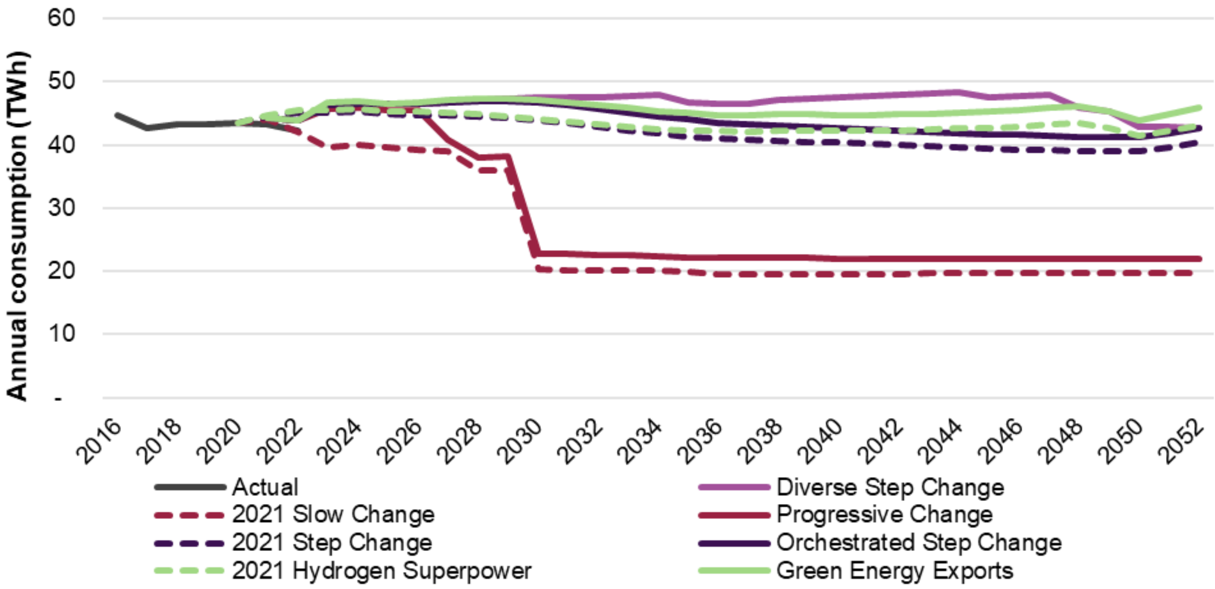
- AEMO's standing data requests from distribution network service providers (DNSPs) regarding prospective and newly connecting loads.
- Media searches and company announcements.

The LIL forecasts therefore capture the expected consumption of the largest existing industrial customers. New industrial loads are not always able to be captured by this survey process and are considered either as part of the broader business forecast, which is informed by forecast GSP, and/or by the potential electrification of new loads that are presently consuming other fuels (such as gas, oil or coal). See Section 3.3.5 for the forecast growth in the NEM from electrification by scenario, informed by the multi sectoral modelling.

Figure 23 shows the current view of LIL consumption, forecast for the 2022 ESOO[61]. Compared to the 2021 LIL forecast, the 2022 forecasts project an increase in electricity consumption from planned expansions, particularly in Victoria and South Australia, informed by surveyed participants. However, there is a material downside risk of industrial load closures should economic conditions and costs deteriorate further for individual loads.

This forecast does not reflect recent volatility in energy costs and continuing inflationary pressures. AEMO will again survey large industrial customers in mid-2023 and update the LIL forecasts before the release of the final 2023 IASR.

Figure 23 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. The international LNG market faces an uncertain future. Global demand for liquid fuels shifts 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[62]. For the NEM's LNG exports facilities in Queensland, AEMO considers that

[61] See Section 2.2.5 of the *2022 Forecasting Assumptions Update*, at https://aemo.com.au/-/media/files/major-publications/isp/2022-forecasting-assumptions-update/final-2022-forecasting-assumptions-update.pdf.

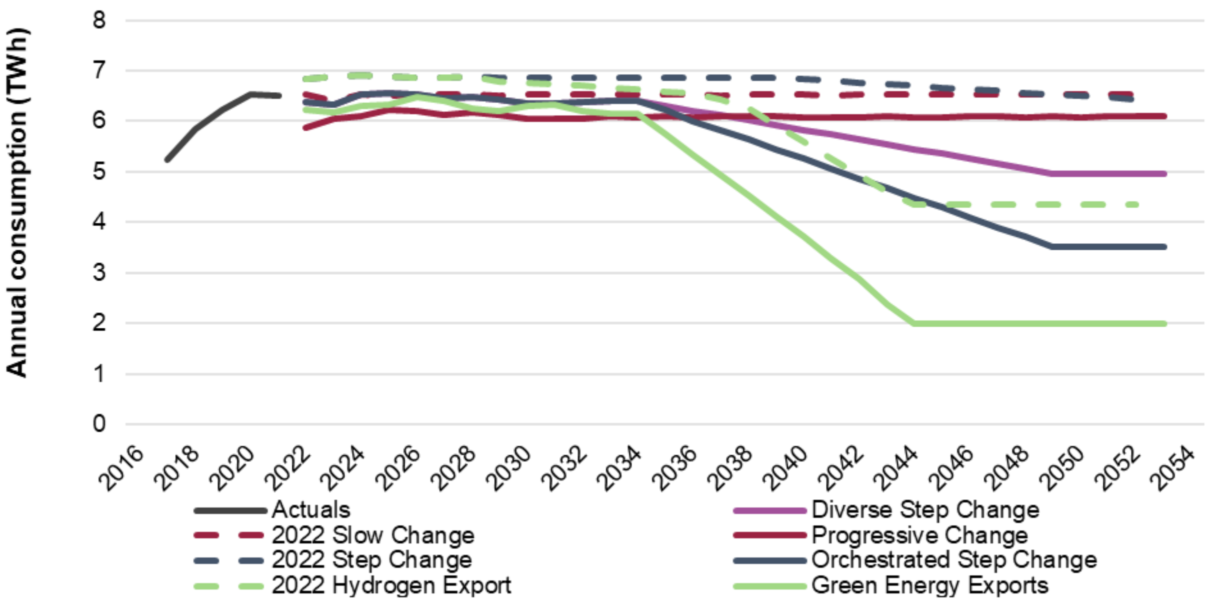
[62] The International Energy Agency outlined an uncertain future for LNG; see International Energy Agency (2021), *Net Zero by 2050: A roadmap for the Energy Sector*, at https://www.iea.org/reports/net-zero-by-2050.

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.

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.

Figure 24 below shows the LNG forecast for electricity consumption that was applied in the 2022 ESOO, compared to the latest forecast estimates based on LNG export natural gas production forecasts. The range reflects the varying economic and decarbonisation pathways across the scenarios, and the resulting impact on international gas consumption, as detailed in the 2022 *Forecasting Assumptions Update*[63]. AEMO will update the LNG forecasts before the release of the final 2023 IASR.

Figure 24 LNG electricity consumption forecast



3.3.12 Energy efficiency forecast

Input vintage	December 2022
Status	Draft
Source	CSIRO and ClimateWorks Australia (multi-sectoral modelling)
Update process	Updated by new consultant forecasts in 2022
Get involved	**FRG discussion is planned for March 2023**

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

AEMO's forecasts reflect the potential role of energy efficiency under varying decarbonisation pathways using outcomes from the multi-sectoral modelling. Figure 2 in Section 3.3.4 shows the scale of utilisation of energy efficiency for each scenario, compared to other decarbonisation pillars.

The modelling approach uses a combination of annual uptake rates by sector and technology[64], and scenario-specific variations based on relativities observed in the IEA WEO 2021 scenarios (see Table 8 in Section 3.2 for scenario mappings). This approach is outlined in detail in CSIRO-CWC's supporting report.

Figure 25 below shows results for electricity consumption savings, which range from 17 TWh to 32 TWh in 2030, and 51 TWh to 92 TWh in 2050. Energy efficiency investment occurs much earlier in the *1.5°C Green Energy Exports* scenario to reduce emissions, particularly in the commercial sector, where significant reductions in cooling and to a lesser degree lighting load occur. Industrial energy efficiency savings are also significant in the Manufacturing and Mining subsectors. More efficient appliances and water heating provide the greatest savings in residential buildings.

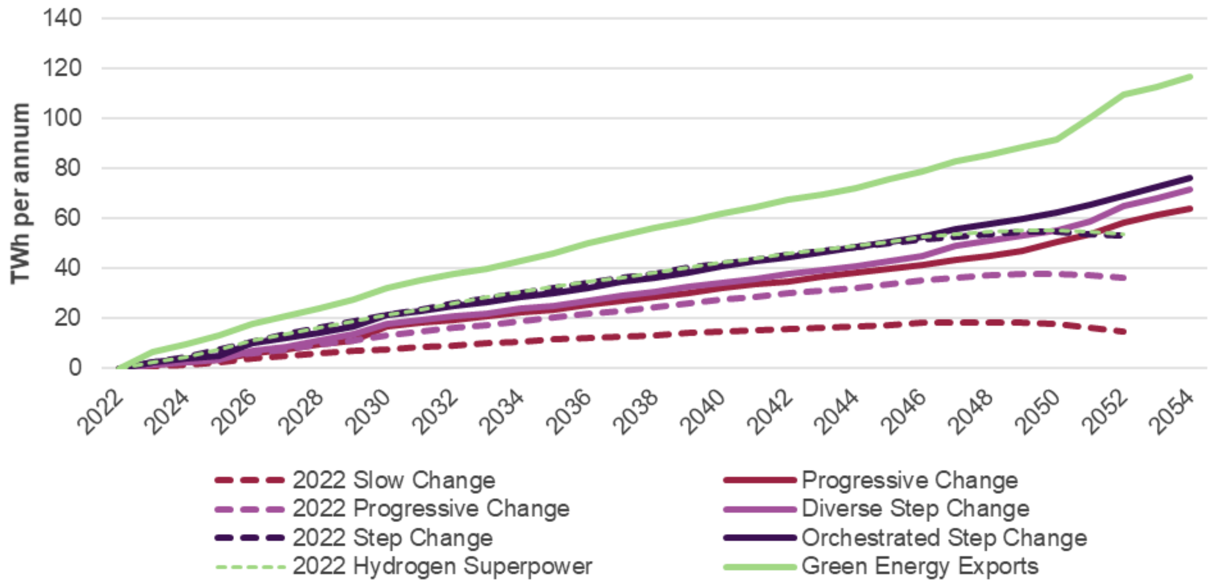
The scale of investment in *1.8°C Orchestrated Step Change* is high, although this is tempered by greater investment in fuel switching to electricity, as the availability of low emissions electricity increases. *1.8°C Diverse Step Change* uses a broader mix of technologies to reduce emissions, and investment in energy efficiency assumes a more moderate pace. Investment in energy efficiency is lower in *2.6°C Progressive Change*, reflecting the impact of lower economic activity on energy requirements.

Figure 25 also shows the relationship between the 2022 forecasts and these Draft 2023 IASR forecasts. In 2022 the forecasts applied a more policy-driven approach to explicitly represent the energy efficiency measures expected from various government initiatives. The Draft 2023 forecast for *1.5°C Green Energy Exports* is much higher than the previous 2022 *Hydrogen Superpower* forecast, reflecting the additional investments that are forecast to be needed beyond even the more aspirational policy measures captured in the 2022 forecast.

Given various government policies across the NEM affecting energy and decarbonisation activities are still to be developed in detail, AEMO will further examine the role of policy settings to refine these draft forecasts in early 2023.

[64] 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.

Figure 25 Energy efficiency savings forecasts



Note: The 2022 *Step Change* scenario is not visible in the chart as it follows a similar trajectory to the 2022 *Hydrogen Superpower* scenario.

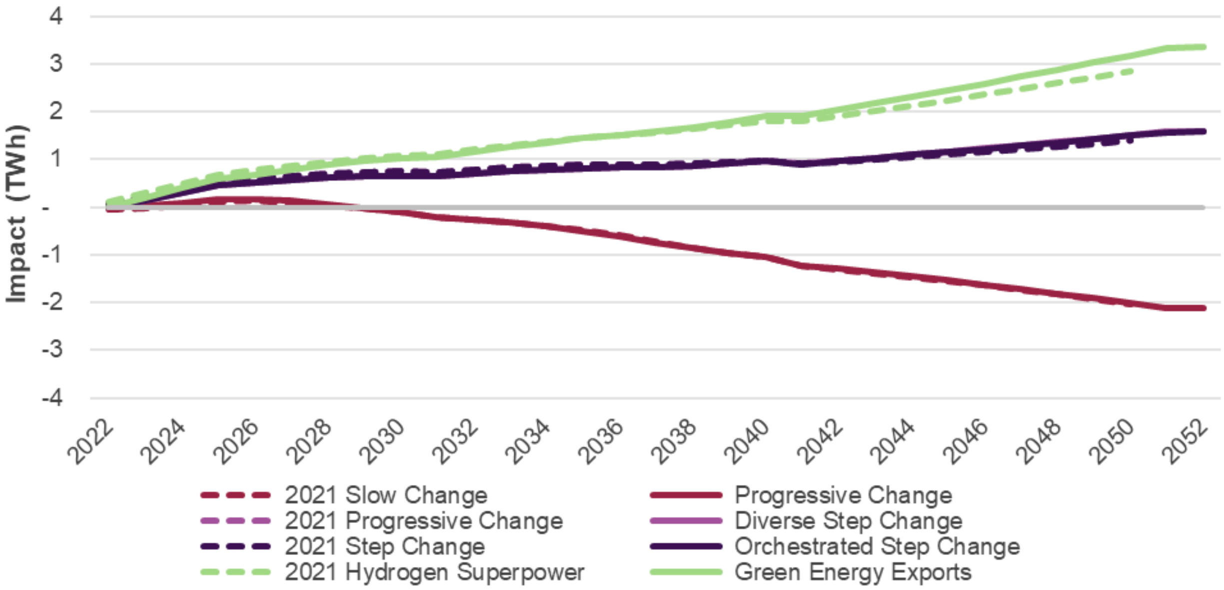
3.3.13 Appliance uptake forecast

Input vintage	March 2022
Status	Interim
Source	• Department of Energy and Environment Energy 2015 Residential Baseline Study for Australia 2000 – 2030, (RBS, 2015) available at www.energyrating.com.au. • Economic forecasts (see Section 3.3.9)
Update process	• Consider the Department of Industry, Science, Energy and Resources 2021 Residential Baseline Study for Australian and New Zealand for 2000 – 2040 (RBS, 2021), available at energyrating.com.au • Update for latest economic forecasts
Get involved	**FRG discussion in April 2023**

AEMO uses data from the 2015 Residential Baseline Study (RBS, 2015) to forecast the growth in appliances per connection in the residential sector. The data allows AEMO to estimate changes to the level of energy services supplied by electricity per household for each NEM region. Energy services here is a measure based on the number of appliances per appliance category, their usage hours, and their capacity and size. The dispersion across the scenarios is derived by applying a per capita Household Disposable Income (HDI) index relative to the moderate economic scenario. Refer to Appendix A5 of the *Electricity Demand Forecasting Methodology* for further details.

Figure 26 shows the appliance uptake trajectories applied to the consumption forecasts for the 2022 ESOO, compared with the 2021 ESOO forecasts. AEMO will update the trajectories before the release of the final 2023 IASR, considering the latest 2021 RBS data and reflecting the latest economic forecasts at that time.

Figure 26 Residential appliance uptake trajectories – consumption change relative to base year (2022)



Note: The *Diverse, Orchestrated* and 2021 *Step Change* scenarios are not visible in the chart as they follow a similar trajectory.

3.3.14 Electricity price indices

Input vintage	October 2022
Status	Interim
Source	• Australian Energy Market Commission (AEMC) annual *Residential Electricity Price Trends* report (2021) available at https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2021 • AEMO internal wholesale price forecasts • Transmission costs from the 2022 ISP's optimal development path
Update process	Retail price trends to be updated with the latest AEMC 2022 report, electricity futures pricing from ASX Energy and internal modelling to provide forecasts for wholesale price forecasts and transmission costs.
Get involved	**FRG discussion in April 2023**

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 27 shows the current retail price index, compared with the 2021 ESOO 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) 2021 *Residential Electricity Price Trends*[65] report.

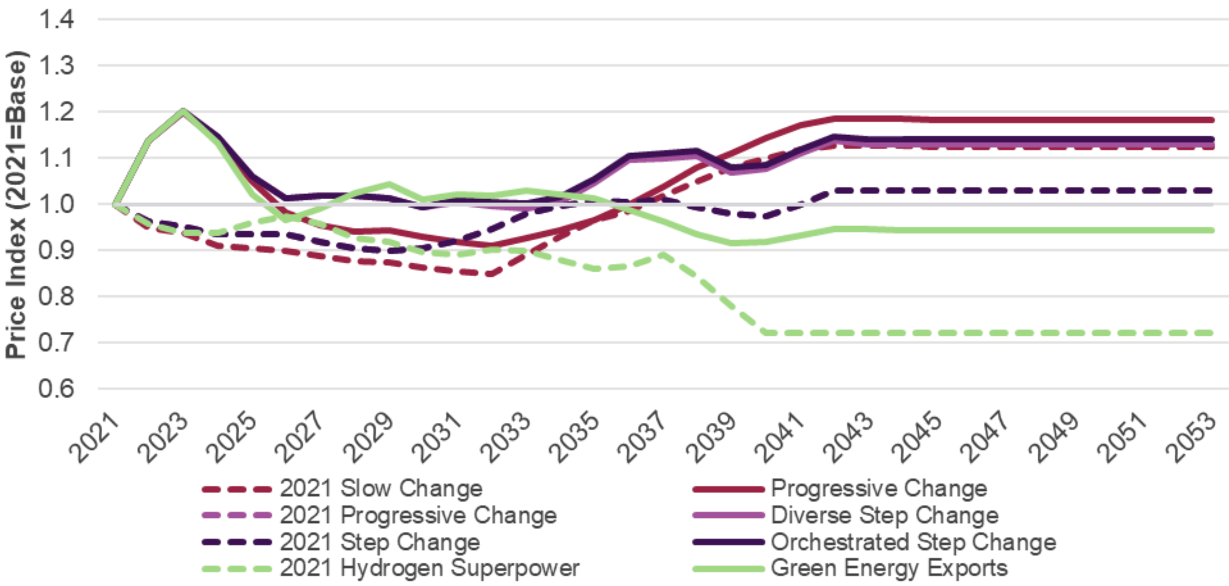
The wholesale price forecasts were informed by AEMO's 2022 GSOO modelling and electricity futures pricing from ASX Energy[66]. Given present volatility in wholesale markets, the pending release of the 2022 AEMC price trends report, and the uncertainty regarding potential structural changes to pricing mechanisms in energy markets

[65] AEMC, Residential Electricity Price Trends, at https://www.aemc.gov.au/market-reviews-advice/.

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

(for example, proposed new or adjusted price caps), AEMO will revise the retail price index before the release of the final 2023 IASR, as relevant information becomes available.

Figure 27 NEM residential retail price index, 2022 compared to 2021 forecast (connections weighted)



Consumption forecasts 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.

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 15 provides the price elasticities of demand that are proposed for the 2023 IASR scenarios.

Table 15 Price elasticities of demand for various appliances and sectors

Project	*1.5°C Green Energy Exports*	*1.8°C Orchestrated Step Change and 1.8°C Diverse Step Change*	*2.6°C 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

3.3.15 Demand side participation (DSP)

Input vintage	June 2022
Status	Current view
Source	Historical meter data analysis and information submitted to the DSP Information portal in April 2022.
Update process	• Current levels and committed/planned changes updated after summer 2021-22 to reflect most recent information. • Target levels to be maintained.
Get involved	**FRG discussion in May 2023**

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*[67].

For the ESOO, AEMO uses existing and committed DSP only, 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 for the 2022 ESOO includes Wholesale Demand Response (WDR) contributions based on the WDR dispatch data during the first 160 days of the 2022 calendar year. 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[68] and Europe[69]) 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 proposed settings for the Draft 2023 IASR scenarios are provided in Table 16 below, driven by the following:

- The *1.8°C Orchestrated Step Change* and *1.5°C Green Energy Exports*[70] scenarios are both 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.

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

[68] 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).

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

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

- The *1.8°C Diverse Step Change* scenario is assumed to have moderate growth in DSP, reflecting the moderate economic growth and technology-led change.
- The *2.6°C Progressive Change* scenario has the lowest assumed growth in DSP (maintaining the current penetration into the future) due to the poor economic outlook and damped uptake of new technologies because of ongoing supply chain issues.

For Tasmania, which tends to be more exposed to energy shortfalls during certain conditions, rather than generation capacity limitations, less incentive exists to deploy DSP solutions that look to manage extreme peak demands. The assumed growth in DSP therefore is halved relative to the mainland regions.

For New South Wales, the now committed NSW Peak Demand Reduction Scheme (PDRS[71]) policy will create a financial incentive to reduce electricity consumption during peak times[72]. AEMO includes this scheme in all scenarios, resulting in a DSP forecast which increases over time and beyond the other NEM regions' 8.5% target. 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.

Table 16 Mapping of DSP settings to scenarios

Scenario	*1.5°C Green Energy Exports*	*1.8°C Orchestrated Step Change*	*1.8°C Diverse Step Change*	*2.6°C Progressive Change*
DSP growth target overall – mainland regions	High growth to reach 8.5% of peak demand by 2053.	High growth to reach 8.5% of peak demand by 2053.	Moderate growth to reach 4.25% of peak demand by 2053.	No change from current levels of DSP (0% growth).
DSP growth target overall – Tasmania	High growth to reach 4.25% of peak demand by 2053.	High growth to reach 4.25% of peak demand by 2053.	Moderate growth to reach 2.125% of peak demand by 2053.	No change from current levels of DSP (0% growth).
NSW 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, then minor growth to 15% by 2039-40 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.

Matters for consultation

- Do you consider it reasonable to target the 8.5% by 2053 in the high growth case in the table above, or should that potentially be brought forward?

[71] 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.

[72] 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.

3.4 Existing generator and storage assumptions

3.4.1 Generator and storage data

Input vintage	November 2022 – Generation Information update
Status	Current view
Source	Participant survey responses
Update process	Updated quarterly in line with Generation Information

AEMO's Generation Information page[73] 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 resource availability for existing, committed, and anticipated VRE generation is modelled using half-hourly generation profiles as described in Section 3.6.2.

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

Input vintage	November 2022 Generation Information update, plus various other sources from 2018-19 onwards, as outlined below.
Status	Draft
Source	Various, see below
Update process	Subject to consultation responses and feedback.

AEMO has sourced the operating and cost parameters of existing generators and storages from several different sources, including AEMO internal studies[74]. 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.
- CER, Electricity sector emissions and generation 2020-21.

The specific parameters obtained from these sources are summarised in Table 17 below.

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

[74] 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.

Table 17 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% POE summer, typical summer and winter) • Auxiliary loads • 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
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
CER, *Electricity sector emission and generation 2020-21*	• 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 Draft 2023 Inputs and 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 loads 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 Draft 2023 Inputs and 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 internal 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 Draft 2023 Inputs and 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*.[75]

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[76]. Instead of emission factors from GHD, AEMO proposes to use the estimated Scope 1 emission factor for biomass from the Australian National Greenhouse Accounts Factors[77] instead.

Matters for consultation

- Do you have specific feedback and data on the assumed technical and cost parameters for existing generators?
- If you are an operator of an existing generator, do you have any specific technical or cost data that you are prepared to be used in AEMO's modelling? It would be preferable if this was data that was able to be published, but confidential data would also be considered.

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

[76] 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.

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

3.4.3 Forced outage rates

Input vintage	June 2022
Status	Current View
Source	Generator surveys and AEP Elical 2022
Update process	Forced outage rates to be updated as part of data collection process for 2023 ESOO
Get involved	**FRG discussion in June 2023**

For the 2022 ESOO, AEMO collected information from all generators on the timing, duration, and severity of unplanned forced outages, via its annual survey process. This includes information on historical outages, and (for selected participants) outage projections across the 10-year forecast period. This data was used to calculate the probability of full and partial forced outages in accordance with the *ESOO and Reliability Forecasting Methodology*[78]. 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. AEMO is currently consulting[79] on the *ESOO and Reliability Forecasting Methodology* with regard to the Forced Outage Rate data collection and analysis.

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*[80], AEMO models outages with a duration longer than five months (long duration outages) from historical outage data from 2010-11 to 2021-22, prior to calculation of the expected forced outage rate. For the 2022 ESOO, AEMO used an extended historical period of all available data (12 years) to determine the (unplanned) long duration outage rates for each region and technology class.

The long duration outages used in 2022 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 18.

Table 18 Existing generators – long duration outages

Fuel type/technology	Long duration outage rate (%)	Mean time to repair (hours)
Brown coal	0.54%	5,290
Black coal NSW	0.70%	5,568
Black coal QLD	0.68%	5,423
All coal average	0.66%	5,466
OCGT	0.83%	6,411

OCGT: Open cycle gas turbine.

[78] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/esoo-and-reliability-forecast-methodology-document.pdf.

[79] *See* https://aemo.com.au/consultations/current-and-closed-consultations/2022-reliability-forecasting-guidelines-and-methodology.

[80] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/esoo-and-reliability-forecast-methodology-document.pdf.

Forced outage rate trajectories (excluding long duration outages)

The first year forced outage rates assumed in the 2022 ESOO were based on participant-provided information and projections for each technology (see Table 19). The 2022-23 rates are higher than those used in the 2021 ESOO.

Table 19 Forced outage assumptions (excluding long duration outages) for 2022-23 year

	Full forced outage rate – 2022 ESOO (%)	Full forced outage rate – 2021 ESOO (%)	Change since 2021 ESOO (%)	Partial forced outage rate (%)	Partial derating (% of capacity)	Mean time to repair – Full outage (hours)	Mean time to repair – Partial outage (hours)
Brown coal	7.49	6.14	+1.35	6.68	19.6	89	10
Black coal QLD	4.97	4.09	+0.88	12.08	23.19	150	48
Black coal NSW	8.11	6.49	+1.62	37.23	17.17	169	48
OCGT	4.63	3.74	+0.89	1.95	4.37	12	13
Small peaking plant*	7.44	6.82	+0.62	0.45	34.95	74	38
Hydro	2.70	2.62	+0.08	0.07	31.46	52	80
CCGT + gas-fired steam turbines	3.55	2.33	+1.22	2.28	9.94	54	18

*Small peaking plants are generally classified as those less than 150 MW in capacity, or with a very low and erratic utilisation (such as Colongra and Bell Bay/Tamar peaking plant)
CCGT: Closed cycle gas turbine.

The 10-year projections for the equivalent full forced outage rate[81] of all technology aggregates are shown in Figure 28 and Figure 29, with and without the effect of long duration outages. The annual equivalent forced 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, forced outage trajectories are provided for the first 10 years of the horizon for technology aggregates only. Due to the small number of coal plant in later years, all regions have been further aggregated to an ‘all coal’ value to protection confidentiality.

[81] Where equivalent full forced outage rate = Full forced outage + partial outage rate x average partial derating.

Figure 28 Equivalent full forced outage rate projections for coal-fired generation technologies

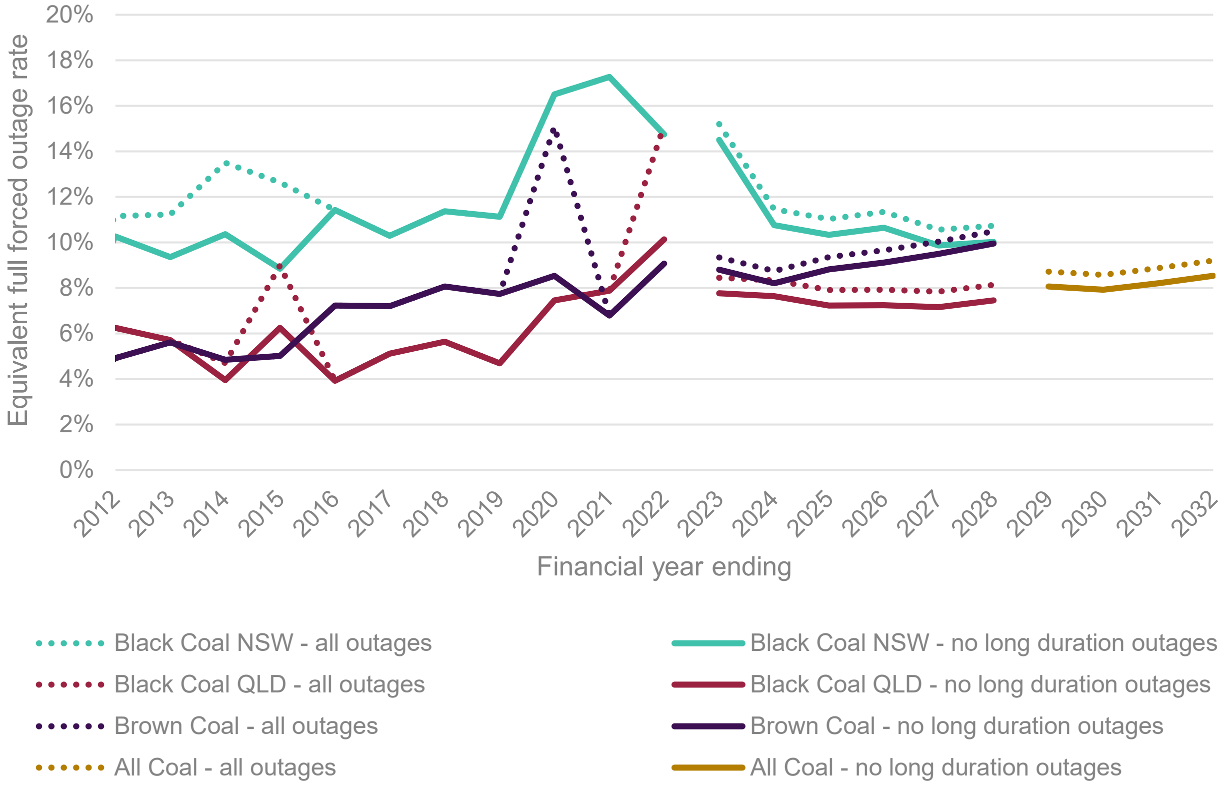
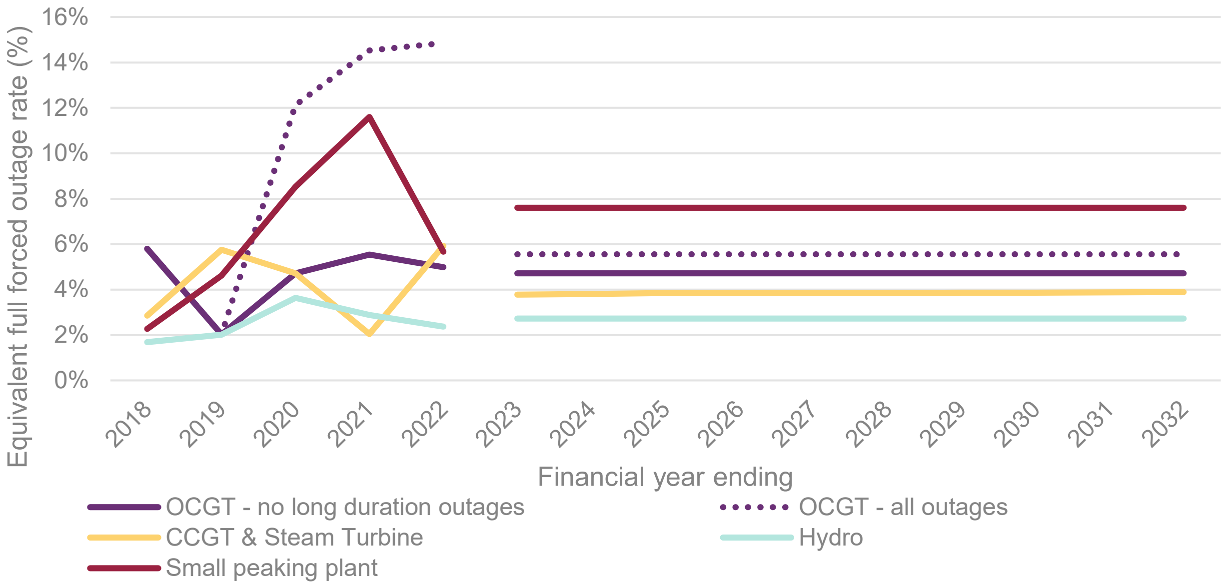


Figure 29 Equivalent full forced outage rate projections for other generation technologies



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*[82].

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.

3.4.4 Generator retirements

Input vintage	• Retirement costs: June 2022 • Retirement dates: November 2022
Status	Current view
Source	• Generation Information page • GHD 2018
Update process	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[83] 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, retirement dates can be adjusted to take place earlier than assumed for some generators, 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 constraints or profitability assessments. Registered closure dates are applied consistently across all scenarios.

For reference, a "closure date" has the meaning specified in NER clause 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 clause 2.2.1(e)(2A)).

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 Draft 2023 Inputs and Assumptions Workbook. Retirement costs incorporate the cost of decommissioning, demolition, and site rehabilitation and repatriation, excluding battery storage technologies where disposal cost data is not known.

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

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

Matters for consultation

- Do you have any views on the approach described above to address generator retirements?

3.4.5 Hydro modelling

Input vintage	Updated based on historical data provided by hydro operators.
Status	Current view
Source	Inflows – hydro operators, considering insights from the Electricity Sector Climate Information (ESCI) project[84].
Update process	Hydro scheme inflows to be updated based on updated data received from participants when available.

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 hydros

Tasmanian hydroelectric generation is modelled by means of individual hydroelectric generating systems linked to one of three categories:

- Long-term storage.
- Medium-term storage.
- Run of river.

Table 20 identifies how schemes or power stations are allocated across these storages and provides assumptions on the energy in storage available. Energy inflow data for each Tasmanian hydro water storage is determined from historical daily yield information provided by Hydro Tasmania.

Table 20 Storage energy (in GWh) of the three types of generation in Tasmania

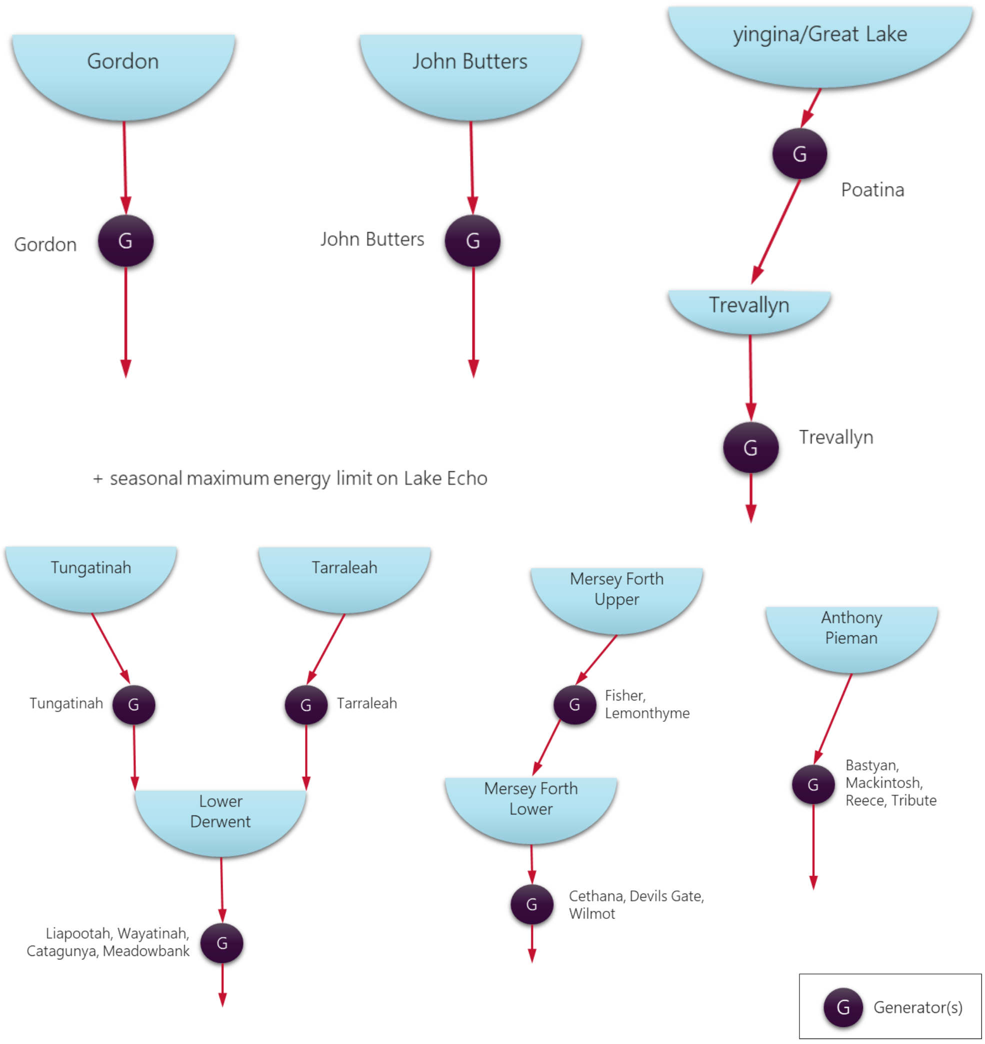
Storage type	Energy in storage	Schemes and stations
Long-term	12,000	Gordon, Poatina John Butters, Lake Echo
Medium-term	400	Derwent
Run of River	200	Antony Pieman, Mersey Forth, Trevallyn

AEMO's approach to modelling the existing Tasmanian hydro schemes relies on a 10-pond[85] topology designed to capture different levels of flexibility associated with the different types of storage outlined above (see Figure 30).

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

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

Figure 30 Hydro Tasmania scheme topology



Mainland hydros

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[86]. The model schedules the electricity production from these generators across the year such that the system cost is minimised within this energy constraint.

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

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

[86] 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.

The latest information on the monthly storage inflows used in market modelling studies can be found in the Draft 2023 Inputs and Assumptions Workbook.

Figure 31 presents a representation of the topology currently modelled for the Snowy scheme.

Figure 31 Snowy Hydro scheme topology

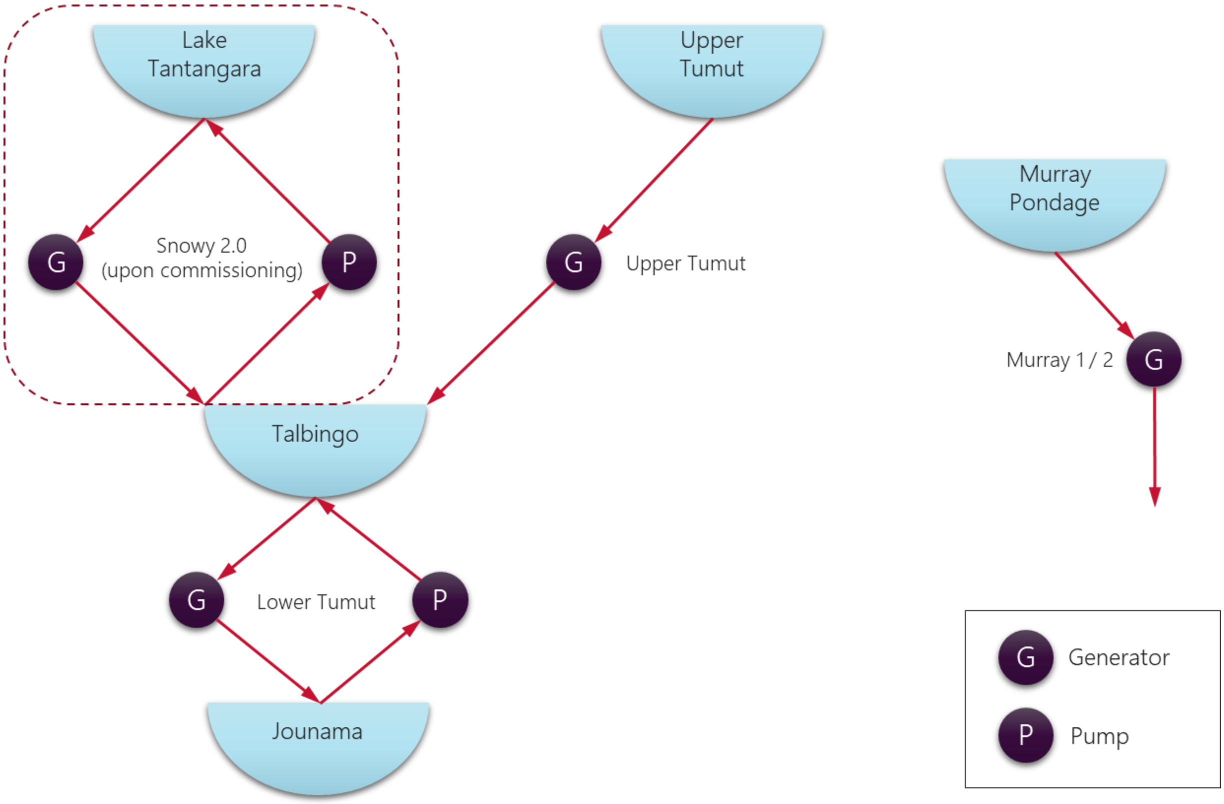
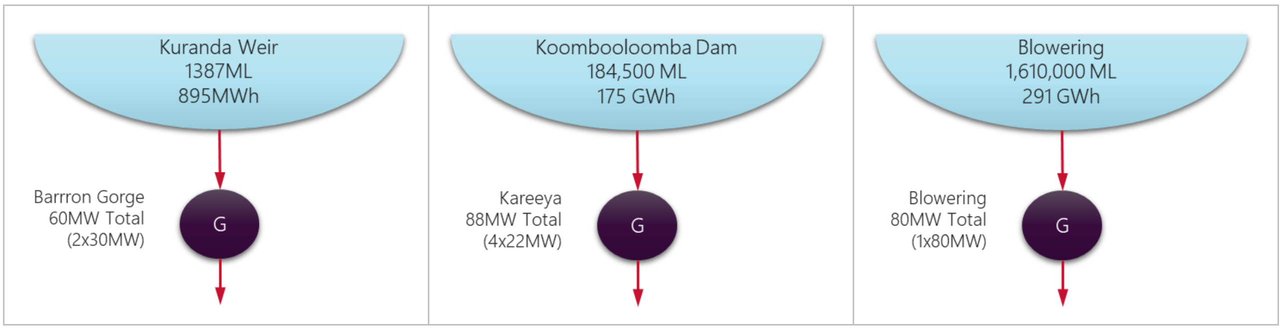
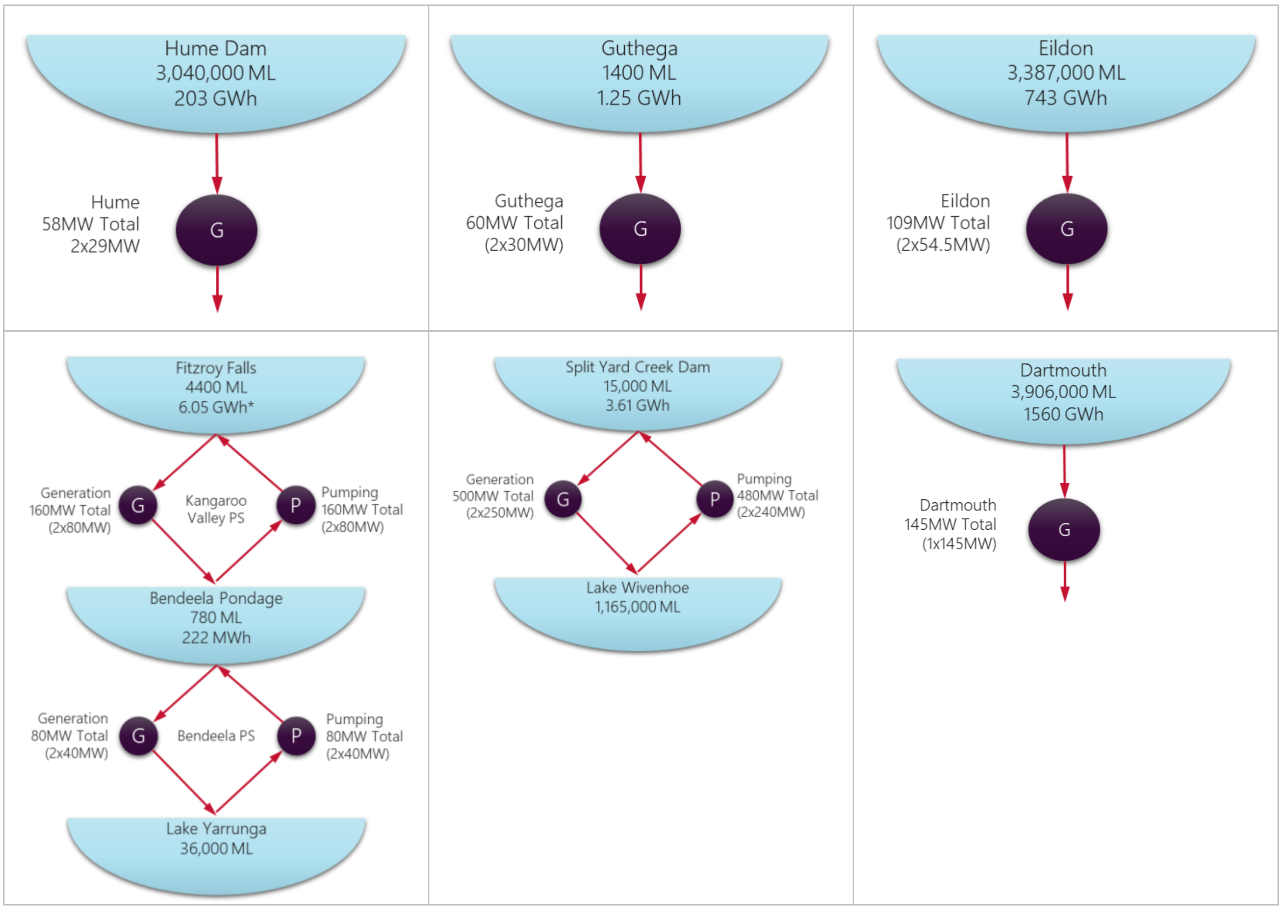


Figure 32 provides graphical representations of the other hydrological models used in the market simulations, as well as the registered capacity of the adjoining generating units[87].

Figure 32 Hydro scheme topologies of other existing hydro power stations



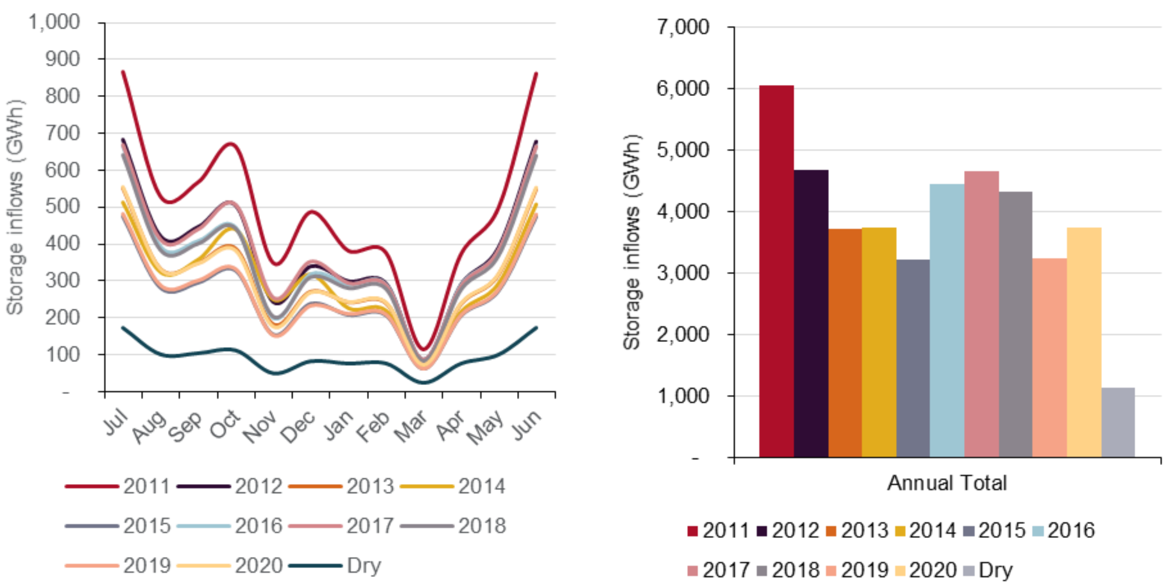
[87] Storage capacities are defined in megalitres (ML).



Note. Origin Energy has proposed an expansion of the Shoalhaven pumped hydro scheme, increasing the storage capacity of the project. As this project is not yet committed, the representation provided reflects the existing capacity only.
*Energy storage at Fitzroy Falls includes full drop through both power stations.

The Draft 2023 Inputs and Assumptions Workbook provides the annual and seasonal variation in hydro inflows for key hydro schemes. An example of this is shown in Figure 33 below, for Snowy Hydro.

Figure 33 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[88].

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 21 for the 1.8°C *Orchestrated Step Change* scenario, as an example. Other scenario hydro climate factors are available in the Draft 2023 Inputs and Assumptions Workbook.

Table 21 Median hydro climate factors, 1.8°C *Orchestrated 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%

3.5 New entrant generator assumptions

3.5.1 New entrant generation projects included in different publications

Input vintage	November 2022
Status	Current view
Source	Participant survey responses
Update process	Updated quarterly in line with Generation Information.

New entrant generators that are announced to market are assessed against commitment criteria published in AEMO's Generation Information page. To classify the commitment status of generators, AEMO uses information provided by both NEM participants and generation/storage project proponents. The key classifications are defined as follows:

- **Committed projects** are considered to become operational on dates provided by the participants.
- **Committed* projects** are assumed to commence operation no earlier than the end of the next financial year (1 July 2024), reflecting uncertainty in the commissioning of these projects. Further details are available in the *Reliability Forecasting Methodology Final Report*[89].

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

[89] See Section 5.3 at https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/Reliability-Forecasting-Methodology/Reliability-Forecasting-Methodology-Final-Report.pdf.

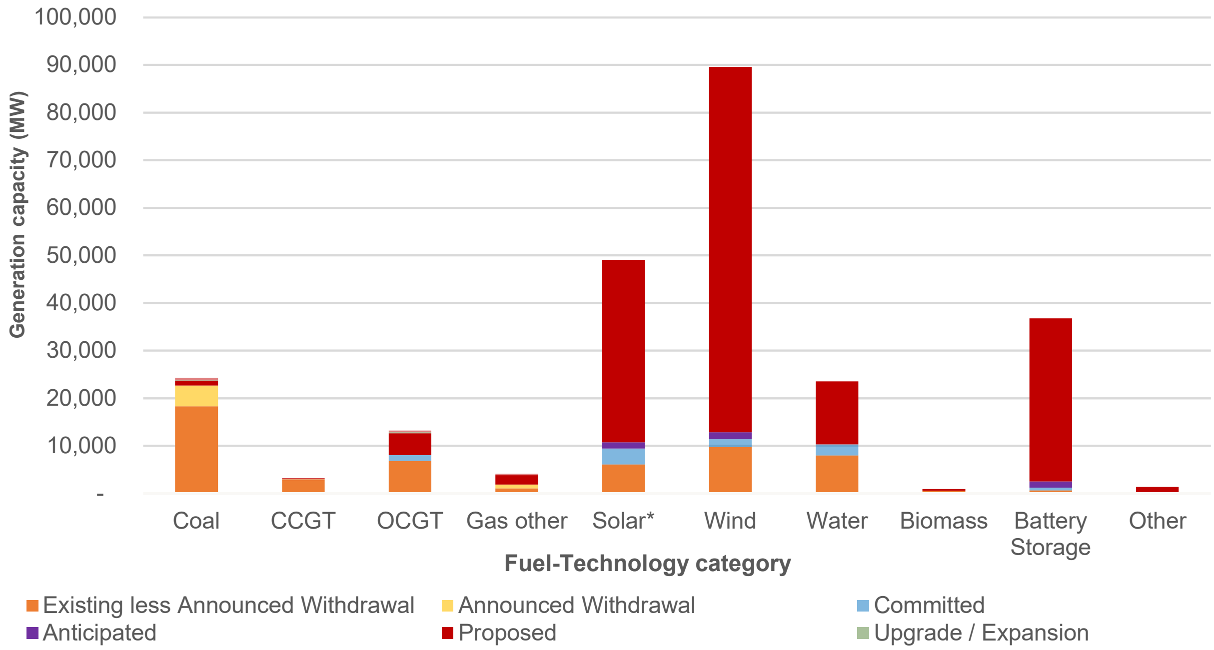
- **Anticipated projects** are defined in a manner consistent with the AER's Cost Benefit Analysis Guidelines and the RIT-T instrument as being a project that "is in the process of meeting at least three of the five criteria for a committed project"[90]. AEMO's process for assessing whether a project is Anticipated is outlined in the *ISP Methodology*. Anticipated projects are assumed to commence operation no earlier than the end of the next financial year (1 July 2024), consistent with the approach applied to Committed* projects.

For reliability assessment purposes, AEMO assumes that Committed projects are sufficiently advanced to meet advised commissioning dates on time, but that the same level of confidence cannot be applied to Anticipated projects. Therefore, Anticipated projects are currently excluded from central ESOO assessments of reliability used for assessing reliability gaps, but complementary analysis identifying the reliability improvement with Anticipated projects developed may also be incorporated. AEMO is currently consulting on the ESOO and Reliability Forecast methodology and may change this implementation for the 2023 ESOO[91].

For ISP purposes, Committed and Anticipated projects with no full commercial use date are assumed to proceed from 1 July 2024 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. In light of feedback received on the Reliability Forecasting Guidelines consultation, AEMO may consider the continued appropriateness of this approach for ISP modelling in the *ISP Methodology* consultation, to be conducted in early 2023.

This Draft 2023 IASR applies the Generation Information November 2022 release. A summary of existing, committed, and anticipated projects included in that release is provided in Figure 34 below.

Figure 34 Generation and storage projects in November 2022 Generation Information page



[90] See Table 15 at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

[91] See https://www.aemo.com.au/consultations/current-and-closed-consultations/2022-reliability-forecasting-guidelines-and-methodology.

Over the 2021-22 financial year there were eight Generation Information updates. AEMO's modelling will reflect the most up-to-date view 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 technology options

Input vintage	December 2022
Status	Draft
Source	• CSIRO: *GenCost 2022-23 Consultation draft* • Aurecon: *2022 Costs and Technical Parameters Review* • GHD: *2018-19 Costs and Technical Parameters Review*
Update process	Dependent on feedback to this Draft 2021 IASR

For the 2024 ISP's capacity outlook modelling, a filtered list of technologies – selected from those provided by Aurecon and CSIRO (GenCost) – are considered, based on technology maturity, resource availability, energy policy settings, and the capacity outlook models' ability to distinguish between technologies.

Table 22 below presents the filtered list of technologies that are proposed to be included in 2023-24 publications.

Table 22 List of candidate generation and storage technology options

List of technologies available in the 2024 ISP	Commentary
CCGT – with CCS	–
CCGT – without CCS	–
OCGT – without CCS, Small unit size	–
OCGT – without CCS, Large unit size	–
Hydrogen-based reciprocating engines	The 2022 ISP model included hydrogen-based OCGTs. Based on Aurecon's 2022 Costs and Technical Parameters Review, AEMO will instead model reciprocating engines, given their lower relative capital and O&M costs, as well as their higher relative efficiency.
Battery storage	AEMO includes storage sizes from 1 to 8 hours in its models. No geographical or geological limits will apply to available battery capacity given its small land footprint.
Solar PV – single axis tracking	–
Solar Thermal Central Receiver with storage (15hr)	The storage component is proposed to be increased from 8hr in the 2022 ISP. Additionally, as discussed in more detail in Section 0, 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 Draft 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 steam	Previous stakeholder feedback on technologies considered within GenCost has suggested the need to pair heat and electricity production. In response, biomass generators in GenCost (and the ISP) now include a heat component. AEMO's capacity outlook modelling does not consider heat demand or location, and as such the heat demand associated with biomass generation (if model choose to build it) will be assumed to exist.
Pumped hydro energy storage (PHES)	AEMO includes variants of PHES, ranging from 8 to 48 hours of storage

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

- New brown coal generation (with or without CCS) – given Victoria's existing policy regarding net zero emissions, this would present an internal inconsistency with that policy requirement. Considering also that there are lower cost dispatchable alternatives offering greater system flexibility, investment risks for new brown coal developments are therefore assumed too high to be considered as a commercially viable development option.
- Advanced ultra-supercritical PC – black coal (with and without CCS) – given the presence of carbon budgets across all scenarios, the existence of lower cost dispatchable alternatives, and informed by generation mixes produced by past ISPs, it is not expected that these technologies will be deployed and are therefore excluded.
- Reciprocating internal combustion engines – reciprocating engines are not modelled due to their high capital cost relative to open cycle gas turbines (OCGTs). Their benefits are not well captured within long-term models, and the differences are not considered material for long-term planning.
- Nuclear generation, including small-modular reactors – currently, Section 140A of the *Environment Protection and Biodiversity Conservation Act 1999*[92] prohibits the development of nuclear installations. In line with the criteria for inclusion of policies in all scenarios laid out in Section 3.1, this is a legislated policy and as such AEMO is including it across all scenarios. Additionally nuclear, as further discussed in the GenCost publication, is a comparatively expensive technology which further supports exclusion.
- 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, nor have they been successfully commercialised in Australia.
- 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 in AEMO's capacity outlook models 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[93]. Given this preference and the relative cost advantage, AEMO models all future solar developments with a SAT configuration to improve model efficiency.
- 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.

Matters for consultation

- Is AEMO's proposed list of candidate technologies reasonable? If not, what changes should be made?

[92] Australian Government, at https://www.legislation.gov.au/Details/C2012C00248.

[93] 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.

3.5.3 Technology build costs

Input vintage	December 2022.
Status	Draft
Source	• CSIRO: *GenCost 2022-23 Consultation draft* • Aurecon: *2022 Costs and Technical Parameters Review* • Entura: *2018 Pumped Hydro Cost Modelling*
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR.

Capital cost trajectories

AEMO's generator 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 has provided estimates of the current capital cost of each generation technology (and supporting technical information). The GenCost projections use CSIRO's GALLM model, which produces capital cost forecasts that are a function of global and local technology deployment.

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.

The build cost projections are given for three GenCost scenarios ("Global NZE by 2050", "Global NZE post 2050" and "Current policies"). These scenarios are described in greater detail in CSIRO's GenCost report[94]. AEMO maps the Draft 2023 IASR scenarios to the Draft 2022-23 GenCost scenarios, as shown in Table 23. The scenario mapping of GenCost scenario to IASR scenario reflects what AEMO considers the best fit to the narratives of AEMO's scenario collection.

Table 23 Mapping AEMO scenario themes to the GenCost scenarios

GenCost scenario	Explanation	AEMO scenario
Current Policies*	Consistent with current commitments to the Paris Agreement, leading to the lowest global emissions reduction ambition and a 2.6°C warming future.	*2.6°C Progressive 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.	*1.8°C Diverse Step Change* and *1.8°C Orchestrated Step Change*
Global NZE by 2050	The most ambitious global emissions reduction scenario, consistent with limiting temperature rises to less than 1.5°C.	*1.5°C Green Energy Exports*

* While *2.6°C 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 35, Figure 36 and Figure 37 present a comparison of Draft GenCost 2022-23's Global NZE post 2050 compared with Final GenCost 2021-22's Global NZE post 2050 build cost projections for selected technologies (if constructed in Melbourne and excluding connection costs). Cost projections for each technology and scenario are available in the accompanying Draft 2023 Inputs and Assumptions Workbook.

As detailed in the accompanying Aurecon report[95], 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%.

[94] At https://doi.org/10.25919/hjha-3y57.

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

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 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 to better account for its impacts. Taking as a starting point Aurecon's figures, GenCost now applies a 'basket of costs' factor to costs 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.

From 2027-28 cost projections are based on modelling results from CSIRO's GALLM only, which provides build cost forecasts that are a function of global and local technology deployment. Between 2023-24 and 2027-28 CSIRO has interpolated values. More information on methodology adjustments from GenCost 2021-22 to GenCost 2022-23 can be found in the Draft GenCost 2022-23 report.

As seen below, the resulting cost projections see a significant increase compared to last estimates over the next few years as a result of this inflationary cycle, especially for wind and storage technologies. As these impacts ease, costs converge closer to previous estimates in the longer term.

Figure 35 2022 vs 2023 Global NZE post 2050: build cost trajectories forecasts for wind and large scale solar

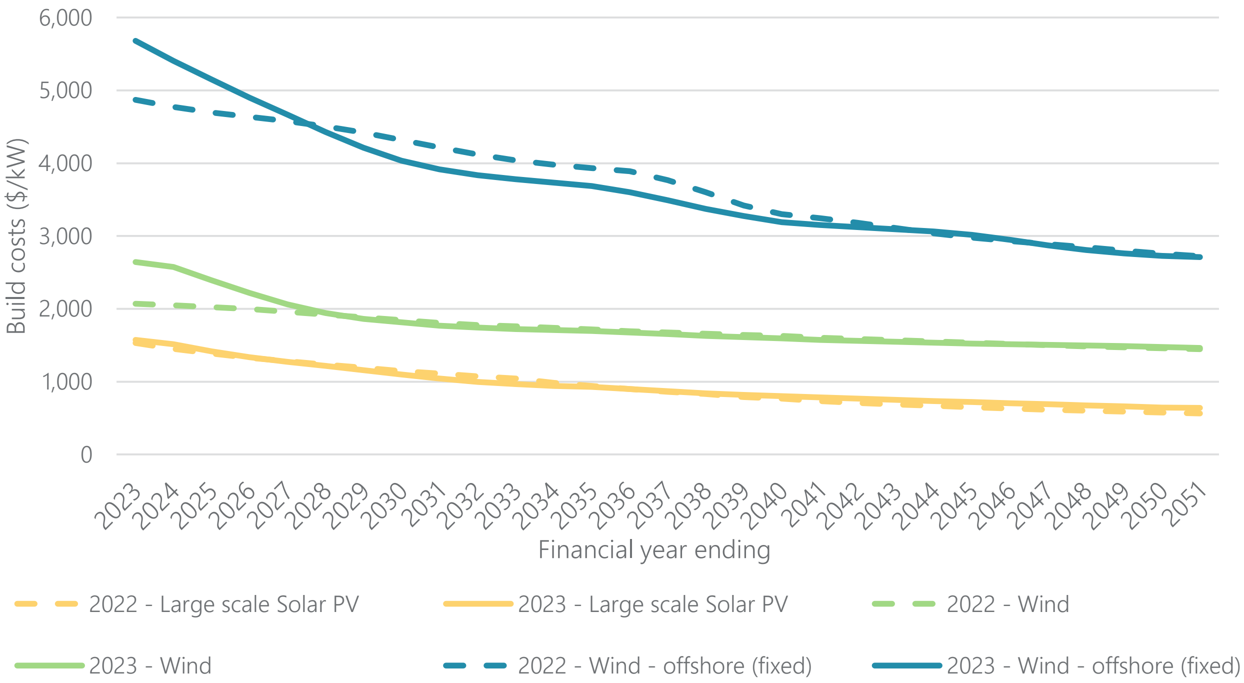


Figure 36 2022 vs 2023 Global NZE post 2050: build cost trajectories forecasts for gas

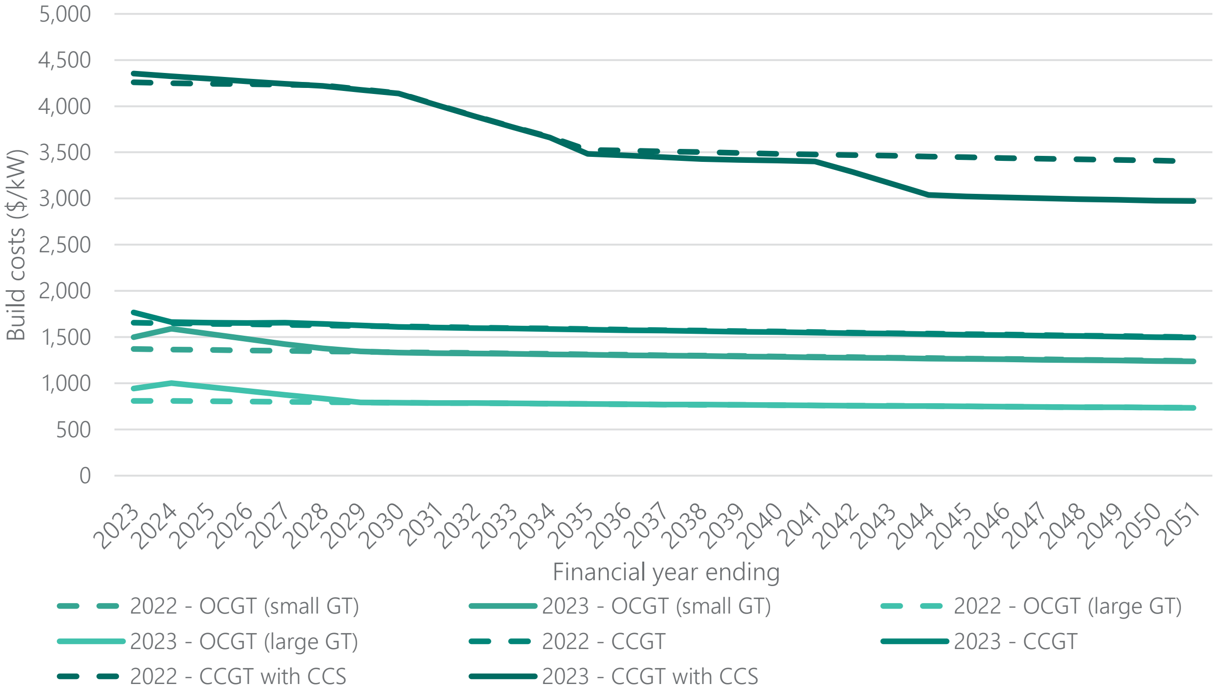
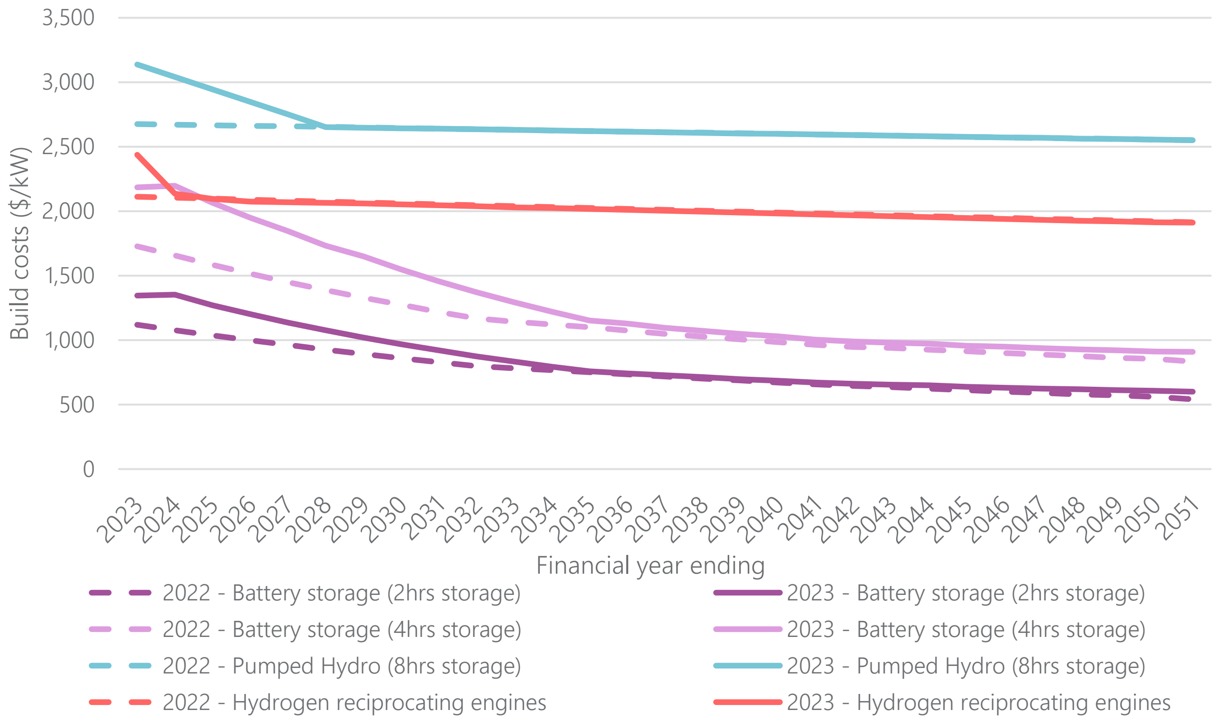


Figure 37 2022 vs 2023 Global NZE post 2050: build cost trajectories forecasts for selected storage and hydrogen



When comparing the capital costs between AEMO's Draft 2023 Inputs and Assumptions Workbook and CSIRO's GenCost trajectories, there are a number of differences that need to be noted:

- GenCost assumes that wind performance improves over time due to technological advancements. In AEMO's modelling, the quality of resource is unchanged over the forecasting horizon, so to account for these improvements the capital costs are reduced by the relative improvement in maximum capacity factor.
- At times, the presentation of real dollars between the two publication is not aligned. Both documents present costs in real June 2022 dollars and as such no adjustment is required.
- In GenCost, 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.
- When comparing GenCost's capital costs in $/kW with Aurecon, note that Aurecon does not include the cost of land in its presentation of $/kW capital costs, whereas this is included by GenCost, and therefore by AEMO[96].

Matters for consultation

- Do you have specific feedback or data on the assumed current and projected costs for new generation and storage technologies?

Wind build costs, site quality deterioration, and efficiency improvements

CSIRO has forecast modest capital cost reductions for wind technologies and improvements in wind turbine efficiencies with larger turbines. This technology efficiency improvement is expected to lead to more energy output for the same installed capacity, lowering the investment cost per unit of energy ($ per MWh).

As applied in previous IASRs, a transformation of CSIRO's cost inputs is therefore required to reflect this increased efficiency trend in AEMO's models. The capital cost of wind technology is adjusted down to effectively mirror the $/MWh cost reductions from turbine efficiency improvements. This adjustment is done to build costs, and as such does not apply to existing generators (and if new wind generation is built, further future adjustments are not applied to it). AEMO considers this a reasonable approach (applying cost reductions and maintaining static renewable energy profiles), given the development of renewable technologies such as wind is targeted largely to provide energy, rather than peak capacity, and therefore accurate representation of the cost per unit of energy is more appropriate than per unit of capacity. This approach provides an appropriate balance of supply modelling complexity and accuracy.

Matters for consultation

- Do you have a view on the described approach to adjust wind build costs?

[96] 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.

Locational cost factors

Input vintage	Updated via the 2022-23 GenCost process, with Draft figures published alongside this IASR.
Source	• GHD: 2018-19 Costs and Technical Parameters Review • Aurecon: 2022 Costs and Technical Parameters Review • AEMO revisions
Update process	Updated based on stakeholder feedback provided on the Draft 2023 IASR.
Get involved	**Draft 2023 IASR consultation**

The Draft IASR 2023 captures updated technology cost component breakdowns, informed by updated data from the Draft GenCost 2022-23. Table 24 presents the most up to date technology cost breakdown ratios. Compared to figures published in the last *Forecasting Assumptions Update*[97], 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).

Table 24 Technology cost breakdown ratios

	Equipment costs	Fuel connection costs	Cost of land and development	Installation costs
OCGT (small GT)	61%	5%	8%	26%
OCGT (large GT)	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 (1hr storage)	82%	0%	5%	13%
Battery storage (2hrs storage)	83%	0%	4%	13%
Battery storage (4hrs storage)	85%	0%	2%	13%
Battery Storage (8hrs storage)	85%	0%	1%	13%
Large scale Solar PV	57%	0%	6%	38%
Solar Thermal (15hrs 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%

To estimate the capital costs of technologies developed in different locations, the locational cost factors provide a multiplicative scalar to the respective generation and storage development component costs (equipment, fuel connection, land and development, and installation). These scalars are derived from regional development cost weightings by cost component, and the technology cost component breakdowns presented above.

The cost groupings (low, medium, and high) consider access to ports, roads and rail, and regional labour costs, but ignore localised environmental, geological, and social drivers which require site-by-site assessments and are difficult to predict pre-feasibility. They also exclude cost premiums that may arise if multiple projects are

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

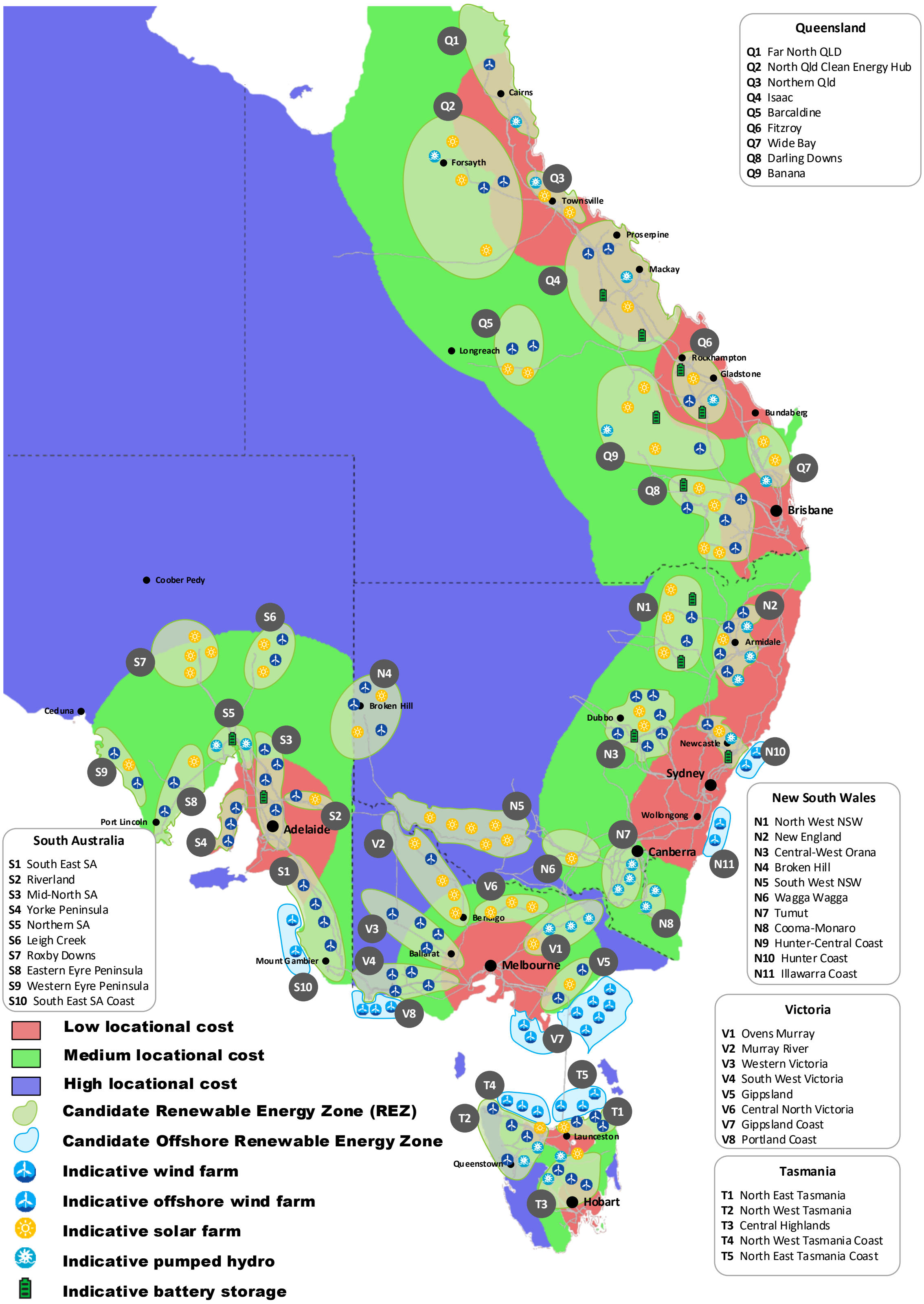
simultaneously competing for scarce resources across the construction supply chain. They remain unchanged from the 2021 IASR assumptions, with the primary source being the GHD 2018-19 review.

Table 25 and Figure 38 presents the estimated NEM locational cost factors.

Table 25 NEM locational cost factors

Region	Grouping	Equipment costs	Fuel connection costs	Cost of land and development	Installation costs	O&M costs
Victoria	Low	1.00	1.00	1.00	1.00	1.00
	Medium	1.03	1.03	1.00	1.03	1.03
	High	1.05	1.05	1.00	1.05	1.05
Queensland	Low	1.00	1.00	1.00	1.00	1.00
	Medium	1.05	1.10	1.00	1.15	1.12
	High	1.10	1.21	1.00	1.31	1.25
New South Wales	Low	1.00	1.00	1.00	1.00	1.00
	Medium	1.05	1.07	1.00	1.10	1.08
	High	1.10	1.16	1.00	1.20	1.17
South Australia	Low	1.00	1.00	1.00	1.00	1.00
	Medium	1.05	1.10	1.00	1.15	1.12
	High	1.10	1.20	1.00	1.29	1.24
Tasmania	Low	1.00	1.00	1.00	1.00	1.00
	Medium	1.05	1.07	1.00	1.10	1.09
	High	1.10	1.14	1.00	1.21	1.17

Figure 38 Locational cost map



† The REZ boundaries for N5 and N9 are indicative and aligned with the draft declaration for these REZs.
‡ EnergyCo is in the early stages of planning for a new REZ in the Illawarra region of New South Wales, as set out under the New South Wales Electricity Infrastructure Act 2020. This REZ is not shown because they are not yet geographically defined.

The accompanying Draft 2023 Inputs and Assumptions Workbook provides additional details of these cost factors, including the resulting regional technology cost adjustment factors.

Matters for consultation

- Do you agree with continuing to use the same regional cost factors as the previous ISP? If not, please provide suggestions for improvements or alternative data sources.
- Are there any other considerations that should be factored into these regional cost factors?

3.5.4 Technical and other cost parameters (new entrants)

Input vintage	May 2022.
Status	Draft
Source	• Aurecon: *2022 Costs and Technical Parameters Review* • GHD: *2018-19 Costs and Technical Parameters Review*
Update process	Updates will be dependent on feedback received on this 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).

These parameters are updated annually to reflect the current trends and estimates of future cost and performance data of new technologies, and are published in the Draft 2023 Inputs and Assumptions Workbook as well as in the supporting material from Aurecon. For 2023-24 modelling, AEMO has updated these parameters where they have been provided by Aurecon, or through the GenCost process more generally.

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 builds will decommission at the end of their respective technical lives, given assumptions of each installed technology. 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 for both technologies. 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.

Matters for consultation

- Do you agree with these proposed technical parameters, as well as fixed and variable operating and maintenance costs of new entrant technologies? If not, please provide suggestions for improvements.

3.5.5 Storage modelling

Input vintage	Updated through the 2022-23 Draft GenCost Consultation process, finalised in December 2022
Status	Draft
Source	• Aurecon: *2022 Costs and Technical Parameters Review* • CSIRO: *GenCost 2022-23 Draft report* • Entura: *2018 Pumped Hydro Cost Modelling* • Hydro Tasmania information on Cethana project
Update process	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.

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

Storage developments are limited by the sub-regional build limits presented in the accompanying Draft 2023 Inputs and Assumptions Workbook. For pumped hydro technologies (see the PHES build limits section below), these limits are informed by sub-regional limits within the 2018 Entura report[98], modified where appropriate to reflect the latest generator development announcements in Generation Information (or announced government development policies). This ensures that the sub-regional limits at least provide sufficient capability to reflect announced development capabilities.

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.

[98] 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.

Pumped hydro energy storage (PHES)

AEMO includes PHES options equivalent to eight, 24, and 48 hours of energy in storage across the NEM. Six- and 12-hour PHES options (identified in GenCost) are consolidated into an eight-hour option to be aligned with the New South Wales Infrastructure roadmap and to reflect likely future PHES developments across the NEM.

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. Other announced developments such as the Borumba Dam and Pioneer-Burdekin projects in Queensland will be considered.

This portfolio of candidates complements deep storage initiatives (such as Snowy 2.0), and existing traditional hydro schemes.

PHES build costs

Locational costs for these pumped hydro storage sizes consider capital cost estimates from Entura, and previous feedback received during previous ISPs which led to pumped hydro cost estimate improvements.

Capital costs will reflect the PHES projects in the Draft GenCost 2022-23. These are provided in detail in the accompanying Draft 2023 Inputs and Assumptions Workbook. For existing, committed, and anticipated projects, capital costs are not applied (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).

In line with all other new entrant technologies, sub-regional locational cost factors are applied to PHES options. Unlike those discussed in Section 3.5.3, cost factors have been derived based on their natural resource and cost advantages and have been sourced from the Entura report, and remain consistent with the 2021 IASR.

Table 26 below presents the pumped hydro energy storage locational cost factors. Tasmanian PHES facilities are at least approximately 25% lower cost than Victorian alternatives, and the cost advantages of pumped hydro in Tasmania increases for deeper storage sizes. These factors apply only to generic Tasmania PHES projects, as a specific cost is assumed for the Cethana project – which uses the midpoint of the cost range estimated by Hydro Tasmania of $1.8m per MW[99].

Table 26 Pumped hydro energy storage locational cost factors

ISP sub-region	Region	PHES: 8hrs	PHES: 24hrs	PHES: 48hrs
Northern Queensland (NQ)	QLD	1.01	0.88	0.86
Central Queensland (CQ)	QLD	1.01	0.88	0.86
Gladstone Grid (GG)	QLD	N/A	N/A	N/A
South Queensland (SQ)	QLD	1.11	0.96	0.88
Northern New South Wales (NNSW)	NSW	0.88	0.82	0.62
Central New South Wales (CNSW)	NSW	1.02	1.08	1.12
South New South Wales (SNSW)	NSW	1.04	1.00	0.91
Sydney, Newcastle, Wollongong (SNW)	NSW	N/A	N/A	N/A
Victoria (VIC)	VIC	1.00	1.00	1.00
Central South Australia (CSA)	SA	1.35	1.67	N/A

[99] See page 6 of https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2021/iasr/submissions/hydro-tasmania.pdf.

ISP sub-region	Region	PHES: 8hrs	PHES: 24hrs	PHES: 48hrs
South East South Australia (SESA)	SA	N/A	N/A	N/A
Tasmania (TAS)	TAS	0.75	0.62	0.46

PHES build limits

AEMO applies sub-regional build limits for pumped hydro expansion candidates to reflect the sub-regional configuration of the capacity outlook models. Limits are based on sub-regional estimates detailed by Entura. AEMO has adjusted the limits to consider proposed projects across NEM regions while maintaining Entura's sub-regional breakdown. Any specific, named projects are included, but subtracted from the relevant limit to avoid relative expansion of the limit.

The pumped hydro sub-regional limits are shown in Table 27. The limits published in the 2021 IASR for CNQ and SA have been further disaggregated into separate limits for NQ and CQ, and CSA and SESA sub-regions respectively, to align with proposed changes to the sub-regional topology (see Section 3.10.1 for further details).

Table 27 Pumped hydro sub-regional limits (in megawatts of generation capacity)

ISP sub-region	Region	PHES: 8hrs	PHES: 24hrs	PHES: 48hrs
Northern Queensland (NQ)	QLD	1,250	278	111
Central Queensland (CQ)+	QLD	1,000	-	89
Gladstone Grid (GG)	QLD	-	-	-
South Queensland (SQ) +	QLD	1,350	-	300
Northern New South Wales (NNSW)	NSW	1,275	500	500
Central New South Wales (CNSW)	NSW	1,750	235	83
South New South Wales (SNSW)*	NSW	2,500	583	167
Sydney, Newcastle, Wollongong (SNW)	NSW	-	-	-
Victoria (VIC)	VIC	2,700	700	400
Central South Australia (CSA)	SA	825	200	-
South East South Australia (SESA)	SA	-	-	-
Tasmania (TAS)^	TAS	1,625	1,200	371

+ The Central Queensland and South Queensland limits do not include the Borumba Dam (2GW) and Pioneer-Burdekin (5GW) projects, which will be modelled as specific projects.
* 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[100]. The limits have been further adjusted to provide sufficient capacity to reflect five projects that have been awarded funding under the NSW Pumped Hydro Recoverable Grants Program[101].
- 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 that may not be mutually exclusive and is aligned reasonably with Tasmanian PHES Generation Information submissions.

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

[101] More information available at https://www.nsw.gov.au/media-releases/pumped-hydro.

- Where applicable, PHES limits have been adjusted above Entura estimates to ensure proposed projects in Generation Information submissions can be accommodated.

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 Draft 2022-23 report. Battery storage degradation, which Aurecon indicates is 1.8% annually, is not able to be modelled explicitly due to computational complexity (particularly in capacity outlook models). While AEMO does not model this factor explicitly, AEMO reduces the storage capacity of all battery storage by 16% which is an estimate of the average storage capacity over the battery life 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.

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 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 proposes to modify 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.

Matters for consultation

- Do you have a view on the cost assumptions for pumped hydro?
- Do you consider the adjustments to pumped hydro limits reasonable?
- Do you consider the proposed approach to model battery storage technologies appropriate?
- Do you consider the proposed change to solar thermal technologies appropriate?

3.6 Fuel and renewable resource assumptions

3.6.1 Fuel prices

Gas prices

Input vintage	December 2022
Status	Draft
Source	Lewis Grey Advisory
Update process	Updates will be dependent on feedback received on this Draft 2023 IASR.

AEMO sourced natural gas price forecasts from consultant Lewis Grey Advisory (LGA). 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 international gas pricing, its influence on Australian gas prices through LNG netback pricing, and the local level of competition[102].

No scenario changes current market settings regarding gas reservation on the Australian east coast. Should market settings change, AEMO will consider what impact that may have on gas prices at that time, with greater information regarding the potential impact to gas prices and consumers.

At the time of writing this Draft 2023 IASR, the Federal Government has recently proposed, and is debating, the introduction of gas (and coal) price caps, to apply for a 12-month period. The influence these new arrangements will have on wholesale or retail gas prices for domestic consumers, including industrial and gas generation users, is unclear, and has not been considered in this forecast. AEMO will consider this in more detail once legislative positions and implementation processes are clear.

Figure 39 compares industrial gas price forecasts at Melbourne across the scenarios. All other regions are provided in the Draft 2023 Inputs and Assumptions Workbook. For the *1.8°C Orchestrated Step Change* scenario, Figure 40 demonstrates the relationship between regions. More information on the derivation of these forecasts is provided in the LGA report.

[102] Gas price forecasts are derived from a game theory model that simulates competitive pricing outcomes suitable to understand contract pricing. The price projections do not attempt to model the full variance of the spot market. The spot market can sometimes experience pricing at very high levels when there is little uncontracted gas available and sometimes at very low levels, even below breakeven, when there is a surplus of uncontracted gas available.

Figure 39 Non-oil indexed industrial gas price forecasts – Melbourne ($AUD / GJ, July 2022 real dollars)

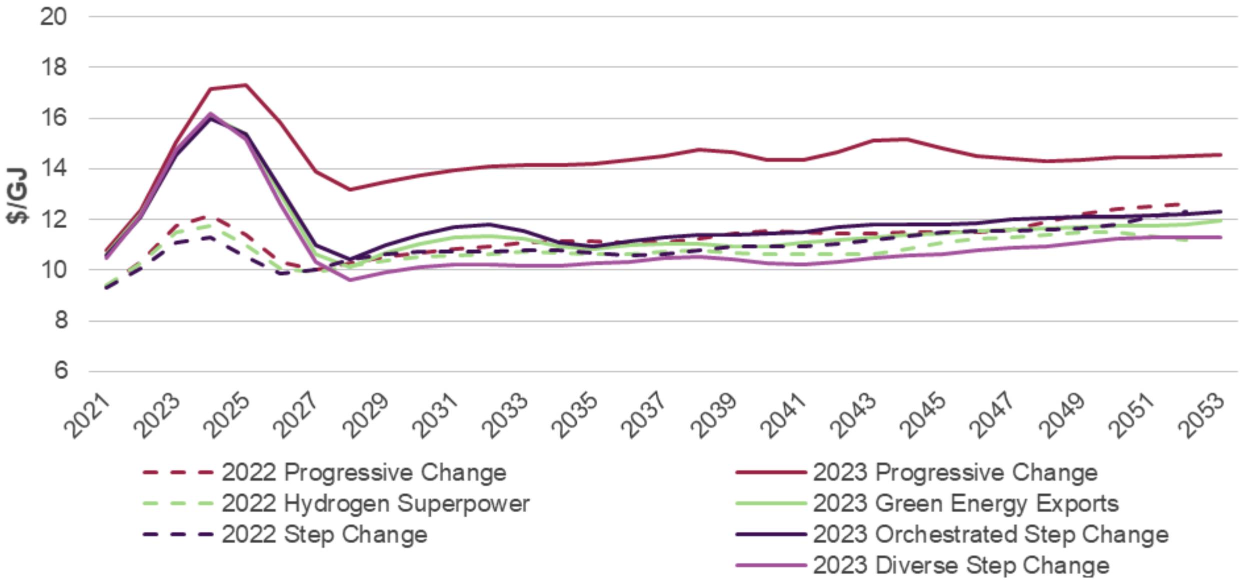
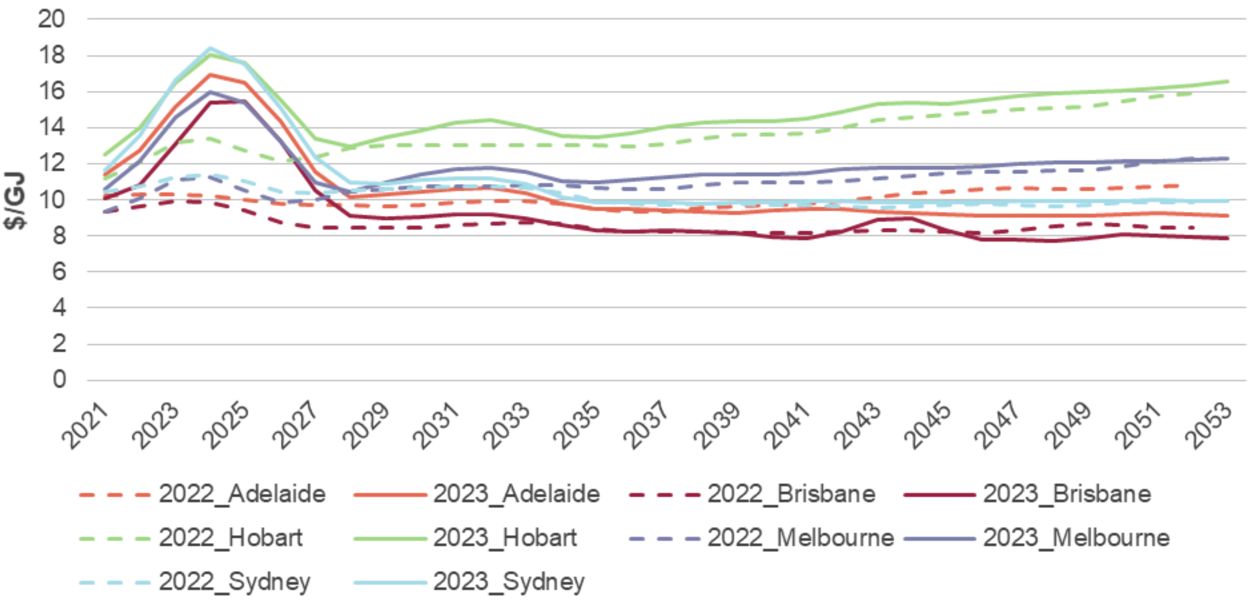


Figure 40 Non-oil indexed industrial gas price forecasts – *1.8°C Orchestrated Step Change* scenario ($AUD / GJ, July 2022 real dollars)



Both figures feature an initial price rise across the next few years, reflecting the current global economics that were not foreseen in the previous gas price forecast. From this point, the price forecasts feature a decline down to near-2021 levels by 2027, consistent with BIS Oxford Economics and ACCC LNG Netback price forecasts[103] which feature near-term global high LNG prices, and assuming an expected return to normal global conditions by around 2026-27. The long-term gas price forecasts are similar to those provided in the previous 2021 IASR, across both scenarios and locations.

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

The scenarios differ based on longer term underlying costs of supply for each scenario, as well as exchange rates and 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.

These gas price forecasts reflect average prices offered across the region rather than marginal prices; The ISP and other AEMO publications focus on total system cost rather than marginal costs; average prices are therefore more important to capture for AEMO's purposes.

The gas prices associated with each gas-powered generator (GPG) are provided in the Draft 2023 Inputs and Assumptions Workbook. The costs include regional pricing, considering the supply options and the relevant cost of pipeline transmission. They also apply a further adjustment based on transmission to the actual GPG plant, and influence of contracts.

Coal prices

Input vintage	December 2022
Status	Draft
Source	Wood Mackenzie and BIS Oxford Economics
Update process	Updates will be dependent on feedback received on this Draft 2023 IASR.

AEMO engaged external consultant BIS Oxford Economics to provide a forecast for Newcastle export thermal coal prices for each scenario, as a strong influence on local coal prices for electricity generation considering the unprecedented volatility in international energy commodities. The export price forecast was used to establish the domestic equivalent cost for black coal generators in Queensland and New South Wales, particularly for those that are export exposed. The domestic forecast reflects a blend of the export price forecast converted to domestic coal quality, coupled with Wood Mackenzie's forecast from 2021.

Some coal generators, for example the Victorian brown coal fleet, are not considered exposed to export markets, and these generators use Wood Mackenzie's 2021 forecast[104].

The fuel price forecasts for all generators, as forecast from either BIS Oxford Economics' forecast or Wood Mackenzie's, are provided in the figures below, and provided in more detail in the Draft 2023 Inputs and Assumptions Workbook.

At the time of writing this Draft 2023 IASR, the Federal Government has recently proposed, and is debating, the introduction of coal (and gas) price caps, to apply for a 12-month period. The influence these new arrangements will have on coal generator fuel costs is unclear, and has not been considered in this forecast. AEMO will consider this in more detail once legislative positions, and implementation processes, are clear.

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

Figure 41 Coal price forecast for existing generators – New South Wales – *1.8°C Orchestrated Step Change*

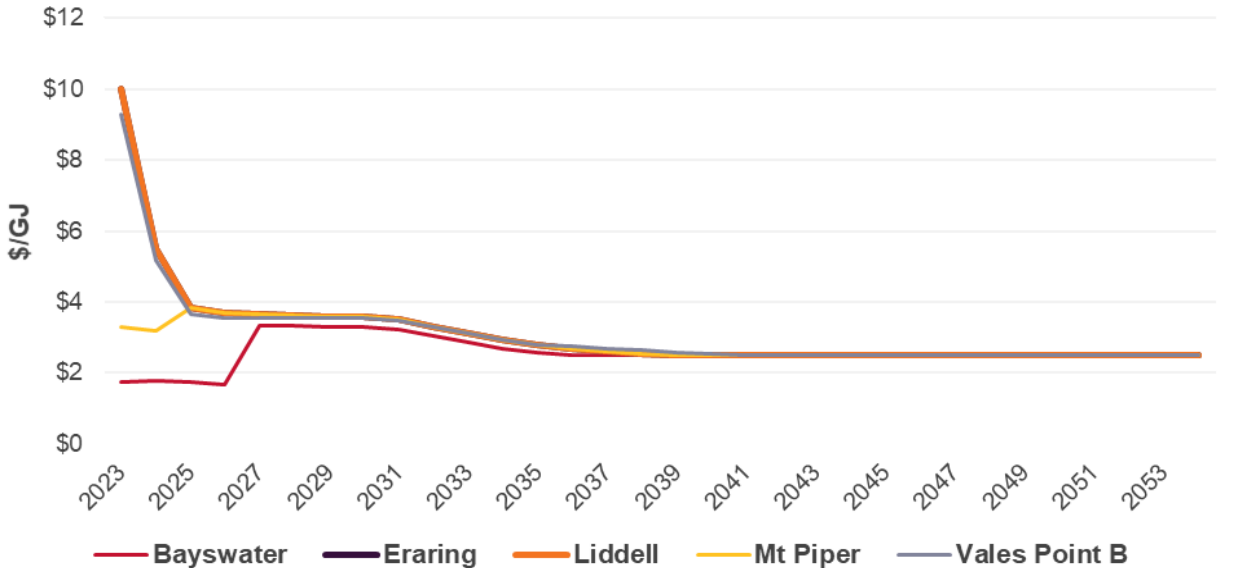
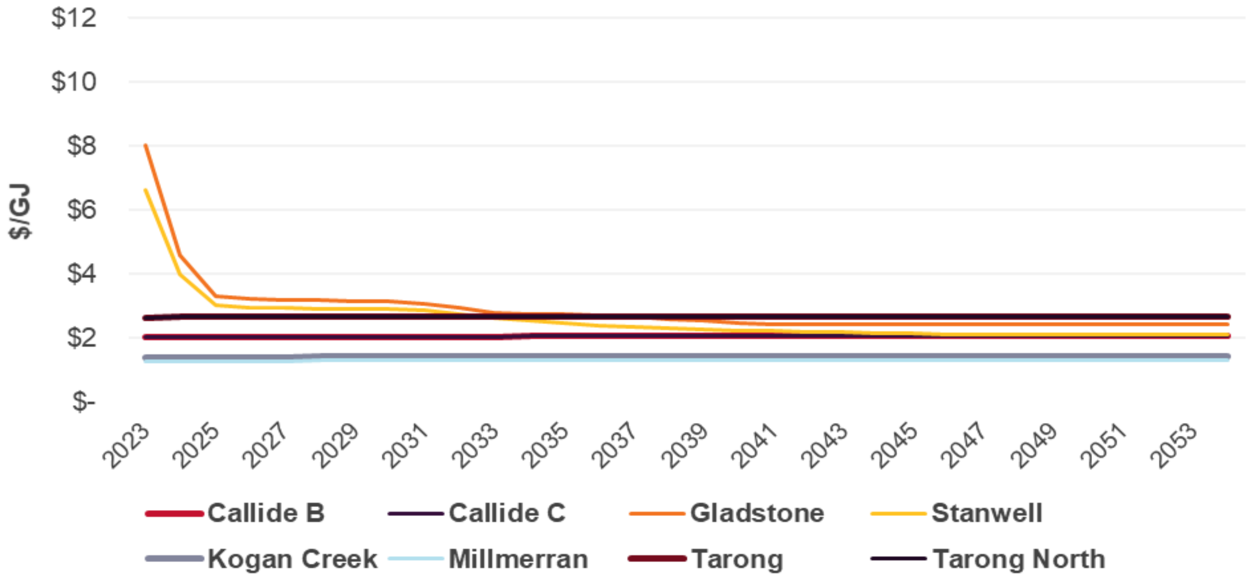


Figure 42 Coal price forecast for existing generators – Queensland – *1.8°C Orchestrated Step Change*



Matters for consultation

- Do you have any feedback on the assumed coal and gas price trajectories?

3.6.2 Renewable resources

Input vintage	July 2022
Status	Current view
Source	• Solcast irradiance and PV output analysis • BoM • AEMO SCADA data • Other relevant reanalysis providers
Update process	To be updated to reflect the 2022-23 reference year

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

- Wind speed (at a relevant hub height) and other relevant reanalysis data.
- 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. Wind generation 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 profiles for existing, committed and anticipated VRE generators is provided in the *ESOO and Reliability Forecast Methodology*[105].

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 transmission infrastructure and announced solar generation projects within each REZ.

Following stakeholder feedback received during the 2022 ISP, AEMO is considering methodological improvements with regards to how representative wind and solar sites in each REZ are selected. The proposed 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. Indicative capacity factors representing the resource potential for each REZ and technology using this new methodology are provided in the Draft 2023 Inputs and Assumptions Workbook, which will be further detailed and consulted on in the 2024 *ISP Methodology Consultation*.

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

3.7 Financial parameters

3.7.1 Discount rate

Input vintage	December 2022
Status	Draft
Source	Synergies Economic Consulting
Update process	Updates will be dependent on feedback received on this Draft 2023 IASR.

The AER's Cost Benefit Analysis Guidelines 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 typically uses the same discount 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 this Draft 2023 IASR, Synergies Economic Consulting was again engaged to provide updated discount rate estimates, to reflect economic developments and changes in financial parameter settings since the 2022 ISP.

Table 28 below presents the proposed values in this Draft 2023 IASR to be used in the 2024 ISP, as well as the 2022 ISP for comparison.

Table 28 Pre-tax real discount rates

	Central estimate	Lower bound	Upper bound
2022 ISP	5.5%	2.0%	7.5%
Draft 2023 IASR	7.0%	4.0%	9.0%

Since the 2021 IASR, estimates have increased, as a result of strong inflationary pressures with an associated sharp increase in the risk-free rate (government long-term bond yields) and a higher debt premium. Further details of the discount rates and the assumptions that underpin these values can be found in the Synergies report[106]. This report, published with the final 2021 IASR, includes details on the calculation methodologies of key discount rate components, including the market risk premium.

Synergies noted that the average investor would seek a stable return on equity over time regardless of the interest rate cycle. To accommodate this preference, the calculation method for the market risk premium applied an average of the Wright and Ibbotson backward-looking approaches. By incorporating the Wright method within a weighted-average approach, the discount rate increased from Synergies' original draft recommendation.

While interest rates are near historically low levels, the 10-year Australian government bond yield has been in decline for the past 40 years, since peaking in 1982, and therefore applying an approach that respects a balanced approach to the required market risk premium for investors we consider to be reasonable. 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

106 Available at https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

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.

The lower bound rate is based on the most recent AER determination, Transgrid Draft decision[107]. This is in accordance with the AER's CBA guidelines. AEMO notes that the AER is due to publish the Rate of Return Instrument (RORI) in February 2023. AEMO may consider the final RORI prior to finalising the IASR.

Matters for consultation

- Do you have a view on the proposed discount rates that will be applied in the 2024 ISP?
- Do you consider that the discount rate is appropriate for private sector investment, consistent with the guidance in the CBA Guidelines?

3.7.2 Value of customer reliability

Input vintage	December 2021
Status	Current view
Source	• AER: 2019 Values of Customer Reliability Review • AER Values of Customer Reliability – Annual adjustment – December 2021
Update process	Updates process dependent on feedback received on this Draft 2023 IASR.

A Value of Customer Reliability (VCR, usually expressed in dollars per kilowatt-hour [kWh]) reflects the value different types of customers place on having 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 2021[108]. AEMO has applied these adjustments to the customer load-weighted state VCRs that were published by the AER in December 2019[109] and used for the 2022 ISP; these are summarised in Table 29 below.

Table 29 AER Values of distribution and transmission customer load-weighted VCR by state

	New South Wales	Victoria	Queensland	South Australia	Tasmania
VCR ($/MWh)	46,025	45,031	43,742	47,238	35,142

Matters for consultation

- Do you have a view on the VCR to be applied in the 2024 ISP?

[107] AER (2022), Transgrid Transmission Determination 2023 to 2028 (1 July 2023 to 30 June 2028), Draft Decision, Attachment 3, Rate of Return, September.

[108] At https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability/update.

[109] 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 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.

3.8.1 Temperature change impacts

Input vintage	January 2019 (CMIP5)
Status	Draft
Source	BoM, CSIRO, ESCI (see ClimatechangeinAustralia.gov.au)
Update process	Subject to the infrequent provision of appropriately tailored climate science.

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[110]. For more information on this, see Appendix A.2.3 of the Electricity Demand Forecasting Methodology[111].

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[112], 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 43 shows the change to summer maximum temperature anomaly ranges expected for Southern Australia under two atmospheric greenhouse gas concentrations relevant to the scenario definitions (RCP4.5 - RCP8.5)[113]. 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.

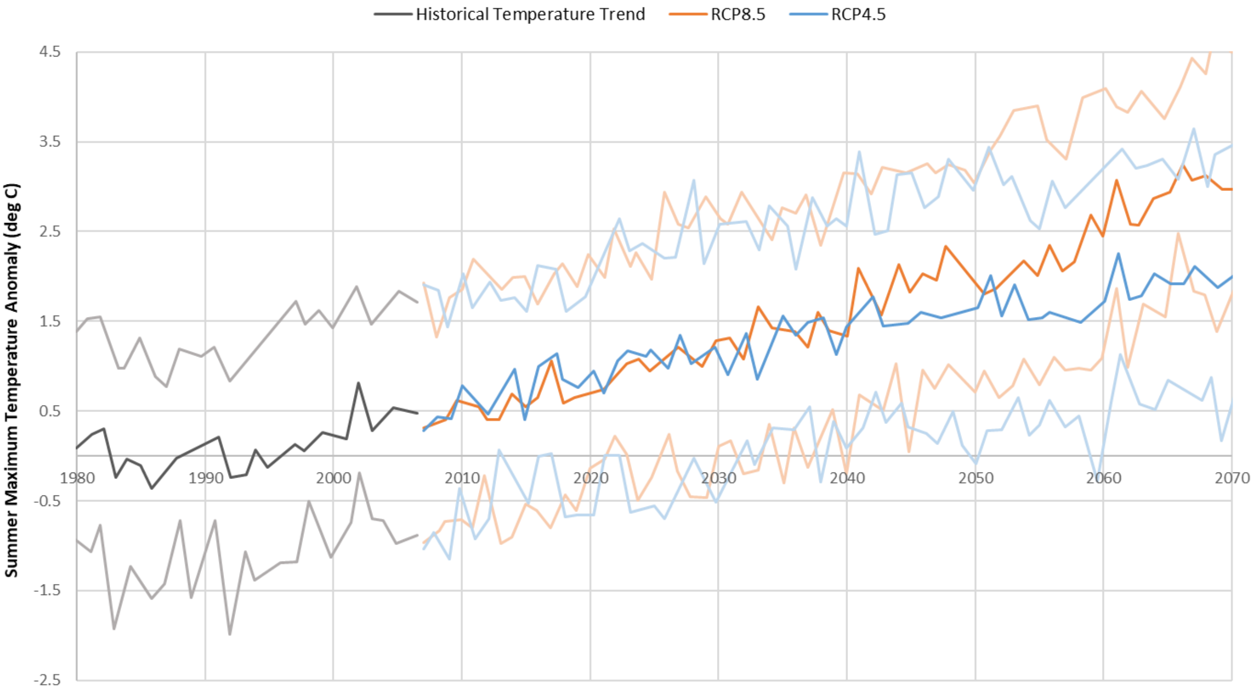
[110] At https://www.climatechangeinaustralia.gov.au/en/climate-projections/explore-data/data-download/station-data-download/.

[111] 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.

[112] See https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/network-data/transmission-equipment-ratings.

[113] Data sourced from www.climatechangeinaustralia.com.au.

Figure 43 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 of REZ design reports.

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). After the 2018 ISP, the REZ candidates have been continuously refined through the 2020 ISP and the 2022 ISP consultation process. AEMO now proposes another evolution to the candidate REZs.

This section describes the parameters around REZs for further refinement for the 2024 ISP. These parameters are:

- Geographic boundaries – Section 3.9.1.
- Resource limits – Section 3.9.2.
- Transmission limits – Section 3.9.3.
- REZ augmentations and network costs – Section 3.9.4.

3.9.1 REZ geographic boundaries

Input vintage	December 2022
Status	Draft
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.
Update process	Updates will be dependent on feedback received on this Draft 2023 IASR.

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[114] .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 44).
- 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.

Candidate REZ identification

AEMO engaged consultants DNV-GL to provide information on the resource quality for potential REZs in the 2018 ISP[115]. The wind resource quality assessment was based on mesoscale wind flow modelling at a height of 150 m above ground level (typical wind turbine height). The latest installed utility-scale hub heights range from 50m to 150m[116], and as such 150m is considered a valid assumption for onshore and offshore wind farms. As rotor diameters increase, assumptions around hub heights may need to be revised in the future.

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

[115] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Multi-Criteria-Scoring-for-Identification-of-REZs.pdf.

[116] See Aurecon (2022) for a discussion on latest trends, at https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation.

Solar resource quality was assessed using Global Horizontal Irradiance (GHI) and Direct Normal Irradiance (DNI) data from the BoM. The work undertaken for the ISP is not intended in any way to replace any site-specific assessment of potential wind and solar farm sites by developers.

These 10 development criteria were used to identify candidate REZs:

- **Wind resource** – a measure of high wind speeds (above 6 m/s).
- **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 the development criteria with feedback received throughout the 2018, 2020 and 2022 ISP consultation, AEMO proposes 43 candidate REZs for inclusion in the 2024 ISP – two more than in the 2022 ISP.

Proposed 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 proposed:

- 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[117].
- AEMO has aligned the boundaries for the Gippsland Coast REZ to the area published in the Commonwealth Notice of proposal[118] to declare an area – Bass Strait off Gippsland. As the proposed area is under consultation, AEMO will update this as required for the final IASR once the final area has been published.
- The New South Wales Government is in the early stages of planning for a new REZ in the Illawarra region of New South Wales, as set out in the *New South Wales Electricity Infrastructure Act* 2020. AEMO will continue to engage with the New South Wales Government in the coming months to determine appropriate modelling information for Illawarra REZ.

[117] New South Wales, Hunter-Coast Renewable Energy Zone draft declaration, at https://www.energyco.nsw.gov.au/sites/default/files/2022-09/hcc-rez-draft-order-declaration.pdf.

[118] Victoria, 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.

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 capacity, but which may also have low quality resources.

For this reason, resource limits, resource quality, and network capacity are also determined for areas of the network that have existing capacity, or where generation retirement is expected resulting 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 proposed for non-REZs since the 2022 ISP:

- Reduce the area of the New South Wales non-REZ to exclude the area surrounding the Bayswater Power Station. The area surrounding Bayswater Power Station is included in the new Hunter-Central Coast REZ.
- Update the connection cost for wind and solar – see Section 3.9.4.

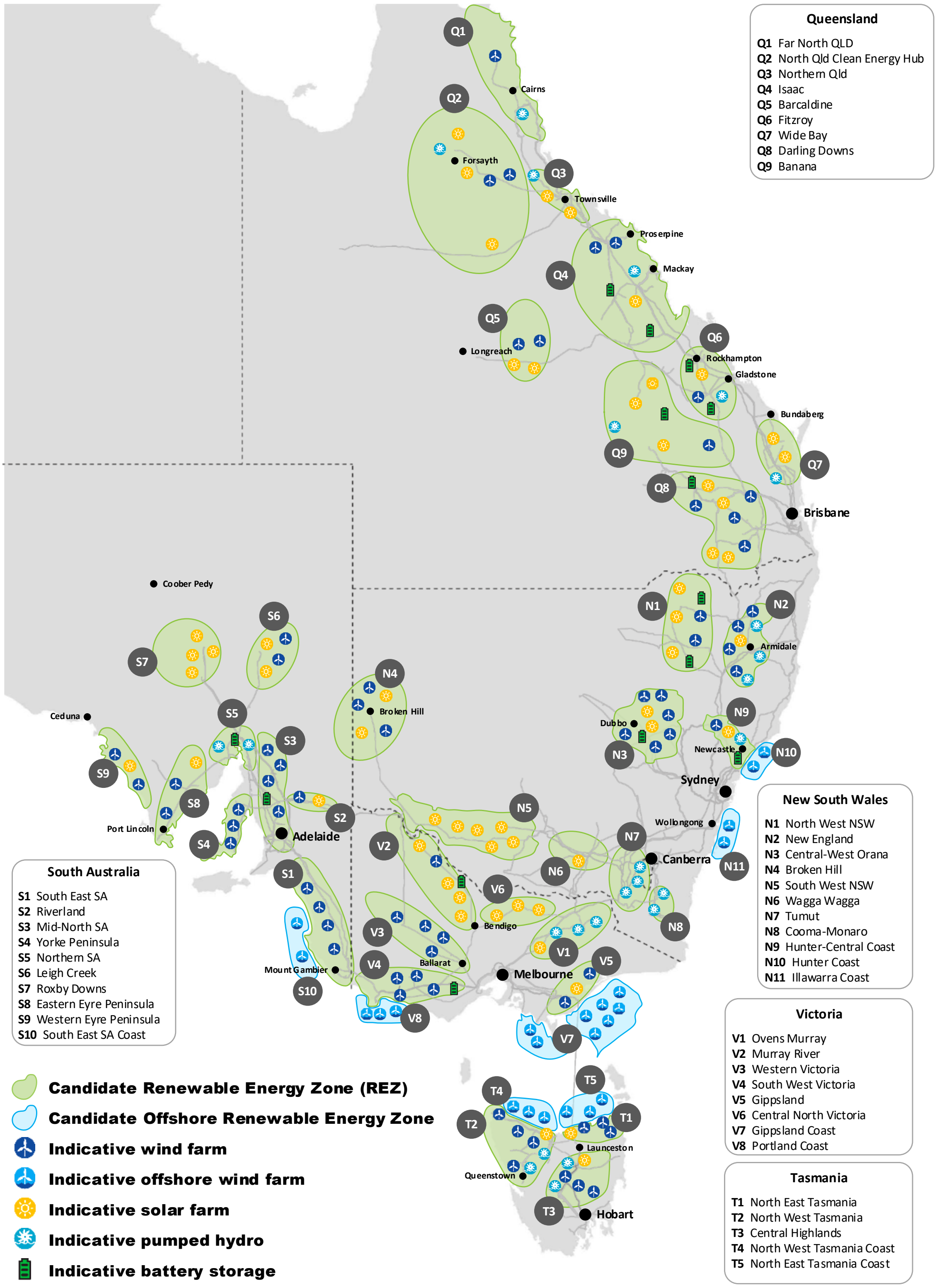
Matters for consultation

- The theoretical design of a counter-factual where no transmission is built is an influential part of the ISP cost-benefit analysis framework. Do you have any suggestions to enhance the approach to modelling a future without any transmission projects?

Propose candidate REZ geographic boundaries

Figure 44 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 44 Renewable Energy Zone map



† The REZ boundaries for N5 and N9 are indicative and aligned with the New South Wales Government's draft declaration for these REZs.
‡ EnergyCo is in the early stages of planning for a new REZ in the Illawarra region of New South Wales, as set out under the New South Wales Electricity Infrastructure Act 2020. This REZ is not shown because they are not yet geographically defined.
* AEMO has aligned the boundaries for the Gippsland Coast REZ to the area published in the Commonwealth Notice of proposal to declare an area – Bass Strait off Gippsland. As the proposed area is under consultation, AEMO will update this as required for the final IASR once the final area has been published.

Matters for consultation

- Do you have specific feedback on the proposed updates to the candidate REZs?

3.9.2 REZ social licence and resource limits

Input vintage	December 2022
Status	Draft
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.
Update process	Updates will be dependent on feedback received on this Draft 2023 IASR.

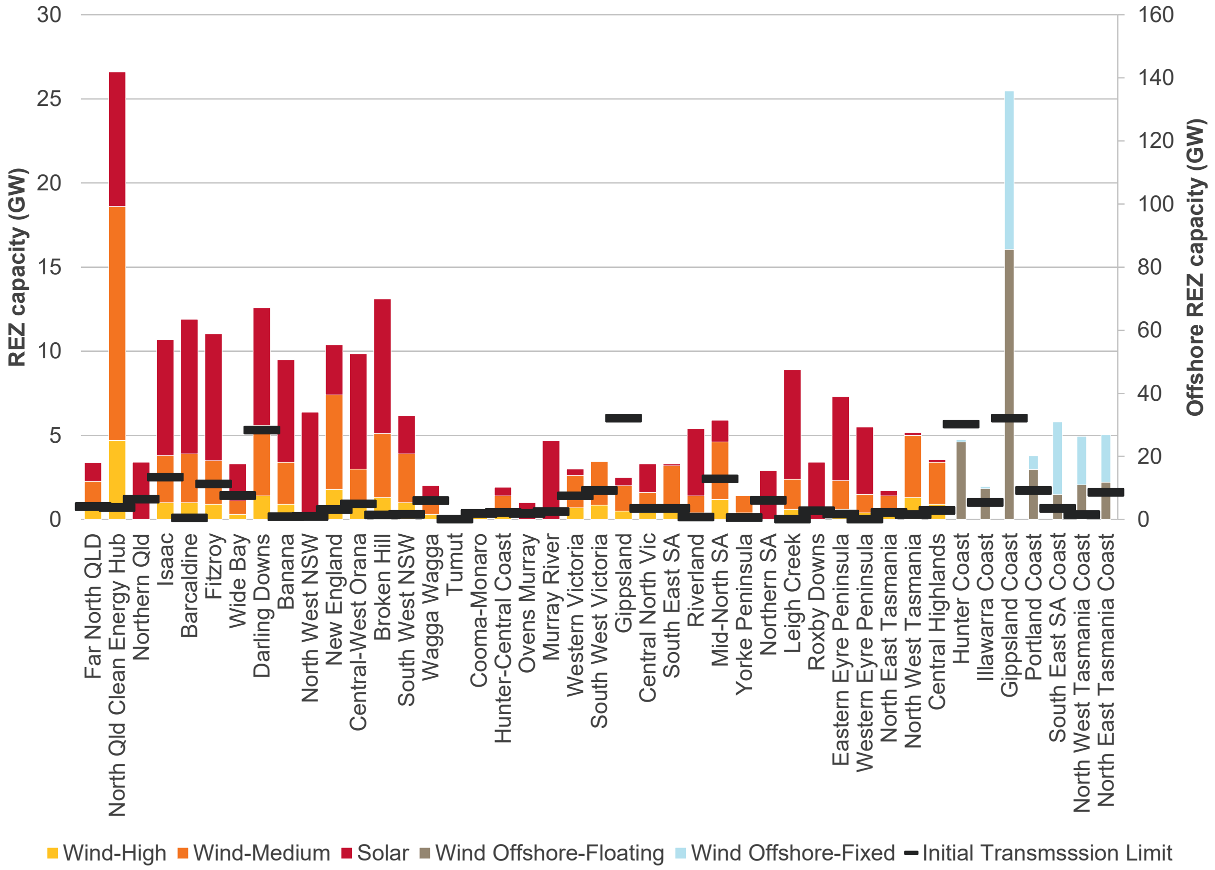
REZ resource limits reflect the total available land for renewable energy developments, expressed as installed capacity (MW). The availability is determined by existing land use (for example, agriculture) and environmental and cultural considerations (such as national parks), as well as the quality of wind or solar irradiance.

AEMO proposes the following changes since 2022 ISP:

- In the 2022 ISP, AEMO updated the REZ boundaries for the South West NSW REZ aligned with geographical area of the SWNSW REZ in Schedule 1 of the draft REZ declaration under the EII Act. For this Draft 2023 IASR, this REZ is now updating all relevant parameters aligned with the update to the geographical area including the update of the resource limit.
- Include resource limits for Hunter-Central Coast REZ
- Update to 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 45, and provided in detail in the Draft 2023 Inputs and Assumptions Workbook.

Figure 45 REZ resource limits and Initial transmission limits



Note: Offshore REZ capacities use right axis scale

Onshore wind farm resource limits

Maximum REZ wind generation resource limits have initially been calculated based on a DNV-GL[119] 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.

The initial resource limits were adjusted in the 2020 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[120] (see Section 3.5.1 for more information on classification of generation projects). No changes are proposed 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 proposed resource limits are shown in Figure 45. The resource limits are further detailed in the Draft 2023 Inputs and Assumptions Workbook.

[119] 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.

[120] 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 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[121].

No changes are proposed to the existing REZ resource limits for 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 proposed resource limits are shown in Figure 45. The resource limits are further detailed in the Draft 2023 Inputs and 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 proposes the following changes from the 2022 ISP for offshore REZs:

- Inclusion of an additional offshore REZ for the North East Tasmania Coast, based on participant feedback.
- Updating the boundaries for Gippsland Coast offshore REZ, aligned with the proposed Gippsland area to be declared by the Federal Government for the nation's first priority area[122] for offshore wind development.
- Specifying 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 30.

Table 30 Proposed offshore REZ resource limits

Offshore REZ	Resource limits - fixed structures (MW)	Resource limits – floating structures (MW)	REZ area (km^2)
N10 – Hunter Coast	700	24,600	5,602
N11 – Illawarra Coast	600	9,800	2,307
V7 – Gippsland Coast	50,300	85,600	27,185
V8 – Portland Coast	4,200	15,900	4,482
S10 – South East SA Coast	23,000	7,900	6,865
T4 – North West Tasmania Coast	15,400	11,000	5.884
T5 – North East Tasmania Coast	15,000	11,800	5,939

[121] AEMO, 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.

[122] 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.

The maximum offshore REZ wind generation resource limit proposed in Table 30 has been calculated based on:

- Assumed turbine capacity density of 5 MW/km^2.
- Allowing for 90% of the offshore REZ area to be developed.
- Fixed offshore wind turbine structures assumed to be built up to a depth of 60 meters.
- Floating offshore wind turbine structures are assumed at a depth above 60 meters but less than 1,000 meters.

Allowance for land use penalty factor in REZs to allow for increase in resource limits.

Land use reviews 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 required above the original REZ total resource limits. This penalty factor was applied to capture the increase in land costs or difficulties in obtaining land.

AEMO proposes for the 2024 ISP to increase the land use penalty factor to $0.27 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.

The land area within a REZ can be found in the Draft 2023 Inputs and Assumptions Workbook.

Social licence

'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 the energy industry securing social licence to develop the new infrastructure assets required of the future power system. Conversely, a lack of social licence could lead to significant project delays and increased total system costs.

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. For instance, alternative assumptions that reflect greater limitations and higher cost, to address social licence issues could also be considered.

The ISP is an engineering and economic options assessment. AEMO proposes three ways to include the quantification of 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 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 is consulting on transmission augmentation cost, generator connection costs and project lead times in the 2023 Transmission Expansion Report consultation. However, we are seeking your views on how social licence could be considered in the development of these parameters in this Draft 2023 IASR consultation. See Section 3.9.4 for more information on the Transmission Expansion Report consultation.

Matters for consultation

- Do you have specific feedback on the proposed REZ resource limits?
- Is the capacity density for offshore wind farms of 5 MW/km2 appropriate for the calculation of offshore REZ offshore wind build limits?
- Is the maximum depth of 60 meters for fixed offshore wind turbine structures reasonable?
- Is it reasonable to assume 90% of the area of the offshore REZ can be developed?
- Is the maximum land use assumption of 5% for the REZ hard limits appropriate?
- Do you have specific feedback on the quantification of social licence in the development of REZs?
- How should AEMO incorporate social licence in the assessment of transmission, generation, and/or storage projects?

3.9.3 REZ transmission limits

Input vintage	December 2022
Status	Draft
Source	AEMO internal – Based on the 2021 Transmission Cost Report and feedback to the ISP Methodology.
Update process	Updates will be dependent on feedback received on this Draft 2023 IASR.

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 large dispatchable generation, AEMO proposes that the generation constraint be updated to reflect this dependency. This will be consulted on through an update to the *ISP Methodology* in 2023.

The following changes are proposed to the 2022 ISP 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 and North East Tasmanian Coast REZ.
- The South West NSW 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; see Table 32.
- 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; see Table 32.
- Gippsland transmission limits now include terms to account for Basslink, Marinus Link and coal and gas generation impacts; see SEVIC1 in Table 31.
- South East SA REZ transmission limit is now modelled as a sub-region flow limit.
- Darling Downs REZ transmission limit now includes terms to account for QNI, CQ-SQ and local coal and gas generation impacts; see SWQLD1 in Table 31.

Table 31 REZ transmission limit constraints

Transmission constraint name	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)	
SWQLD1	Darling Downs	1	Darling Downs REZ generation	5,300
		-1.5	NSW to QLD interconnector flow (QNI)	
		0.3	Central QLD to South QLD flow	
		-0.6	Existing South West Queensland coal and gas generation (Tarong, Tarong North, Kogan Creek, Darling Downs, Braemar)	
		-1.5	Millmerran coal generation	

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 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 32 REZ secondary transmission limits

REZ	Constraint Terms	Transmission constraint name	Transmission-limit (summer peak/summer typical/winter reference)
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	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

Matters for consultation

- Do stakeholders have any other suggestions for representation of REZ transmission limit constraints and the secondary REZ transmission limits?

Group constraints

The transmission system is a highly meshed system, and 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 proposed that 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 33 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 proposed:

- 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.
- An increase in the NSA1 transmission-limited total build to reflect the Davenport – Cultana 275 kV line uprating project[123], which is expected to be completed in 2024-25.

Table 33 REZ group transmission constraints

REZ ID/ Flow path	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	1,400/1,400/1,400
Q7	Wide Bay		
VIC-SA	Heywood Interconnector	SWV1	1,700/1,700/1,700
V4	South West Victoria		
V8	Portland Coast		
S3	Mid-North SA	MN1††	2,400/2,400/2,400*
0.5 x S4 †	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††	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
T5	North East Coast Tasmania		

† Only 50% of the renewable energy developed in the Yorke Peninsula contributes to this transmission constraint.

[123] 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.

†† MN1 and NSA group constraints are removed in the *1.5°C Green Energy Export* 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 be removed.
* 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.

Matters for consultation

- Do stakeholders have any other suggestions for representation of inter-related constraints across multiple REZs and/or REZs and flow paths?

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 Draft 2023 Inputs and Assumptions Workbook. Committed and anticipated transmission augmentation projects are defined in sections 3.10.3 and 3.10.4.

Matters for consultation

- Do you have any feedback on the proposed values of the REZ transmission modifiers as a result of interconnectors or sub-regional augmentations, and the REZs they apply to?

3.9.4 REZ augmentations and network cost

Input vintage	July 2022
Status	Interim
Source	AEMO internal – Based on the Transmission Cost Database and TNSP data.
Update process	Transmission Cost Database update and the 2023 *Transmission Expansion Report* consultation
Get involved	**2023 *Transmission Expansion 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 will continue this initiative by publishing a *Transmission Expansion 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

The draft report will be published in early May 2023, followed by a period of consultation. AEMO will then publish the final 2023 *Transmission Expansion Report* alongside the 2023 IASR in July 2023.

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 proposed 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 will be consulted on through the Draft 2023 Transmission Expansion Report and includes transmission upgrades that are not committed or anticipated that will be assessed in the 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 will be updated and consulted on through the Draft 2023 *Transmission Expansion Report*.
- **Preparatory activities** – the 2022 ISP triggered preparatory activities for six future ISP projects. By 30 June 2023, the relevant TNSPs will provide 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
Status	Draft
Source	AEMO internal – Prepared for the 2022 ISP and adjusted and consulted on through the 2021 IASR.
Update process	Updates will be dependent on feedback received on this Draft 2023 IASR.

Depending on the purpose and the stage of the modelling, 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 is proposing the following changes to the sub-regional topology since the 2022 ISP:

- **Separating Central and Northern Queensland (CNQ) into two sub-regions –** AEMO proposes further dividing 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 proposes dividing the South Australia region into two sub-regions, namely South East South Australia (SESA) and Central South Australia (CSA) sub-regions. The new sub-regional model will assist to better capture network limitations between SESA and Victoria and across South Australia.

Table 34 lists all the regions and the proposed 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 34 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**
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

NEM region	ISP sub-region	Reference Node	REZs
	South NSW (SNSW)	Canberra 330 kV	N4, N5, N6, N7 and N8
	Sydney, New Castle, Wollongong (SNW)	**Sydney West 330 kV**	N10 and N11
Victoria	Victoria (VIC)	**Thomastown 66 kV**	V1, V2, V3, V4, V5, V6, V7 and V8
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

*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.
**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 proposing 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 proposed are presented and described in Figure 46, and Table 35. For each flow path, AEMO models the AC and the DC interconnector separately, which can result in multiple parallel flow paths. AEMO includes information on this proposed implementation in this Draft 2023 IASR to provide context for the draft inputs described in the remaining sections. It also provides an opportunity for stakeholders to provide early input into the proposed model improvement.

Figure 46 ISP sub-regional model

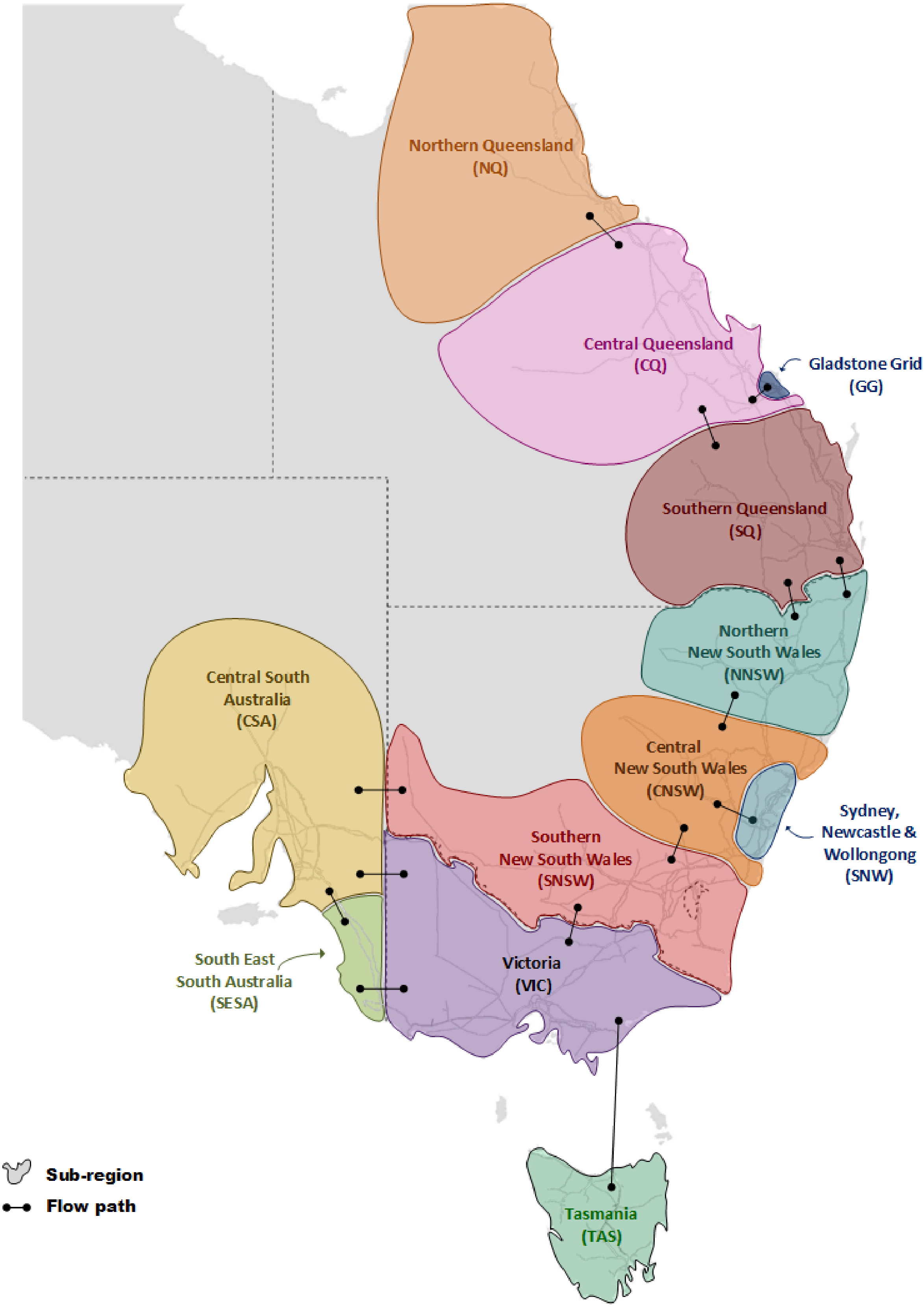


Table 35 Existing network flow path representation between sub-regions

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 (Queensland – New South Wales interconnector, or 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)

Flow path definition	Inter-zonal flow path (forward direction of power flow)
	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-region is presented in the table below. Sub-region loads are to be 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. Initial views on this representation are welcome as part of this consultation.

Table 36 Load and generation representation within the sub-regional model

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 NSW, all load and generation including and north of Tamworth substation.
Central New South Wales (CNSW)	Wellington 330 kV	Within NSW, 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 NSW (SNSW)	Canberra 330 kV	Within NSW, all load and generation including and south of Gullen Range, Marulan and Kangaroo Valley substations. All load and generation in South West NSW.
Sydney, Newcastle and Wollongong (SNW)	Sydney West 330 kV	All NSW 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 SA (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

Matters for consultation

- Does the proposed sub-regional model reasonably represent the network? Are there any additional sub-regions which should be considered (and why)?

Detailed time-sequential model representation

AEMO does not propose any changes to the detailed time-sequential model. The time-sequential models used in the ISP and ESOO use a regional topology. The NEM transmission network is represented using detailed transmission constraint equations, 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	December 2022
Status	Current view
Source	AEMO internal supplemented by advice from TNSPs via joint planning.
Update process	Updates will be dependent on feedback received on this Draft 2023 IASR.

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 proposes the following changes since the 2022 ISP:

- Inclusion of flow path limits between Central Queensland (CQ) and Northern Queensland (NQ).
- Inclusion of flow path limits between South East SA (SESA) and Central SA (CSA).
- Revision of flow path limits between Tasmania (Tas) and Victoria (Vic) regions aligned with current operational advice.

These proposed notional transfer limits in the Draft 2023 IASR are presented in Table 37 below. These 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 Draft 2023 Inputs and Assumptions Workbook.

Table 37 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	1,200	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.

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	
SQ – CQ	700	700	1,000	2,100	2,100	2,100	No changes to 2022 ISP. The SQ-CQ limits were determined with the inclusion of minor augmentation of the Blackwall/Rocklea – South Pine 275 kV single circuit loop.
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. QLD to NSW transfer limit is influenced by generation output from Sapphire wind farm. For peak demand, typical summer and winter reference conditions Sapphire wind 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 shouldn't 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 Draft 2023 Inputs and Assumptions Workbook for more details CNSW-SNW transfer limit improvement with Waratah Super Battery (WSB) with a system integrity protection scheme (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 system integrity protection scheme (SIPS) with 250 MW battery storage in western side of Melbourne raises the thermal capacity of Victoria-New South Wales interconnector. VIC - 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.

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	
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 flows 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 Draft 2023 Inputs and Assumptions Workbook.

Matters for consultation

- Do you have any specific feedback on the existing and proposed flow path transfer capabilities?
- Do you have any feedback on the uplift factors applied to flow paths as a result of committed and anticipated projects?

3.10.3 Committed transmission projects

Input vintage	December 2022
Status	Current view
Source	AER and TNSPs – AER's approval of Contingent Project Application and advice from TNSPs on the status of projects meeting the 5 commitment criteria.
Update process	As projects receive committed status, these are updated in the Input and Assumptions and the Transmission Information Webpage.

AEMO applies the five-criteria definition of a committed project from the AER's regulatory investment test[124]; 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.

[124] At https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20-%2025%20August%202020.pdf.

- 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 draft 2023 IASR applies the committed projects listed in the Transmission Augmentation Page[125], December 2022 release. For further details on these projects please refer to the Draft 2023 Inputs and Assumptions Workbook or to 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	December 2022
Status	Current view
Source	AER and TNSPs – AER's approval of Contingent Project Application and advice from TNSPs on the status of projects meeting the commitment criteria.
Update process	As projects receive anticipated status, these are updated in the Input and Assumptions and the Transmission Information Webpage.

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 (as 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[126] 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.

[125] AEMO, Transmission Augmentation Page at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

[126] 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.

This draft 2023 IASR applies the anticipated projects listed in the Transmission Augmentation Page[127], December 2022 release. For further details on these projects please refer to the Draft 2023 Inputs and Assumptions Workbook or to the Transmission Augmentation Page.

3.10.5 Flow path augmentation options

Input vintage	July 2021
Status	Interim
Source	AEMO, 2022 ISP, TNSP
Update process	2023 *Transmission Expansion Report* consultation and through further TNSP engagements
Get involved	**2023 *Transmission Expansion Report* consultation**

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 0.

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 alternative current (HVAC) technology.
- High voltage direct current (HVDC) technologies.
- Virtual transmission lines (using grid-scale batteries).

AEMO will consult on flow path augmentation options, including the capacity gained and lead time to deliver the project, through the 2023 *Transmission Expansion Report*. Please see Section 3.9.4 for more details.

3.10.6 Transmission augmentation costs

Input vintage	July 2021
Status	Interim
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
Update process	The 2023 *Transmission Expansion Report* consultation
Get involved	**The 2023 *Transmission Expansion Report* consultation**

[127] AEMO, Transmission Augmentation Page at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

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 has engaged expert consultant Mott MacDonald to update the Transmission Cost Database. The update to the Transmission Cost Database will include:

- Review and update the cost and risk data to align with latest changes in market costs.
- To incorporate the latest transmission project information in the update and calibrate escalation factors.
- Prepare an updated Cost and Risk Data workbook and report to AEMO.

AEMO has undertaken two stakeholder engagement sessions to seek feedback on the work and share the preliminary outcomes and key insights of the Transmission Cost Database update.

The updated Transmission Cost Database will be completed in January. AEMO will use the updated Transmission Cost Database to develop cost estimates for future ISP projects for use in the 2024 ISP and consult on these through the 2023 *Transmission Expansion Report*.

3.10.7 Preparatory activities

Input vintage	June 2022
Status	Current view
Source	TNSPs
Update process	2023 IASR process
Get involved	**2023 *Transmission Expansion Report* consultation**

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[128]. 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 along with engagement on the route and necessary planning approvals. 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. Preparatory activities are to be completed by 30 June 2023.

Table 38 Preparatory activities

Project	Indicative timing	Responsible TNSP(s)
South East SA REZ expansion (Stage 1)	2025-26 to 2045-49	ElectraNet
Darling Downs REZ Expansion (Stage 1)	2025-26 to 2047-48	Powerlink
Mid-North SA REZ Expansion	≥ 2028-29	ElectraNet

[128] See definition in NER clause 5.10.2 and clause 5.22.6(c)-(d).

Project	Indicative timing	Responsible TNSP(s)
QNI Connect (500 kV option)	2029-30 to 2036-37	Powerlink and Transgrid
QNI Connect (330 kV option – NSW scope)		Transgrid†
South West Victoria REZ Expansion	≥ 2033-34	AEMO (Victorian Planner)

† AEMO triggered preparatory activities for Reinforcing Sydney, Newcastle & Wollongong Supply and QNI Connect (NSW scope) in the 2020 ISP for use in the 2022 ISP. Although Transgrid provided AEMO with the preparatory activities reports, the costs were provided on a confidential basis. The ISP regulatory framework is designed to be transparent and consultative for all stakeholders, and AEMO does not consider it appropriate to use confidential transmission costs in the ISP. Accordingly, AEMO used its own estimates for these projects in the 2022 ISP and requests that Transgrid provide the information in a format that can be published.

For preparatory activities requested and received in response to the 2020 ISP, AEMO proposes to escalate the costs from the previous preparatory activities received. AEMO welcomes feedback to the appropriate escalation factors to consider when updating the costs for the preparatory activities from the 2020 ISP.

Matters for consultation

- Is there any specific feedback on the treatment of costs and options developed via preparatory activities for inclusion in the ISP?
- How should AEMO escalate the cost for preparatory activities received in response to the 2020 ISP for use in the 2024 ISP?

3.10.8 Non-network options

Input vintage	June 2022
Status	Draft
Source	Previous projects, stakeholder submissions
Update process	2023 IASR and progression of RIT-Ts.
Get involved	**2023 *Transmission Expansion Report***

AEMO seeks input on any non-network options for consideration in the 2024 ISP. 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[129], prior to the Draft ISP, AEMO is required to:

[129] AER Cost Benefit Analysis guidelines, at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

- 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.

At this stage, AEMO is seeking information on non-network technologies or proponents so ISP modelling can flag opportunities for competitive non-network investment. In order to model non-network technologies, AEMO is seeking information on:

- Specific non-network concepts and proposals.
- The resultant network capacity gained.
- Cost of the non-network solution.
- Project lead time.

Matters for consultation

- Is there any information on non-network technologies or proponents regarding opportunities for competitive non-network investment?
- Given that non-network investments generally involve commercial arrangements with plant with multiple revenue streams, how should AEMO estimate their cost transparently?

3.10.9 Network losses

Input vintage	July 2021
Status	• Current view for existing network inter-regional loss factor equations, loss equations and proportioning factors. • Interim view for future inter-regional/intra-regional loss factor equations, and loss equations and proportioning factors. • Draft view for existing network intra-regional loss factor equations, and loss equations and proportioning factors.
Source	AEMO *Marginal Loss Factors Report* 2022-23 Financial Year and internal processes
Update process	• Updated in line with AEMO's *Marginal Loss Factors Report*. • For existing network intra-regional loss factor equations, loss equations and proportioning factors, the Draft 2023 IASR report. • For future augmentation options, the Draft 2023 *Transmission Expansion Report*.
Get involved	**2023 *Transmission Expansion Report* consultation**

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 Regional Reference Node (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 2022-23 Financial Year* report and are presented in the 'Network losses' tab of the Draft 2023 Inputs and Assumptions Workbook

For committed and anticipated projects that impact interconnector flows, the inter-regional loss equations, loss factor equations and proportioning factors are updated. AEMO is consulting on this through the Draft 2023 IASR and are presented in the 'Network losses' tab of the Draft 2023 Inputs and Assumptions Workbook.

For future projects that impact interconnector flows, AEMO will be consulting on these inter-regional loss equations, loss factor equations and proportioning factors through the 2023 *Transmission Expansion Report*.

Intra-regional loss and loss factor equations

AEMO proposes modelling 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. AEMO has identified Northern Queensland as being remote from load centres under all scenarios except *1.5°C Green Energy Export* (based on insights from the 2022 ISP's *Hydrogen Superpower* scenario outcomes). AEMO proposes the following changes from the 2022 ISP:

- Removing the MLF penalty factors applied to Far North Queensland and Queensland Clean Energy Hub applied to all scenarios except the *1.5°C Green Energy Export* scenario.
- Using 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 *1.5°C Green Energy Export* scenario.

The Draft 2023 Inputs and Assumptions Workbook 'Network losses' factors tab' captures the proposes intra-regional loss factor equations.

Matters for consultation

- Is there any specific feedback on the proposed intra-regional loss equations and loss factor equations?
- Is there any feedback on the proposed updated inter-regional loss equations, loss factor equations and proportioning factors following committed and anticipated network upgrades?

3.10.10 Marginal loss factors

Input vintage	April 2022
Status	Current view
Source	AEMO *Marginal Loss Factors Report* 2022-23 Financial Year and internal processes
Update process	Updated in line with AEMO's *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. In the NEM, transmission network losses are represented through MLFs.

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 difference between a generator's output and the energy that is actually delivered to consumers. 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 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. MLFs are updated every financial year with the publication of AEMO's *Marginal Loss Factors Report*. AEMO proposes to update 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 Draft 2023 Inputs and Assumptions Workbook.

3.10.11 Transmission line unplanned outage rates

Input vintage	July 2022
Status	Current View
Source	AEMO Network Outage Schedule and other AEMO sources.
Update process	To be updated as part of data collection process for 2023 ESOO.
Get involved	**FRG discussion in June 2023**

Unplanned outage rates of inter-regional transmission elements are critical inputs for AEMO's reliability assessments. Information is collected on the timing, duration, and severity of the transmission outages to inform transmission forced outage rate forecasts. Table 39 shows the rates and method used in the 2022 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 39 Inter-regional transmission flow path outage rates

Flow path	2022 FOR (%)	2022 Mean time to repair (hours)	Outage rate method
Liddell – Muswellbrook – Tamworth – Armidale – Dumaresq – Bulli Creek (QNI)	1.5	5	Annual static
Murraylink	0.1	8.9	Annual static
Mortlake – Heywood – South East (V-SA))	0.3	20.1	Annual static
Basslink	6.4	244	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 IBR[130] 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.

AEMO's *Power System Requirements* document[131] 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	June 2022
Status	Draft
Source	AEMO internal
Update process	Updates will be dependent on feedback received on this Draft 2023 IASR.
Get involved	**Draft 2023 IASR consultation**

[130] 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.

[131] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power-system-requirements.pdf.

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[132]. 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[133].

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 proposes the following planning assumptions for unit commitment requirements:

- **New South Wales, Queensland and Victoria** – for these regions that have a predominance of coal-fired power generation, AEMO proposes to apply a 'half-life' approach and assume that the number of units required will halve every two years from 2025-26 for the *2.6°C Progressive Change, 1.8°C Diverse Step Change* and *1.8°C Orchestrated Step Change* scenarios. For the *1.5°C Green Energy Export* scenario, AEMO proposes that the number of units would halve under the planning assumption every one year to align with the with rapid and widespread transformation of the economy and rapid decarbonation under the *1.5°C Green Energy Export* 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 reducing the minimum synchronous machine requirement[134]. In addition, there are no remaining coal-fired units in South Australia. For all scenarios, AEMO proposes to apply the 'half-life' approach for gas-fired units in South Australia but to begin the reduction from the 2022-23 financial year in the modelling[135].
- **Tasmania** – AEMO does not propose a fixed assumption for unit commitment in Tasmania, as that 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 this region as many of the generators can be operated in synchronous condenser mode when required.

Figure 47 and Figure 48 provide the proposed 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.

[132] 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.

[133] See https://aemo.com.au/-/media/files/initiatives/engineering-framework/2022/nem-engineering-framework-priority-actions.pdf.

[134] Stakeholder engagement materials relating to synchronous generator requirements in South Australia can be accessed via 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.

[135] As for other regions, this assumption is for planning and market modelling purposes only. Real time operations will be dependent on limit advice.

Figure 47 New South Wales, Queensland, Victoria and South Australia projected unit commitment requirements for all scenarios except for the *1.5°C Green Energy Export* scenario

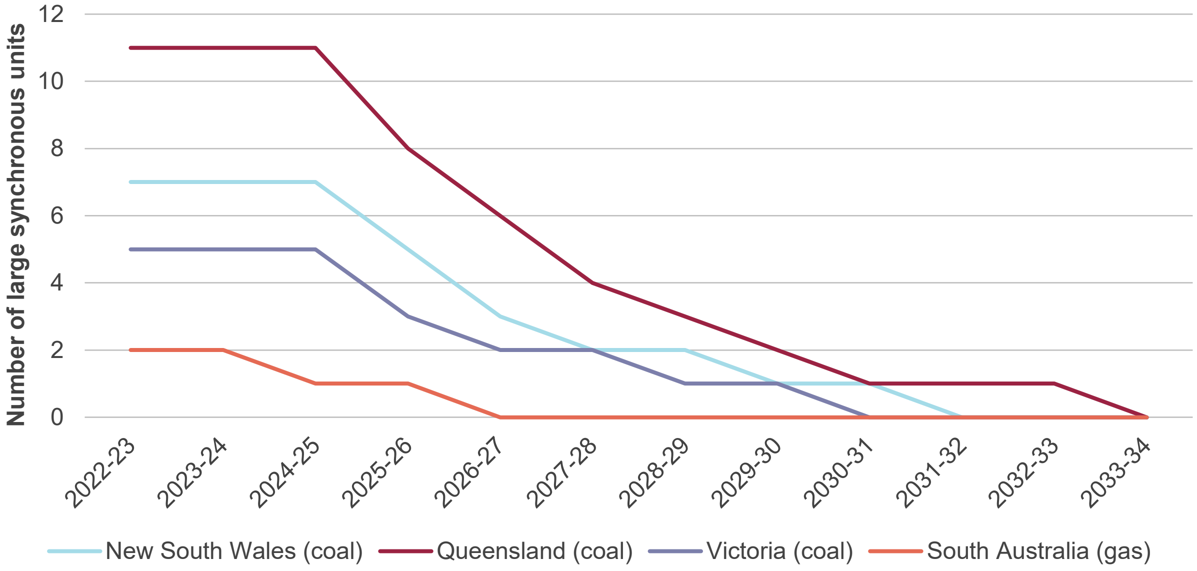
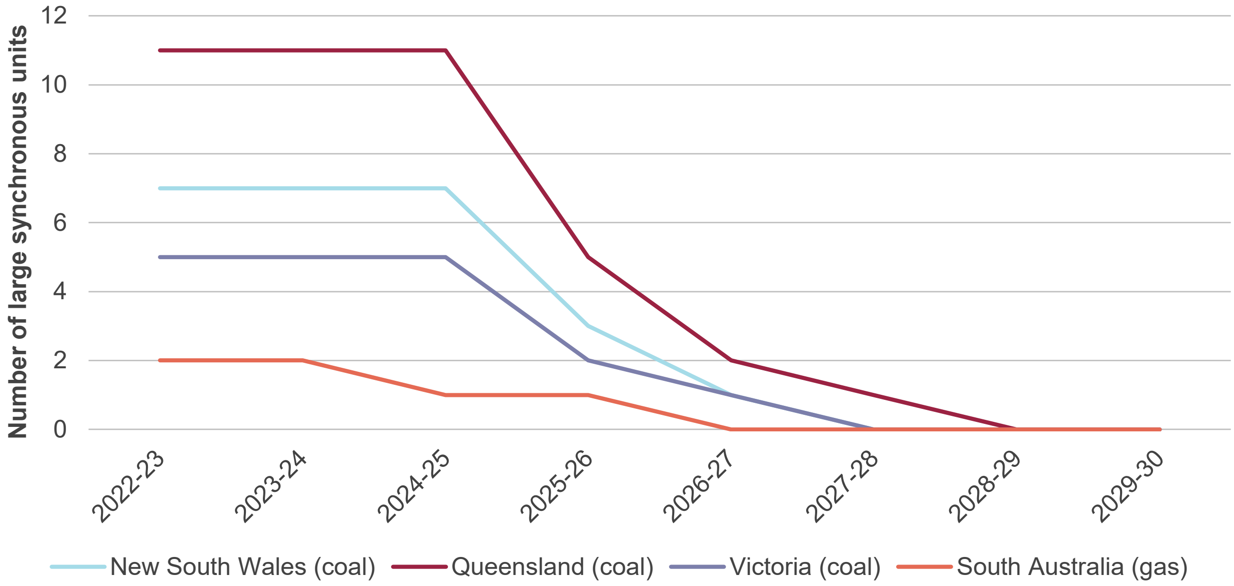


Figure 48 New South Wales, Queensland, Victoria and South Australia projected unit commitment requirement for the *1.5°C Green Energy Export* scenario



3.11.2 System strength requirements and cost

Input vintage	June 2022
Status	• Current view for the system strength requirements • Interim for system strength costs and the application of the new system strength standards in the ISP.
Source	AEMO internal
Update process	• 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). • Costs to deliver the efficient level of system strength will be consulted on through the *Transmission Expansion Report*.
Get involved	***ISP Methodology* and *Transmission Expansion Report* consultation.**

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*[136]) 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[137]. Under the previous rule AEMO was required to determine the fault level requirements across the NEM and identify whether a fault level shortfall is likely to exist now or in the coming five years. From 1 December 2022 onwards, AEMO declared a system strength standard for each system strength node in the NEM, against which the local System Strength Service providers (SSSP) must provide services to meet the full requirement starting from 1 December 2025.

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[138] defines the process AEMO must apply to set these standards.

For the efficient level of system strength, AEMO proposes to incorporate a $/kW value in the ISP modelling for the system strength services provided to enable connection and operation of IBR within REZs. AEMO has engaged expert consultant Mott MacDonald to update the Transmission Cost Database, which was used for the 2020 ISP (see Section 3.10.6 for more details). AEMO will use 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 will be consulted on through the *Transmission Expansion Report* in May 2023.

AEMO updates the system strength requirements annually[139]. AEMO intends to use the system strength requirements as inputs to the 2024 ISP and will seek feedback on their application in the 2024 *ISP Methodology* consultation.

[136] At https://aemo.com.au/-/media/files/electricity/nem/system-strength-explained.pdf.

[137] See https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system.

[138] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf.

[139] See https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

3.11.3 Inertia requirements

Input vintage	June 2022
Status	Current view
Source	AEMO internal
Update process	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[3]. Forecasted 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[140].

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 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 2022
Status	Current
Source	AEMO internal and TNSP limits advice.
Update process	AEMO draws on the latest information from TNSP limits advice and the corresponding constraint equation information in AEMO's market management system.

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.

[140] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning.

- 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[141].

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	December 2022
Status	Draft
Source	CSIRO: *GenCost 2022-23 Consultation draft* Qld Government: 'Enabling Queensland's hydrogen production and export opportunities' ARUP: Australian hydrogen hub study report 2019
Update process	Updates will be dependent on feedback received on this Draft 2023 IASR and may be further updated through the *ISP Methodology* consultation process.
Get involved	**ISP Methodology consultation**

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 consumption assumed across scenarios is discussed in Section 3.3.7.

Hydrogen production technologies

To produce hydrogen, AEMO's forecasts include production potential from two primary technologies:

- 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.
- Steam methane reforming (SMR) – reacts methane (natural gas) with steam under pressure to produce hydrogen and carbon dioxide. CCS can also be utilised to partially mitigate carbon emissions from this process.

New SMR production is present across all scenarios, increasing gas demand forecasts. Electricity demand for SMR operations is immaterial. In the 1.5°C *Green Energy Export* scenario, only green hydrogen from renewable

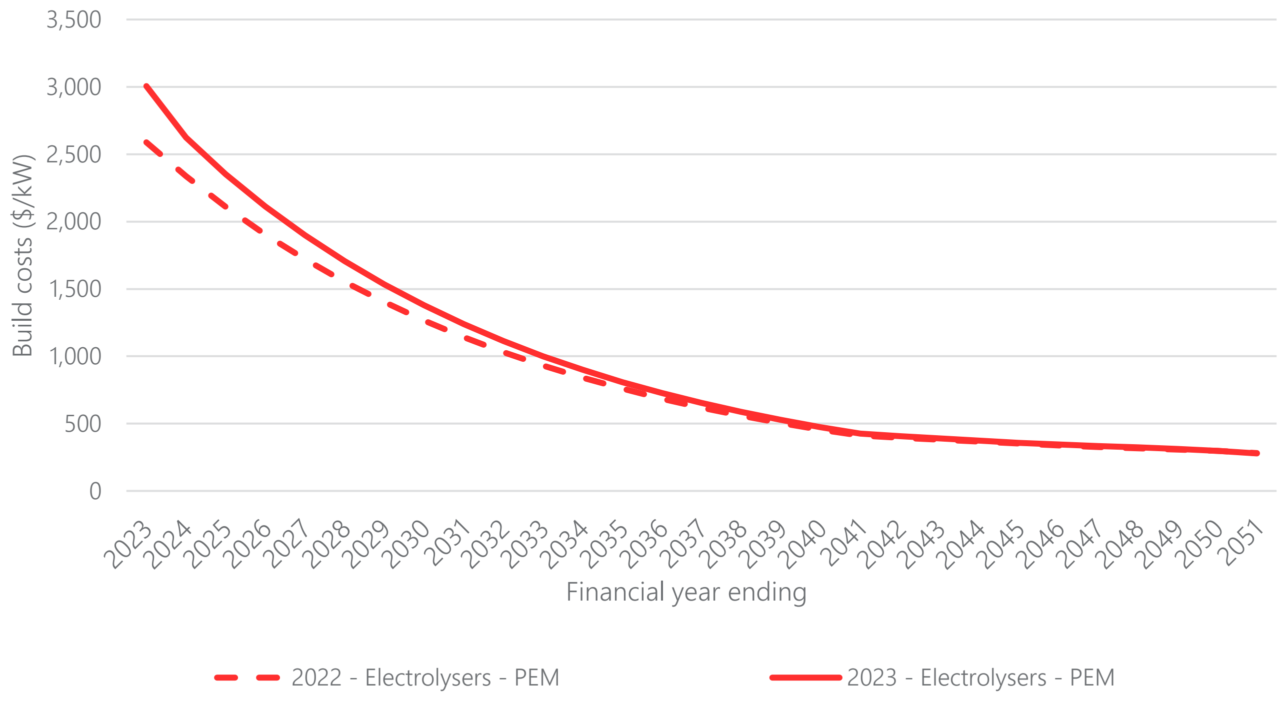
[141] AEMO. Constraint Formulation Guidelines, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource.

sources is exported. All scenarios assume that SMR with or without CCS could be used to produce domestic hydrogen.

PEM characteristics

Figure 49 below presents the capital cost projections for new PEM installations as forecast in the Draft GenCost 2022-23 for its Global NZE post 2050 scenario, compared to Final GenCost 2021-22 projections. There has been an increase in hydrogen electrolysers cost in early years, driven by significant cost pressures factored in GenCost 2022-23. See Section 3.5.3 for more detail on these cost adjustments, as well as detail on scenario mappings between the GenCost and Draft 2023 IASR scenarios. Cost projections for PEM electrolysers for each scenario are available in the accompanying Draft 2023 Inputs and Assumptions Workbook.

Figure 49 2022 vs 2023 Global NZE post 2050: build cost trajectories forecasts for electrolysers – proton exchange membrane



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). The 2021 IASR assumed that the baseload demand consumed by the electrolyser would be 10% of total demand, even when the electrolyser is not producing hydrogen.

The Energiepark Mainz facility in Germany reports a baseload of 4.5%[142]. Discussions with equipment suppliers, international research organisations and stakeholders during the 2021 IASR development process indicated that

[142] 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.

this load may reduce to around 2% with increased scale. AEMO proposes to continue assuming 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 water located at the consumer) or molecules (with electrolysers and water 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. At this stage AEMO is not proposing to increase the complexity of the model's derivation to incorporate the alternative configuration.

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[143]. An additional candidate port has been added at Mackay in Queensland, to align with the recent Queensland Government report into hydrogen export opportunities[144] and provide sufficient granularity across the state to reflect the ISP model sub-regions.

The following table lists the 10 candidate hydrogen export ports (shown in Figure 50) that provide a geographic spread with access to REZ and port infrastructure. These 10 candidate ports will be considered as options in the ISP modelling.

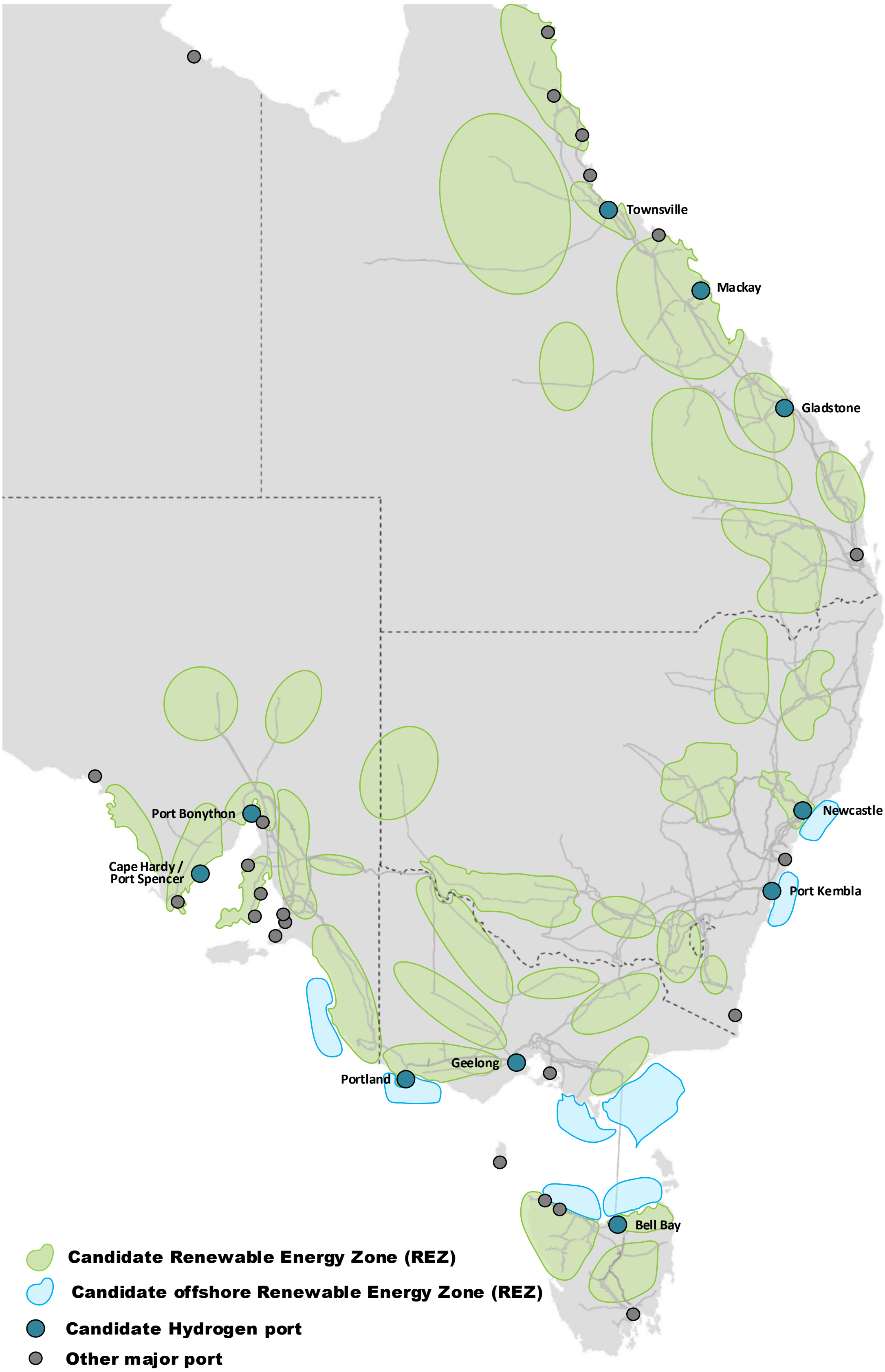
Table 40 Candidate hydrogen export ports

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

[143] At https://www.dcceew.gov.au/sites/default/files/documents/nhs-australian-hydrogen-hubs-study-report-2019.pdf.

[144] 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 50 Candidate hydrogen export ports



Matters for consultation

- Do you have any specific feedback on the proposed hydrogen export ports?

Water supply

For the 2024 ISP, water availability is not considered to be a limiting factor to affect 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
Status	Draft
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.
Update process	Updates will be dependent on feedback received on this Draft 2023 IASR and may be further updated through the *ISP Methodology* consultation process.

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[145]. 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 proposed employment factors that will be used to estimate the workforce requirements needed to implement the ISP. AEMO proposes that a smoothed infrastructure sensitivity could be included in the 2024 ISP to explore the costs and benefits of reducing the volatility of employment demand (see Section 2.5).

3.13.1 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.

[145] See https://aemo.com.au/-/media/files/major-publications/isp/2022/supporting-materials/the-australian-electricity-workforce-for-the-2022-isp.pdf.

Table 41 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

3.13.2 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 42 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/$m

Matters for consultation

- Do you have any feedback on the proportion of manufacturing that is assumed to be onshore, and how it may vary over time in response to state policies?

A1. List of tables and figures

Tables

Figures

A2. Supporting material

In addition to the Draft 2023 Inputs and Assumptions Workbook, Table 43 documents additional information related to AEMO's inputs and assumptions.

Table 43 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	Transmission costs for the 2022 Integrated System Plan	https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan
AEMO	2022 GSOO Stakeholder Surveys and gas supply input data	https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2022/2022-gas-statement-of-opportunities-supply-data.zip
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
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
BIS Oxford Economics	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
BIS Oxford Economics	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 ClimateWorks Centre	2022 Multisector 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	Draft GenCost 2022-23	Report: https://doi.org/10.25919/hjha-3y57 Data: https://doi.org/10.25919/p7nf-9k21
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

Organisation	Document/source	Link
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
Lewis Grey Advisory	Lewis Grey Advisory Fuel Prices	Report: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/lewis-grey-advisory-2023-gas-price-projections-for-eastern-australia.pdf Workbook: https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/2023-inputs-assumptions-and-scenarios-consultation/supporting-materials-for-2023/lewis-grey-advisory-2023-gas-price-projection-workbook.xlsx
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
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