

Draft 2025 Inputs, Assumptions and Scenarios Report

December 2024

Draft report

For use in Forecasting and Planning studies and analysis





We acknowledge the Traditional Custodians of the land, seas and waters across Australia. We honour the wisdom of Aboriginal and Torres Strait Islander Elders past and present and embrace future generations.

We acknowledge that, wherever we work, we do so on Aboriginal and Torres Strait Islander lands. We pay respect to the world's oldest continuing culture and First Nations peoples' deep and continuing connection to Country; and hope that our work can benefit both people and Country.

'Journey of unity: AEMO's Reconciliation Path' by Lani Balzan

AEMO Group is proud to have launched its first [Reconciliation Action Plan](#) in May 2024. 'Journey of unity: AEMO's Reconciliation Path' was created by Wiradjuri artist Lani Balzan to visually narrate our ongoing journey towards reconciliation - a collaborative endeavour that honours First Nations cultures, fosters mutual understanding, and paves the way for a brighter, more inclusive future.

Important notice

Purpose

AEMO publishes this Draft 2025 Inputs, Assumptions and Scenarios Report (IASR) in accordance with 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) and the Wholesale Electricity Market (WEM) in Western Australia. This publication is generally based on information available to AEMO as at 30 November 2024 unless otherwise indicated.

Disclaimer

AEMO has made reasonable efforts to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances.

Modelling work performed as part of preparing this publication inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual results, because events and circumstances frequently do not occur as expected, and those differences may be material.

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Version control

Version	Release date	Changes
1.0	11/12/2024	Initial release

Executive summary

Background

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

Publication of this Draft 2025 *Inputs, Assumptions and Scenarios Report* (Draft 2025 IASR) commences formal consultation on the scenarios, inputs and assumptions proposed for use in AEMO's 2024-25 forecasting and planning activities, including the 2026 ISP. While most assumptions that will apply to AEMO's planning publications are consulted on through this document's formal consultation process, some inputs and assumptions operate on different update cycles, as set out in the summary box under relevant sections of this report, and AEMO encourages interested stakeholders to use these subsequent engagement opportunities to consult with AEMO on these additional inputs.

Consultation process

Prior to the release of this Draft 2025 IASR, AEMO has provided several opportunities for stakeholder input that has helped shape the proposed scenarios in the Draft 2025 IASR and several of the draft assumptions. In July 2024, AEMO received submissions from 50 stakeholders with feedback and suggestions, and has published a consultation summary paper¹ that demonstrates the considerations that the feedback has provided to AEMO in developing this Draft 2025 IASR, in informing the scenarios, and in some instances the assumptions, in this Draft 2025 IASR².

The Draft 2025 IASR is being released in two stages for consultation

The IASR includes a wealth of inputs and assumptions that apply to AEMO's planning publications, and are used across the industry for other planning purposes, including for use in regulatory tests for transmission. In April 2024, the Energy and Climate Change Ministerial Council (ECMC) published its response to a review conducted to examine the optimal function and form of the ISP, and in June 2024 the Australian Energy Market Commission (AEMC) commenced rule change processes to address various ECMC-endorsed recommendations from the ISP Review³. If these rule changes are made, they will expand the scope of considerations in the ISP, so AEMO has needed to consider the breadth of the inputs and assumptions necessary to support this.

¹ See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/consultation-paper.pdf?la=en.

² A summary of submissions was presented at the 25 September 2024 Forecasting Reference Group meeting pack; see <https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg>.

³ See <https://www.aemc.gov.au/rule-changes/improving-consideration-demand-side-factors-isp> and <https://www.aemc.gov.au/rule-changes/better-integrating-gas-and-community-sentiment-isp>.

To extend the Draft 2025 IASR to include these additional considerations, AEMO is releasing the Draft 2025 IASR in two stages for consultation. Many of the traditional inputs and assumptions are included in this release (Stage 1), while new assumptions required for the ISP Review recommendations and some assumptions involving emissions reduction will be released in Stage 2:

- **Stage 1 release** (this publication) on 11 December 2024, with consultation on this release commencing on that date and submissions closing at 6.00 pm AEDT on 11 February 2025.
- **Stage 2 release** in February 2025, will include emissions reduction parameters as well as new inputs needed to consider new elements of the ISP's scope, with consultation on this release commencing on that date and submissions closing in March 2025.

AEMO will update the Stakeholder Engagement web page⁴ to outline changes to the above schedule, and to inform stakeholders of other opportunities, including use of the Forecasting Reference Group (FRG)⁵ and any other forums, as appropriate.

Notice of Consultation: Invitation for written submissions

AEMO is committed to continued engagement on the content of this Draft 2025 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 supports any views or claims that are put forward.

Submissions should be sent in PDF format via email to forecasting.planning@aemo.com.au and are required by 6.00 pm AEDT on Tuesday 11 February 2025 for the Stage 1 publication and March 2025 for the Stage 2 publication. Please note that submissions will be published, other than confidential material, subject to AEMO's Consultation submission guidelines⁶.

After receiving submissions for both stages of this Draft 2025 IASR, AEMO will facilitate a webinar to discuss the key issues raised by stakeholders, focusing discussions on inputs and assumptions referenced most frequently across the submissions. Other opportunities for engagement on the Draft 2025 IASR may emerge in relation to companion activities, including consultations on the *ISP Methodology*⁷ and *Electricity Demand Forecasting Methodology*⁸. Details for the current Draft 2025 IASR engagement opportunities can be found in Table 1 in

⁴ At <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/opportunities-for-engagement>.

⁵ See <https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg>.

⁶ At https://aemo.com.au/-/media/files/stakeholder_consultation/working_groups/industry_meeting_schedule/aemo-consultation-submission-guidelines---march-2023.pdf?la=en&hash=DB5BAA8CC5A29297C205B91640A97518.

⁷ At <https://www.aemo.com.au/consultations/current-and-closed-consultations/2026-isp-methodology>.

⁸ At <https://aemo.com.au/consultations/current-and-closed-consultations/2024%20Electricity%20Demand%20Forecasting%20Methodology%20Consultation>.

Section 1.1, and will be updated on the Opportunities for Engagement web page⁹. AEMO's ISP Timetable¹⁰ has details on all major milestones specific to the ISP development process.

Proposed scenarios and sensitivities

The use of scenario planning is an effective practice when planning in highly uncertain environments. Scenarios are a critical aspect of forecasting, enabling the assessment of future risks, opportunities, and development needs in the energy industry. Scenarios therefore purposefully 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 while meeting the policies of Australia's governments that are supporting the energy transition.

Scenarios represent plausible future 'worlds', being a collection of circumstances and external variations that determine the environment in which the energy transition occurs, driving different conditions for energy supply and demand. Scenarios do not describe the outcomes of the planning process and are thus not focused on particular solutions. 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; the value of the scenario collection is in describing uncertainties from which further analysis identifies benefits or regrets of various alternative investments.

The proposed scenarios in this Draft 2025 IASR reflect a similar scenario collection to the 2023 IASR scenarios applied in the 2024 ISP, with adjustments based on stakeholder feedback across various engagement opportunities since the Draft 2024 ISP was released. These changes are described further in Section 2.1.

The scenarios, representing plausible future worlds within which the energy transition occurs, all reflect and consider the policies that Australia's governments have committed to in order to transition Australia's economy to net zero emissions by 2050¹¹. The scenarios provide a mechanism to explore the investment needs of the energy system with consideration of various pathways to that outcome. As such, the scenarios continue to provide a broad range of environments on which to:

- Plan the energy system, supporting decision makers in identifying overall investment needs and applying them to AEMO's statutory functions to assess electricity system reliability and security, and gas system adequacy.
- Inform regulatory network and non-network investment processes, including both the development of the ISP and application of the regulatory investment test for transmission (RIT-T).
- Test the risks of under- and over-investment.

In developing the scenarios, AEMO focused on the principles that scenarios should remain broad, distinct, internally consistent, and plausible, and take into consideration the requirements and guidance provided in the AER's cost benefit analysis (CBA) guidelines¹².

⁹ At <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/opportunities-for-engagement>.

¹⁰ At <https://aemo.com.au/-/media/files/major-publications/isp/2026/2026-isp-timetable.pdf>.

¹¹ As per National Electricity Rules (NER) 5.22.3(b), which acknowledges that AEMO must (or may) consider eligible government policies when identifying power system needs and in developing how the ISP contributes to achieving the national electricity objective. See Section 3.1.

¹² See <https://www.aer.gov.au/system/files/2024-11/AER%20-%20Cost%20Benefit%20Analysis%20guideline%20%28clean%29%20-%202021%20November%202024.pdf>.

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

- The growth of the Australian economy, and associated population trends and economic activity that may be expected across Australia's industrial, commercial, manufacturing, mining and transportation sectors (and others), including emerging commercial loads such as data centres.
- The pace and scale of consumer energy resources (CER) investments, which comprise small-scale embedded generation and storage technologies, such as residential and commercial photovoltaic (PV) systems, battery storage, and electric vehicles (EVs), as well as consumer appetite for the coordination of these active devices.
- Cost trends for the range of technologies that may be developed across electricity generation, storage and network developments.
- The opportunities for emerging energy technologies affecting Australia's decarbonisation pathway and export economy, including hydrogen production and manufactured products that utilise hydrogen (such as green iron and ammonia products), and other technologies (such as biomethane) that may impact the emissions intensity of energy.

AEMO has defined three scenarios in this Draft 2025 IASR for its planning activities, including the 2026 ISP. Scenarios may be supported by sensitivity analysis to explore the effect of specific uncertainties on AEMO's planning publications, including the power system development outlook in the ISP, or emerging electricity/gas supply availability in the statements of opportunities.

The proposed scenarios are as follows:

- **Step Change** – refines the 2023 *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 consistent with international efforts to the same goal. Compared to the 2023 *Step Change* scenario, while consumer investment in the energy transition remains strong (with energy efficiency and electrification investments, as well as aggregators of consumer resources, being a key part of the transition), consumers are tentative to share control and coordinate the operation of their consumer energy devices through a third party such as their electricity retailer. Investment in CER, particularly in rooftop solar and batteries, reflects that households place high value on the benefits provided by these systems, and typically install relatively large household systems to improve their self-supply. The scenario captures some of the ambition in developing hydrogen associated opportunities, reflecting the economic challenges of establishing this new industry, while trends in artificial intelligence and other data-heavy applications encourage continued growth in data centres in Australia.
- **Progressive Change** – continues to explore a transition to net zero emissions within an economy that features less growth and greater challenges than other scenarios. In response to weaker economic circumstances, investment in decarbonisation is more gradual at sufficient pace to meet the requirement of Australia's current 2030 Paris Agreement commitments (and other state-based policy commitments) resulting in greater aggregate emissions even in achieving current commitments. Conversely, slower economic activity and population growth reduces the pace of electrification that increases electricity demand while energy-intensive industry are at greater risk of closure due to the weak economic circumstances, with a material proportion of large energy-intensive businesses in each NEM region shut down in the short to medium term. Consumers continue to invest in CER, yet with relatively less growth than other scenarios, and consumer

adoption of measures to share control of their devices to aggregators is lowest of all the scenarios, reducing the coordination opportunity for these assets.

As a result, the scenario has a less robust economy and a smaller population base consuming less electricity. A weaker and slower energy transition globally, higher technology costs, and tighter supply chains affecting consumer investments relative to other scenarios, combine to slow the pace of change to limit the medium-term ambition beyond current policy targets. As a result, this scenario requires less investment to achieve the decarbonisation goals.

- **Green Energy** (which will examine one of two variants, *Green Energy Exports* or *Green Energy Industries*) – refines the 2023 *Green Energy Exports* scenario, and is this IASR’s most ambitious scenario, with the strongest decarbonisation and strongest economic growth. The scenario features a rapid transformation of Australia’s energy sectors, utilising all available pathways to net zero including strong adoption of electrification, and action to reduce the emissions intensity of molecular forms of energy. Australia’s energy transition in this scenario is commensurate with global actions underway to limit temperature increases to 1.5°C. Consumers in this scenario continue to invest in CER, with the greatest relative uptake of these assets, and the greatest relative acceptance of coordination opportunities.

Higher economic growth internationally (and locally) increases global demand for green energy, enabling greater development of green energy products for both domestic and international customers (particularly green iron and ammonia products). Compared to the 2023 *Green Energy Exports* scenario, NEM-connected hydrogen production is lower reflecting that the scale of hydrogen developments remains uncertain and the opportunity for embedded electricity supply is expected to reduce grid investment. Two scenario variants are proposed that include, or exclude, some hydrogen export opportunities, and AEMO seeks stakeholder feedback on both in this consultation. In the ISP, AEMO is likely to examine one of the variants as one of the three scenarios, and explore the investment impacts of the other variant as a sensitivity. Further detail on the two variants and AEMO’s proposed treatment of them in the ISP context is in Section 2.1.

AEMO considers that this scenario collection provides consistency for comparison with the 2023 IASR collection, used in the 2024 ISP and other planning assessments, and suitably reflects developments since then, including stakeholder feedback during early consultation.

AEMO is exploring two variations to its most ambitious energy transition scenario, and seeks stakeholder feedback on the more appropriate variant for its scenario planning activities in the ISP.

Sensitivities

To increase confidence in the robustness of the investment conclusions developed in the ISP and to test the resilience of investment outcomes against various uncertainties, AEMO employs sensitivity modelling. Most commonly, this involves changing a single variable at a time.

AEMO invites stakeholders to submit their views on what sensitivities to explore in the 2026 ISP. An indicative list of sensitivities that AEMO will consider for the 2026 ISP will be published in the final 2025 IASR in July 2025.

Inputs and assumptions

This Draft 2025 IASR describes in detail the inputs and assumptions in relation to:

- Government policy inputs, 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 zones (REZ).
- Transmission modelling.
- 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.

AEMO publishes the Draft 2025 *Inputs and Assumptions Workbook*¹³ alongside this Draft 2025 IASR to provide more detail on the various inputs.

Recognising policy uncertainty

Government policy is included as an input for the purpose of AEMO's planning analysis. The range of policies included is set out in the IASR.

If there is a significant change to energy policies that may materially change AEMO's planning analysis, AEMO would adopt the updated policy as appropriate. This would involve consultation and could result in the requirement to restart planning activities, depending on the magnitude of the change and the type of planning analysis being undertaken.

Next steps

This Draft 2025 IASR invites stakeholders to provide submissions on its contents, acknowledging that a further stage to the Draft 2025 IASR will be released in February 2025, and containing additional, complementary inputs and assumptions to this release. In many instances, this release indicates the inputs to be released in the next IASR release.

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 required to be used for the ISP. AEMO has published key engagement milestones for the 2026 ISP in its ISP Timetable¹⁴ and will provide stakeholders with updates to the engagement

¹³ See <https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr>.

¹⁴ At <https://aemo.com.au/-/media/files/major-publications/isp/2026/2026-isp-timetable.pdf>.

opportunities on the Opportunities for Engagement web page¹⁵. Other forums, such as the FRG¹⁶, may provide further opportunity to consult or inform stakeholders on other inputs for AEMO's forecasting and planning processes.

AEMO will continue to engage with governments to further understand any developments or changes to existing policy initiatives to include in the final IASR and ISP, consistent with the requirements in the National Electricity Rules (NER).

AEMO will use these inputs, assumptions and scenarios in its planning work including the development of the 2025 GSOO (to be published March 2025), the 2025 ESOO (August 2025), the Draft 2026 ISP (December 2025), and the final 2026 ISP (June 2026).

¹⁵ At <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/opportunities-for-engagement>.

¹⁶ See <https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg>.



Contents

Executive summary	3
1 Introduction	11
1.1 Consultation process	13
2 Scenarios	15
2.1 Scenario narratives and descriptions	16
2.2 Key scenario parameters	20
2.3 Scenario likelihoods	22
2.4 Sensitivities	22
3 Inputs and assumptions	23
3.1 Policy settings	23
3.2 Emissions and climate assumptions	41
3.3 Consumption and demand: historical and forecasting components	45
3.4 Existing generator and storage assumptions	80
3.5 New entrant generator assumptions	92
3.6 Fuel and renewable resource assumptions	108
3.7 Financial parameters	117
3.8 Climate change factors	120
3.9 Renewable energy zones (REZs)	122
3.10 Network modelling	138
3.11 Power system security	160
3.12 Gas infrastructure	167
3.13 Employment factors	169
A1. ISP Review implementation measures	172
A2. Supporting material	174
List of tables and figures	175
Abbreviations	179

1 Introduction

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

- **Electricity Statement of Opportunities (ESOO)** – provides operational and economic information about either the National Electricity Market (NEM) or the Wholesale Electricity Market (WEM) over a 10-year outlook period, with a focus on electricity supply reliability. The NEM 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 WEM ESOO includes the 10-year long-term projected assessment of system adequacy, used to assess reserve capacity requirements. The ESOO also includes forecasts of annual electricity consumption, maximum demand, and demand side participation (DSP). It is published annually for each jurisdiction, 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 in either the East Coast Gas Market or in Western Australia. It is published annually for each jurisdiction, with updates if required.
- **Integrated System Plan (ISP)** – is a roadmap for the transition of the NEM power system, with a clear plan for essential infrastructure that will meet future energy needs. It sets out the needed generation, storage and network investments to transition to net zero by 2050 through current policy settings and deliver significant net market benefits for consumers. It identifies transmission projects that should be progressed urgently by relevant network service providers, as well as providing information on broader opportunities to invest in generation, storage and other non-network investments to achieve the decarbonisation objectives of governments and deliver an efficient energy transition for electricity consumers. AEMO published the inaugural ISP for the NEM in 2018, and publishes it every two years.

For the 2026 ISP, the breadth of the ISP will expand to implement recommendations of the ISP Review endorsed by the Energy and Climate Change Ministerial Council (ECCMC). These recommendations require AEMO to expand the technical scope of the ISP, and consider broader inputs and assumptions, affecting both the *ISP Methodology* and the IASR. Appendix 2 in this IASR describes AEMO's approaches to addressing the ISP Review actions, and the relevant opportunities for stakeholders to engage with AEMO on these.

AEMO 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 Scenarios Report (IASR)*.

In this Draft 2025 IASR, AEMO seeks stakeholder feedback on the proposed scenarios and assumptions to identify the current risks and opportunities in Australia's energy transition. AEMO provides transparency on the scenarios and their inputs and assumptions, and separately on the methodologies that apply them, to support effective decision making.

This report documents the draft scenarios, and their respective draft inputs and assumptions, that will be finalised after incorporating stakeholder feedback, ahead of deploying them in the relevant planning publications.

The scenario set traverses a range of plausible futures based on key uncertainties facing the energy sector as it decarbonises:

- The **growth of the Australian economy**, and the role the energy sector will play in decarbonising it towards net zero emissions by 2050.
- The **role of demand-side factors** in the energy transition through ongoing consumer investments in increasingly energy efficient appliances and buildings, new preferences in electric and other low-emissions technology alternatives, and in particular the uptake and potential coordination of consumer energy resources (CER).
- **Emerging commercial and industrial sectors** including electrification (switching from other fuels to electricity) in the business, industrial and transport sectors, the development of hydrogen production and manufactured products that utilise hydrogen (such as green iron, green steel and ammonia products), and emerging commercial developments in data centres to support a growing demand for Australian digital technology services.
- The **trends in technology costs** affecting the potential developments required to meet consumers' energy needs in electricity generation, storage and transportation, as well as costs and potential infrastructure developments to maintain and improve Australia's gas networks and markets, including potential gas supply developments that support broader energy consumers and Australia's electricity needs through flexible gas-powered generation facilities.

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

The use of scenarios is enhanced by sensitivity analysis. Sensitivities enable deeper analysis on key uncertainties and the impacts of alternative solutions to those uncertainties.

The information in this report is supported by the Draft 2025 *Inputs and Assumptions Workbook*¹⁷, which provides more granular detail about the inputs and assumptions for use in 2025-26 forecasting, modelling, and planning processes and analyses.

All dollar values provided in this report are in real June 2024 Australian dollars unless stated otherwise.

Consultation on the draft inputs and assumptions released in two stages

The IASR includes a wealth of inputs and assumptions that apply to AEMO's planning publications, and are used across the industry to inform other planning purposes, including for use in RIT-T assessments. Several of the rule changes flowing from the ISP Review involve material expansions to the scope and breadth of considerations within the ISP, and as such AEMO has needed to consider the breadth of the inputs and assumptions appropriate for this.

To extend the IASR to include these additional factors, AEMO has chosen to release the Draft 2025 IASR in two stages for consultation, with many of the traditional inputs and assumptions released in the first stage, while new inputs and some existing but complex assumptions involving decarbonisation will be released in a second stage.

¹⁷ See <https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr>.

The Draft 2025 IASR will be released in two stages for consultation:

- **Stage 1** (this publication) release on 11 December 2024, with consultation from that date and submissions closing on 11 February 2025.
- **Stage 2** release commencing in February 2025, will include emissions reduction parameters as well as new inputs needed to consider new elements of the ISP's scope, with consultation from that date and submissions closing in March 2025.

This Draft 2025 IASR therefore does not include all inputs and assumptions necessary to define each scenario and quantify all aspects of each scenario's decarbonisation narrative. Stage 2 will provide added clarity on:

- The pace of decarbonisation in the Australian economy, particularly emissions reduction expected in the energy sector, and emissions reduction expected outside the energy sector including through sequestration (mainly in the land-use sector). These inputs define each scenario's carbon budgets (applied in the ISP).
- Energy efficiency investments to improve energy productivity and save energy.
- Fuel-switching expectations away from fossil fuels to zero or near-zero emissions alternatives, including electrification and alternative renewable gases.

1.1 Consultation process

Engaging with stakeholders on planning inputs, assumptions and methodologies is essential to shape their development and ensure their effective implementation both in AEMO publications, and to enable action by stakeholders, policy-makers, investors and consumers.

Being transparent and building trust in the way AEMO engages with stakeholders is not only a key part of planning 'best practice', but also one of AEMO's four Corporate Priorities¹⁸.

In developing the 2025 IASR, AEMO has appropriate regard for the consultation requirements set by the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines¹⁹. In considering these minimum requirements, AEMO strives to at least meet, and where appropriate exceed, these guidelines, leading to regular consultation and engagement opportunities using both formal and informal channels such as through AEMO's formal stakeholder consultations, and through various relevant forums such as the Forecasting Reference Group (FRG). These engagement opportunities seek to improve transparency and clarity on AEMO's decision-making processes, modelling approaches and preliminary inputs, and provide transparency on how AEMO has considered stakeholder feedback.

Ahead of the publication of this Draft 2025 IASR, AEMO has undertaken a variety of engagement activities including:

- Consulting selected key stakeholders, including TNSPs, jurisdictional bodies and AEMO's ISP Consumer Panel, to reflect on the 2023 IASR scenario collection and identify issues and opportunities impacting future scenarios and how the existing collection should evolve.

¹⁸ Priority 3: Engaging our stakeholders. See *AEMO Corporate Plan FY 2025*, at <https://aemo.com.au/about/corporate-governance/corporate-plan>.

¹⁹ At <https://www.aer.gov.au/system/files/AER%20-%20Forecasting%20best%20practice%20guidelines%20-%202025%20August%202020.pdf>.

- Consulting all interested stakeholders on the 2025 IASR scenarios via formal consultation, to support early verification of the scenario collection and their narratives.
- Consulting with stakeholders on preliminary forecast components through the FRG²⁰, an open forum that provides an opportunity to engage on key inputs as they are under development.
- Engaging regularly with the ISP Consumer Panel to consult on the scenarios, ensuring that the Panel's experience and consumer perspectives remains at the centre of development of the 2025 IASR.

Table 1 below summarises key engagement activities conducted to date and planned to support the development of the 2025 IASR²¹.

Table 1 Stakeholder engagement on the 2025 IASR

Activity	Date
Activity to Date:	
Pre-development scenario discussions with TNSPs, jurisdictional bodies and the ISP Consumer Panel	April 2024
2025 IASR Scenario Consultation Paper publication	16 July 2024
Forecasting Reference Group – scenario consultation	31 July 2024 and 25 September 2024
2025 IASR Scenarios – consumer verbal submission session	12 August 2024
2025 IASR Scenario Consultation Paper submissions close	13 August 2024
Forecasting Reference Group – preliminary component forecasts	August 2024 – December 2024
ISP Consumer Panel consultation	August 2024 – December 2024
Draft 2025 IASR Stage 1 publication	11 December 2024
Planned activities following the Draft 2025 IASR publication:	
Draft 2025 IASR Stage 1 webinar	23 January 2025
Draft 2025 IASR Stage 1 – consumer verbal submission session	11 February 2025
Draft 2025 IASR Stage 1 submissions close	11 February 2025
Draft 2025 IASR Stage 2 publication	February 2025
Draft 2025 IASR Stage 2 webinar	March 2025
Draft 2025 IASR Stage 2 – consumer verbal submission session	March 2025
Draft 2025 IASR Stage 2 submissions close	March 2025
Draft 2025 IASR submissions reflections webinar	April 2025
2025 IASR publication	By 31 July 2025

For more information about related engagement including engagement for the broader 2026 ISP, see the 2026 ISP Stakeholder Engagement Plan²².

²⁰ See <https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg>.

²¹ Presentations and recordings of webinars are available at <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/opportunities-for-engagement>.

²² At <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2026-integrated-system-plan-isp/opportunities-for-engagement>.

2 Scenarios

The use of scenario planning is an effective practice when planning in highly uncertain environments. Scenarios are a critical aspect of forecasting, enabling the assessment of future risks, opportunities, and development needs in the energy industry. Scenarios are designed to 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 to assess system adequacy with existing and expected investments, and (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. The scenario collection helps to build understanding for the potential benefits or regrets of developments when investing amidst uncertainty, and to identify various risks to the energy transition.

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

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

The proposed scenarios explore critical dimensions and uncertainties affecting the energy sector while meeting emissions reductions objectives set by the commitments of Australia's governments. Key uncertainties include:

- The growth of the Australian economy.
- The development of demand side factors, including CER (including rooftop solar, battery storage and electric vehicles, or EVs), alongside the potential coordination of these resources, and other consumer investments in demand flexibility and energy efficiency.
- Cost outlooks for technologies across electricity generation, storage and transportation, as well as costs and potential infrastructure developments to maintain and improve Australia's gas networks and markets.
- The emergence of hydrogen and related value-added products, as well as biomethane.
- The changing nature of commercial and industrial loads, including the potential for closures and the growth of data centres.

AEMO proposes to develop three scenarios to inform its scenario planning approach used across its forecasting and planning publications to examine a plausible range of variations in the pace and directions of the transition.

AEMO's proposed scenario collection predominantly re-uses the 2023 IASR names to support comparison of modelling outcomes.

Stakeholders have provided input in developing the scenarios

Preliminary stakeholder input throughout 2024 has helped shape the proposed scenarios and their inputs and assumptions in this Draft 2025 IASR. In July 2024, AEMO published the *Draft 2025 IASR Scenarios consultation paper*²³ and received submissions from 50 stakeholders with feedback and suggestions, which have helped shape the revised scenarios in this Draft 2025 IASR.

A summary of stakeholder feedback to the scenarios and AEMO's considerations is in the consultation summary report on AEMO's website²⁴.

2.1 Scenario narratives and descriptions

Scenarios describe plausible future worlds, being a collection of circumstances and external variations that determine the environment in which the energy transition occurs, driving different conditions for energy supply and demand. Scenarios do not describe the outcomes of the planning process and are thus not focused on particular solutions. The collection of scenarios in the IASR enables consideration of combinations of various uncertainties from which further analysis identifies benefits or regrets of various alternative investments to meet the future needs of the NEM power system. The scenarios intentionally span a range of current and future trends in energy consumption, consumer energy investments, and technology costs.

The proposed scenarios in this Draft 2025 IASR reflect a similar scenario collection to the 2023 IASR scenarios, applied in the 2024 ISP, with adjustments reflecting stakeholder feedback including:

- Reduction in anticipated hydrogen developments associated with exports, yet greater recognition of the diverse production opportunities associated with green commodities (such as green iron, steel, alumina and ammonia),
- Moderation of assumptions regarding forecast growth in CER coordination,
- Increased consideration of emerging commercial loads, in particular the growing role of data centres associated with increased digital services provided in Australia.

AEMO considers that the proposed scenarios continue to provide a broad range of futures to inform regulatory network and non-network investment purposes, and enable identification of emerging system adequacy risks (for reliability and security assessments) as well as test the risks of under- and over-investment (for investment planning purposes).

²³ See https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/consultation-paper.pdf

²⁴ See <https://aemo.com.au/-/media/files/major-publications/isp/2025/2025-IASR-Scenarios-Consultation-Summary-Report.pdf>

2.1.1 AEMO's scenario collection

This 2025 IASR scenario collection provides consistency for comparison with the 2023 IASR collection, used in the 2024 ISP and other planning assessments, which AEMO considers is useful for ongoing planning activities. The scenarios provide a breadth of plausible futures to consider power system needs for a range of planning purposes.

Step Change

This proposed scenario refines the 2023 *Step Change* scenario. It is centred around achieving a scale of transformation that supports Australia's contribution to limiting global temperature rise to below 2°C compared to pre-industrial levels. With broader decarbonisation activities outside the electricity sector, Australia's contribution may approach 1.5°C alignment also, though investments to deliver the energy transition would be equivalent to those needed to achieve 2°C alignment only.

The scenario experiences moderate economic conditions on average, with population growth that is also moderate, reflecting long term average trends. Recent economic challenges and current economic conditions affect the starting conditions for the scenario.

In this scenario, consumers continue to provide a key role in the transition, with strong investments in electrification, CER and energy efficiency measures. There is also strong transport electrification, driven by consumer preferences and supported by ongoing government support across various government programs. Investment in CER, particularly in rooftop solar and batteries, reflects that households place high value on the benefits provided by these systems, and typically install relatively large household systems to improve their self-supply.

Emerging commercial and industrial loads have moderate growth outcomes, with data centres and electrification of larger industries leading to material new electricity consumption, but with greater potential growth unrealised. While ambition remains for hydrogen production opportunities to develop, these are slower and more focused on domestic opportunities, reflecting the economic challenges of establishing this new industry.

Notably, compared to the 2023 *Step Change* scenario, consumers are more hesitant to share control of their CER with third-party aggregators or their retailer, such as via virtual power plants (VPPs) and vehicle-to-grid (V2G), although there remains moderate long-term growth in coordinating these resources, and aggregators of consumer resources do become a strong contributor of the transition.

Scenario purpose

To explore the investment needs in a world with strong decarbonisation of the electricity sector, supporting other sectors decarbonising their current energy activities through electrification. Consumers increase their investment in CER, potentially reducing the need for utility-scale alternatives, but the coordination of these resources is more gradual than it could be, with initial difficulties to demonstrate to consumers the great potential value in coordinating these assets as well as reward consumers' choice to provide increased access to their resources to improve the efficiency and effectiveness of the transition.

Progressive Change

This proposed scenario describes a world that aims to achieve Australia's current Paris Agreement commitments of 43% emissions reduction by 2030, amid economic circumstances that are more challenging. The scenario features slower and weaker economic growth domestically, and global ambition to address climate change is less ambitious after current commitments. While achieving current decarbonisation commitments, global action is insufficient to meet the intent of the Paris Agreement to limit temperature rise to less than 2°C, and aggregate emissions over the coming decades are higher than other scenarios as Australia more gradually reaches a net zero emissions economy by 2050.

With weaker economic conditions, major industrial loads are much more likely to wind up Australian operations in favour of offshore alternatives. Australia's emissions-intensive industries are therefore at much greater operational risk, and the scenario explicitly reflects this risk with closures to large energy-intensive loads in each NEM region. Lesser economic and population growth reduces the overall scale of change required to achieve net zero. Lower global investment reduces the speed of technology cost decline, and supply chain challenges relative to other scenarios slow the pace of change affecting Australia's demand for energy. As a result, this scenario requires less investment to achieve the decarbonisation goals.

Progressive Change slows the pace of decarbonisation from consumers and from industry, meaning local benefits from new green industry opportunities are relatively unrealised. With weaker economic activity, consumers continue to embrace ways to support the transition, but with less capacity to invest in demand side factors such as energy efficiency savings and CER, and are even less willing also to give operational control of their resources to third parties, instead preferring to maximise their individual benefits, leading to less coordination of these valuable assets. Consumer adoption of measures to share control of their devices to aggregators is lowest of all the scenarios, reducing the coordination opportunity for these assets.

Scenario purpose

To explore investment needs in a world with headwinds to decarbonisation, including lesser growth across Australia's economy. As a consequence, this scenario examines possible over-investment risks in a more slowly growing economy.

Green Energy

This proposed scenario refines the 2023 *Green Energy Exports* scenario. It 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, utilising all available pathways to net zero including a strong use of electrification, and transformation of other sectors at pace, including action to reduce the emissions intensity of molecular forms of energy. Higher economic growth internationally (and locally) increases technology developments and leading to more rapid cost decline for new tech, and the global demand for green energy is very high given the strong global appetite for low and zero emissions fuel sources. Australia's economy is boosted from hydrogen production opportunities to service domestic and international interest in hydrogen and in green energy products, particularly commodities produced with green energy, such as green iron and steel.

Consumers in this scenario continue to invest in CER, with the greatest relative uptake of these assets, and the greatest relative acceptance of coordination opportunities.

In this future, Australia also embraces a rapid change to the emissions intensity of the energy sector. With strong renewable energy penetration, the opportunity for large-scale development of hydrogen and associated commodities is greater than other scenarios, offsetting emissions intensive components of Australia's economy. Australia's international trading partners, particularly in Asia, provide great opportunities for Australia's potential to develop and deliver green commodities to support their decarbonisation actions. Australia therefore is a relatively strong contributor to global efforts to embrace low/zero emissions alternatives through this transition, with hydrogen replacing declining coal and gas exports.

The scale of the *Green Energy* scenario is smaller relative to previous versions of AEMO's scenarios, reflecting that the scale of hydrogen developments remains uncertain and the opportunity for embedded electricity supply is expected to reduce broader power system needs.

In relation to green commodity exports, exports of hydrogen and value-add commodities are a focus; as the world's largest iron ore exporter for example, and with high renewable energy opportunities, Australia in this scenario is well placed to service the growing global need for green energy commodities.

Considering stakeholder feedback to date, the *Green Energy* scenario will reflect one of two alternatives that are focused around 1.5°C scale decarbonisation actions in Australia, but with more/less embracement of Australia's export potential in this world. In the ISP, AEMO anticipates that one of the scenario variants will be adopted as the scenario narrative, while the other will enable, exploration of the investment impacts of the other variant through sensitivity analysis.

The proposed scenario variants are:

- *Green Energy Exports* – includes development of a hydrogen industry, focusing on value-add hydrogen products such as green iron and steel, for domestic and export. Also includes significant opportunity for hydrogen production and associated manufacturing users to develop products for export, including hydrogen as an energy carrier.
- *Green Energy Industries* – includes development of a hydrogen industry, focusing on value-add hydrogen products such as green iron and steel, for domestic and export. The variant excludes those developments that are expected to support hydrogen exports as an energy carrier, thereby representing a materially smaller hydrogen impact on investment requirements than the *Green Energy Exports* variant.

Both variants are very similar to the 2023 IASR scenario, with domestic and export opportunities, with a reduced level of hydrogen activity – particularly for exports – relative to the 2023 IASR. Value-add commodity developments represent a key potential driver of Australia's economic activity in the medium to long term in this scenario, and Australia is well-placed with strong renewable energy generation potential and critical access to raw materials that may benefit from green energy in conversion processes. The *Green Energy Industries* variant is thematically identical to *Green Energy Exports* in all areas of the scenario's key parameters except for a lower level of new investment in value-add commodities and hydrogen exports.

Scenario purpose

To explore investment needs in a world embracing very rapid decarbonisation to support the strong potential economic benefits Australia’s renewable generation potential. It will therefore identify the scale and speed of investments that may be required to realise this potential in a rapidly decarbonising global economy.

This Draft 2025 IASR may use either the *Green Energy* or the *Green Energy Exports* names in this report when referring to inputs and assumptions that are identical between the two variants. Where the two variants lead to alternative inputs and assumptions, *Green Energy Industries* is also described. Many of the differentiated inputs will be available in the second stage of the Draft IASR release, however AEMO is seeking stakeholder feedback on the appropriateness of the scenario narrative to apply as the scenario.

Matters for consultation

- Are the scenarios, and the scenario collection, suitable for use in AEMO's planning publications including the 2026 ISP? Does the scenario collection support the exploration of a diverse range of possible futures that could occur over the planning horizon?
- Which of the two described scenario variants for the *Green Energy* scenario is the more appropriate variant for application as the scenario in AEMO’s 2025 IASR scenario collection (depending on the planning analysis, AEMO may apply the alternate variant in sensitivity analysis).

2.2 Key scenario parameters

Table 2 summarises decarbonisation targets, key demand drivers, technological trends and other key parameters for each of the scenarios. Details are in the Draft 2025 *Inputs and Assumptions Workbook*. Scenarios vary by the pace of the transition to net zero, considering global, national and sectoral influences, leading to variations in future energy system needs while achieving the emissions reduction policy objectives of Australia’s governments.

Table 2 Key parameters, by scenario

Parameter	<i>Green Energy</i> ^A	<i>Step Change</i>	<i>Progressive Change</i>
National decarbonisation targets	At least 43% emissions reduction by 2030. Net zero by 2050	At least 43% emissions reduction by 2030. Net zero by 2050	At least 43% emissions reduction by 2030. Net zero by 2050
Global economic growth and policy coordination	High economic growth, stronger coordination	Moderate economic growth, stronger coordination	Slower economic growth, lesser coordination
Australian economic and demographic drivers	Higher, with near-term economic growth impacted somewhat by current economic challenges	Moderate economic growth, with near-term economic growth impacted by current economic challenges	Lower
Electrification	Higher electrification efforts to meet aggressive emissions reduction objectives, with faster pace of adoption	High electrification to meet emissions reduction commitments, with pace of adoption reflecting economic conditions	Electrification is tailored to meet existing emissions reduction commitments, with slower adoption given weaker economic circumstances
Emerging commercial loads	Emerging sectors such as data centres match opportunities	Emerging sectors such as data centres match opportunities	Emerging sectors such as data centres experience lower

Parameter	Green Energy ^A	Step Change	Progressive Change
	associated with higher domestic economic drivers	associated with moderate domestic economic drivers	growth as weaker economic circumstances limit technology uptake
Coordination of CER (VPP and V2G)	High long-term coordination, with faster acceptance of coordination	Moderate long-term coordination, with gradual acceptance of coordination	Low long-term coordination, with gradual acceptance of coordination
Energy efficiency	Higher	High	Moderate
Hydrogen use and availability	High production for domestic industries, with moderate exports in the short term, and high exports in the longer term	Moderate-low production for domestic use, with minimal export hydrogen	Low production for domestic use, with no export hydrogen
Industrial load closures	No specific load closures	No specific load closures	Weak economic conditions provide challenging commercial conditions, resulting in load closures across key commercial and industrial facilities
Demand side participation uptake	Higher	Moderate	Lower
CER investments (batteries, PV and EVs)	Higher	High	Lower
Renewable gas blending in gas distribution network ^B	Up to 10% (hydrogen), with unlimited blending opportunity for biomethane and other renewable gases	Up to 10% (hydrogen), with unlimited blending opportunity for biomethane and other renewable gases	Up to 10% (hydrogen), with unlimited blending opportunity for biomethane and other renewable gases
Potential for supply chain limitations affecting demand forecasts	Low	Moderate	High
Global/domestic temperature settings and outcomes ^C	Applies Representative Concentration Pathway (RCP) 1.9 where relevant, consistent with a global temperature rise of ~ 1.5°C by 2100	Applies RCP 2.6 where relevant, consistent with a global temperature rise of ~ 1.8°C by 2100	Applies Representative Concentration Pathway (RCP) 4.5 where relevant, consistent with a global temperature rise of ~ 2.6°C by 2100
International Energy Agency (IEA) 2024 World Energy Outlook scenario alignment	Net Zero Emissions by 2050 (NZE)	Announced Pledges Scenario (APS)	Stated Policies Scenario (STEPS)

A. Both the Green Energy scenario variants, *Green Energy Exports* and *Green Energy Industries*, are equivalent in terms of these key parameters and their qualitative descriptors for each key parameter.

B. Hydrogen blending into the gas distribution network will need to accommodate the technical requirements of distribution pipelines, as well as the capabilities of connected gas appliances. Higher blends than ~10% by volume are assumed possible for industrial use but may require equipment change and/or shifts to dedicated hydrogen transmission pipelines.

C. RCPs were adopted in the Intergovernmental Panel on Climate Change (IPCC) first Assessment Report, see <https://www.ipcc.ch/report/ar5/syr/>.

Matters for consultation

- Are the scenarios parameters, and parameter values, clear and suitably aligned with their respective narratives?

2.3 Scenario likelihoods

The scenario collection defines three broad scenarios that each are plausible and internally consistent and will challenge the scale, timing and need for new investments. Each scenario therefore is not expected to explore uncertainties in the transition that are equally likely. As such, for some planning processes that influence investment planning, it is appropriate to develop a view on the likelihood of each scenario to subsequently identify projects that are optimal across the scenario collection on a scenario-weighted basis. This is particularly important for the ISP, while other analyses such as the gas and electricity statements of opportunities may focus primarily on the most likely scenario, or each scenario individually, when assessing reliability and system adequacy.

AEMO is not providing the weightings of the scenario collection in the Draft 2025 IASR. AEMO prefers to examine scenario likelihood at a point closer to when these scenario weightings are applied, to ensure that the latest market or policy developments are incorporated into this consideration.

AEMO will identify stakeholder engagement opportunities prior to assessing scenario weightings, to ensure interested stakeholders are kept informed of the key milestones for this particular scenario ‘input’.

2.4 Sensitivities

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

There is inherent uncertainty around the specific impacts of any given assumption, and sensitivity analysis is often used to complement scenario-based planning approach to examine the degree to which outcomes may be influenced by individual (or a subset of) scenario settings. Sensitivities can be used to test the impact of varying key input assumptions in the scenarios.

All AEMO’s planning publications tend to include some degree of sensitivity analysis. The specific sensitivities are identified either by evaluating stakeholder uncertainty in the inputs, or by examining scenario outcomes and adapting the modelling to develop deeper and richer insights. In developing the ISP, sensitivity analysis is used to test the resilience of the investments, to increase confidence in the robustness of the investment conclusions. Most commonly, this would involve change to a single variable at a time. There may also be change to multiple variables, although this is less common, as it is then unclear in isolation which variable was the primary driver for any result variation.

This Draft 2025 IASR does not provide an explicit list of sensitivities for the 2026 ISP, however AEMO invites stakeholder feedback on important components or insights to deploy sensitivity analysis on for the 2026 ISP.

Matters for consultation

- What uncertainties are valuable to explore with sensitivity analysis?

3 Inputs and assumptions

3.1 Policy settings

Input vintage	December 2024
Source	Australian governments
Updates since 2023 IASR	Additional policies or aspects of policies have been incorporated since the 2023 IASR.

Australia’s governments have a critical role in setting the pace and breadth of the energy transition through policy direction and international commitments. Efficient investments in the energy transition therefore must have visibility of, and regard to, the direction that is provided through government policy. As a roadmap for the development of the NEM power system to support the energy transition, which informs further policy-making and investment decisions, it is important that the ISP reflects government policy settings to ensure these decisions can be made efficiently. The Draft 2025 IASR considers policies which AEMO must or may consider under NER 5.22.3(b) in determining the power system needs to be met by the ISP and how the ISP contributes to achieving the national electricity objective (NEO).

3.1.1 Identifying the policies to be considered

The framework in the NER that underpins the ISP recognises that policy settings are a key influence on the future investment needs of the power system. Under NER 5.22.3(b), the provision for two separate types of policy collections is outlined:

- Policies that governments have created to meet emissions reduction objectives, provided by them to the AEMC and included in the AEMC Emissions Targets Statement. By providing these policies to the AEMC for this purpose, jurisdictions are outlining those policies that market bodies, including AEMO, must consider, at minimum, in having regard to the emissions reduction element in the national electricity objective. AEMO considers these policies as inputs to the ISP and does so by recognising their influence within AEMO’s forecasting, modelling and scenarios.
- Policies that governments have committed to by sufficiently progressing the policy such that it meets at least one of the eligibility criteria in NER 5.22.3(b)(2), described in the section below. By meeting clear eligibility criteria (for example, by legislating a policy target or by allocating material funding in the jurisdiction’s State or Territory budget papers), jurisdictions are demonstrating a sufficiently high standard of commitment to the policy to indicate that AEMO, in the context of the ISP, should incorporate the policy into its forecasting, modelling and scenarios, with the power system needs to meet the policy at lowest cost identified through the ISP modelling and evaluation process.

The following sub-sections describe how AEMO assesses the eligibility of jurisdictional policies under NER 5.22.3(b) to be considered in the ISP. Section 3.1.2 then provides a description of how AEMO considers eligible policies within its forecasting and modelling approach, and across its scenarios.

Emissions reduction targets in AEMC targets statement

AEMO must consider the emissions reduction targets stated in the Australian Energy Market Commission's (AEMC's) emissions targets statement²⁵ as required by NER 5.22.3(b)(1). Emissions reduction targets are defined in the NER to mean targets set by jurisdictions for reducing greenhouse gas emissions or which are likely to contribute to reducing emissions. The targets statement is structured to reflect these two categories of targets. The requirement for AEMO to consider the targets supports Australian governments' intention that the targets statement provides a publicly available, up-to-date list of government targets that decision-makers, including AEMO, must take into account at a minimum when having regard to achieving the emissions reduction element of the NEO²⁶.

AEMO therefore includes all policies in the AEMC targets statement as inputs to the ISP's development, meaning the ISP modelling results will demonstrate collectively what is required to meet these policies.

Other policies eligible to be considered

Additionally, the NER allow AEMO to consider an environmental or energy policy that is not in the targets statement if:

- it is sufficiently developed for AEMO to identify its impacts on the power system; and
- it meets at least one of the following criteria specified in NER 5.22.3(b)(2):
 - a commitment has been made in an international agreement to implement the 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 a relevant participating jurisdiction; or
 - AEMO has been advised by the Ministerial Council of Energy to include the policy.

By engaging with jurisdictions, AEMO will assess the degree to which each policy is sufficiently developed to enable incorporation into its forecasting and modelling, and whether it sufficiently meets at least one of the five minimum requirements for consideration. This engagement enables AEMO to determine the degree to which the detail of each policy position is compatible with AEMO's various ISP models and forecasts, ensuring that the policy collection includes only those policies that are sufficiently detailed to influence the ISP's development outcomes.

If AEMO assesses that such a policy is eligible to be considered, AEMO's practice is to include these policies that may be considered under the NER alongside the targets in the AEMC targets statement that must be considered under the NER, to ensure the ISP identifies an appropriate scale of investment requirements and power system needs that reflects the governments' aggregate policy positions.

²⁵ At: <https://www.aemc.gov.au/regulation/targets-statement-emissions>.

²⁶ Statutes Amendment (National Energy Laws) (Emissions Reduction Objectives) Bill, Second Reading Speech, Minister for Infrastructure and Transport, Minister for Energy and Mining, the Hon. A. Koutsantonis, 14 June 2023, at <https://hansardsearch.parliament.sa.gov.au/daily/Ih/2023-06-14/38?sid=68968ae9a2ec4e84aa>. Section 32A(5) of the National Electricity Law (NEL) requires decision-makers who are required to have regard to the NEO under the NEL, National Energy Regulations or the NER to consider, at a minimum, the targets stated in the targets statement.

3.1.2 How AEMO includes policies in the ISP

Having considered policies for inclusion, including the targets in the targets statement and other policies eligible to be considered (collectively, '**included policies**'), the ISP process then identifies the power system needs required to collectively meet the objectives of included policies at lowest cost while meeting reliability and security requirements.

Policies influence demand-side factors, supply investments and transmission development

As outlined in this chapter, jurisdictions have developed a wide range of policies to support and drive Australia's net zero transition that AEMO assesses to be included policies. These policies traverse many parts of Australia's economy, focusing on consumers, industry, energy suppliers, and other infrastructure developers.

AEMO's incorporation of these policies may therefore impact the inputs and assumptions for forecasting consumers' energy consumption and demand patterns (including residential, commercial and industrial consumers), as well as the development of supply and transmission developments in the ISP. Incorporating the policies may therefore influence AEMO's energy forecasts, having regard to its forecasting approach, or influence supply and/or network infrastructure developments identified by the ISP models through explicit development constraints (for example, targeting a particular amount of generation technology to be deployed).

AEMO applies included policies in all scenarios

AEMO considers that taking a consistent approach to both emissions targets and other eligible policies best meets the purposes for consideration of the included policies and satisfies the requirements in the AER's CBA Guidelines for how AEMO must conduct its cost-benefit analysis in the ISP.

This analysis requires AEMO to apply a 'weighted average net-economic benefit' approach to all scenarios in assessing the net market benefits of each development path used to select the optimal development path. This means that, when assessing the combination of investments that will be selected as the optimal development path, AEMO's analysis combines the outcomes from all assessed scenarios.

While the optimal development path must demonstrate positive benefits in the most likely scenario, all scenarios are still intrinsically part of the cost benefit analysis, necessitating consistent consideration of policies across each scenario. AEMO considers that an approach in which only some policies are selectively considered in the scenarios would result in inconsistent consideration of the policies across the scenario collection, once the weighted net economic benefits of each scenario are combined to select the optimal development path. AEMO has not identified a need to develop a different approach based on how a policy is assessed to be an included policy under NER 5.22.3(b).

This approach recognises that inefficient outcomes are likely to emerge where power system planning does not adequately consider committed government policy (i.e. the included policies). While it is possible that an included policy's objectives or the actual pace of achievement of those objectives may change after the publication of the ISP, AEMO considers it appropriate for each of the ISP scenarios to model for the stated objectives of these policies.

Recognising policy uncertainty

The ISP rules in the NER do not require AEMO to assess the merits or feasibility of such policies. However, in accordance with the CBA Guidelines and ISP rules, AEMO may explore the robustness of the power system

needs set out in the ISP through sensitivity analysis, in the event that the implementation of included policies is not able to achieve their targeted timeframes due to uncertainties in key assumptions (such as the availability of supply chains).

If an included policy is discontinued or materially amended or new policy is developed and this would result in a change to a key planning input or assumption that may materially change AEMO's planning analysis, such as selection of the optimal development path in the ISP, AEMO would incorporate the changes to the policy in its analysis (or remove it if discontinued). This would involve consultation and may take some time. As the IASR is used for a range of planning assessments, such as the ESOO and GSOO, the extent to which these other assessments are impacted would need to be considered at the time. In terms of the ISP, the rules in the NER enable AEMO to address a material change through consulting on the changed inputs, and consulting on and issuing an ISP update²⁷, or the change may be included in the next ISP, depending on its timing.

3.1.3 Policies included in the Draft 2025 IASR

Table 3 summarises the policies included in this Draft 2025 IASR. The sub-sections following Table 3 describe the various policy settings to be applied in the Draft 2025 IASR scenario collection.

²⁷ NER 5.22.15.

Table 3 Summary of policies included in the Draft 2025 IASR

Policy type	Federal	Australian Capital Territory	New South Wales	Queensland	South Australia	Tasmania	Victoria
Emission reduction	43% below 2005 levels by 2030 and net zero by 2050 under the <i>Climate Change Act 2022</i> . Safeguard Mechanism		Economy-wide emission reduction target relative to 2005 levels of 50% by 2030, 70% by 2035 and net zero by 2050 under the <i>Climate Change (Net Zero Future) Act 2023</i> .	30% reduction below 2005 levels by 2030, 75% reduction by 2035, and net zero by 2050 in the <i>Clean Economy Jobs Act 2024</i> .	Emission reduction target of 60% below 1990 levels by 2050 (legislated) / 60% reduction below 2005 levels by 2030 and net zero by 2050 ²⁸ .	Net zero or lower (already achieved since 2015)	Emission reduction target of 28-33% below 2005 levels by 2025, 45-50% by 2030, 75-80% by 2035 and net zero by 2045 under the <i>Victoria's Climate Change Act 2017</i> and the <i>Climate Change and Energy Legislation Amendment (Renewable Energy and Storage Targets) Act 2024</i> .
Renewable energy development support	82% renewable energy target by 2030. Capacity Investment Scheme		Construct new renewable generation by end of 2029 that can produce the same electricity as 8 gigawatts (GW) in New England REZ, 3 GW in Central-West Orana REZ, and 1 GW elsewhere (<i>New South Wales Electricity Infrastructure Investment Act 2020</i> [NSW EII Act]). REZ Access Schemes to support the coordination of renewable energy and storage investment in REZs	Queensland Renewable Energy Target (QRET) of 50% by 2030, 70% by 2032, and 80% by 2035.	100% net renewable energy by 2030 (AEMC Targets Statement) / 100% net renewable energy by 2027 (pending legislation).	150% Tasmanian Renewable Energy Target (TRET) by 2030 and 200% by 2040.	Victorian Renewable Energy Target (VRET) of 40% by 2025, 50% by 2030, 65% by 2030 and 95% by 2035; VRET auctions 1 and 2.

²⁸ AEMO will model the existing legislated 60% reduction by 2050 (compared to 1990 levels). Although not yet legislated, the *Climate Change and Greenhouse Emissions Reduction (Miscellaneous) Amendment Bill 2024* is expected to pass by publication of the 2025 IASR. AEMO proposes to model this policy, unless it is not sufficiently advanced by publication of the 2025 IASR.

Policy type	Federal	Australian Capital Territory	New South Wales	Queensland	South Australia	Tasmania	Victoria
Storage targets			Target of 2 GW/16 gigawatt hours (GWh) of deep storage by 2030 and 28 GWh of deep storage by 2034 under the NSW EII Act. Firming round tender including the Federal Government contribution under the Capacity Investment Scheme.	Borumba Dam Pumped Hydro (included as an anticipated project ²⁹).		Battery of the Nation (as development candidate).	Renewable Energy Storage target of 2.6 GW by 2030 and 6.3 GW by 2035.
Offshore wind targets							Offshore wind targets of 2 GW by 2032, 4 GW by 2035, and 9 GW by 2040.
Hydrogen policies			Renewable Fuels Scheme of the New South Wales Hydrogen Strategy.		Hydrogen Jobs Plan including 250 megawatts (MW) electrolyser project, 200 MW hydrogen turbine.		
Transmission support policies	Concessional Finance		REZ network infrastructure projects and priority transmission infrastructure projects under the NSW EII Act, including Waratah Super Battery System Integrity Protection Scheme as committed and Central-West Orana Transmission Project as anticipated.	SuperGrid Infrastructure Blueprint and Queensland Renewable Energy Zone (QREZ) infrastructure will be treated as options. CopperString 2032 development is considered to be anticipated with the Townsville to Hughenden connection being modelled			<i>National Electricity (Victoria) Act 2005</i> (NEVA)-supported transmission projects and VicGrid planning of REZs, including some projects treated as development options and others as committed or anticipated projects (for example, Western Renewables Link as anticipated and

²⁹ Projects are modelled as committed or anticipated based on criteria covering five areas of development: land/site acquisition, contracts for major components, planning and other approvals, financing, and construction. Further information is available on AEMO's Generation Information and Transmission Augmentation Information pages accessible via <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information> and <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information>.

Policy type	Federal	Australian Capital Territory	New South Wales	Queensland	South Australia	Tasmania	Victoria
				quantitatively as a REZ network expansion.			the Mortlake Turn-in as committed).
Transmission land payment programs			Strategic Benefit Payments Scheme.	SuperGrid Landholder Payment Framework.			Landholder Payments For A Fairer Renewables Transition.
CER-related policies	Small-scale Renewable Energy Scheme (SRES).	Sustainable Households Scheme and other CER incentives.	Funded actions under New South Wales Consumer Energy Strategy.		Voluntary retailer contributions feed in tariff.		Solar Homes Program and Solar for Business Program.
Electric vehicles	New Vehicle Efficiency Standard, EV fringe benefits tax (FBT) exemption, infrastructure funding (Driving the Nation) and fleet purchases.	ACT Zero Emissions Vehicle strategy 2022-2030. 80-90% of sales ZEV by 2030.	Funded infrastructure initiatives under the New South Wales EV Strategy.	Zero Emission Vehicle (ZEV) Strategy 2022-2032. 50% of new passenger vehicle sales ZEV by 2030, 100% by 2036.	170,000 EVs by 2030. 1,000,000 EVs integrated by 2040.	Stamp duty waiver, 100% government vehicles by 2030.	Zero Emissions Vehicle Roadmap – 50% of light vehicle sales ZEV by 2030.
Energy efficiency	National Construction Code (NCC) 2022 and NCC 2025; National Australian Built Environment Rating Scheme; Greenhouse and Energy Minimum Standards; National Energy Performance Strategy and National Energy Productivity Target; Household Energy Upgrades Fund.	ACT Energy Efficiency Improvement Scheme.	New South Wales Energy Savings Scheme and Peak Demand Reduction Target under the New South Wales Energy Security Safeguard.		South Australian Retailer Energy Productivity Scheme.		Victorian Energy Upgrades program.
Other government policies		Policy on new gas connections.					Gas Substitution Roadmap.

3.1.4 Australia's emissions reduction targets

Climate Change Act (2022) (C'th)

In September 2022, the Federal Government legislated Australia's economy-wide emissions reduction target, committing to reducing greenhouse gas emissions by 43% below 2005 levels by 2030 and achieving net zero emissions by 2050. These targets are complemented by an emissions budget for the period 2021-2030 amounting to 4,381 million tonnes of carbon dioxide equivalent (MtCO₂-e)³⁰. AEMO must consider these targets as they are in the emissions targets statement, and the target has also been submitted to the United Nations Framework Convention on Climate Change (UNFCCC) as Australia's updated Nationally Determined Contribution (NDC) under the Paris Agreement. AEMO expects to include Australia's 2035 NDC when it is determined.

Powering Australia Plan

The Federal Government has committed to achieve an 82% share of renewable generation by 2030 as announced in the *Powering Australia Plan*³¹. AEMO must consider this target as it is specified in the emissions targets statement.

Safeguard Mechanism

The Safeguard Mechanism is a federal policy, enacted through legislation³², aimed at reducing emissions at Australia's largest industrial facilities in line with Australia's 2030 and 2050 emission reduction targets. It was reformed in 2023 and sets out a number of targets for participating industrial facilities, including the requirement that net emissions from all Safeguard facilities should not exceed 100 MtCO₂-e in 2030 (and net zero in 2050). AEMO may consider the policy given it meets the legislative requirements of NER 5.22.3(b)(2); it does not feature in the AEMC Emissions Targets Statement.

The Safeguard Mechanism is expected to influence industrial electrification volumes, energy efficiency investments, and operational efficiency improvements. AEMO captures these within its electrification and energy efficiency forecasts (both are supported by forecasts that AEMO engages suitably qualified consultants to provide), as well as within its large industrial load forecasts (informed by industrial surveys).

State-based emissions targets

All states and territories in Australia have net zero emissions ambitions that are either legislated or currently introduced in state parliaments. AEMO must consider each of these that are captured within the AEMC Emissions Targets Statement.

State-based positions regarding emissions reduction are shown in Table 4.

³⁰ The emissions budget is not directly found in the Act but is referenced in Australia's Nationally Determined Contribution; see <https://unfccc.int/sites/default/files/NDC/2022-06/Australias%20NDC%20June%202022%20Update%20%283%29.pdf>.

³¹ At <https://www.energy.gov.au/government-priorities/australias-energy-strategies-and-frameworks/powering-australia>.

³² At <https://www.dcccew.gov.au/climate-change/emissions-reporting/national-greenhouse-energy-reporting-scheme/safeguard-mechanism>. Enacted via the *National Greenhouse and Energy Reporting Act 2007* and other legislation.

Table 4 State-level economy-wide emission reduction ambitions relative to 2005 levels (in financial year unless otherwise stated)

	New South Wales	Australian Capital Territory ^{A,B}	Queensland	South Australia ^A (Calendar year)	Tasmania ^B	Victoria (Calendar year)	Western Australia	Northern Territory
Instrument	<i>Climate Change (Net Zero Future) Act 2023</i>	<i>Climate Change and Greenhouse Gas Reduction Act 2010</i>	<i>Clean Economy Jobs Act 2024</i>	60% by 2050 relative to 1990 level as legislated via <i>Climate Change and Greenhouse Emissions Reduction Act 2007</i> . Proposed updates to 2030 and 2050 targets by the <i>Climate Change and Greenhouse Emissions Reduction (Miscellaneous) Amendment Bill 2024</i> , introduced in August 2024 to the South Australian Parliament.	<i>Climate Change (State Action) Act 2008</i> as amended by the <i>Climate Change (State Action) Amendment Act 2022</i> .	2050 legislated via <i>Victorian Climate Change Act 2017</i> ; other targets formalised via the <i>Climate Change and Energy Legislation Amendment (Renewable Energy and Storage Targets) Act 2024</i> .	<i>Climate Change Bill 2023</i> , introduced in Parliament in November 2023 but not yet passed. Sets out a net zero target as well as the requirement to set interim targets (not yet announced, to be set as soon as practicable following Australia's submission of an NDC).	Aspirational target published in "Climate Change Response – Towards 2050", not legislated
2025		50-60% reduction				28-33% reduction		
2030	50% reduction	65-75% reduction	30% reduction	60% reduction	Net zero or lower	45-50% reduction		
2035	70% reduction		75% reduction			75-80% reduction		
2040		90-95% reduction						
2045		Net zero				Net zero		
2050	Net zero		Net Zero	60% reduction (legislated) and Net Zero (amendment in Parliament)		Net zero	Net Zero	Net Zero

Notes: Timing of emissions reduction ambition may be rounded to the nearest five-yearly increment, for presentation purposes.

A. Relative to 1990 levels.

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

For the 2026 ISP, AEMO proposes to exclude the targets for Tasmania and Australian Capital Territory on the basis that neither are appropriate to quantify within the ISP models:

- Tasmania has already achieved its net zero target (in 2015).
- The Australian Capital Territory has already achieved its objectives through direct support to inter-state renewable energy projects (which is an implementation that is not modellable within AEMO's ISP models).

3.1.5 Relevant federal and state energy policies

New South Wales Electricity Infrastructure Roadmap

In 2020, the New South Wales Government released its Electricity Infrastructure Roadmap³³, and enabling legislation, the *Electricity Infrastructure Investment Act 2020* (NSW EII Act), was passed that provided a plan to transform New South Wales's electricity system reliably and affordably. The NSW EII Act sets out 'minimum infrastructure investment objectives'³⁴ to construct, by 31 December 2029, a minimum target of the equivalent of 12 gigawatts (GW) of new renewable energy capacity. This is within the AEMC Emissions Targets Statement, and therefore must be considered by AEMO.

The implementation of these objectives is underpinned by Long-Term Energy Service Agreements (LTESAs) with the New South Wales Consumer Trustee that provide revenue protection to project developers.

Although these objectives are specified for these REZs, the generation constructed and operated under LTESAs are not required to be located in a REZ if the Consumer Trustee is satisfied the project demonstrates "outstanding merit". This target is proposed to be implemented as a trajectory to 33,600 gigawatt hours (GWh) by 2030, in line with the 2023 *Infrastructure Investment Opportunities Report*.

The NSW EII Act also sets an infrastructure investment objective for the construction of long-duration storage infrastructure (classified as storage with capacity that can be dispatched at full power for at least eight hours) with at least storage of 16 GWh and 2 GW capacity by the end of 2029. The New South Wales Government has legislated a second target for long-duration storage, of an additional 12 GWh, for a cumulative 28 GWh, to the end of 2033, in addition to Snowy 2.0³⁵.

The target of 16 GWh of long duration storage capacity is within the AEMC Emissions Targets Statement, and therefore must be considered by AEMO, and the additional 12 GWh of long duration storage which is legislated will also be considered.

The infrastructure investment objectives exclude any generation capacity that was either existing or committed at or before AEMO's November 2019 Generation Information page. Therefore, any generation that has progressed to committed or existing since that time is included as contributing to the achievement of these objectives.

The 2025 IIO Report is anticipated to be released prior to the finalisation of the 2025 IASR. Where practical, AEMO will consider any adjustments to the IIO development trajectories within that publication in the 2026 ISP.

³³ See <https://www.energy.nsw.gov.au/nsw-plans-and-progress/major-state-projects/electricity-infrastructure-roadmap>.

³⁴ *Electricity Infrastructure Investment Act 2020* (NSW), s.44, at <https://legislation.nsw.gov.au/view/whole/html/inforce/current/act-2020-044>.

³⁵ See <https://www.parliament.nsw.gov.au/bills/Pages/bill-details.aspx?pk=18673>.

REZ access schemes

Access schemes are a key part of the NSW EII Act, which support the coordination of renewable energy and storage investment in REZs. Generation and storage projects that seek to connect to the network infrastructure where a REZ access scheme applied may be subject to access rights – either through application or competitive tender. The fees paid to gain access rights contribute to community benefit and employment purposes in the region.

A REZ access scheme can provide investor certainty, streamline the grid connection process, and govern the volume of projects that may connect into REZ network infrastructure. AEMO proposes to model REZ access schemes as they are developed by EnergyCo, currently including:

- **Central-West Orana** – a maximum connection limit of 7.7 GW of new variable renewable energy (VRE) is applied, and is lifted if transmission augmentation increases the REZ capacity beyond the scope of the Central-West Orana REZ Network Infrastructure Project³⁶.
- **South West New South Wales** – a maximum connection limit of 3.98 GW of new VRE is applied, and is lifted if transmission augmentation increases the REZ capacity beyond the scope delivered by Project EnergyConnect, HumeLink and Victoria – New South Wales Interconnector West (VNI West)³⁷.

Queensland Energy (Renewable Transformation and Jobs) Act 2024

The *Energy (Renewable Transformation and Jobs) Act 2024* (Qld)³⁸ includes a range of measures for the development of renewable and firming generation in Queensland, including providing for the establishment of REZs and facilitating transmission investments.

The Act includes targets to achieve 50% of electricity generated in Queensland to be from renewable energy sources by 2030, 70% by 2032, and 80% by 2035. The Queensland Renewable Energy Target (QRET) will be incorporated in the modelling for all scenarios as it is a legislated target and is also included in the AEMC's emissions targets statement.

Additional Queensland Government measures include the development of Borumba Pumped Hydro and the hydrogen-ready Brigalow Peaking Power Plant. In addition, the Act establishes planning and governance frameworks for REZs, and requires the government to develop a Queensland SuperGrid Infrastructure Blueprint, the next of which is due for release by May 2025. AEMO will incorporate these other developments in accordance with its normal project commitment assessments as evaluated in AEMO's regular Generation Information and Transmission Augmentation Information processes, and its consultation on the Draft 2025 *Network Expansion Options Report*.

³⁶ EnergyCo. *Notification of Draft Headroom Assessment in the Central-West Orana REZ*, at <https://www.energyco.nsw.gov.au/sites/default/files/2024-08/Notification%20of%20Draft%20Headroom%20Assessment%20for%20the%20Central-West%20Orana%20REZ%20Access%20Scheme.pdf>.

³⁷ EnergyCo. *South West REZ access rights tender update*, at <https://www.energyco.nsw.gov.au/news/south-west-rez-access-rights-tender-update>.

³⁸ See <https://www.legislation.qld.gov.au/view/whole/html/inforce/current/act-2024-015>.

Tasmanian Renewable Energy Target (TRET)

The TRET is a renewable energy target in the *Energy Co-ordination and Planning Act 1995* (Tas)³⁹ requiring development of sufficient renewable energy capacity to double current electricity consumption (or 21,000 GWh of production) by 2040 with an interim target of 150% (or 15,750 GWh) by 2030.

This policy will be incorporated in all scenarios as it is legislated and published in the emissions targets statement.

South Australia's net-100% renewable energy generation target

The South Australian Government has announced and is seeking to legislate for a target of net 100% renewable energy generation by 31 December 2027⁴⁰. This means that South Australia will target generation of enough additional renewable energy (to be consumed within South Australia and exported interstate) to net the volume of local fossil fuel generation. This is an update of the net 100% renewable energy generation by 2030 target (which remains in the emissions targets statement) that existed previously in South Australia.

AEMO proposes to model the 2027 target given the South Australian Parliament is considering legislation for the proposed new target. AEMO will continue to engage with the South Australian government to evaluate the appropriateness of this as the 2025 IASR is finalised.

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

Underpinning Victoria's electricity sector contributions to emissions reductions are the Victorian Renewable Energy Target (VRET), the Victorian Energy Upgrades (VEU) program, and a target for 50% zero-emission vehicles new sales by 2030 as outlined in the Zero Emissions Vehicle Roadmap.

The *Renewable Energy (Jobs and Investment) Act 2017* (Vic)⁴¹ contains the VRET, which mandates 40% of the region's generation (including CER) be sourced from renewable sources by 2025, and 65% by 2030, and 95% by 2035⁴². These targets will be included in all scenarios of the 2024-25 forecasting and planning activities (including specific projects that are funded via VRET auctions conducted to date⁴³).

The legislation includes offshore wind energy generation targets of at least 2 GW of offshore generation capacity by 2032, 4 GW by 2035, and 9 GW by 2040.

The legislation also includes energy storage targets⁴⁴ of at least 2.6 GW of storage and dispatch capacity by 2030, and at least 6.3 GW of storage and dispatch capacity by 2035.

AEMO will include these three targets (VRET, the offshore wind target and the storage target) in all scenarios as all are included in the emissions targets statement.

³⁹ *Energy Co-ordination and Planning Act 1995* (Tas) s.3C, at <https://www.legislation.tas.gov.au/view/html/inforce/current/act-1995-047>.

⁴⁰ *Climate Change and Greenhouse Emissions Reductions (Miscellaneous) Amendment Bill 2024* (SA), clause 4, at [https://www.legislation.sa.gov.au/lz?path=/b/current/climate%20change%20and%20greenhouse%20emissions%20reduction%20\(miscellaneous\)%20amendment%20bill%202024](https://www.legislation.sa.gov.au/lz?path=/b/current/climate%20change%20and%20greenhouse%20emissions%20reduction%20(miscellaneous)%20amendment%20bill%202024).

⁴¹ See <https://www.legislation.vic.gov.au/in-force/acts/renewable-energy-jobs-and-investment-act-2017/003>.

⁴² See <https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets>.

⁴³ See <https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets/victorian-renewable-energy-target-auction-vret1>.

⁴⁴ At <https://www.energy.vic.gov.au/renewable-energy/victorian-renewable-energy-and-storage-targets>.



Large-scale Renewable Energy Target (LRET)

Australia's Renewable Energy Target (RET) established targets for large-scale and small-scale renewable investments. The LRET aims to deliver 33,000 GWh of electricity from renewable sources each year until 2030. AEMO modelling captures the operation the LRET until the end of the currently legislated targets in 2030.

Capacity Investment Scheme

In December 2022, the Federal Government announced the Capacity Investment Scheme, which provides a national framework to drive new renewable and dispatchable capacity. The scheme provides a revenue underwriting mechanism aimed at unlocking around \$10 billion of investment in clean dispatchable power to support energy reliability and security.

Three Capacity Investment Scheme tenders have been launched to date to support the scheme. A fourth upcoming tender will announce successful bids in Q3 2025.

In November 2024, the Federal Government released a *Market brief on Renewable Energy Transformation Agreement allocations by jurisdiction November 2024*, outlining updated allocations by jurisdiction as agreed as part of Renewable Energy Transformation Agreements between the Federal Government and other jurisdictions.

AEMO will incorporate the outcomes of Capacity Investment Scheme tenders in its modelling, as well as the cumulative dispatchable allocations by jurisdiction. As the mechanism continues to develop, AEMO may incorporate further detail into the 2026 ISP.

Battery of the Nation

The Battery of the Nation project announced by Hydro Tasmania represents an increase in capacity of existing hydro generators, as well as the development of additional pumped hydro generation in Lake Cethana⁴⁵. Hydro Tasmania suggests that with further interconnection, upgrading assets and adapting hydropower operation can result in up to 390 megawatts (MW) of additional capacity across Western Tasmania, Gordon Power Station and Tarraleah Power Station.

AEMO proposes to model the Cethana pumped hydro station as a separate build candidate with its potential development optimised within the ISP models. Further interconnection with Tasmania allows for more efficient re-development of Tarraleah, Gordon Power Station and West Coast hydro generation by repurposing maintenance expenditure resulting in collective additional capacity.

South Australia Firm Energy Reliability Mechanism

The Government of South Australia has developed a framework to support the provision of long duration firm capacity to enable a reliable and resilient power system for the state. The Firm Energy Reliability Mechanism (FERM) is planned to be calculated as part of the annual South Australia Electricity Development Plan, to be supported by a form of tender process. Subject to the release of sufficient detail to define its impact upon power

⁴⁵ See [unlocking-tasmania's-energy-capacity_december-2018.pdf](#) for further information on the impact of greater interconnection on existing latent capacity.

system needs and a clear pathway to implementation before the finalisation of the 2026 ISP, AEMO intends to consider this policy further prior to finalising the 2025 IASR.

Jurisdictional policies regarding hydrogen development

Various jurisdictions have announced funding to support the establishment of hydrogen technologies, particularly renewable hydrogen production. AEMO proposes to include the following policies:

- The South Australian Government is supporting a number of projects, including the Hydrogen Jobs Plan⁴⁶ which seeks to establish hydrogen production and power generation in South Australia. The output from a 250 MW electrolyser project is included in the hydrogen production forecasts for each scenario. The electrolyser is expected to be complemented with a 200 MW hydrogen-capable generator. The generator is assessed according to AEMO's standard generation commitment criteria.
- The New South Wales Hydrogen Strategy⁴⁷ includes the Renewable Fuels Scheme, established in the *Electricity Supply Act 1995*⁴⁸. The Scheme targets increasing production of renewable hydrogen up to 8 petajoules (PJ) per annum by 2030⁴⁹. There is a consultation underway to expand the scheme to include other fuels. The effect of the currently legislated Renewable Fuels Scheme is considered in forecasting hydrogen production needs for each scenario.

3.1.6 Transmission project support

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

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

The VNI West project is also subject to NEVA Orders which act to accelerate the project and specify requirements for its configuration. These orders relate only to the Victorian side of VNI West. VNI West is currently an Actionable ISP project.

⁴⁶ See <https://www.ohpsa.sa.gov.au/about-the-project> and <https://www.statebudget.sa.gov.au/our-budget/jobs-and-economy/hydrogen>.

⁴⁷ See <https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard/renewable-fuel-scheme#:~:text=The%20Renewable%20Fuel%20Scheme%20was%20established%20under%20the,will%20commence%20in%202024%20and%20run%20until%202044>.

⁴⁸ See <https://legislation.nsw.gov.au/view/whole/html/inforce/current/act-1995-094>.

⁴⁹ *Electricity Supply (General) Regulation 2014* (NSW), at <https://legislation.nsw.gov.au/view/whole/html/inforce/current/sl-2014-0523>.

AEMO will consider the development of projects supported under the NEVA as transmission options in the Draft 2025 *Network Expansion Options Report*, or as committed or anticipated projects in some cases, as outlined in AEMO's Transmission augmentation information page⁵⁰.

Rewiring the Nation

In 2022, the Federal Government announced the Rewiring the Nation program, which aims to modernise the grid and ensure the country's transmission networks are ready for the renewables and storage investment needed for the decarbonisation task ahead. The framework aims to prioritise transmission projects of national significance and support a transition to renewable energy. The Rewiring the Nation program provides up to \$20 billion in finance at concessional rates to minimise the cost of investments that will help strengthen, grow and transition Australia's electricity grids. Managing the Rewiring the Nation fund, the Clean Energy Finance Corporation is administering \$19 billion of low-cost finance for Rewiring the Nation. An additional \$1 billion has been allocated to the Rewiring the Nation Special Account, which enables the Government to invest in the timely delivery of eligible projects. The Federal Government has so far entered the following agreements with NEM states:

- The Federal Government has committed \$4.7 billion (which joins 3.1 billion from the New South Wales Transmission Acceleration Facility) to help New South Wales realise its Electricity Infrastructure Roadmap and unlock priority projects including VNI West, HumeLink, Sydney Ring, and the Central-West Orana, New England, Hunter Central Coast, and South-West REZs.
- The Federal Government has committed to provide low-cost finance to Marinus Link as well as support for eligible Battery of the Nation and grid-firming projects in Tasmania.
- The Federal Government has committed \$2.25 billion of concessional financing to Victorian projects, including \$750 million for VNI West as well as concessional financing for Victorian REZ projects, including offshore wind projects.

AEMO will include concessional finance in the 2026 ISP where any of the benefit will be shared with consumers for projects where funding is publicly committed or an agreement is likely to be executed, consistent with the recommended approach in the AER's CBA Guidelines⁵¹. Details regarding concessional finance will be maintained on the Transmission Augmentation Information Page⁵².

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

The New South Wales Minister for Energy and Minister for Climate Change may direct that REZ network infrastructure projects and PTIPs be carried out.

⁵⁰ See <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information>.

⁵¹ AEMO. *Cost Benefit Analysis Guidelines*, at <https://www.aer.gov.au/industry/registers/resources/reviews/2024-review-cost-benefit-analysis-and-regulatory-investment-test-guidelines/final-decision>.

⁵² See <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information>.

Waratah Super Battery is a PTIP under the NSW EII Act⁵³, and is listed as a committed project in AEMO's transmission augmentation information page⁵⁴. It is being delivered with a System Integrity Protection Scheme (SIPS) to improve transfer capabilities from: Central New South Wales (CNSW) to Sydney, Newcastle and Wollongong (SNW); Southern New South Wales (SNSW) to CNSW; and Northern New South Wales (NNSW) to CNSW, while the scheme is in place.

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

The Central-West Orana Transmission project is a REZ network infrastructure project under the NSW EII Act⁵⁵ and is listed as an anticipated project in AEMO's transmission augmentation information page⁵⁶. EnergyCo is overseeing the planning and approval processes for the project and has selected ACE Energy as the first ranked network operator for the project.

Queensland SuperGrid Infrastructure Blueprint, Queensland REZ Roadmap, and CopperString 2032

The Queensland Government SuperGrid Infrastructure BluePrint⁵⁷ was released in 2022 and is scheduled to be updated in 2025. The Queensland REZ Roadmap⁵⁸, published in March 2024, laid out the framework to develop and connect grid-scale renewable energy.

AEMO will consider the development of the blueprint projects and the Queensland REZ Roadmap as transmission options in the Draft 2025 *Network Expansion Options Report*.

The Queensland Government has announced that it is working to deliver the CopperString 2032 transmission project – approximately 1,100 km of transmission lines from Mount Isa to south of Townsville – to connect the North West Minerals Province to the NEM. CopperString 2032 is listed as an anticipated project in AEMO's transmission augmentation information page⁵⁹.

Only the Townsville to Hughenden connection will be modelled as a REZ network expansion. Insufficient data is available to AEMO at this time to capture the currently off-grid load and development opportunities at Mount Isa and the broader western minerals province; the full connection may be considered in future planning activities.

Jurisdictional landholder payment schemes

In some jurisdictions, landholder payment schemes have been established to provide payments to landholders for hosting transmission infrastructures. These payments are in addition to any compensation that is paid under

⁵³ For more information, see <https://www.energyco.nsw.gov.au/projects/waratah-super-battery>.

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

⁵⁵ See <https://www.energyco.nsw.gov.au/cwo>.

⁵⁶ See <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information>.

⁵⁷ At https://www.epw.qld.gov.au/_data/assets/pdf_file/0030/32988/queensland-supergrid-infrastructure-blueprint.pdf.

⁵⁸ At https://www.epw.qld.gov.au/_data/assets/pdf_file/0036/49599/REZ-roadmap.pdf.

⁵⁹ See <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information>.

conventional land acquisition frameworks. AEMO will model landholder payment schemes in New South Wales, Queensland and Victoria. If new landholder payment schemes are announced, AEMO will use reasonable endeavours to model them.

New South Wales

In October 2022, the New South Wales Government established a Strategic Benefit Payments Scheme⁶⁰ for new major transmission projects. Under this scheme, private landowners hosting new high voltage transmission projects critical to the energy transformation and future of the electricity grid will be paid a set rate of \$200,000 (in real 2022 dollars) per kilometre of transmission hosted, paid out in annual instalments over 20 years.

Queensland

Taking effect from May 2023, Powerlink's SuperGrid Landholder Payment Framework⁶¹ offers payments to landowners that host new transmission infrastructure. Powerlink has also become the first transmission company in Australia to offer payments to landholders with properties adjacent to new transmission infrastructure. To represent this framework, AEMO will apply a cost of \$230,000 (in 2023 dollars) per km of new transmission, paid out in a lump sum – noting that landholders can decide between a lump sum or annualised payments.

Victoria

The Victorian Government announced in 2023 it will pay landholders whose properties host new power transmission lines \$200,000 over a 25-year period in annual instalments indexed to inflation, to help smooth the state's transition to a 95% renewable grid by 2035.

3.1.7 Nuclear technology

AEMO is technology agnostic in its planning functions, and in particular in its assessment of generation options in identifying power system needs in the ISP. Rather, AEMO's analyses identifies efficient combinations of generation, storage and network developments to provide a reliable and secure power system for consumers.

Currently, Section 140A of the *Environment Protection and Biodiversity Conservation Act (1999)* (C'th) prohibits the Federal Government from approving the construction or operation of a nuclear installation that is for the purpose of generating electricity. This is current legislation that prohibits a particular electricity generation technology, and as such AEMO cannot consider the technology option in any of its scenarios.

If this legislation were changed, AEMO would endeavour to include the new policy, noting that AEMO would need to develop and consult on the new inputs and assumptions relevant to each technology.

3.1.8 Policies affecting consumer demand

Numerous state and federal policies support investment in energy savings measures and the development of CER, including small-scale technology certificates (STCs) and Australian carbon credit units (ACCUs).

⁶⁰ See <https://www.energyco.nsw.gov.au/sites/default/files/2023-01/overview-strategic-benefit-payments-scheme.pdf>.

⁶¹ See <https://www.powerlink.com.au/sites/default/files/2023-05/SuperGrid-Landholder-Payment-Framework.pdf>.

Energy efficiency policies

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

- Building energy performance requirements contained in the Building Code of Australia (BCA) 2010, the National Construction Code (NCC) 2019, NCC 2022, and NCC 2025⁶².
- The Nationwide House Energy Rating Scheme (NatHERS), which is a pathway for new dwelling designs to demonstrate compliance with the NCC 2022.
- Building rating and disclosure schemes of existing buildings such as the National Australian Built Environment Rating System (NABERS) Energy for Offices and Commercial Building Disclosure (CBD).
- National Framework for Disclosure of Residential Energy Efficiency Information sets out high-level policy settings for future energy performance disclosure regimes.
- The Equipment Energy Efficiency (E3) program (or Greenhouse and Energy Minimum Standards [GEMS]) of mandatory energy performance standards and/or labelling for different classes of appliances and equipment.
- State-based schemes, including the New South Wales Energy Savings Scheme (ESS), the Victorian Energy Upgrades (VEU) program, the South Australian Retailer Energy Productivity Scheme (SA REPS), and the Australian Capital Territory's Energy Efficiency Improvement Scheme.
- The National Energy Performance Strategy (NEPS)⁶³, which provides a framework for policies that improve energy performance through energy efficiency, demand flexibility, and electrification or fuel switching. Energy efficiency policies such as the NCC are considered supporting actions under the NEPS.
- The Clean Energy Finance Corporation (CEFC) Household Energy Upgrades Fund (HEUF).

CER and electric vehicle policies

Australian governments have announced numerous policies to encourage CER investment, including:

- The Small-scale Renewable Energy Scheme (SRES) to encourage investment in small-scale PV.
- The New South Wales Consumer Energy Strategy, which includes funded actions to give one million households access to rooftop solar and a battery system by 2035, rising to nearly 1.5 million by 2050.
- The Victorian Government's Solar Homes Program to enable the installation of solar systems, hot water systems and batteries, for over one million homes to be powered by renewable energy.

Governments have also promoted increased uptake in EVs through:

- The Federal Government's New Vehicle Efficiency Standard which requires each manufacturer to meet per kilometre efficiency standards for new cars, 4WDs and utility vehicles.
- EV infrastructure initiatives funded under the New South Wales Government's EV Strategy to ensure that EVs represent most new car sales by 2035.

⁶² NCC 2025 is undergoing continued development. See <https://consultation.abcb.gov.au/engagement/ncc-2025-public-comment-draft/>.

⁶³ See <https://www.dcceew.gov.au/energy/strategies-and-frameworks/national-energy-performance-strategy>.

- Victoria's Zero Emissions Vehicle Roadmap, which aims for 50% of light vehicle sales to be zero emission vehicles (ZEVs) by 2030, and for all public transport buses to be ZEVs from 2025.
- Queensland's Zero Emission Vehicle Strategy 2022-2032 which plans for ZEVs to account for 50% of new passenger vehicle sales by 2030, and 100% by 2036.
- The South Australian Government's goal for 170,000 EVs by 2030 and one million EVs to be integrated into the electricity system over the next 20 years.

New South Wales Energy Security Safeguard

New South Wales has a target for energy efficiency savings through its established Energy Security Safeguard⁶⁴, both in general through the Energy Savings Scheme⁶⁵, and at time of peak demand through the Peak Demand Reduction Scheme (PDRS)⁶⁶. Both are modelled, with details in Section 3.3.12 for energy efficiency and Section 3.3.15 for the PDRS (the PDRS is explicitly included in the emissions targets statement).

Victoria Gas Substitution Roadmap

The Victorian Government released its Gas Substitution Roadmap⁶⁷ in October 2022 (updated in 2023⁶⁸) to support net zero emissions in Victoria in 2050 and halving emissions by 2030. The Roadmap outlines options for replacing gas usage (such as energy efficiency, electrification, hydrogen and biogas) to reduce emissions and consumer costs. On 1 January 2024, the Victoria Planning Provisions were amended to ban new residential gas connections for developments requiring a planning permit⁶⁹.

Australian Capital Territory ban on new gas connections

The Australian Capital Territory Parliament in June 2023 passed the *Climate Change and Greenhouse Gas Reduction (Natural Gas Transition) Amendment Act 2023*⁷⁰, allowing the Australian Capital Territory Government to develop regulation banning new gas connections in the territory. Regulation preventing new gas network connections in most areas commenced on 8 December 2023⁷¹.

3.2 Emissions and climate assumptions

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

⁶⁴ See <https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard>.

⁶⁵ See <https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard/energy-savings-scheme>.

⁶⁶ See <https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard/peak-demand-reduction-scheme>.

⁶⁷ See <https://www.energy.vic.gov.au/renewable-energy/victorias-gas-substitution-roadmap>.

⁶⁸ See https://www.energy.vic.gov.au/_data/assets/pdf_file/0027/691119/Victorias-Gas-Substitution-Roadmap-Update.pdf.

⁶⁹ See <https://www.gazette.vic.gov.au/gazette/Gazettes2024/GG2024S001.pdf>.

⁷⁰ See https://www.legislation.act.gov.au/b/db_66446/.

⁷¹ See <https://www.climatechoices.act.gov.au/energy/canberras-electrification-pathway/preventing-new-gas-network-connections#:~:text=Compliance%20and%20enforcement-,Overview,and%20electrify%20Canberra%20by%202045>.

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

AEMO scenarios in this Draft 2025 IASR will be underpinned by national carbon budgets that are compatible with global temperature targets (relating to Relative Concentration Pathways, see Section 3.2.2 for more details) by aligning to International Energy Agency (IEA) World Energy Outlook (WEO) 2024 scenarios.

AEMO develops carbon budgets to apply to the electricity sector by engaging multi-sectoral modelling to identify the decarbonisation efforts across the economy needed to meet the temperature rise goals associated with each scenario. The model applies four decarbonisation pillars to reduce emissions in a growing economy:

- Electrification and other fuel-switching away from emissions-intensive fuels.
- Energy efficiency improvements to improve energy productivity.
- Decarbonising the electricity sector.
- Non-energy emissions reduction and emission sequestration.

To achieve the emissions pathways therefore relies on actions not just within the energy sector but also in other parts of Australia's economy, including the agriculture and land use sectors. Least-cost solutions for Australia's economy will consist of a mixture of these four pillars (discussed in Section 3.3.4), and earlier actions to decarbonise will reduce the need for more aggressive actions later.

The multi-sectoral modelling will translate the national carbon budgets to NEM-wide carbon budgets that ultimately underpin the ISP, as discussed in the current *ISP Methodology*⁷². These NEM-wide carbon budgets recognise that the electricity sector has a key role to play as an early mover by enabling the decarbonisation of other sectors via electrification and increased energy efficiency.

AEMO must consider the policies in the AEMC emissions targets statement under NER 5.22.3(b)(1) in determining the power system needs to be met by the ISP and how the ISP can contribute to achieving the emissions reduction targets as part of achieving the national electricity objective. The scenarios therefore also include a number of complementary carbon budgets and state government policy as described in the previous sections. The derivation of NEM-wide and state-level targets is further discussed in Section 3.2.3.

The multi-sectoral modelling commissioned by AEMO is ongoing and will be separately consulted on as part of the Draft 2025 IASR Stage 2, to be published in February 2025. As such, this section does not present the proposed carbon budgets to be modelled in the 2026 ISP.

3.2.1 Alignment to IEA World Energy Outlook scenarios

AEMO's Draft 2025 IASR scenarios have been aligned to the IEA 2024 WEO scenarios to anchor them to global narratives on developments and commitments to the Paris Agreement. This means AEMO's scenarios are consistent with global economic settings and temperature goals. IEA's scenarios provide a global backdrop to economic and multi-sectoral modelling. They describe the transition towards a lower carbon economy with

⁷² At <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/isp-methodology>.

differing levels of ambition and the associated changes in energy consumption and production at international and regional level.

AEMO's Draft 2025 IASR scenarios align to the WEO scenarios which inform the economic settings and forecasts. The scenarios also help provide context for Australia's share of meeting various temperature outcomes as well as guidance to the multi-sectoral modelling regarding fossil fuel export projections and uptake rate and limits on energy efficiency and electrification across scenarios.

The 2024 WEO did not contain the *Sustainable Development Scenario* (SDS) which was aligned with the 2023 IASR *Step Change*. However, as discussed below, the narrative of the *Announced Pledges Scenario* aligns closely with the *Step Change* scenario as presented in the Draft 2025 IASR.

The 2024 WEO scenarios and how they align with the Draft 2025 IASR scenarios are summarised in Table 5.

Table 5 The 2024 IEA WEO scenario summaries

IEA scenario	Summary narrative
Net Zero Emissions by 2050 (NZE)	This is a normative scenario that maps a transition pathway limiting global warming to within 1.5°C by the end of the century with a 50% probability but with limited overshoot. This scenario sees the most ambitious deployment of electrification and energy efficiency, with consumption declining by 2030. By 2050, clean energy meets 90% of global energy demand with around one-third of the remaining fossil fuel demand being fully abated and another third offset by negative emissions.
Announced Pledges Scenario (APS)	The <i>Announced Pledges Scenario</i> was added in the 2021 WEO. It explores the full and timely implementation of national energy and climate goal, including net zero emission targets, and its impact on the energy sector. In this scenario, electrification and energy efficiency, as well as deployment of low-carbon hydrogen, increases relative to STEPs. Consumption peaks in 2030 and then slowly declines. The share of clean energy in global energy demand increases to nearly three-quarters by 2050. This scenario results in an increase in median surface temperatures over pre-industrial levels of 1.7°C with a 50% probability.
Stated Policies Scenario (STEPS)	This scenario is based on current policy settings and also considers the implications of industrial policies that support clean energy supply chains as well as measures related to energy and climate. The scenario sees a decline in the share of fossil fuels in primary energy demand from 80% in 2023 to 58% by 2050. Electrification of transport and heat, as well as energy efficiency, all play a role. By the end of the century, the scenario is aligned with median surface temperature increases over pre-industrial levels of 2.4°C with 50% probability.

In mapping the IEA's 2024 scenarios to the scenarios in this Draft 2025 IASR, AEMO provides the following observations:

- With a more stringent emission target aiming to achieve the aspirational 1.5°C target of the Paris Agreement and with significant structural changes in global energy consumption underpinning its narrative, the **Green Energy** scenario is most closely aligned to NZE.
- The IEA's APS scenario is consistent with the Paris Agreement target of limiting temperature increase to well below 2°C, which aligns to AEMO's **Step Change** scenario.
- The **Progressive Change** scenario aligns best to STEPS as it reflects currently legislated or funded policy positions only. It also fails to meet the Paris Agreement globally despite Australia fulfilling its commitments under its Nationally Determined Contribution submitted to the United Nations Framework Convention on Climate Change.

3.2.2 Alignment with the Inter-governmental Panel on Climate Change's Relative Concentration Pathways

The Draft 2025 IASR scenarios also map to the RCPs framework used by the Intergovernmental Panel on Climate Change (IPCC)⁷³. There are multiple RCPs defined, representing trajectories of emissions and land-use and their resulting impact on temperature increases. AEMO scenarios map to these temperature pathways as follows:

- AEMO's **Green Energy** scenario sees a global drive to limit temperature rise to 1.5°C by the end of the century. It is best aligned to RCP1.9 which targets that 1.5°C outcome.
- The **Step Change** scenario is aligned to RCP2.6, which is consistent with a temperature rise less than 2°C by the end of the century and in line with the Paris Agreement.
- The **Progressive Change** scenario is aligned to RCP4.5, which is consistent with a temperature rise of approximately 2.7°C by the end of the century.

The mapping of scenarios to IEA scenarios and RCP temperature targets is summarised in Table 6.

By mapping the Draft 2025 IASR scenarios to global outlooks in this manner, forecast components that are influenced by global conditions and broader economic narratives may be developed in a more internally consistent manner.

Table 6 Mapping of scenarios between studies

2023 IASR scenario	2024 WEO scenario	RCP Framework
Green Energy	NZE	RCP1.9
Step Change	APS	RCP2.6
Progressive Change	STEPS	RCP4.5

3.2.3 Translating international climate scenarios to NEM-wide carbon budgets

To ensure the scenarios adopt emissions abatement outcomes consistent with the scenario narratives and mapping to the WEO scenarios and RCPs described above, multi-sectoral modelling has been commissioned to produce carbon budgets for the Australian economy⁷⁴ (including a distinct budget for the electricity sector and the NEM) among other forecasting influences described in Section 3.3.4.

This project is ongoing, and outcomes will be provided in the Draft 2025 IASR Stage 2 to be published in February 2025.

State-level carbon budgets

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

Carbon budgets will be provided in the Stage 2 of the Draft 2025 IASR.

⁷³ See, for example, page 65 in https://www.ipcc.ch/report/ar6/syr/downloads/report/IPCC_AR6_SYR_LongerReport.pdf.

⁷⁴ The economy-wide carbon budget is broadly consistent with the 2021 to 2030 carbon budget defined in the *Climate Change Act (2022)*.

3.3 Consumption and demand: historical and forecasting components

AEMO updates its projections of energy consumption and demand at least annually⁷⁵. AEMO's Forecasting Approach applies methodologies that examine electricity and gas customer segments, and enables forecasting of key forecast components affecting those customer segments. This approach enables appropriately granular models to be deployed in a way that provides transparency of method and influence on energy consumption, and enables scenario diversity where key uncertainties exist. Updates to these forecast components are informed by stakeholder consultation through the FRG and other engagement opportunities where appropriate, and consider a range of forecasting components, including:

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

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

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

The *Electricity Demand Forecasting Methodology*⁷⁶ and *Gas Demand Forecasting Methodology Information Paper*⁷⁷ 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 Portal⁷⁸.

⁷⁵ Updated forecasts (within a year) can be issued in case of material change to input assumptions.

⁷⁶ At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/electricity-demand-forecasting-methodology.pdf.

⁷⁷ At https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2024/gas-demand-forecasting-methodology-2024.pdf.

⁷⁸ At <https://forecasting.aemo.com.au/>.

The following sections describe the individual model inputs and component forecasts. Where appropriate, comparisons are made with this Draft 2025 IASR’s scenarios against relevant 2023 IASR scenarios.

3.3.1 Historical demand data

Input vintage	<ul style="list-style-type: none">• November 2024 for demand data• November 2024 for loss data• November 2024 for auxiliary load data
Status	<ul style="list-style-type: none">• Current view
Source	<ul style="list-style-type: none">• SCADA/EMMS/NMI Data• Generation Information page• AER, WA-based retailer Synergy and network operators
Update process	<ul style="list-style-type: none">• Continuously updated

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’ refers to the demand that is served from electricity that is generated from scheduled generating units, semi-scheduled generating units, and some non-scheduled generating units⁷⁹.

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 is net of the auxiliary 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 megawatts or megawatt hours (MWh).

Large industrial loads

AEMO’s *Electricity Demand Forecasting Methodology* defines a methodology for identifying large loads for inclusion in the large industrial load (LIL) sector. AEMO collects the historical consumption of existing 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 A6 (Residential-business segmentation) of the *Electricity Demand Forecasting Methodology*. The hybrid approach is required given the

⁷⁹ 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.

inconsistent level of interval meter penetration in some regions, meaning that if insufficient penetration exists for interval data (bottom up), then basic meter analysis is required (top down). The bottom-up approach is based on sampling of AEMO residential meter data. The top-down approach considers consumption data provided by electricity distribution businesses to the AER as part of their Economic Benchmarking Regulatory Information Notice (RIN). AEMO must perform some calibration of the RIN data to bring it into alignment with AEMO’s definition of delivered energy, as described in Appendix A6 of the *Electricity Demand Forecasting Methodology*.

In the WEM, AEMO applies the segmentation of residential and business historical consumption using a simplified top-down approach. This process makes use of aggregated residential data provided by the Western Australian government owned retailer Synergy, combined with AEMO metering data for LILs.

Distributed PV uptake and generation

AEMO sources historical PV installation data from the Clean Energy Regulator and applies a solar generation model to estimate the amount of power generation at any given time. Refer to Section 3.3.7 for details.

3.3.2 Historical weather data

Input vintage	November 2024
Status	Current view
Source	Bureau of Meteorology (BoM)
Update process	Continuously updated

AEMO uses historical weather data for training the annual consumption and minimum and maximum demand models as well as developing forecast reference year traces that provide a half-hourly representation of future demand and supply patterns.

The historical weather data comes from the Bureau of Meteorology (BoM), using a subset of the weather stations that BOM make available across Australia, as shown in Table 7, Table 8 and Figure 1.

AEMO selected these weather stations based on data availability and correlation with forecast consumption or demand. AEMO’s current *Electricity Demand Forecasting Methodology* uses one weather station per region, except where weather stations have been discontinued, however AEMO is currently consulting on an updated *Electricity Demand Forecasting Methodology* that proposes to increase the spatial granularity of the forecasting approach. This intends to introduce greater consideration of sub-regional differences, which will require additional weather stations for each sub-region. Table 7 therefore includes the current regional weather stations, and Table 8 lists proposed weather stations for the sub-regions if the changed approach is adopted⁸⁰.

⁸⁰ The in-progress consultation on AEMO’s forecasting approach is available at <https://aemo.com.au/consultations/current-and-closed-consultations/2024-electricity-demand-forecasting-methodology-consultation>.

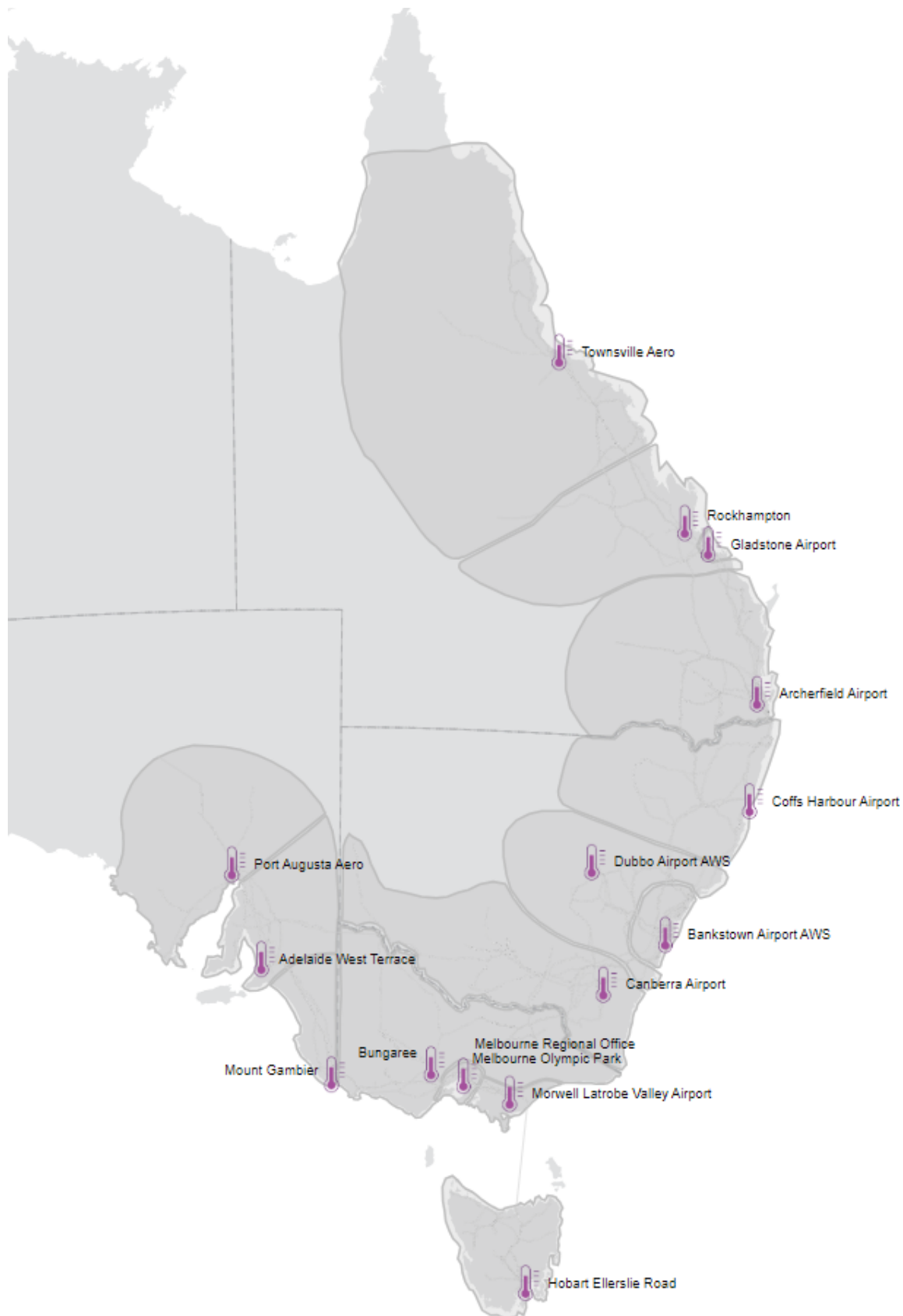
Table 7 Weather stations used in forecasting consumers electricity use (regional)

Regional weather stations			
Region	Station name	Date range	BoM site number
New South Wales	Bankstown Airport AWS	January 1968 – Now	066137
Queensland	Archerfield Airport	April 1929 – Now	040211
South Australia	Adelaide (Kent Town)	October 1993 – July 2020	023090
	Adelaide (West Terrace)	July 2020 – Now	023000
Tasmania	Hobart (Ellerslie Road)	January 1882 – Now	094029
Victoria	Melbourne Regional Office	January 1908 – January 2015	086071
	Melbourne (Olympic Park)	May 2013 – Now	086338
Western Australia	Perth Metro	February 1993 – Now	009225

Table 8 Weather stations used in forecasting consumers electricity use (sub-regional)

Proposed weather stations for NEM sub-regions				
Region	Sub-region	Station name	Date range	BoM site number
New South Wales	Central New South Wales	Dubbo Airport AWS	January 1946 – Now	065070
New South Wales	Northern New South Wales	Coffs Harbour Airport	August 2013 – Now	059151
New South Wales	Sydney, Newcastle & Wollongong	Bankstown Airport AWS	January 1968 – Now	066137
New South Wales	Southern New South Wales	Canberra Airport	September 2008 – Now	070351
Queensland	Central Queensland	Rockhampton	January 1927 – Now	039264
Queensland	Gladstone Grid	Gladstone Airport	October 1993 – Now	039326
Queensland	Northern Queensland	Townsville Aero	January 1940 – Now	032040
Queensland	Southern Queensland	Archerfield Airport	April 1929 – Now	040211
South Australia	Central South Australia	Adelaide (Kent Town)	October 1993 – July 2020	023090
		Adelaide (West Terrace)	July 2020 – Now	023000
South Australia	Northern South Australia	Port Augusta Aero	July 2001 – Now	018201
South Australia	South East South Australia	Mount Gambier (Blue Lake Holiday Park)	January 1975 – Now	026085
Tasmania	Tasmania	Hobart (Ellerslie Road)	January 1882 – Now	094029
Victoria	Greater Melbourne and Geelong	Melbourne Regional Office	January 1908 – Jan 2015	086071
		Melbourne (Olympic Park)	May 2013 – Now	086338
Victoria	West and North Victoria	Bungaree (Kirks Reservoir)	August 1881 – Now	087014
Victoria	South East Victoria	Morwell (Latrobe Valley Airport)	January 1984 – Now	085280

Figure 1 Map of weather stations used in forecasting consumers electricity use, per NEM sub-region



Matters for consultation

- Will these weather stations provide appropriate weather information to apply to the NEM sub-regions when forecasting consumers' electricity use, including annual aggregate electricity consumption and importantly the peak maximum, and minimum, demand conditions?

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

Input vintage	October 2024 for installed capacity (Generation Information page) October 2024 for historical and forecast ONGS generation
Source	<ul style="list-style-type: none">• Generation Information page• Settlements data• NMI data• DER Register
Update process	Updated quarterly

AEMO reviews its list of other non-scheduled generation (ONSG, which is non-scheduled generation that excludes rooftop solar) using information from AEMO's Generation Information⁸¹ dataset obtained through surveys, and supplements where applicable with submissions from network operators, the DER Register and relevant publicly available information where appropriate.

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

AEMO's current view of ONGS is contained in the Generation Information page. As at the October 2024 release of Generation Information page, used for the development of the energy and demand forecasts, aggregate capacity by region is shown in Figure 2 below. Note that this excludes any ONGS that is used solely as peaking capacity, as these generators are modelled as part of AEMO's DSP forecast instead (see Section 3.3.15).

⁸¹ At <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>.

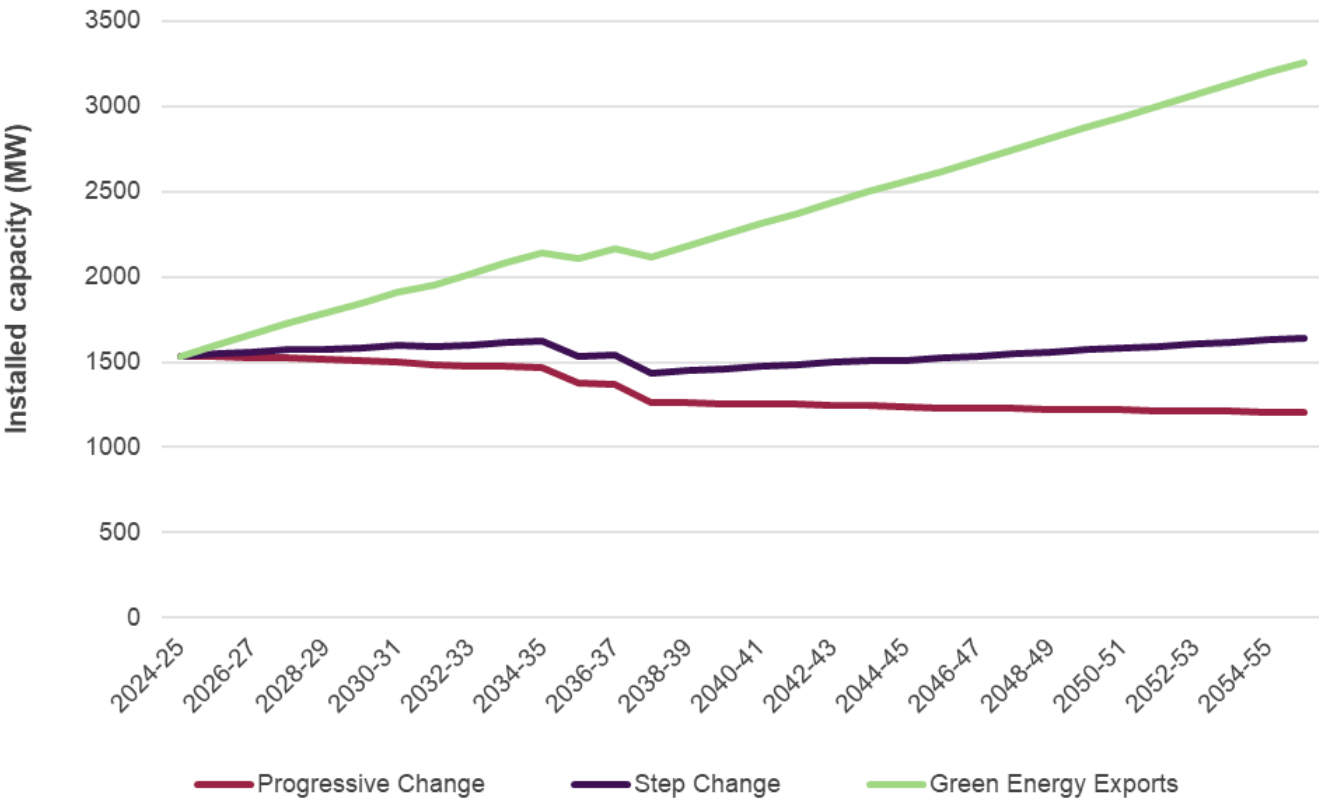
Figure 2 Aggregate ONSG capacity, by NEM region (MW)

AEMO forecasts commissioning or withdrawal of ONSG generators based on firm commitment statuses of these generators in the short term and applying historical trends of ONSG by technology type (for example, gas or biomass-based cogeneration, or generation from landfill gas or wastewater treatment plants) for the *Step Change* scenario in the long term.

For the *Progressive Change* scenario, the same withdrawal of capacity is modelled, but forecast growth is slightly slower. The *Green Energy* scenario, on the other hand, has significantly more growth assumed for renewable technologies (small-scale wind and biomass). Figure 3 shows the NEM-wide installed capacity for the three scenarios.

Historical capacity factors by technology type are used to forecast generation using the projected installed capacities, offsetting the electricity consumption in the forecast. AEMO's current view on ONSG for producing the forecasts is based on the Generation Information page released in July 2024.

Figure 3 Forecast NEM-wide other non-scheduled generation capacity (MW)



3.3.4 Multi-sectoral modelling influences to demand forecasts

Input vintage	Not included in this stage of the Draft 2025 IASR
Status	In progress
Source	CSIRO
Get involved	Formal consultation on this input in Stage 2 of the Draft 2025 IASR.

AEMO has engaged CSIRO to model least-cost pathways for the Australian economy to achieve emissions targets within the parameters of scenario-based demand drivers such as economic growth, energy efficiency, electrification, CER and road transport EV, that may affect the domestic as well as Australia’s export economy. Multi-sectoral modelling also considers the mix of energy forms appropriate to achieve these targets, including the potential development of alternative gaseous fuels (such as hydrogen and biomethane).

Using the CSIRO and ClimateWorks Centre (CWC) AUS-Times model, the multi-sectoral modelling approach provides whole-of-economy interactions, by simultaneously considering a range of options available to meet scenario-specific emissions targets at the least cost. The emissions targets align to specific global temperature outcomes, informed by the RCP and IEA WEO scenario definitions (see Table 5 and Section 3.2) for key scenario parameters).

The options to transition Australia’s economy broadly align with four pillars of decarbonisation. The scenarios consider all four pillars to varying degrees, to align with the scenario narratives and to reflect the uncertainty around future technology improvements, costs, and barriers to deployment. These pillars complement traditional

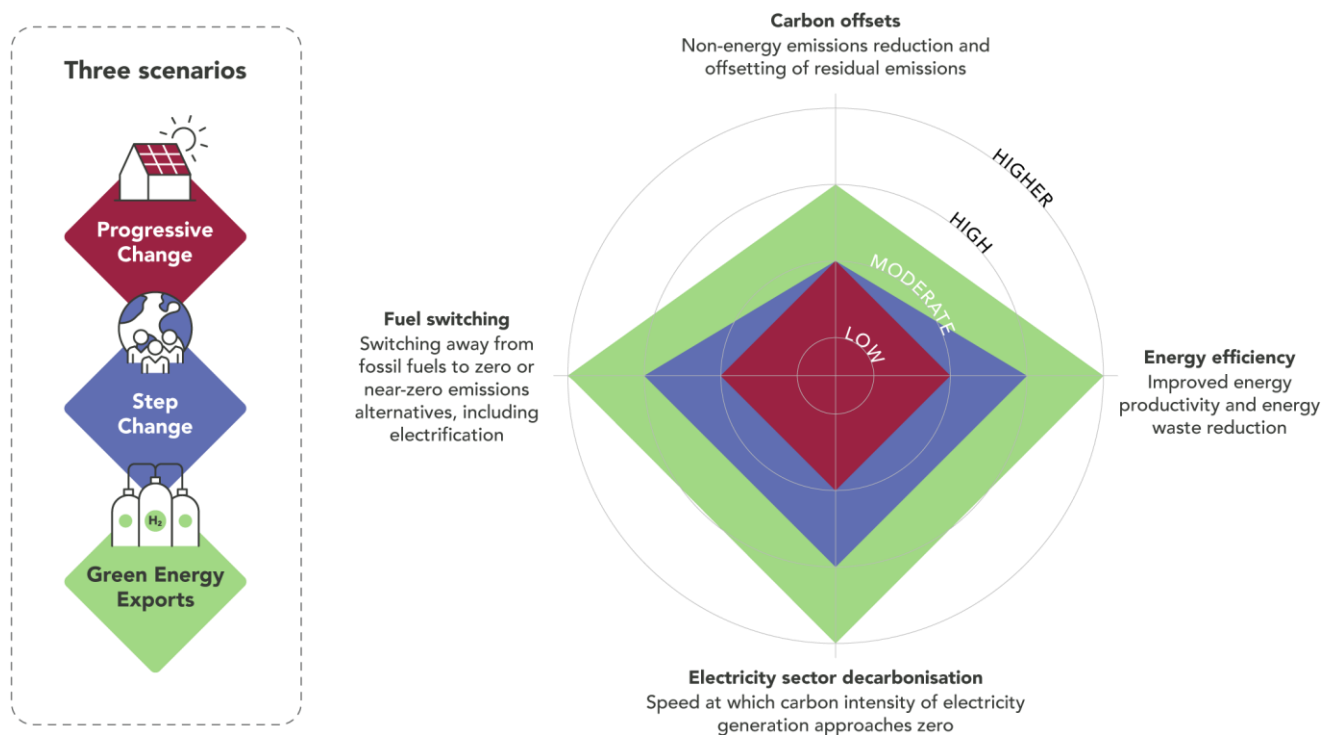
component forecasts outlined in subsequent sections, considering scenario drivers that may not be readily captured by trend-based or historical regression modelling.

The four pillars are:

- **Energy efficiency** to improve energy productivity and reduce energy waste.
- **Decreasing carbon intensity** of electricity generation to near zero through increasing penetration of renewable energy generators.
- **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).

Figure 4 illustrates the scale of utilisation of the four pillars across the scenarios.

Figure 4 Forecast utilisation of the four pillars of decarbonisation, by scenario



The model outputs that will be explicitly used to inform this 2025 IASR include:

- Future energy consumption trends and fuel-switching opportunities, particularly the electrification of other sectors of Australia's economy. Energy consumption trends may also be adopted as long-term drivers for forecast business mass market and LIL growth.
- National and NEM emissions pathways (see Section 3.2.3 for further details), including forecast needs for emission sequestration via land use sequestration, direct air capture (DAC), and carbon capture and storage (CCS).

- Domestic hydrogen demand, as a substitute for other energy sources, complementing assumed hydrogen export demand in the scenarios (see Section 3.3.6 for further details).

The multi-sectoral modelling outcomes will be published in Stage 2 of the Draft 2025 IASR in February 2025.

3.3.5 Electrification

Input vintage	Not included in this stage of the Draft 2025 IASR
Status	In progress
Source	CSIRO multi-sectoral modelling for non-road transport electrification
Update progress	Non-transport electrification updates to be published in Stage 2 of the Draft 2025 IASR
Get involved	Formal consultation on this input in Stage 2 of the Draft 2025 IASR.

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

The cost-efficiency of electrification depends on many factors including appliance replacement costs, electricity infrastructure capabilities and costs, and the availability of alternative low emissions fuels, such as hydrogen and biomethane. The 2025 IASR scenarios therefore consider a range of electrification outcomes, with the *Green Energy* scenario adopting both a high degree of electrification and fuel-switching to hydrogen.

In the residential and commercial building sectors, space heating, cooking, and water heating appliances can all be electrified from gas or liquefied petroleum gas (LPG). Electrification of the transport sector is expected in all scenarios, although the pace and magnitude of electrified transportation also varies across scenarios (transport sector electrification is described in detail in Section 3.3.7).

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

The electrification forecasts, influenced by multi-sectoral modelling, will be published in Stage 2 of the Draft 2025 IASR in February 2025.

3.3.6 Fuel-switching to alternative gaseous fuels

Input vintage	Alternative gas volumes not included in this stage of the Draft 2025 IASR. Biomethane production cost estimates as at December 2024.
Source	ACIL Allen (biomethane availability and production costs)
Updates since 2023 IASR	Updates of fuel-switching to biomethane
Get involved	Formal consultation on this input in Stage 2 of the Draft 2025 IASR.

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

Hydrogen production

A number of hydrogen production projects are identifiable across the eastern states of Australia, as listed in CSIRO's HyResource⁸² project listing. Although every state has outlined hydrogen strategies the cost, timing and magnitude of an eventual hydrogen economy within Australia is highly uncertain. Hydrogen developments may, however, be significant in affecting the needs of the power system, and AEMO considers various hydrogen futures within the Draft 2025 IASR scenarios.

The assumptions for hydrogen production, including for value-add commodity production, will be published in Stage 2 of the Draft 2025 IASR.

Biomethane

While biomethane is a proven technology widely used in Europe⁸³ and other countries, there is relatively low existing production in Australia. Biomethane has the potential to provide a low or zero emissions molecular fuel source to blend into gas pipelines, lowering the emissions intensity of gas use⁸⁴. As such, it provides a decarbonisation alternative to electricity for industries that cannot easily electrify their industrial processes.

The uptake for each scenario's biomethane forecast, particularly in the short to medium term, will be informed by gas production insights from surveyed gas market participants for the East Coast Gas Market's GSOO, and further influenced by the forecast that comes from the multi-sectoral modelling considering estimated available volumes and forecast biomethane costs.

For the Draft 2025 IASR, AEMO engaged consultant ACIL Allen to forecast biomethane production cost and available volumes by feedstock type, state, and scenario. Figure 5 shows a snapshot of ACIL Allen's forecast for the various feedstock available volumes in PJ per year by scenario, including production cost in \$/gigajoule (GJ) for selected years⁸⁵.

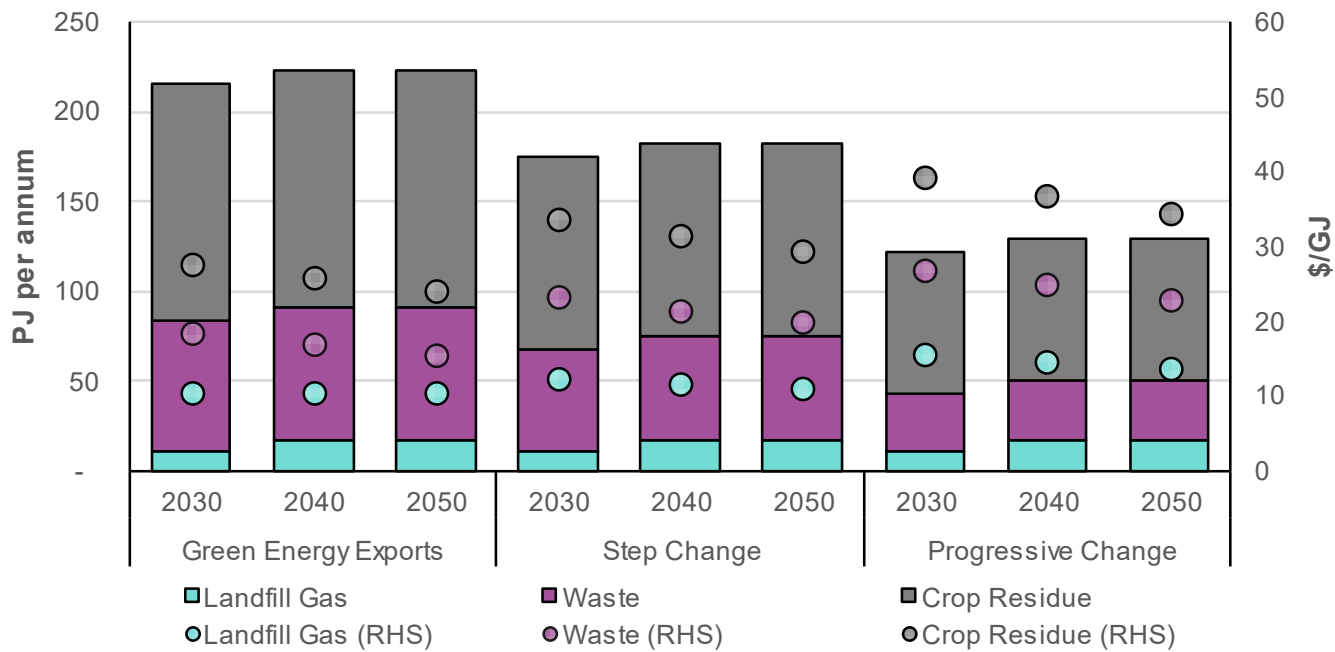
⁸² CSIRO, HyResource, at <https://research.csiro.au/hyresource/>.

⁸³ See [New record for biomethane production in Europe shows EBA/GIE Biomethane Map 2022-2023 | European Biogas Association](https://energy.ec.europa.eu/topics/renewable-energy/bioenergy/biomethane_en#:~:text=The%20Biomethane%20Industrial%20Partnership%20(BIP,of%20its%20potential%20by%202050.) and [https://energy.ec.europa.eu/topics/renewable-energy/bioenergy/biomethane_en#:~:text=The%20Biomethane%20Industrial%20Partnership%20\(BIP,of%20its%20potential%20by%202050.](https://energy.ec.europa.eu/topics/renewable-energy/bioenergy/biomethane_en#:~:text=The%20Biomethane%20Industrial%20Partnership%20(BIP,of%20its%20potential%20by%202050.)

⁸⁴ See <https://www.dcceew.gov.au/sites/default/files/documents/national-greenhouse-accounts-factors-2022.pdf> (page 13).

⁸⁵ Detailed data sets can be found in the ACIL Allen reports at <https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr>.

Figure 5 ACIL Allen biomethane available volume and production cost estimates by feedstock and scenario



The estimated available volumes provided above will be an input into multi-sectoral modelling.

Draft biomethane production forecasts per scenario will be published in Stage 2 of the Draft 2025 IASR in February 2025.

3.3.7 Consumer energy resources

Input vintage	December 2024
Status	Draft
Source	<ul style="list-style-type: none">• CSIRO• Green Energy Markets• Clean Energy Regulator
Updates since 2024 Forecasting Assumptions Update	Updated with new consultant forecasts in 2024 and latest historical data

CER predominantly describes consumer-owned devices that can generate or store electricity and includes flexible loads that can alter demand in response to external signals. In AEMO’s forecasting approach, CER refers to embedded solar systems and battery devices within the distribution system, while energy management systems are considered in AEMO’s forecasting of demand flexibility (in demand-side participation forecasts) and energy efficiency. Customer’s solar and battery devices may operate passively (such that they operate without regard to the broader power system conditions but instead with a customer-centric behaviour) but also may have the ‘smarts’ to actively manage and minimise a customer’s energy import and export from the grid.

AEMO’s CER forecasts include small-scale embedded generation such as residential and commercial rooftop PV systems (less than 100 kilowatts [kW]), battery storage, and EVs. 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 and are included in this section; rooftop PV and PVNSG forecasts are referred to as distributed PV.

Given the importance of CER in the energy transition, AEMO commissioned two expert consultants – CSIRO and Green Energy Markets (GEM) – to support the development of the CER forecasts. The two consultant forecasts use the same scenario narratives, and both use uptake models that focus on purchase decisions from an economically rational consumer-focused behaviour perspective.

AEMO's forecasts of CER per scenario have been consolidated from the two consultants' forecasts according to Table 9 below, with 'average' indicating a simple average of GEM and CSIRO. AEMO proposes this scenario mapping, considering that this selection maintains the integrity of the drivers of CER uptake presented in each consultant's forecast, while matching appropriately to the expected contributions from CER within each scenario's key parameters (outlined earlier in Table 2). In general, GEM's forecasts reflect a more buoyant outlook, whereas CSIRO's forecasts reflect a relatively more conservative consumer adoption.

Table 9 Consultant scenario mapping for CER

Scenario	Green Energy	Step Change	Progressive Change
Rooftop PV forecast mapping	Average	Average	CSIRO
PVNSG forecast mapping	GEM	GEM	CSIRO
Battery and VPP forecasts mapping	Weighted average (1/3 GEM + 2/3 CSIRO)	Weighted average (1/3 GEM + 2/3 CSIRO)	CSIRO

Details of the key assumptions and methodologies of each consultant's forecast are provided in the consultant reports that supplement this IASR (see Appendix A2). The forecasts reflect up-to-date views on actual installations, and reflect the economic and population forecasts (in Section 3.3.8). The forecasts also consider each consultant's updated views on tariff options, technology costs, and system size projections.

AEMO notes stakeholder interest in how distribution network limitations may impact the growth and operation of CER. Each consultant's forecast approach focuses on the economic value for PV and battery installation. That value is primarily derived from reducing or avoiding electricity purchases from the grid, with very low payback from grid exports given low feed-in-tariffs. The approach does not explicitly consider distribution network constraints. The National CER Roadmap is providing renewed focus on the challenges and opportunities to integrate CER into the power system, and AEMO's adjusted *ISP Methodology* in response to the Energy and Climate Ministers' ISP Review⁸⁶ will begin to explore distribution network interaction with CER operation. AEMO considers that the forecasting approach that does not consider distribution constraints, coupled with the *ISP Methodology*, will appropriately capture opportunities for distribution investments and other distributed resources in each scenario's development opportunities in the ISP.

⁸⁶ See <https://www.energy.gov.au/energy-and-climate-change-ministerial-council/energy-ministers-publications/energy-ministers-response-review-integrated-system-plan>.

Distributed PV

This section comprises rooftop PV and PVNSG forecasts, which together make up total distributed PV. The Draft 2025 *Inputs and Assumptions Workbook* provides greater detail on each CER component, including system count and system size assumptions.

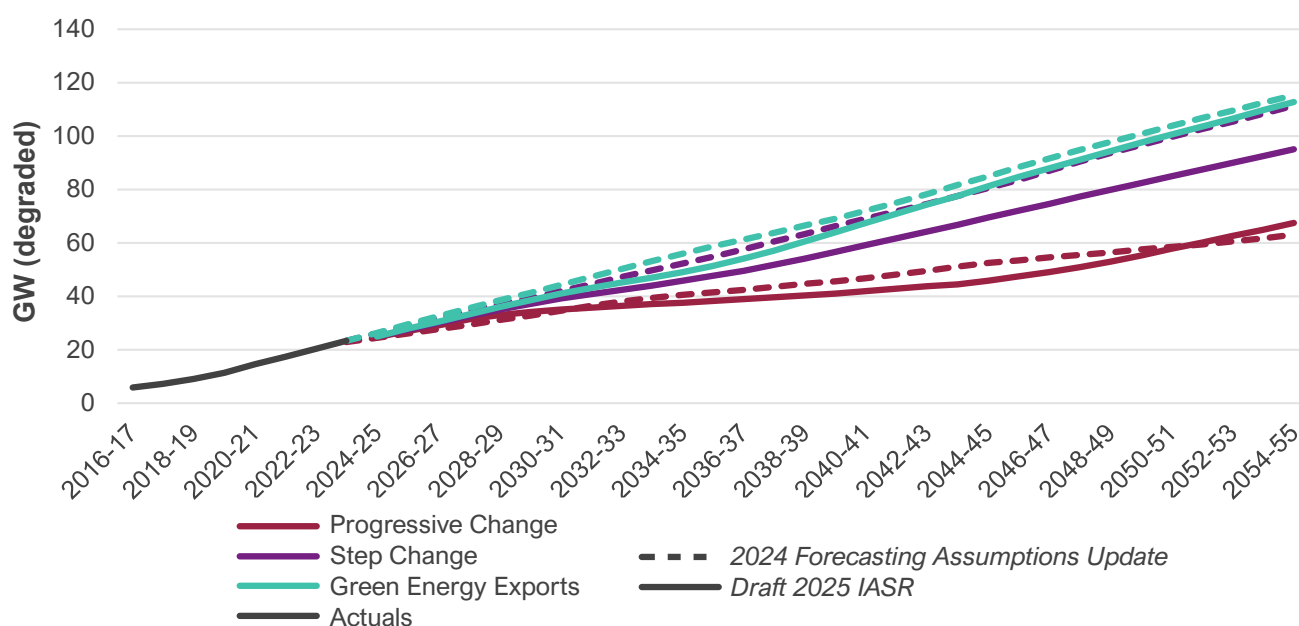
Current installed capacity estimates for distributed PV are sourced from the Clean Energy Regulator⁸⁷, with AEMO's DER Register available as a comparison. The forecasts were based on the latest actual installation data available at the time of production (end of June 2024), with 20.6 GW of installed capacity for rooftop PV in the NEM (23.2 GW including the WEM), and 1.48 GW for PVNSG in the NEM (1.53 GW including the WEM). Consumers have continued to install larger PV systems, with the average rooftop PV system size now being approximately 8.5 kW per installation (although the most common installation size remains approximately 6-7 kW per installation). This trend of larger systems is expected to continue as consumers increase their electricity consumption with electrification (particularly for EVs). It is expected that system sizes will reach a natural limit over time, as roof space availability and/or the size of the customer load will eventually cap the current trend.

Rooftop PV

AEMO forecasts that the market penetration of rooftop PV will continue to rise. PV system penetration on houses and semi-detached dwellings (prime candidates for PV installations) currently sits at around 39%, and in 2050 that is projected to increase to 69% (for the *Step Change* scenario). While there is no defined saturation point in AEMO's forecasts, the effect of shading, dwelling size and consumer's financial capacity to invest in these resources will limit uptake to well below 100%.

Figure 6 below demonstrates the forecasts for each scenario in terms of rooftop PV capacity.

Figure 6 Actual and forecast rooftop PV installed capacity (NEM and WEM), 2016-17 to 2054-55 (GW [degraded])



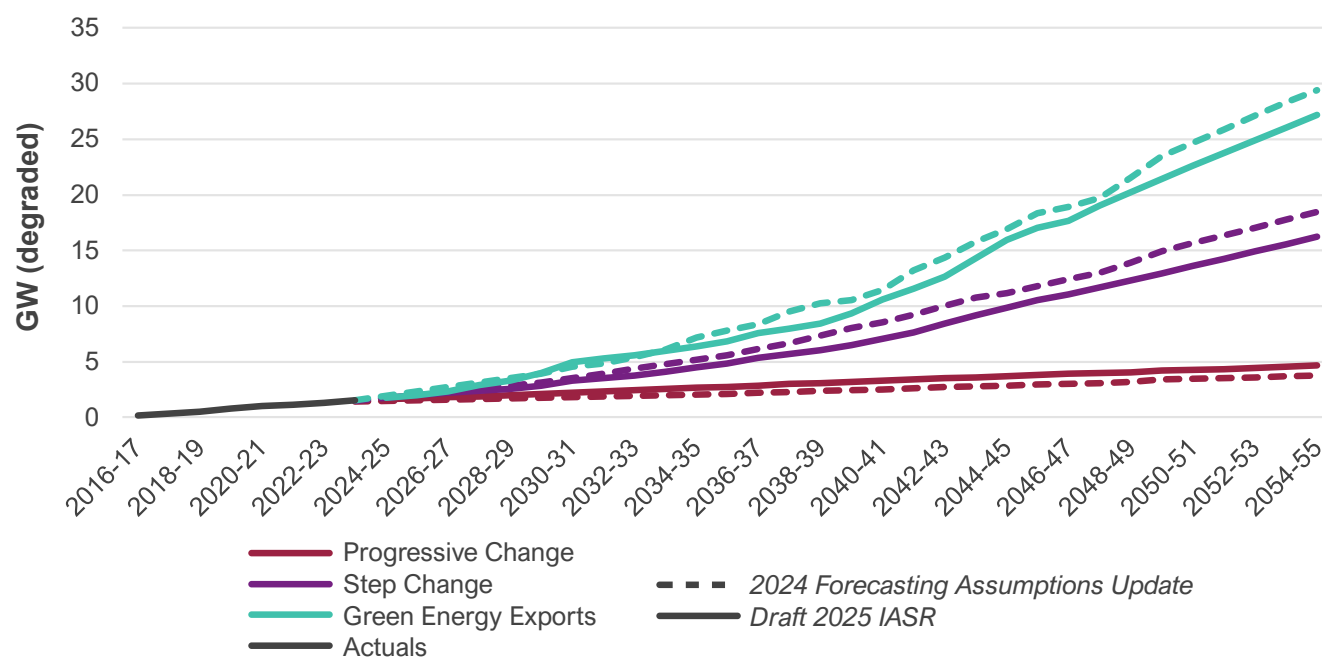
⁸⁷ Latest data is provided by the Clean Energy Regulator directly to AEMO and is complemented with data available through their website: <https://cer.gov.au/markets/reports-and-data/small-scale-installation-postcode-data>.

The forecasts moderate those that were provided in AEMO's 2024 Forecasting Assumptions Update, particularly in the longer term, as AEMO has considered the causes for CSIRO's lower uptake forecast are appropriate to have a greater influence in the forward trend than was previously available. While average system size is still forecast to grow, AEMO considers that the growth of system sizes is more likely to reflect a trend between the forecasts of each consultant, and in applying this lesser system size growth trajectory, the uptake trajectory in some scenarios (particularly *Step Change*) is lower.

PV non-scheduled generation

Growth in larger-scale PV systems (on commercial or industrial facilities for example) is expected to provide a growing contribution as technology costs decline, however at a much lower scale than rooftop PV systems. As shown in Figure 7, there is reasonable uncertainty captured by the scenario spread, with PVNSG's overall capacity forecast at up to 8-22% of the rooftop PV capacity across scenarios by end of June 2050

Figure 7 Actual and forecast PVNSG capacity (NEM and WEM), 2016-17 to 2054-55 (GW [degraded])



Aggregate distributed PV

Figure 8 below aggregates the rooftop PV and PVNSG components, to construct the total aggregate distributed PV forecast.

Figure 9 shows a breakdown between rooftop PV and PVNSG for the *Step Change* scenario, demonstrating that rooftop PV provides the majority of distributed solar installations.

Figure 8 Actual and forecast distributed PV installed capacity (NEM and WEM), 2016-17 to 2054-55 (GW [degraded])

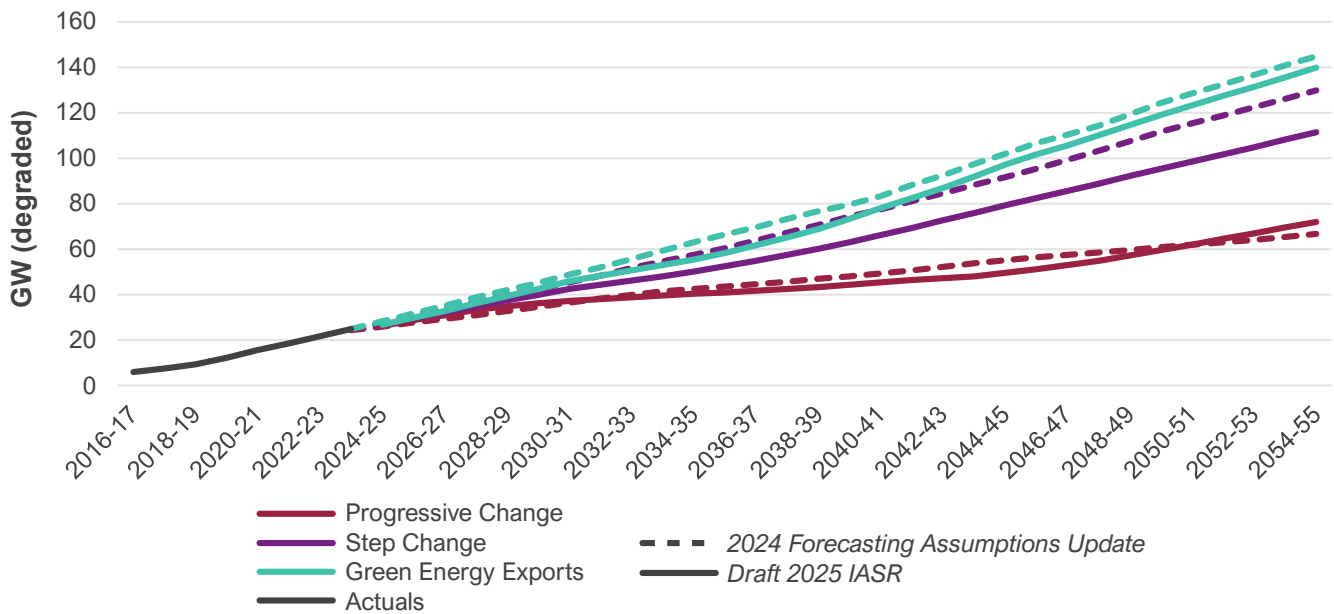
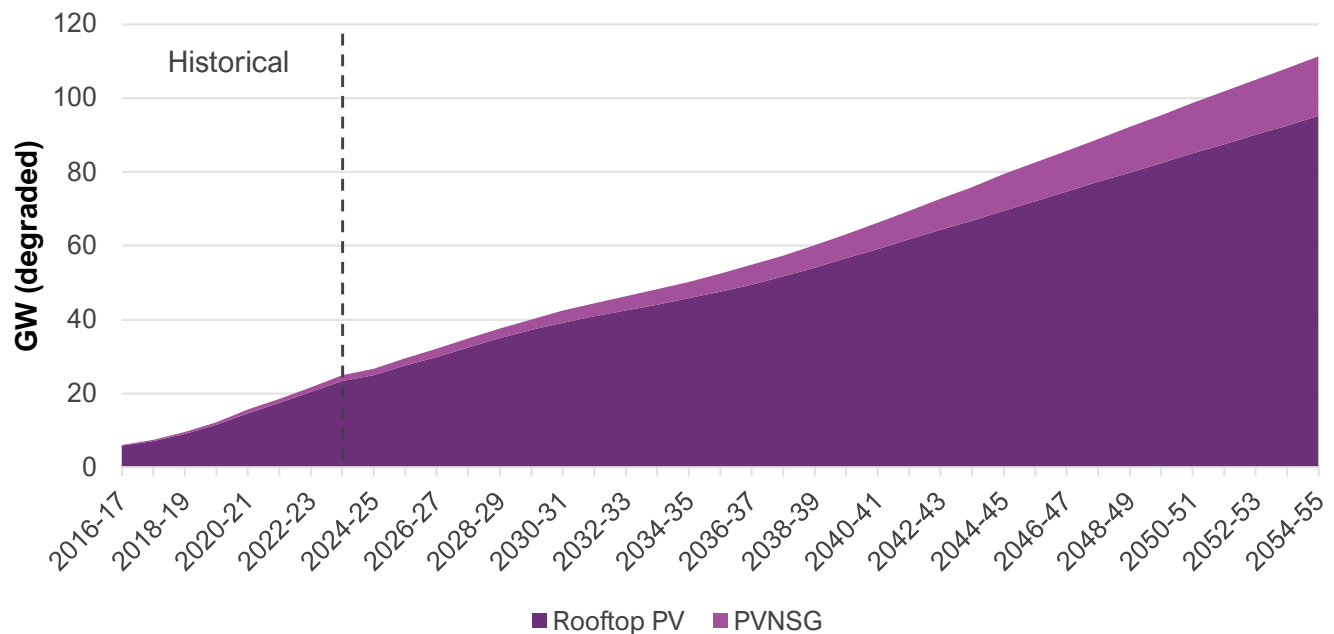


Figure 9 Actual and forecast rooftop PV and PVNSG installed capacity (NEM and WEM) for the Step Change scenario, 2016-17 to 2054-55 (GW [degraded])



Embedded energy storage

Distributed residential and commercial battery systems are an emerging consumer energy resource, and one that provides significant opportunity to increase the flexibility of consumer load. Investment, and in particular coordination, of these assets (and other controllable devices) can provide a means to change the demand profile of the power system, reducing the magnitude of maximum demands and reducing the challenges associated with operating during minimum load conditions.

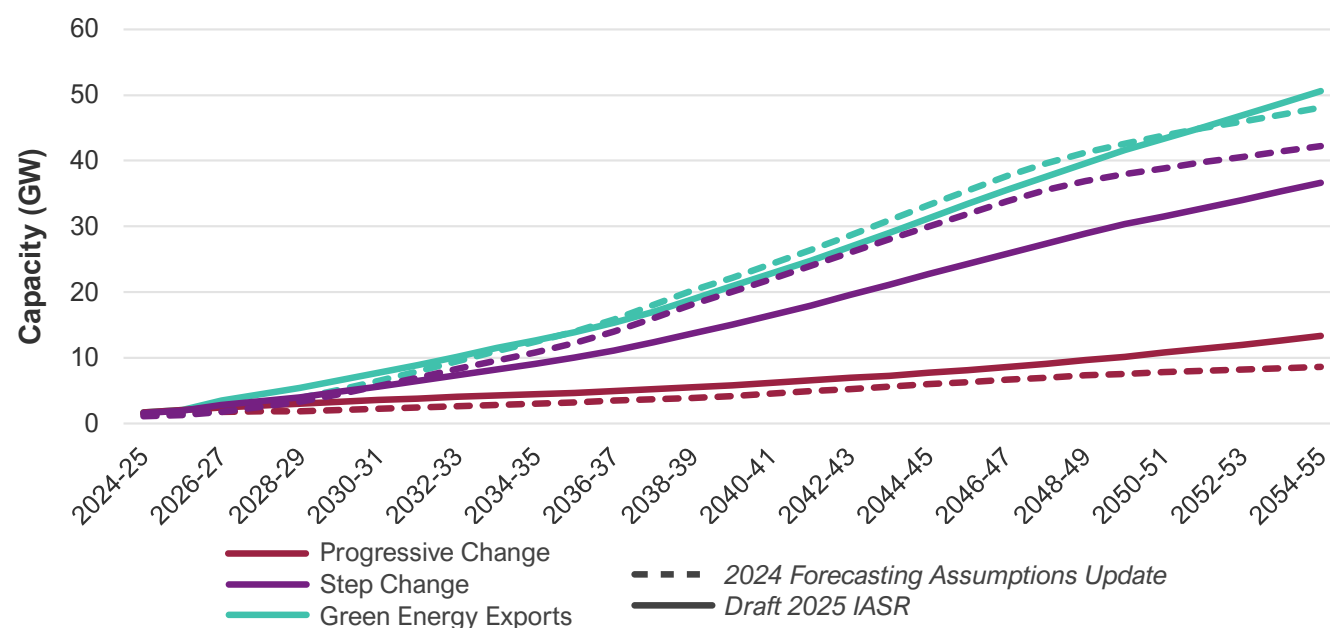
AEMO's forecast of embedded energy storages considers the insights provided by each of the CER consultants:

- GEM's forecasts assumed that battery costs to consumers will fall significantly in the next 10 years, while battery systems will increase in size, to approximately 20 kilowatt hours (kWh) by 2050. Much of this growth is anticipated as consumers are financially rewarded to embrace coordination, through VPPs.
- CSIRO forecasts a more gradual cost reduction, approximately half the rate of decline to GEM, with battery system growth largely mirroring the pace of PV system size growth.

AEMO has considered these broad trajectories and propose to weight the two forecasts to produce each scenario's outlooks, as per Table 9 above. This approach recognises the slower growth in CSIRO's forecasts for *Progressive Change*, while recognising greater potential development in the other two scenarios. AEMO does not propose to evenly weight the two forecasts, considering that the scale of positive change required to produce GEM's outcomes as ambitious. Considering the potential opportunity for the ISP to identify distribution investments and distributed resources beyond the CER forecasts, AEMO considers this approach retains an appropriate trajectory with further upside potential.

The resulting forecasts are shown in Figure 10 below, which includes non-aggregated and aggregated batteries:

Figure 10 Distributed battery capacity forecast for the NEM+WEM (GW), including non-aggregated and aggregated batteries



Battery operation is likely to be a mix of simple “solar shifting” and more sophisticated time-based or price-based operation to maximise the value to the householder. In practice, there may be little difference between the operating modes with most charging occurring during periods of high solar PV output and most discharging occurring at periods of high consumption.

AEMO's forecasts include a significant proportion of consumers will choose to join VPPs to gain greater (potential) financial reward from their batteries via the coordination provided by their retailer or a third-party aggregator. This is described in the section below.

Community batteries

An emerging sector for energy storage is "community" (or "neighbourhood") batteries, which typically refers to sub-utility-scale batteries installed in the distribution networks. Batteries at this scale are expected to help support the distribution networks in managing volatility in local demand, driven largely by the ongoing uptake of rooftop solar installations. The majority of community batteries expected to be installed in the short term are funded by federal and state government programs. AEMO's CER forecasting approach does not specifically identify community battery installations, but the ISP may identify distributed resources to complement the CER forecasts.

Aggregated energy storage – virtual power plants

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

While battery operation and management will be very similar for each approach, AEMO's modelling methodologies assume that VPP aggregators can improve the that batteries can provide to discharge when most valuable to the power system during tight supply conditions, and charge when most valuable to the power system during low load conditions.

If CER is coordinated at scale and in a predictable and reliable manner, there may be a significant reduction for the scale of network and utility-scale investments needed to firm renewable energy supplies to maintain reliable and secure supply.

There are currently around 20 VPP providers in the NEM+WEM, and technical work programs (for example by Project Symphony⁸⁸ and by Project EDGE⁸⁹) have demonstrated the feasibility and end-to-end technical capabilities of the technology.

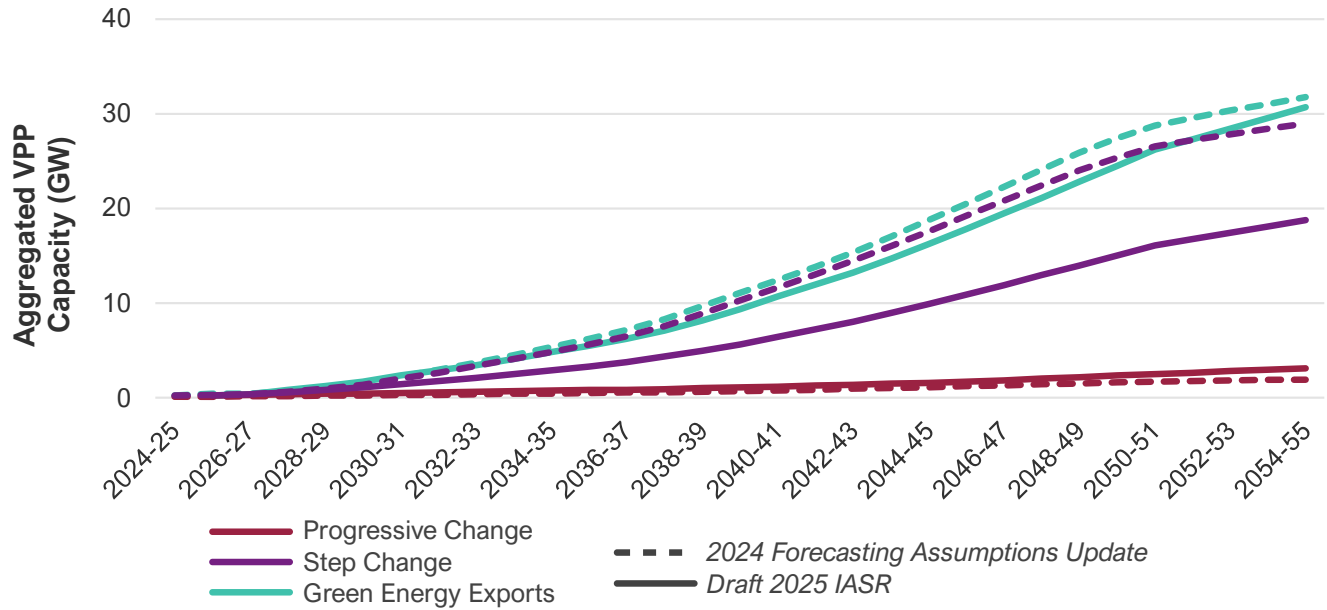
Despite the long-term potential, the uptake of VPP products to date has been modest. AEMO's forecasts provide a wide band between the scenarios to reflect the uncertainty of both uptake and relative scale of coordination. The companion reports from AEMO's consultants demonstrate differing views of success, with success hinging on what support is provided to consumers to adopt battery systems, considering the various state government policies supporting battery uptake. Likewise, the National CER Roadmap is also focused on improving CER integration, which may influence the social licence and technical capability of battery systems to be coordinated in the manner that is forecast.

The VPP capacity outlook reflecting AEMO's consolidation of the consultant inputs is shown in Figure 11 below. For *Step Change*, the 2025 scenario is purposefully designed to recognise the slower embrace of battery uptake, and has a slower pace of adoption as compared with the 2023 IASR scenarios, and the most recent forecasts. Slower adoption also is anticipated for *Green Energy*, although the magnitude of that forecast is closer to the previous forecasts.

⁸⁸ See <https://aemo.com.au/en/initiatives/major-programs/wa-der-program/project-symphony>.

⁸⁹ See <https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge>.

Figure 11 Aggregated VPP capacity for NEM+WEM (GW)



Matters for consultation

- Are the CER forecasts suitable for their respective scenarios? What strategic factors do you consider may influence CER projections?

Electric vehicles

This section will be updated in Stage 2 of the Draft IASR.

3.3.8 Economic and population forecasts

Input vintage	October 2024
Status	Final draft
Source	<ul style="list-style-type: none">• Deloitte Access Economics (DAE)• ABS
Update process	Forecasts may be rebased using the latest release of the national accounts if required, prior to the publication of the Final 2025 IASR.

In 2024, AEMO engaged Deloitte Access Economics (DAE) to develop long-term economic forecasts for each Australian state and territory. DAE developed the economic forecasts using its proprietary macro-econometric model, which is described in more detail in its report⁹⁰. Inputs and drivers to the economic model include factors such as domestic production, labour market conditions, and prices and wages, in addition to physical⁹¹ and

⁹⁰ Deloitte Access Economics: Economic forecasts 2024-25, at <https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr>

⁹¹ Physical risks associated with climate change in Australia cover the damages that are likely to affect land, labour, and capital.

transition⁹² risks associated with climate change. The economic forecasts are used as a key input to AEMO's energy and demand forecasts.

Across all scenarios over the forecast period, assumed variations in the drivers of economic growth (demographic profiles, labour productivity growth, decarbonisation pathways, and global conditions) result in divergent economic futures. Table 10 details the key assumptions and summary results for the three scenarios, including both variants of the *Green Energy* scenario. In total, four projections are therefore provided.

Table 10 Economic forecast details by scenario

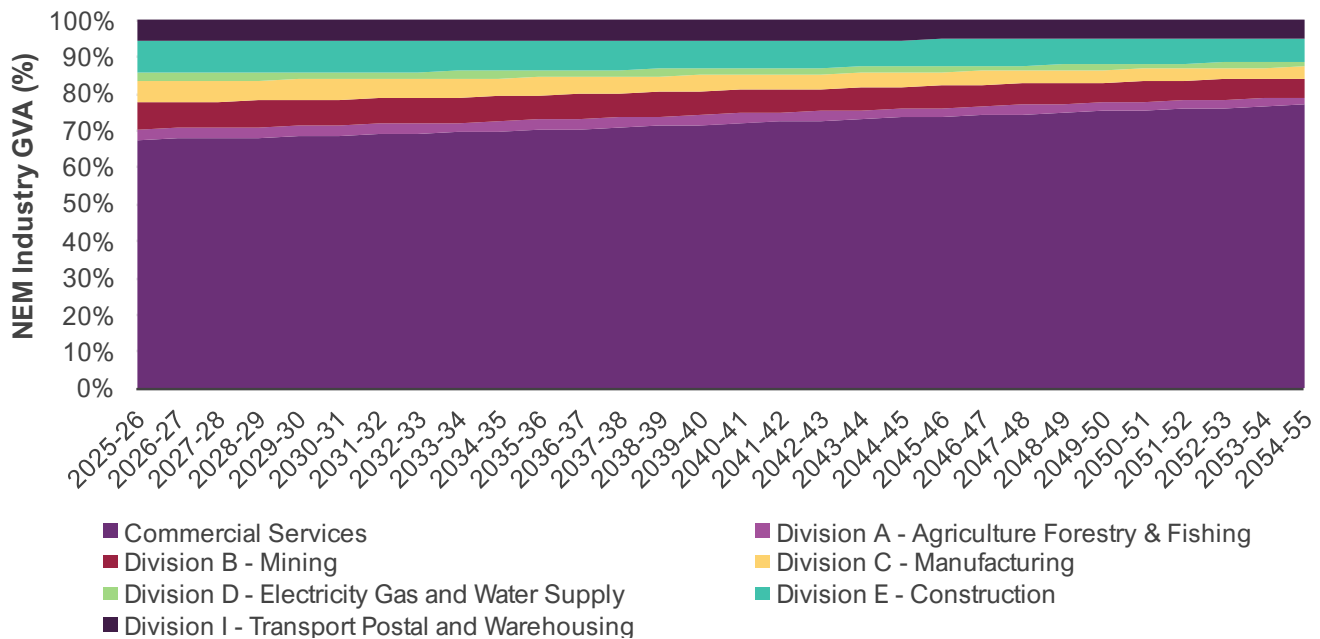
Scenario	Forecast annual economic growth (GDP)	Scenario details
<i>Step Change</i>	1.8%	<ul style="list-style-type: none"> <i>Step Change</i> is the central scenario for the economic forecasts. An ageing population and declining productivity growth place downward pressure on economic growth over the forecast period. Australia's decarbonisation pathway limits emissions and constrains economic growth. States and territories with emissions intensive industries see lower rates of economic growth relative to the national average.
<i>Progressive Change</i>	1.3%	<ul style="list-style-type: none"> <i>Progressive Change</i> is a downside scenario relative to <i>Step Change</i>. <i>Progressive Change</i> assumes slower population and productivity growth, as well as reduced climate change action coordination. A smaller and less productive economy (relative to <i>Step Change</i>) contends with a heavier climate change burden.
<i>Green Energy Exports</i>	2.5%	<ul style="list-style-type: none"> <i>Green Energy Exports</i> is an export orientated upside scenario relative to <i>Step Change</i>. <i>Green Energy Exports</i> assumes higher population growth and productivity growth and lower climate change costs relative to <i>Step Change</i>. Global decarbonisation efforts support Australia's green hydrogen industry. Mining activity slows, but critical minerals output increases due to strong demand and targeted industrial policy. Investment in renewable energy infrastructure and hydrogen production supports the construction, manufacturing, and utilities industries.
<i>Green Energy Industries</i>	2.5%	<ul style="list-style-type: none"> <i>Green Energy Industries</i> is a variation to the <i>Green Energy Exports</i> scenario. <i>Green Energy Industries</i> is underpinned by the same population and productivity assumptions as <i>Green Energy Exports</i>, but also assumes that Australia does not export renewable hydrogen. By the end of the forecast period, manufacturing industry output is smaller by 12% relative to the <i>Green Energy Exports</i> scenario.

Across all scenarios, the economic composition of the Australian economy is expected to change over time. Throughout the forecast period, the share of Gross Value Added (GVA) attributed to the manufacturing and mining industry is expected to decline, as industries which are relatively emissions-intensive come under pressure from the physical and transition risks associated with climate change. Conversely, the share of GVA attributed to commercial services is expected to increase.

Figure 12 illustrates the predicted economic composition of the NEM over the forecast period for the *Step Change* scenario.

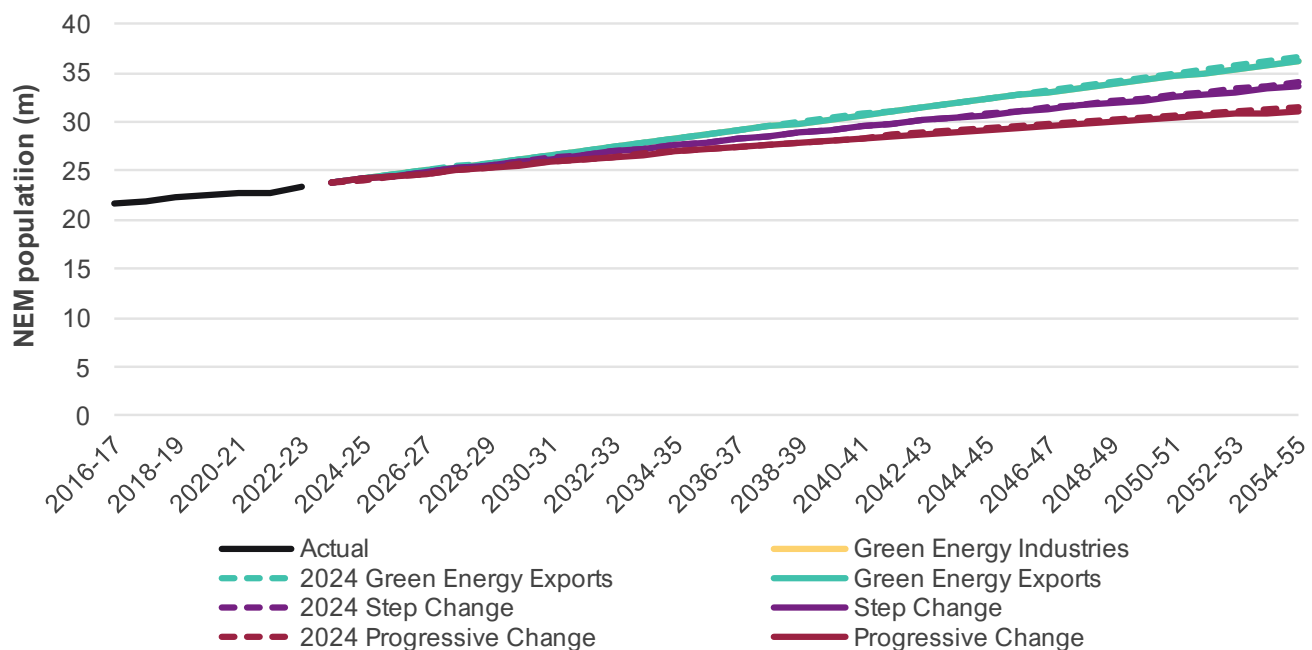
⁹² Transition risks arise from the mitigating actions taken in response to climate change, including policy and regulatory change, technological developments, or shifting consumer preferences.

Figure 12 Economic composition of the NEM, Step Change scenario



Population growth rates underpin rates of economic and productivity growth. Lower population growth has the effect of Australia's population ageing more rapidly. An ageing population weighs on productivity growth as labour force participation decreases. Population assumptions are varied across the scenarios. Relative to the *Step Change* scenario, the *Green Energy Exports* and *Green Energy Industries* scenarios forecast higher rates of population growth, whereas the *Progressive Change* scenario forecasts reduced population growth consistent with the scenario's exploration of weaker economic activity (see Figure 13).

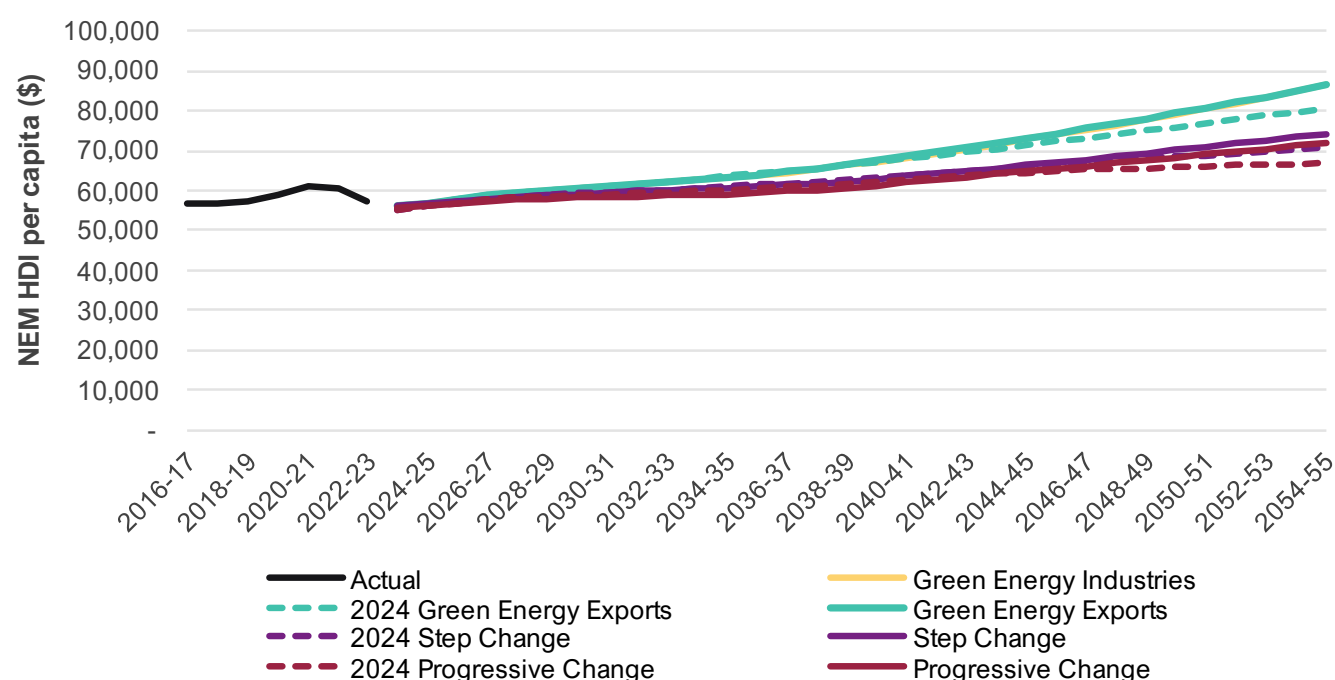
Figure 13 Population growth in the NEM by scenario



Note: The *Green Energy Industries* forecast follows a similar trajectory to *Green Energy Exports*, so it is not clearly visible in the figure above.

Economic growth is expected to remain relatively slow throughout 2024-25 due to tight monetary policy, cost-of-living pressures, and weakness in dwelling construction activity. In the short term, expected reductions in inflation and interest rate pressures are forecast to increase Household Disposable Income (HDI) (see Figure 14) and support economic growth as household consumption of goods and services accelerates throughout the economy. HDI is driven by employment and wages growth, and limited by cost of living pressures. Higher HDI particularly benefits industries producing discretionary and luxury goods, such as retail and hospitality. In the longer term, in the *Green Energy Exports* and *Green Energy Industries* scenarios in particular, higher levels of forecast productivity growth drive faster wage growth and consequently higher levels of HDI relative to the *Step Change* and *Progressive Change* scenarios.

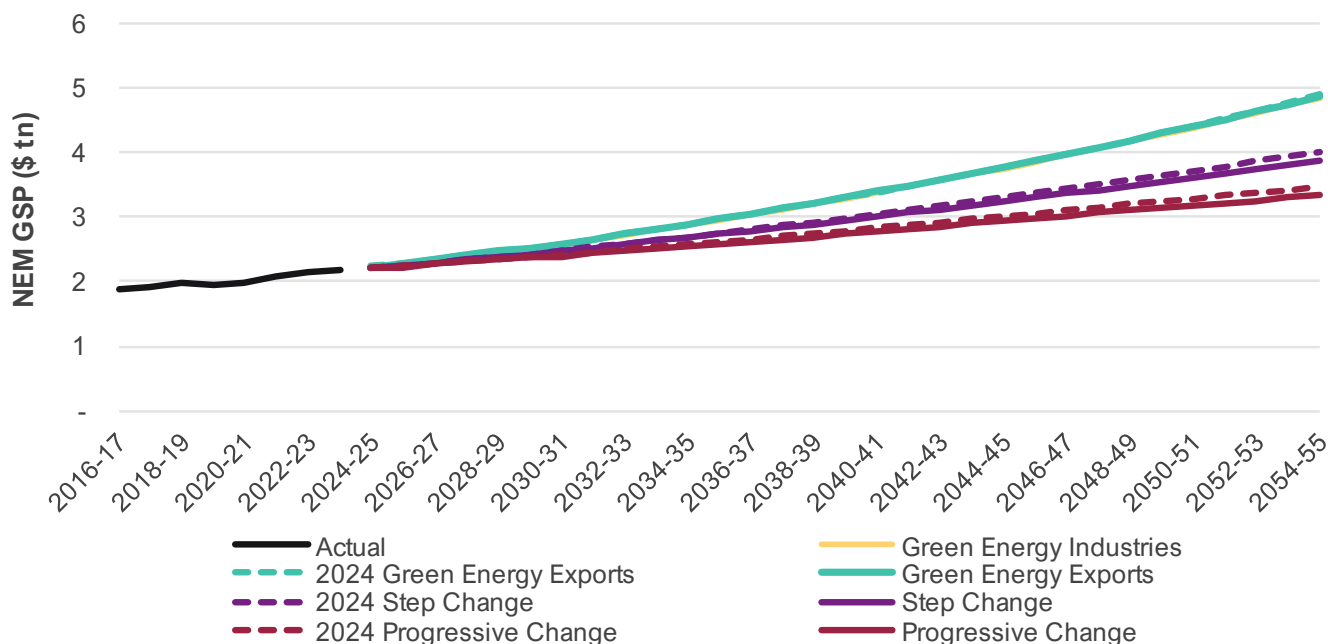
Figure 14 NEM household disposable income per capita by scenario



Note: The *Green Energy Industries* forecast follows a similar trajectory to *Green Energy Exports*, so it is not clearly visible in the figure above.

Economic growth diverges across the scenarios over the forecast period (see Figure 15). Higher population and productivity growth, alongside targeted industrial policy and investments in renewable energy infrastructure, drive increased economic growth in the *Green Energy* scenario variants (*Green Energy Exports* and *Green Energy Industries*). Lower population growth, lower productivity growth, and increased climate change costs decrease expected economic growth in the *Progressive Change* scenario.

Figure 15 NEM aggregated Gross State Product by scenario



Note: The Green Energy Industries forecast follows a similar trajectory to Green Energy Exports, so it is not clearly visible in the figure above.

3.3.9 Households and connections forecasts

Input vintage	June 2024
Status	Current view
Source	<ul style="list-style-type: none"> • ABS • DAE • AEMO meter database
Update process	Will be updated in mid 2025 with the latest dwellings forecast and AEMO's latest actual connections data
Get involved	FRG discussion in March/ April 2025 (WEM) and May 2025 (NEM)

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

AEMO estimates the number of new residential electricity connections by combining existing dwelling stock information from the ABS and AEMO metering data, with forecast dwelling completions (newly constructed dwellings net of dwelling demolitions) sourced from the economic consultancy.

AEMO uses the current number of connections as the starting point. The 2024 forecasts for the NEM (used in the 2024 NEM ESOO) started at a lower level compared to the 2023 forecasts, in part due to adjustments in how existing connections were reported, as well as low dwelling completions at the time.

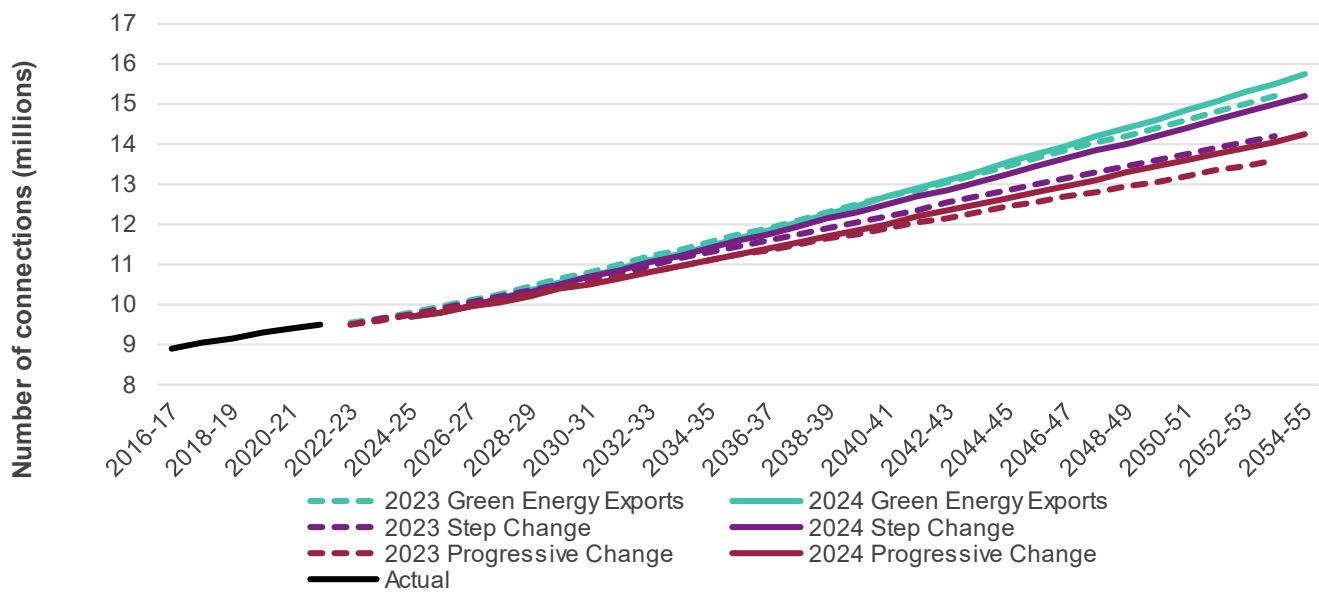
In the short term (3-5 years), lower dwelling completions persist, before recovering to an annual growth rate of around 1.5%. In the *Step Change* scenario, connections are forecast to grow to around 15 million connections by

2054, which is approximately 800,000 more than forecast in the 2023 *Step Change* scenario. These additional connections are backed by a higher population forecast in the longer term, compared to the 2023 forecasts.

The distribution of new connections is different between regions across the NEM, with increased connections in New South Wales, Victoria and Queensland and reduced activity in the Australian Capital Territory, South Australia and Tasmania compared to the 2023 forecasts.

Figure 16 shows the 2024 residential connections actual and forecast for all scenarios in the NEM. The connections forecasts for the NEM and WEM will be updated in time for the final 2025 IASR.

Figure 16 2024 Actual and forecast NEM residential connections, all scenarios, compared to the 2023 forecast



3.3.10 Large industrial loads

Input vintage	June 2024
Status	Current view
Source	<div><ul style="list-style-type: none">Surveys/InterviewsAEMO meter databaseNetwork service providersLIL forecasts of multi-sectoral modellingEconomic outlookMedia search/announcements</div>
Update process	Will be updated in mid-2025 following AEMO's industrial load surveying processes
Get Involved	FRG discussion in March/ April 2025 (WEM) and May 2025 (NEM)

AEMO forecasts LILs independent of smaller medium and commercial business customers (termed the business mass market [BMM] customer segment), to better account for their considerable energy consumption and specific business circumstances, avoiding potential limitations of more general econometric models. Industrial loads also tend to exhibit a different time-of-day and seasonal load profile to other electricity customers.

The *Electricity Demand Forecasting Methodology*⁹³ defines LILs as loads that are over 10 MW at least 10% of the latest financial year.

AEMO currently sources information regarding LILs from:

- Historical data at the NMI level.
- Surveys and interviews, with surveyed loads provided with forecast conditions consistent with the economic outlook for each scenario, to increase survey consistency.
- Information request responses from NSPs on prospective and newly-connecting loads.
- Media searches and company announcements, such as on the ASX for Australian listed companies.

LIL forecasts therefore cover the projected energy consumption of all significant industrial customers, including existing ones, new market entrants, and prospective projects.

The LIL forecasts include prospective projects that are considered committed loads, and take into account start dates and likely growth rates over the outlook period. AEMO proposes to broaden the consideration of prospective loads that are not currently committed, but are likely to impact electricity consumption in the medium to longer term. A detailed description of AEMO's consideration of prospective projects is described in the *Electricity Demand Forecasting Methodology*⁹⁴.

When information on the expected energy consumption of prospective projects is not available, AEMO applies the load factor of similar existing industrial loads to the rated demand. Further, based on information from NSPs and media searches, AEMO may reduce annual consumption and rated demand depending on the likelihood of a project being developed, and revise the timing of projects if delays are identified. AEMO may also consider gradually ramping up consumption of a prospective project, if the full load is not likely to be reached shortly after commissioning.

Figure 17 and Figure 18 compare the 2023 and 2024 LIL electricity consumption forecasts for the NEM and WEM, respectively. These forecasts will be updated in time for the final 2025 IASR, acknowledging the opportunity for engagement via the FRG outlined in the table at the start of this section.

Existing NEM LILs accounted for 27% of the total delivered electricity in 2023-24. Based on the 2024 forecasts, LIL growth is expected to be primarily driven by data centres, mining, and manufacturing expansions. In the medium to long term, the forecasts are informed by projected growth from mining and manufacturing sectors identified by multi-sectoral modelling, driven by decarbonisation objectives and declining electricity costs, particularly from renewables.

The *Progressive Change* scenario for the NEM shows drops in consumption in the short to medium term, accounting for challenging economic conditions resulting in closure risks for major electricity consumers. That scenario explicitly includes closures of major industrial facilities across the NEM to enable investigation of

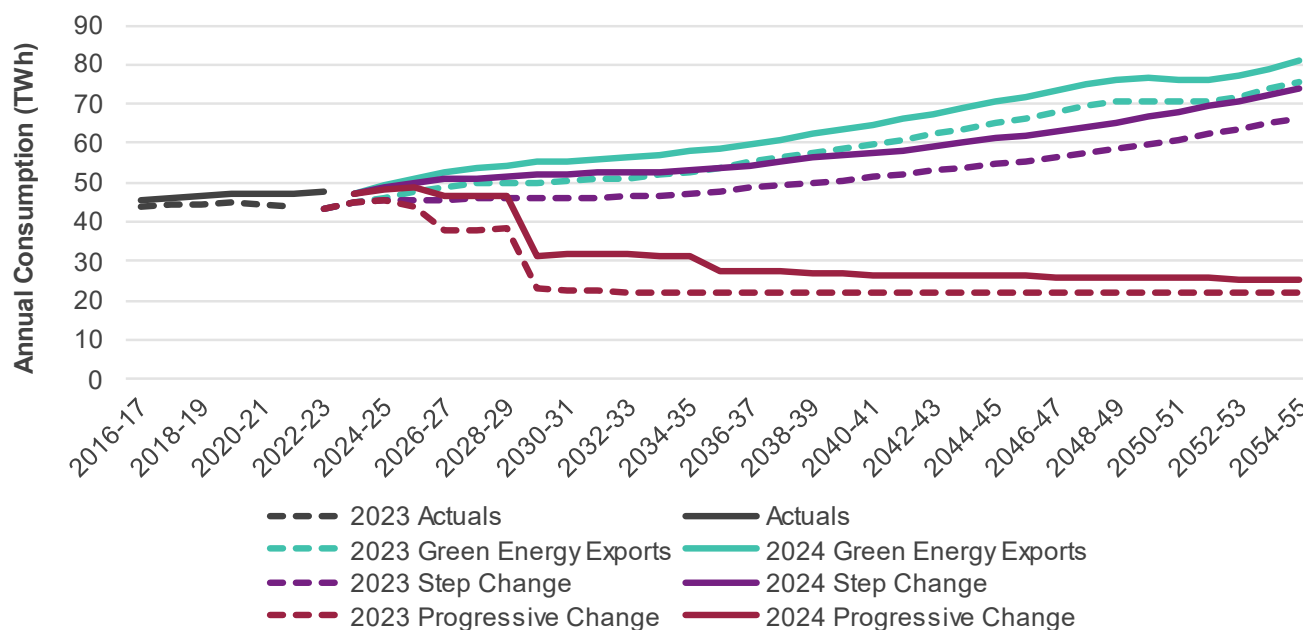
⁹³ AEMO is presently consulting on the *Electricity Demand Forecasting Methodology*, and while a change to this definition is not anticipated, the LIL definition will be determined in that document. The Draft 2025 IASR describes the current definition, and any changes to the method will be reflected in future LIL forecast updates.

⁹⁴ See Section 2.1 of the 2022 *Electricity Demand Forecasting Methodology* for criteria on committed projects, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2022/forecasting-approach-electricity-demand-forecasting-methodology.pdf. This methodology is currently under consultation and may change – see <https://aemo.com.au/consultations/current-and-closed-consultations/2024-electricity-demand-forecasting-methodology-consultation>.

over-investment risks in the ISP. The scenario is not forecasting the possible closure of key facilities, but is assuming possible closure outcomes to enable appropriate exploration of investment risks. This is a key feature of the scenario's narrative.

Existing WEM LILs accounted for 32% of total delivered electricity in the Capacity Year⁹⁵ 2023-24. WEM LIL growth in the 2024 forecasts is driven by expansions in lithium mining and refining, and a proposed desalination plant.

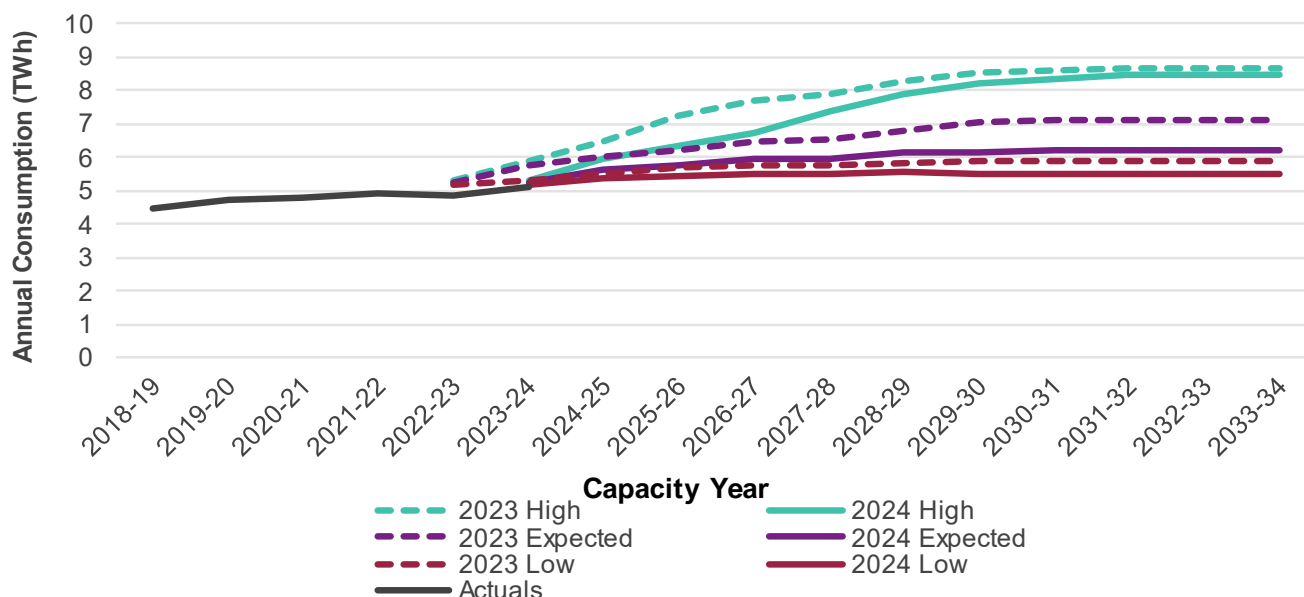
Figure 17 2024 NEM LIL electricity consumption forecast compared to the 2023 forecast (terawatt hours [TWh])



Notes:

- A number of industrial sites were re-classified as LILs for the 2024 NEM ESOO, lifting the forecast and historical data compared to the 2023 NEM ESOO.
- The forecasts contain loads from existing and committed data centres, however AEMO is proposing to treat data centres as a separate business customer segment for 2025 publications onwards.

⁹⁵ A capacity year is a 12-month period used for planning and accounting in the WEM, commencing in 08:00 Trading Interval on 1 October and ending in 07:30 Trading Interval on 1 October of the following calendar year

Figure 18 2024 WEM LIL electricity consumption forecast compared to the 2023 forecast (TWh)

Liquified natural gas

Queensland's LNG industry represents a substantial NEM load, consuming approximately 5% of AEMO's total business consumption category in the NEM in 2024-25. Due to their significance, AEMO forecasts LNG loads separately for improved transparency.

Figure 19 shows the 2024 forecast for LNG electricity consumption.

The LNG forecasts estimate the expected electricity consumption drawn from the NEM by operations of coal seam gas (CSG) fields, using data provided by the LNG consortia via the GSOO survey process. This data considers the anticipated operating range of CSG facilities over the short to medium term until 2034-35. Beyond then, the longer-term forecast is developed by extending the surveyed trend by scenario-dependent assumptions of global natural gas production and LNG demand, particularly in the Asia Pacific. AEMO shaped the long-term trajectory of scenarios in LNG forecasts based on trends observed in the 2023 IEA WEO⁹⁶, whereby:

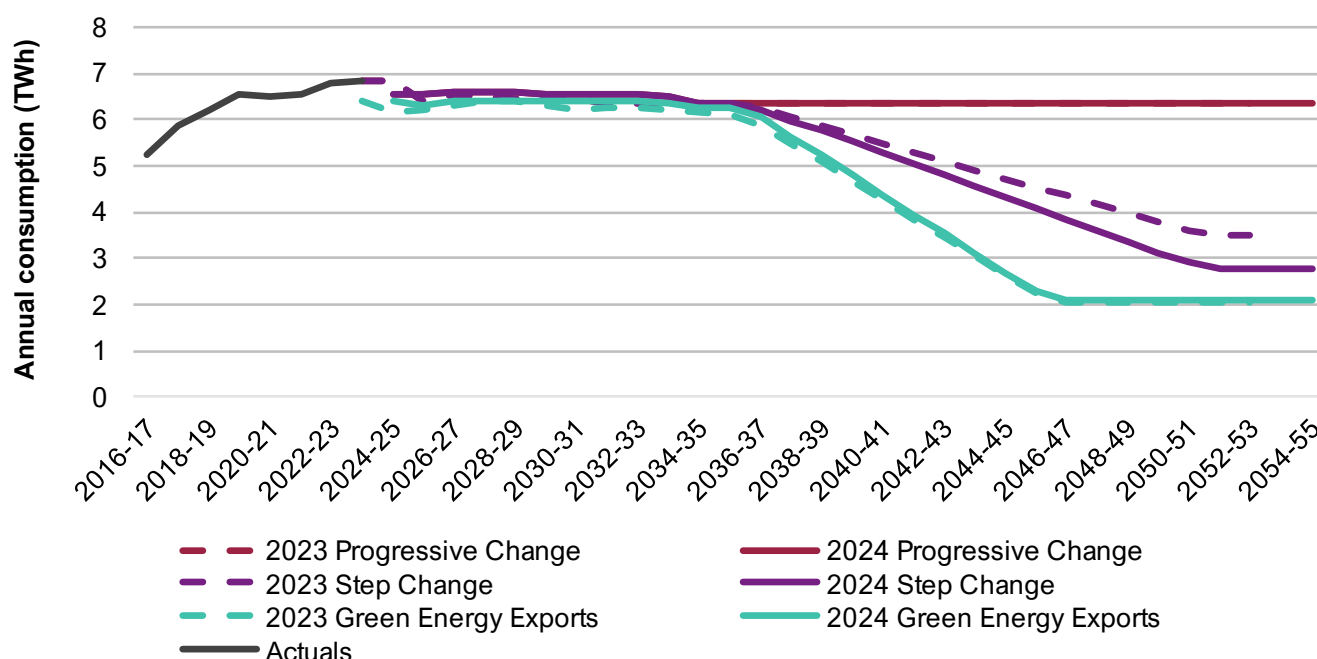
- The *Progressive Change* scenario has been aligned to the IEA's Stated Policies Scenario (STEPS). Lower global economic growth and reduced action towards global decarbonisation means LNG continues to be a valued energy form and LNG export consumption stays flat post 2035.
- The *Green Energy* scenario features the greatest level of global decarbonisation action to reduce energy sector emissions and assumes the Queensland LNG industry will consolidate to the equivalent of a single remaining LNG train by 2050.
- The *Step Change* scenario features a moderate level of global decarbonisation ambition. In this scenario, LNG export consumption falls between levels projected in the IEA's Announced Pledges Scenario (APS) and AEMO's *Green Energy* scenario.

⁹⁶ Where possible, AEMO's LNG forecasts have been aligned with IEA forecasts of LNG export from Australia from the 2023 World Energy Outlook (see <https://www.iea.org/reports/world-energy-outlook-2023>).

The international LNG market faces an uncertain near-term future, affected by geopolitical uncertainties in Europe and the Middle East contributing to volatility, while large amounts of new liquefaction capacity are forecast to come online from Qatar and United States by 2030, as the transition towards cleaner energy and focus on energy security are influenced by geographical locations. The degree of uncertainty regarding the future scale of LNG export demand is reflected by the spread in forecast LNG electricity consumption across AEMO's modelled scenarios.

The *Step Change* and *Green Energy* scenarios are slightly higher in the short term than those forecast in the 2023 IASR, while the *Progressive Change* scenario remains the same.

Figure 19 LNG electricity consumption forecast



3.3.11 Data centre forecast

Input vintage	N/A
Status	To commence early 2025
Source	<ul style="list-style-type: none"> • Surveys/Interviews • AEMO meter database • NSPs • Economic outlook • Media search/announcements
Update process	Will be developed in early to mid-2025
Get involved	<ul style="list-style-type: none"> • AEMO's <i>Electricity Demand Forecasting Methodology</i> consultation • FRG consultation in March/ April 2025 (WEM) and May 2025 (NEM)

Data centres are a rapidly growing sector being driven by demand for cloud computing and artificial intelligence-based applications. AEMO proposes to forecast data centres as a separate business customer

segment for 2025 publications onwards, and is consulting on this adjustment to its forecasting approach in the *Electricity Demand Forecasting Methodology*⁹⁷.

Industrial-scale data centres that meet the definition of an LIL will be forecast at an individual site level. Key parameters that may be considered include the ramp-up period (the duration for the new connection to reach full load [which may take years]) and the load realisation factor (a scaling factor representing the amount of load that will be realised, compared to the rated demand for that project).

For the remaining commercial-scale data centres, AEMO proposes to use either a regression-based approach based on historical data (similar to the BMM methodology) or scenario-based assumptions supported by consultant data.

Data centre sources of information include:

- Historical data at the NMI level.
- Surveys and interviews for large data centres (LIL size), with surveyed loads provided with forecast conditions consistent with the economic outlook for each scenario, to increase survey consistency.
- Information request responses from NSPs regarding prospective and newly connecting loads.
- Media searches and company announcements, such as on the ASX for Australian listed companies.
- Public and commercially available records containing information on data centres.

AEMO proposes to publish an aggregated forecast comprising both industrial-scale and smaller commercial-scale data centres, as a separate business customer segment.

3.3.12 Energy efficiency forecast

Input vintage	Not included in this stage of the Draft 2025 IASR
Status	In progress
Source	<ul style="list-style-type: none">• Strategy. Policy. Research. (SPR)• CSIRO multi-sectoral modelling
Update process	<ul style="list-style-type: none">• SPR presented on preliminary policy-driven and autonomous energy efficiency forecasts to the FRG in October 2024.• Draft forecasts incorporating both consultancies to be published in Stage 2 of the Draft 2025 IASR.
Get involved	FRG discussion in March/ April 2025 (WEM) and May 2025 (NEM)

AEMO has engaged two consultants, Strategy. Policy. Research. (SPR) and CSIRO, to model energy efficiency forecasts for the 2025 IASR scenarios. SPR's approach considers policy-led energy efficiency savings (expected to be delivered by federal and state government measures) and market-led energy efficiency likely to occur without policy intervention. CSIRO's multi-sectoral modelling approach identifies the potential role of energy

⁹⁷ For further details see <https://aemo.com.au/consultations/current-and-closed-consultations/2024-electricity-demand-forecasting-methodology-consultation>.

efficiency under varying decarbonisation pathways, using a combination of annual uptake rates by sector and technology⁹⁸, and scenario-specific variations based on relativities observed in the IEA WEO 2024 scenarios.

Both consultants use scenario-specific economic, population, dwellings and connections forecasts as inputs to modelling energy efficiency, and these input assumptions drive further variation across the scenarios. In the case of SPR, varying fuel shares over time will be informed by multi-sectoral modelling, and the forecasts may also consider developments that exceed current levels of policy support, reflecting growth in market or (expanded) policy-driven developments that are aligned to the scenario parameters.

Compared to the 2023 IASR, the updated modelling will incorporate the following key changes:

- Greater alignment between SPR's approach to modelling energy efficiency and the energy efficiency estimates developed by CSIRO as part of multi-sector modelling.
- Energy efficiency improvements that will assist Australia's largest industrial facilities to reduce their emissions are now influenced by reforms to the Safeguard Mechanism that came into effect in July 2023. Industrial energy efficiency savings attributable to the Safeguard Mechanism will be higher than previous IASR publications.
- Inclusion of Clean Energy Finance Corporation (CEFC) Household Energy Upgrades Fund (HEUF).

SPR presented preliminary forecasts for the three scenarios to the FRG in October 2024⁹⁹. **Further modelling results will be published in Stage 2 of the Draft 2025 IASR.**

3.3.13 Appliance uptake forecast

Input vintage	June 2024
Status	Interim
Source	<ul style="list-style-type: none"> • Department of Industry, Science, Energy and Resources (DISER), <i>2021 Residential Baseline Study for Australia and New Zealand for 2000 – 2040</i>, available at www.energyrating.gov.au • Economic forecasts (Section 3.3.8)
Update process	Update for latest economic forecasts
Get involved	FRG discussion in March/ April 2025 (WEM) and May 2025 (NEM)

AEMO used data from the former Federal Government Department of the Environment and Energy (now the Department of Climate Change, Energy, the Environment and Water [DCCEEW]) to forecast the growth in appliances per connection in the residential sector. The data allowed AEMO to estimate changes to the level of energy services supplied by electricity per households across the NEM.

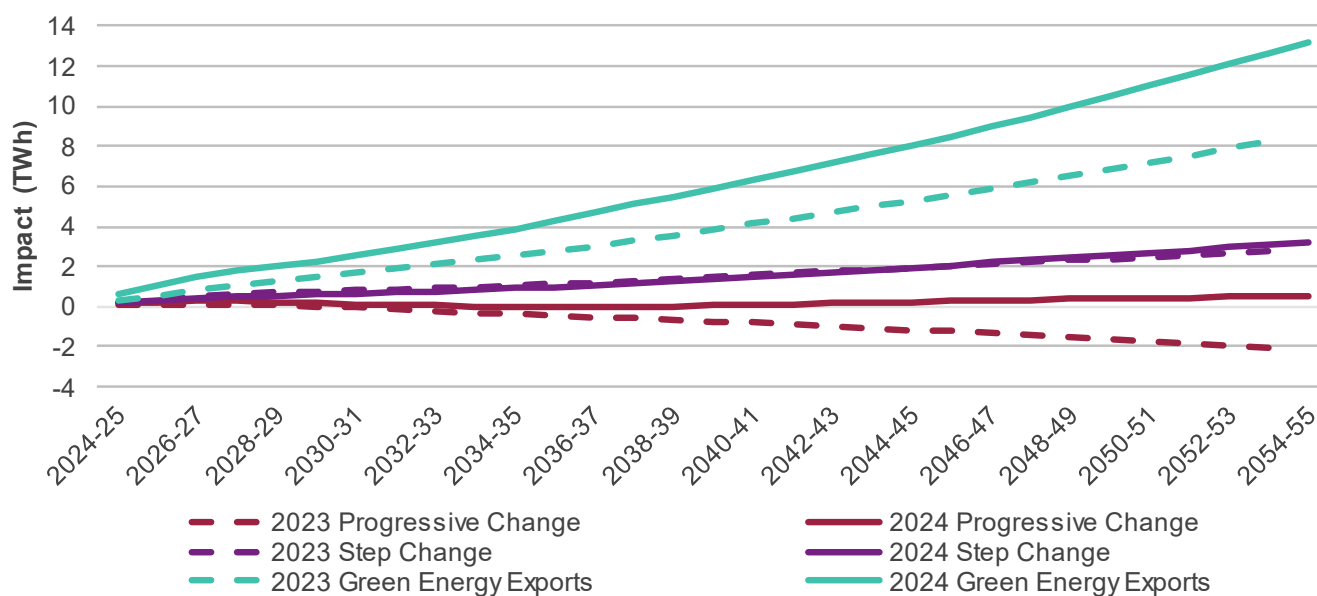
⁹⁸ Based on ClimateWorks Australia's (2014) Deep Decarbonisation Pathways Project, at https://www.climateworkscentre.org/wp-content/uploads/2014/09/climateworks_pdd2050_initialreport_20140923-1.pdf and ClimateWorks Australia's (2016) Low Carbon. High Performance: Modelling Assumptions, prepared for ASBEC (Australian Sustainable Built Environment Council), at <https://www.asbec.asn.au/wordpress/wp-content/uploads/2016/05/160509-CliamteWorks-Low-Carbon-High-Performance-Modelling-Assumptions.pdf>.

⁹⁹ See FRG Meeting #7 on 16 October 2024. Meeting materials are available for download at: <https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg>.

Energy services here is a measure based on the number of appliances per appliance category, their usage hours, and their capacity and size (see Appendix A5 of AEMO's *Electricity Demand Forecasting Methodology* for details on the methodology used).

Figure 20 shows the appliance uptake trajectories applied to the consumption forecasts for the 2024 NEM ESOO, compared with the 2023 NEM ESOO. AEMO will update the trajectories before the release of the final 2025 IASR for both the NEM and WEM, using the latest economic forecasts available.

Figure 20 Residential appliance uptake trajectories for the NEM, consumption change relative to base year (2024), 2023-24 to 2054-55 (TWh)



3.3.14 Electricity price indices

Input vintage	June 2024
Status	Current view
Source	<ul style="list-style-type: none"> AEMO internal wholesale price forecasts. Transmission costs from the 2024 ISP's optimal development path¹⁰⁰. ASX Energy Electricity Futures. AER Determinations and Access Arrangements¹⁰¹. Australian Energy Market Commission (AEMC) annual Residential Electricity Price Trends, 2024 report^{102,103}. Australian Competition and Consumer Commission (ACCC) Inquiry into the National Electricity Market report - November 2022¹⁰⁴. Synergy wholesale prices (WEM)

¹⁰⁰ At <https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp>.

¹⁰¹ At <https://www.aer.gov.au/industry/registers/determinations>.

¹⁰² At <https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2024>.

¹⁰³ As outlined in Table 11, AEMO uses ASX Energy electricity futures to inform the short term wholesale price trends rather than the 2021 AEMC derived forecasts. An updated AEMC Residential Electricity Price Trends report was released in November 2024, and AEMO will consider its insights before consulting on and finalising this component.

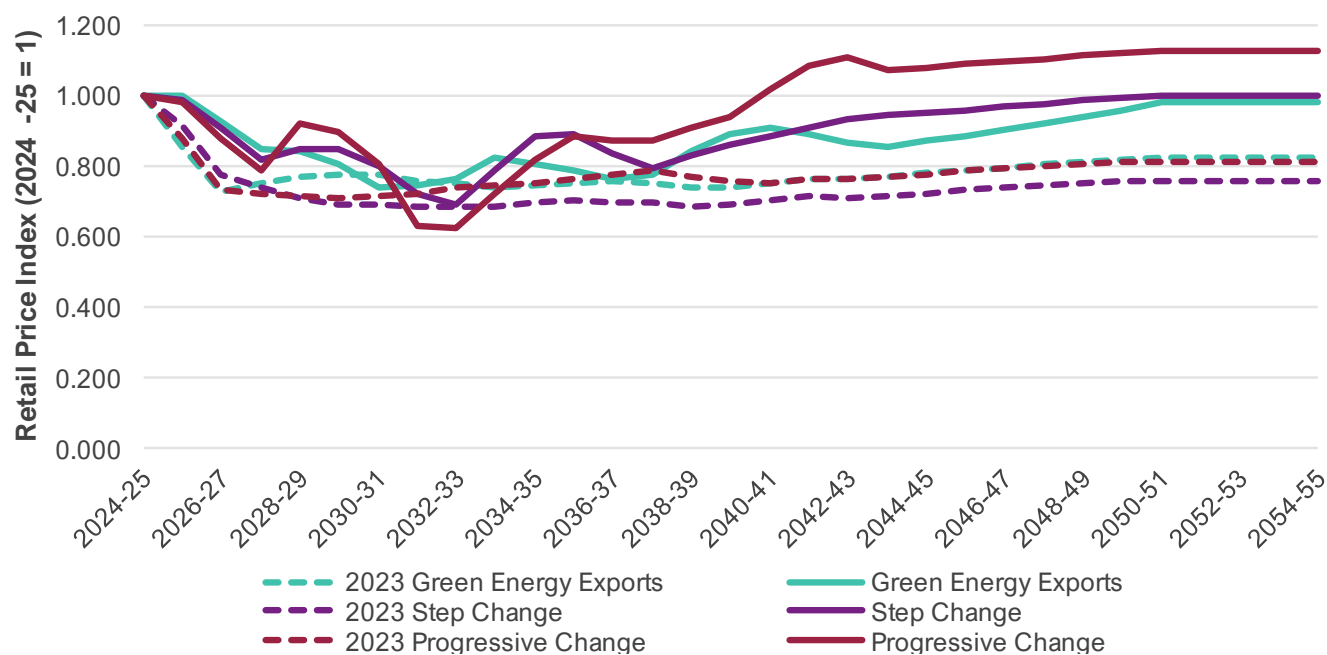
¹⁰⁴ At <https://www.accc.gov.au/about-us/publications/serial-publications/inquiry-into-the-national-electricity-market-2018-25-reports/inquiry-into-the-national-electricity-market-report-november-2022>.

	<ul style="list-style-type: none"> Western Australia State Budget (WEM)
Update process	<ul style="list-style-type: none"> Retail price forecasts are updated with components from the latest available AER pricing proposals and transmission determinations, AEMO wholesale price forecasts, and transmission costs associated with the latest available ISP. Retail price forecasts are updated annually.
Get involved	FRG consultation in May 2025 (NEM).

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

Figure 21 illustrates the retail price indices determined for the 2023 and 2024 NEM ESOOs for the *Progressive Change*, *Step Change*, and *Green Energy* scenarios. The retail price indices for the NEM and WEM will be updated in time for the final 2025 IASR.

Figure 21 NEM Residential retail price forecasts, 2024-25 to 2054-55



Note: Price weighted by household consumption per region.

Prices are expected to trend downwards until the early 2030s as significantly more low-cost renewable energy generation is expected to come online. Prices are expected to rise in 2028-29, driven by the expected retirement of coal power stations and forecast delays to some VRE and battery storage projects. Some price volatility is expected in the mid-2030s as traditional thermal generation is phased out and replaced by renewables with firming from utility-scale battery storage. Modest increases in wholesale prices in the 2040s are projected due to the increased penetration of flexible gas power generation. Gradual increases in network charges beyond the 2040s are driven by transmission investment costs required to meet the ISPs optimal development path for each scenario. The difference in residential retail price trajectories between scenarios represents a differing pace and pathway of decarbonisation, including the shift to renewables and the transformation of the transmission and distribution networks.

AEMO's retail price forecasts are formed from bottom-up projections of the various components of retail prices. Table 11 details the various price inputs used, and their incorporation into the 2024 scenarios. AEMO proposes a similar treatment for the 2025 IASR scenarios, to apply in the 2025 ESOO and 2026 ISP, with updated inputs as available prior to applying AEMO's forecasting approach.

Table 11 Retail price input settings by scenario

Scenario	Progressive Change	Step Change	Green Energy
Wholesale component	<ul style="list-style-type: none"> Short term (up to FYE 2027): Blend of ASX Futures and 2024 ISP Progressive Change. Longer term (FYE 2028 onwards): Solely based on wholesale price trends informed from the 2024 ISP. 	<ul style="list-style-type: none"> Short term (up to FYE 2027): Blend of ASX Futures and 2024 ISP Step Change scenario. Longer term (FYE 2028 onwards): Solely based on wholesale price trends informed from the 2024 ISP. 	<ul style="list-style-type: none"> Short term (up to FYE 2027): Blend of ASX Futures and 2024 ISP Green Energy Exports scenario. Longer term (FYE 2028 onwards): Solely based on wholesale price trends informed from the 2024 ISP.
Transmission costs	<ul style="list-style-type: none"> Short term (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). Longer term (FYE 2030 onwards): Forecast charges based on forecast transmission network augmentations per the 2024 ISP Progressive Change scenario. 	<ul style="list-style-type: none"> Short term (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). Longer term (FYE 2030 onwards): Forecast charges based on forecast transmission network augmentations per the 2024 ISP Step Change scenario. 	<ul style="list-style-type: none"> Short term (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). Longer term (FYE 2030 onwards): Forecast charges based on forecast transmission network augmentations per the 2024 ISP Green Energy Exports scenario.
Distribution costs	<ul style="list-style-type: none"> Short term (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). Longer term (FYE 2030 onwards): Same growth trajectory as transmission costs. 	<ul style="list-style-type: none"> Short term (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). Longer term (FYE 2030 onwards): Same growth trajectory as transmission costs. 	<ul style="list-style-type: none"> Short term (up to FYE 2029): AER pricing proposals and determinations actuals (latest available). Longer term (FYE 2030 onwards): Same growth trajectory as transmission costs.
Environmental costs	AEMC (2021) to FYE 2024 then decline to zero by FYE 2030.	AEMC (2021) to FYE 2024 then decline to zero by FYE 2030.	AEMC (2021) to FYE 2024 then decline to zero by FYE 2030.
Retail component	ACCC (2022) derived residual.	ACCC (2022) derived residual.	ACCC (2022) derived residual.

The retail price indices are only used to inform annual electricity consumption forecasts and consider the potential response from consumers to price. Consumption forecasts consider the price elasticity of demand; that is, the percentage change in demand for a given change in price. The underlying price elasticity of demand that is used to give effect to the price indices and influence the consumption forecasts is as per the 2023 IASR. Table 12 below provides the price elasticities of demand adopted across the modelled scenarios, where negative values indicate a reduction in consumption resulting from a price increase.

Table 12 Price elasticities of demand for various appliances and sectors

Scenario	Progressive Change	Step Change	Green Energy
Residential: baseload appliances	0	0	0
Residential: weather-sensitive appliances	-0.10	-0.10	-0.10
Business: all load components	-0.10	-0.10	-0.05

3.3.15 Demand side participation (DSP)

Input vintage	June 2024
Status	Current view
Source	Historical meter data analysis and information submitted to the DSP Information portal in April 2024.
Updates since 2023 IASR	<ul style="list-style-type: none"> • Current levels and committed/planned changes updated after summer 2023-24 to reflect most recent information. • Target levels to be maintained.
Get involved	FRG consultation in May 2025 (DSP and WDR)

AEMO's forecasting approach considers DSP explicitly in its market modelling, meaning that demand forecasts reflect what demand would be in the absence of DSP¹⁰⁵. DSP accounts for the demand flexibility which often does not have a regular and repetitive pattern; it occurs in response to a price trigger (to avoid high market prices) or lack of reserve (LOR) conditions (LOR2 or LOR3)¹⁰⁶. Due to the often-irregular pattern of DSP responses, they are not captured by AEMO's demand or supply forecasts, so they need to be forecast separately. This approach, most recently updated in December 2023, remains relevant, yet may require further updates to address whether the assumed levels accurately reflect future DSP capabilities and are not overly conservative considering potentially increasing demand-side capabilities in near future (for example, load flexibility offered by VPPs).

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. The DSP forecast also includes Wholesale Demand Response (WDR) contributions based on the WDR dispatch data; WDR estimates are calculated as a weighted average response of dispatched WDR for each price trigger. Finally, to forecast the total reliability response, the estimated DSP response during reliability events (which AEMO defines as cases where an actual LOR2 or LOR3 is declared) is added to the price-triggered response. This process is completely documented in AEMO's *Demand Side Participation Forecast Methodology*¹⁰⁷.

In accordance with this methodology, AEMO uses existing and committed DSP only for the ESOO, representing the current level discussed above with adjustments for committed changes to DSP as reported to AEMO through the DSP IP, or through policy targets with supporting legislation implemented. 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; except for the *Progressive Change* scenario which assumes no growth in the current level of DSP participation. The target level, defined as the DSP's proportion relative to maximum demand, is linearly interpolated between the beginning and end of the outlook period. The target level at the end of the outlook period aims to reach 8.5% of maximum demand adoption scenario, informed by an international review of demand response potential (primarily in the

¹⁰⁵ For further details, see Appendix 6 of 2024 ESOO, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2024/2024-electricity-statement-of-opportunities.pdf.

¹⁰⁶ See AEMO's reserve level declaration guidelines, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power_system_ops/%20reserve-level-declaration-guidelines.pdf.

¹⁰⁷ See DSP methodology at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/dsp-forecasting-methodology-and-dsp-information-guidelines-consultation/final-stage/2023-dsp-forecast-methodology.pdf.

United and Europe)^{108,109}. This 8.5% figure represents an upper estimate, allowing for growth drivers both from technology and policy schemes (such as WDR).

The settings for the current IASR scenarios are provided in Table 13 below:

- The *Green Energy*¹¹⁰ scenario assumes high growth in DSP, representing a future with highly engaged consumers who, in addition to embracing CER technologies, value the savings from orchestrated DSP programs over the convenience of fixed tariffs and uncontrolled demand.
- The *Step Change* scenario assumes moderate growth in DSP, reflecting moderate economic growth and technology-led change.
- The *Progressive Change* scenario assumes no growth in DSP, maintaining the current penetration level into the future due to a relatively poor economic outlook that limits the capability to install new technologies to increase flexibility, hampered also by supply chain issues affecting demand-side innovations.

For New South Wales, the Peak Demand Reduction Scheme (PDRS) policy¹¹¹ aims at creating a financial incentive to reduce electricity consumption during peak demand times in summer¹¹². AEMO includes this scheme in all of the above scenarios. The PDRS has been applied since 2022-23 with the target growing to 10% of forecast peak demand by 2029-30, slightly fluctuating due to reaching the end-of-life for some batteries, and remaining flat from 2039-2040 onward. It is assumed that 25% of the PDRS target will be met through energy efficiency and battery storage rather than DSP, with DSP adjustments made to avoid double counting. For any given year in New South Wales, the higher value between the PDRS target and standard DSP growth will be used.

Table 13 Mapping of DSP settings to scenarios

Scenario	<i>Green Energy</i>	<i>Step Change</i>	<i>Progressive Change</i>
DSP growth target overall	High growth to reach 8.5% of peak demand by 2050, then remains flat.	Moderate growth to reach 4.25% of peak demand by 2050, then remains flat.	No change from current levels of DSP (0% growth).
New South Wales PDRS	Started in 2022-23 with target growing to 10% of peak demand by 2029-30 and remaining flat afterwards (summer only).	Started in 2022-23 with target growing to 10% of peak demand by 2029-30 and remaining flat afterwards (summer only).	Started in 2022-23 with target growing to 10% of peak demand by 2029-30 and remaining flat afterwards (summer only).

Matters for consultation

- Are the long-term DSP settings, grown to meet a target level by scenario informed by international review, suitable for use in AEMO's planning publications?

¹⁰⁸ See Federal Energy Regulatory Commission (FERC), "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/power-sales-and-markets/demand-response/reports-demand-response-and-advanced-metering>).

¹⁰⁹ See <https://www.sia-partners.com/en/news-and-publications/from-our-experts/demand-response-study-its-potential-europe>.

¹¹⁰ Note that the DSP does not include the flexibility provided by electrolyzers, which is modelled separately.

¹¹¹ See <https://www.energy.nsw.gov.au/nsw-plans-and-progress/regulation-and-policy/energy-security-safeguard/peak-demand-reduction-scheme>.

¹¹² 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	October 2024
Status	Current view
Source	Participant survey responses
Update process	Updated quarterly

AEMO's Generation Information page¹¹³ 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 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 planning publications (and clearly identified in each publication). The Draft 2025 *IASR Assumption Workbook* includes details from the October 2024 publication. Further updates will be made prior to the finalisation of the 2025 IASR, and these updates will be considered in the 2025 ESOO and Draft 2026 ISP (unless material changes are observed during the course of ISP modelling).

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

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

Input vintage	December 2024
Status	Draft
Source	Various, see below
Update process	Updates will be dependent on feedback received on this Draft 2025 IASR
Updates since 2023 IASR	Updated based on October 2024 Generation Information and Clean Energy Regulator's Electricity sector emissions and generation 2022-23.

AEMO has sourced the operating and cost parameters of existing generators and storages from several different sources, including AEMO internal studies¹¹⁴. They include:

- AEMO's Generation Information page.
- Aurecon, 2020 to 2024 Energy Technology Cost and Technical Parameter Review.
- GHD, 2018-19 AEMO Energy Technology Cost and Technical Parameter Review.
- AEP Elical, 2020 Assessment of Ageing Coal-Fired Generation Reliability.

¹¹³ At <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>.

¹¹⁴ Consultant reports and data books from GHD, Aurecon and AEP Elical are available at <https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr>.

- Generator surveys.
- Clean Energy Regulator, Electricity sector emissions and generation 2022-23.
- Specific adjustments to the above sources if required, based on confidential or non-confidential engagement with specific generators or developers.

The specific parameters obtained from these sources are summarised in Table 14 below.

Table 14 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	<ul style="list-style-type: none"> • Maximum capacities • Seasonal ratings (10% probability of exceedance [POE] summer, typical summer and winter) • Auxiliary loads • Reserves • Commissioning and retirement dates
GHD 2018-19 AEMO Energy Technology Cost and Technical Parameter Review (for use for existing generators as of 2018)	<ul style="list-style-type: none"> • Heat rates • Maintenance rates • Fixed and variable operating and maintenance costs • Ramp rates • Minimum up and down time
Aurecon 2020 to 2024 Energy Technology Cost and Technical Parameter Review (primarily for new entrant generators but also referred to for some existing generators since 2019)	<ul style="list-style-type: none"> • 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	<ul style="list-style-type: none"> • Unplanned outage rates
AEP Elical 2020 Assessment of Ageing Coal-Fired Generation Reliability	<ul style="list-style-type: none"> • Assessment of forward-looking coal-fired generator reliability
AEMO internal studies	<ul style="list-style-type: none"> • Complex heat rates, informed by Aurecon and GHD • Minimum stable levels • Ramp rates • Minimum and maximum capacity factors
Clean Energy Regulator, Greenhouse and energy information by designated generation facility 2022-23	<ul style="list-style-type: none"> • Scope 1 emission intensity for existing generators
DCCEEW, 2023 Australian National Greenhouse Accounts Factors	<ul style="list-style-type: none"> • Emission factor for biomass

The specific assumptions on the parameters documented in the above table are contained in the Draft 2025 *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 appropriate to incorporate without simplification to more static assumptions.

The relative coarseness of the ISP’s capacity outlook models requires that some operational limitations are applied using simplified representations such as minimum stable levels or capacity factor limitations to represent technical constraints and power system security requirements. This helps ensure that relatively inflexible generators, such as coal-fired generators, are not dispatched in a manner that exceeds their technical capability or that would not be commercially viable. The current view of these operational limits is described in the accompanying Draft 2025 *Inputs and Assumptions Workbook*. They may also be refined during the ISP as described in the *ISP Methodology*, as an outcome of the iterative market modelling process.

Minimum stable levels for existing generators are based on AEMO’s analysis of historical generation and operational experience. Minimum stable levels for new entrant generators are sourced from Aurecon. For the purposes of the capacity outlook model, these minimum stable levels are converted into minimum capacity factors.

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 2025 *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.

AEMO may apply these assumptions when performing specific analyses that warrant the higher degree of technical complexity; they may not always be applied to balance the simulation complexity.

Further details on the implementation of these technical limitations can be found in AEMO’s *ISP Methodology*¹¹⁵.

3.4.3 Generator unplanned outage rates

Input vintage	April 2024
Status	Draft
Source	Generator surveys, AEP Elical 2020, and Aurecon 2024 Cost and Technical Parameter Review
Update process	Updates will be dependent on feedback received on this Draft 2025 IASR
Updates since 2023 IASR	Unplanned outage rates were updated with latest data in April 2024 as part of data collection process for the ESOO. The updates were presented to the FRG in June 2024.

In April 2024, AEMO collected outage information for existing scheduled generators, including storage units, on the timing, duration, and de-rating of historical unplanned outages via an annual survey process. This data is then

¹¹⁵ At <https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/isp-methodology>. This methodology is also under consultation for the 2026 ISP, at <https://aemo.com.au/consultations/current-and-closed-consultations/2026-isp-methodology>.

used to forecast the full and partial unplanned outage rates¹¹⁶ (UORs) for each financial year, for each generator over the ESOO horizon consistent with the *ESOO and Reliability Forecasting Methodology*¹¹⁷. For small peaking plants and hydro generator technology types, technology aggregates are applied to individual stations. Where AEMO asked participants to provide outage rate projections, these projections were adopted in consultation with the station owners/operators.

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

Long duration unplanned outages

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

The long duration outages used in 2024 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 15.

Table 15 Existing generators – long duration outages

Fuel type/technology	Long duration outage rate (%)	Mean time to repair (hours)
All coal	0.91%	6,331
OCGT	0.73%	4,872
Hydro	0.17%	4,065
Other gas and liquid	0.54%	6,632

OCGT: Open cycle gas turbine.

Unplanned outage rate trajectories (excluding long duration outages)

The forecast equivalent full and partial unplanned outage rates by technology for 2024-25, the first year of the forecast horizon period in the 2024 ESOO, are based on participant-provided information as shown in Table 16.

Table 16 Unplanned outage assumptions (excluding long duration outages) for 2024-25 financial year

Technology	Full unplanned outage rate (%)	Partial unplanned outage rate (%)	Partial derating (% of capacity)	Mean time to repair – full (hours)	Mean time to repair – partial (hours)
Brown coal	7.39	15.45	17.39	92	37
Black coal NSW	5.22	27.08	17.67	136	28
Black coal QLD	5.37	13.70	24.03	160	44
OCGT	8.25	2.32	9.86	57	130
Small peaking plant*	8.65	0.35	28.29	201	323

¹¹⁶ Planned outages are not modelled in the ESOO, because these are assumed to be planned in lower demand periods or to shift if low reserve conditions were to occur, and therefore not impact USE outcomes.

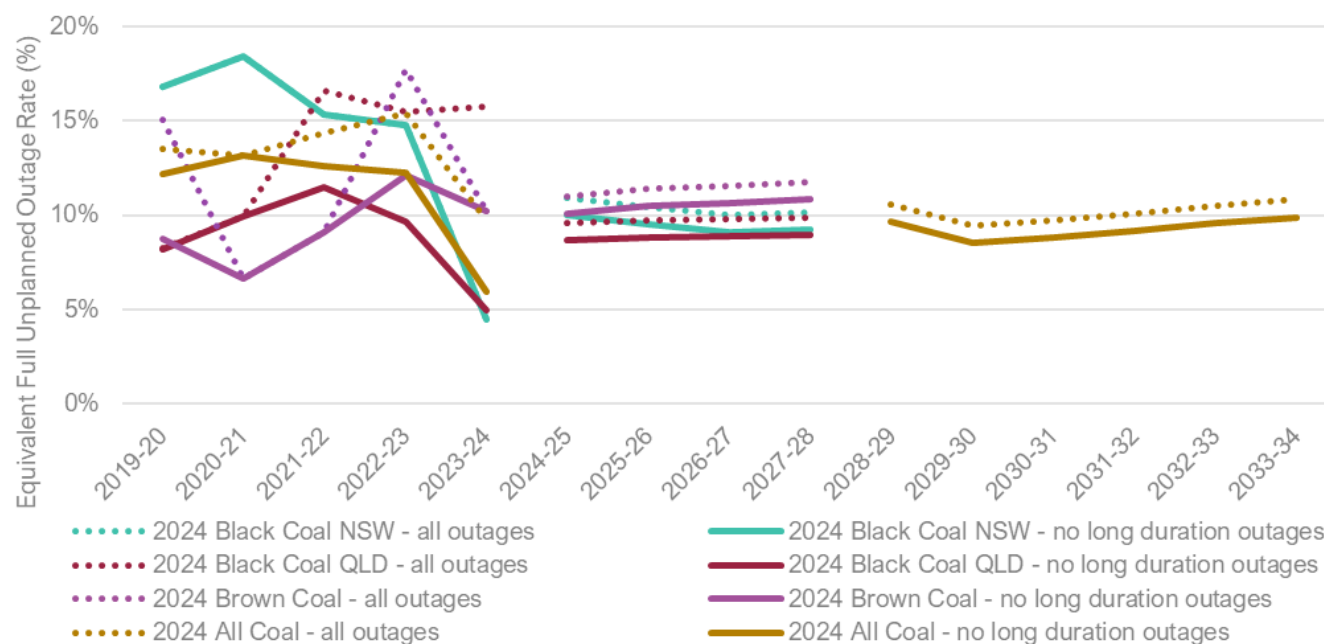
¹¹⁷ At <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo>.

Technology	Full unplanned outage rate (%)	Partial unplanned outage rate (%)	Partial derating (% of capacity)	Mean time to repair – full (hours)	Mean time to repair – partial (hours)
Hydro	4.56	1.06	13.30	51	436
Closed cycle gas turbine (CCGT) and gas-fired steam turbine	6.71	1.25	13.25	54	38
Batteries	1.84	N/A	N/A	141	N/A

*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)

The 10-year projections for the equivalent full unplanned outage rate¹¹⁸ of all technology aggregates are shown in Figure 22, Figure 23 and Figure 24, with and without the effect of long duration outages. The annual equivalent unplanned outage rates are affected by changes to assumed reliability and retirements of generators over the horizon. To protect the confidentiality of the individual station-level information used, unplanned outage trajectories are provided for the first 10 years of the horizon for technology aggregates only. Due to the small number of coal plants in later years, all regions have been further aggregated to an ‘All Coal’ value to protect confidentiality.

Figure 22 Equivalent full unplanned outage rate projections for coal-fired generation technologies



¹¹⁸ Where equivalent full unplanned outage rate = Full outage rate + partial outage rate x average partial derating.

Figure 23 Equivalent full unplanned outage rate projections for OCGT, CCGT and steam turbine generation and small peaking plant technologies

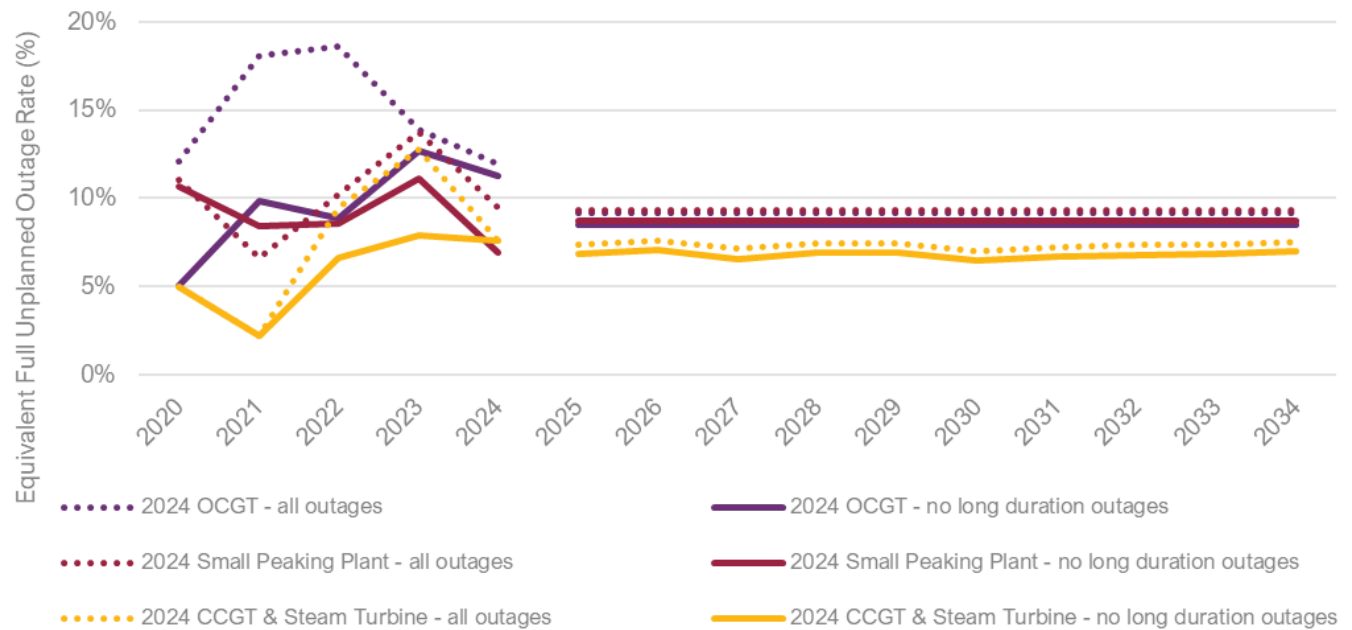
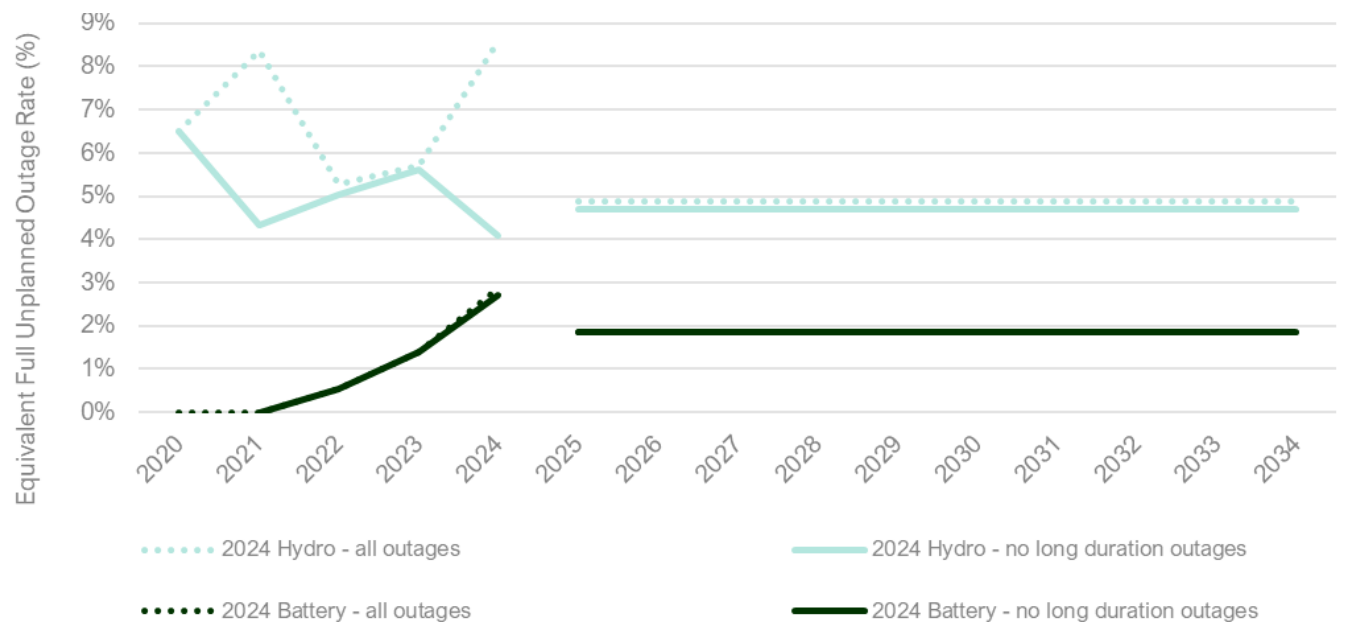


Figure 24 Equivalent full unplanned outage rate projections for battery and hydro technologies



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 a plant ages and nears retirement, it is difficult to predict this trend with any accuracy beyond 10 years, 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*¹¹⁹.

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	<ul style="list-style-type: none"> Retirement costs: December 2024 Retirement dates: Generation Information October 2024
Status	Current view
Source	<ul style="list-style-type: none"> Generation Information GHD 2018
Update process	Updated quarterly
Updates since 2023 IASR	Expected closure years and closure dates have been updated to reflect the most recent data collection.

For existing generators, AEMO applies the expected closure year as provided by participants and published through AEMO's Generation Information¹²⁰ page as a latest retirement date, as follows:

- In ESOO, MT PASA and EAAP, expected closure years are applied consistent with the participant-provided information.
- In the ISP, retirements may be brought forward ahead of the expected closure year if it reduces overall system costs, as described in the *ISP Methodology*. As discussed in more detail in that document, retirements may be modelled to meet carbon budgets or broader policy constraints.

For reference, a *closure date* has the meaning specified in NER 2.10.1(c1) which specifies the date a generator will cease to supply or acquire electricity in the market or trade directly in the market, while an *expected closure year* is the year in which a generator expects to cease to supply electricity (as per NER 2.1B.3(a)). Generators in relation to which there is an expected closure year tend to be projects that are scheduled to close in the near term, over the next few years or so, and are published in the Generating Unit Expected Closure Year subset of the Generation Information page.

As discussed in the *ISP Methodology*, if a generator has notified 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.

¹¹⁹ At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en.

¹²⁰ At <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>.

Retirement costs by generation technology have been provided by AEMO’s technology cost consultants and are presented in the accompanying Draft 2025 *Inputs and Assumptions Workbook*. A number of technologies (biomass, solar thermal, offshore wind) do not have a retirement cost estimate. Given the development lead times of these technologies (generally greater than six years) and the economic life (generally greater than 25 years), retirement costs would be incurred beyond the end of the ISP modelling horizon. Retirement costs incorporate the cost of decommissioning, demolition, and site rehabilitation and repatriation, excluding battery storage technologies where disposal cost data is not known.

Matters for consultation

- Are the retirement cost assumptions detailed in the accompanying Draft 2025 *Inputs and Assumptions Workbook* appropriate?

3.4.5 Hydro modelling

Input vintage	June 2023
Status	Current view
Source	Inflows – hydro operators, considering insights regarding long-term rainfall trends from the Electricity Sector Climate Information (ESCI) project ¹²¹ .
Update process	Scheme inflows will be updated for the 2025 IASR.
Updates since 2023 IASR	Hydro scheme inflows have been updated based on data received from participants in April and June of 2023.

Hydro scheme inflows

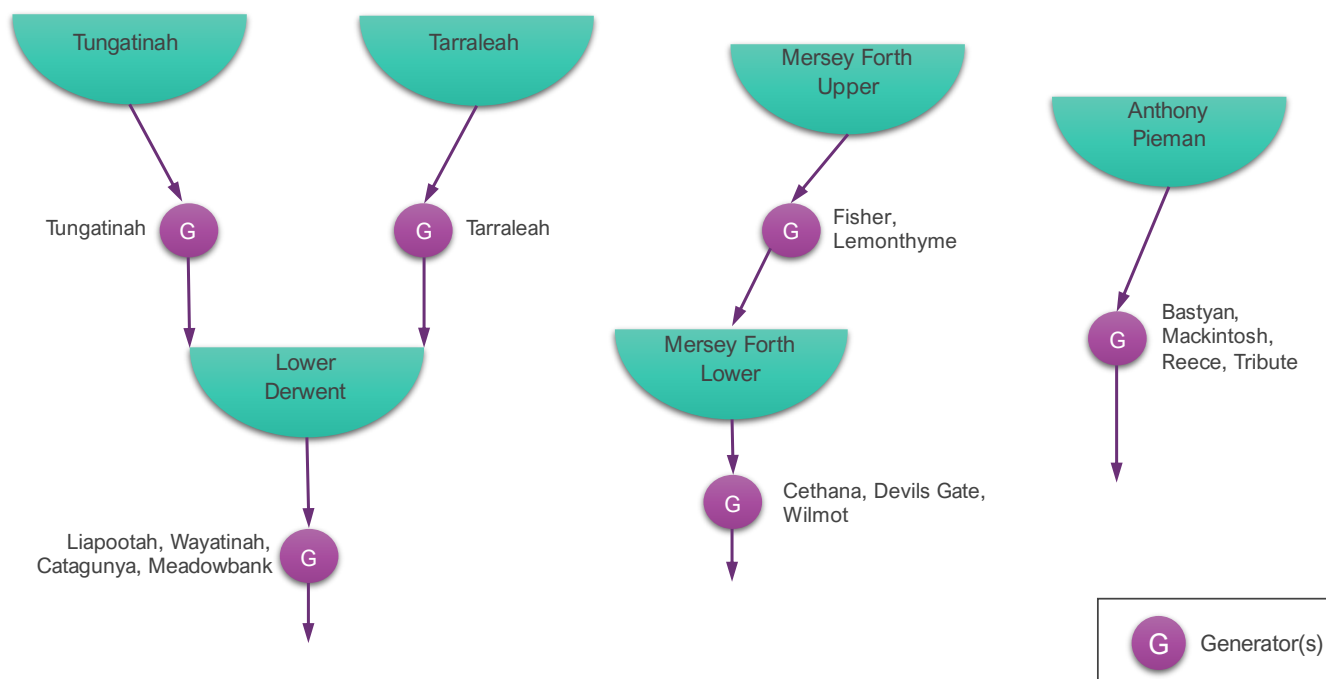
AEMO models each of the large-scale hydro schemes using inflow data for each generator, with aggregation of some run-of-river generators.

Tasmanian hydro scheme

AEMO’s approach to modelling the existing Tasmanian hydro schemes relies on a 10-pond¹²² topology designed to capture different levels of flexibility associated with the different types of storage outlined above (see Figure 25).

¹²¹ ESCI information available at <https://www.climatechangeinaustralia.gov.au/en/projects/esci/>.

¹²² The capacity outlook model may aggregate long-term storages together to reduce simulation time.

Figure 25 Hydro Tasmania scheme topology

Mainland hydro scheme

Some of the Victorian hydroelectric generators are modelled using maximum annual capacity factor constraints on each individual generator; these are West Kiewa and Bogong-Mackay¹²³. The model schedules the electricity production from these generators across the year such that system costs are minimised within this energy constraint.

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

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

Monthly storage inflows used in market modelling studies can be found in the Draft 2025 *Inputs and Assumptions Workbook*.

Figure 26 presents a representation of the topology currently modelled for the Snowy scheme.

¹²³ 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.

Figure 26 Snowy Hydro scheme topology

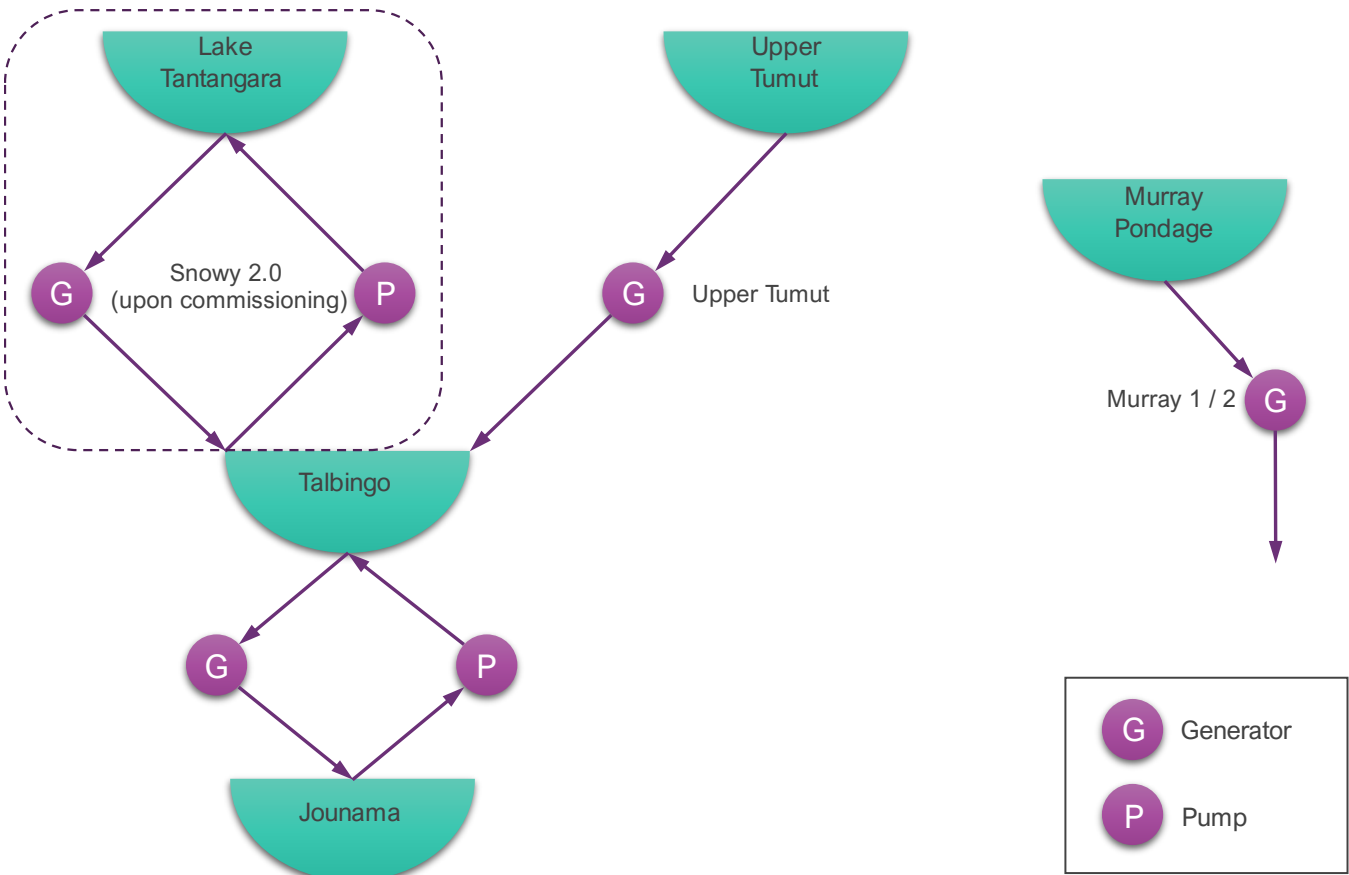
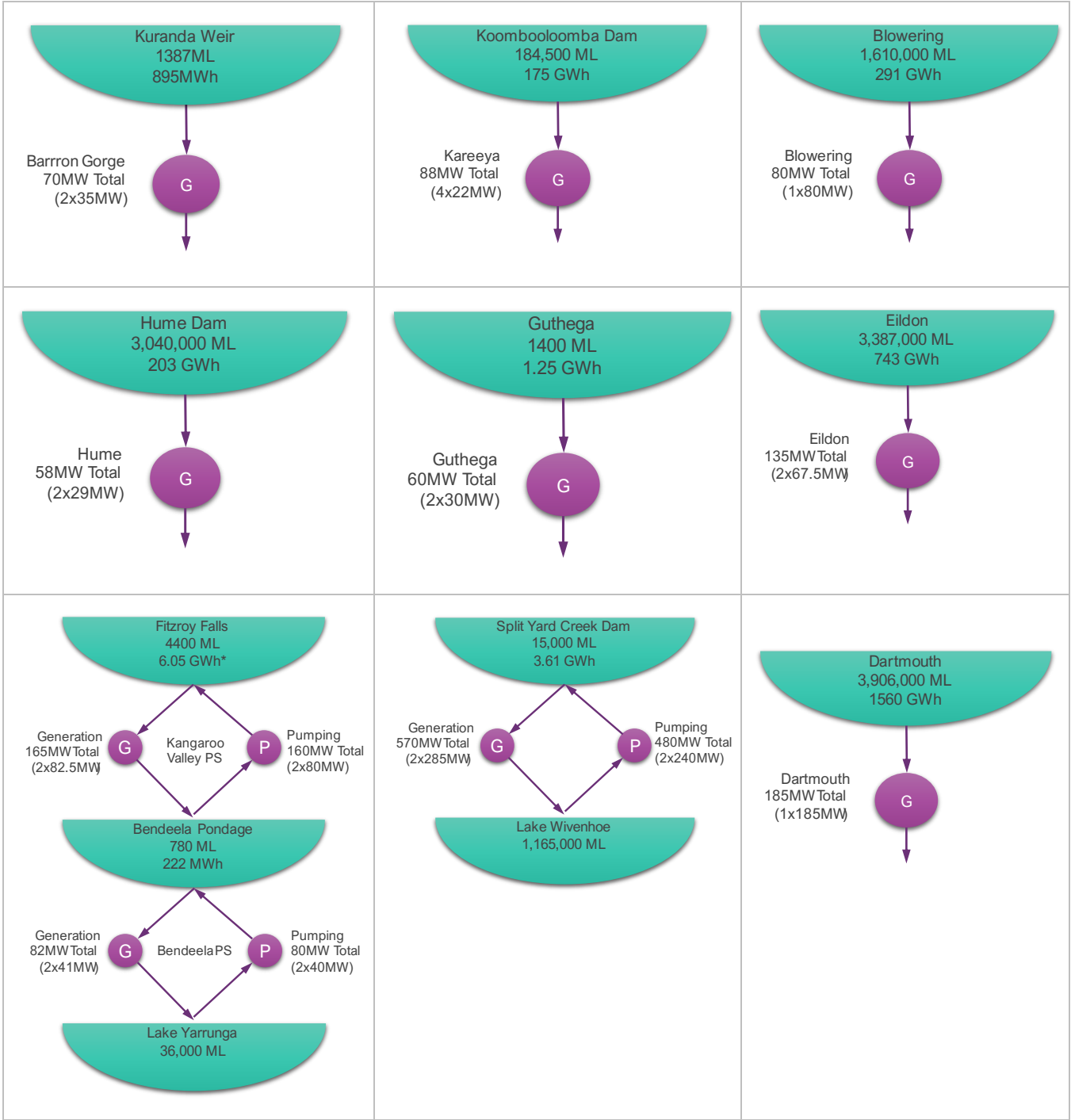


Figure 27 provides graphical representations of the other hydrological models used in the market simulations, as well as the registered capacity of the adjoining generating units¹²⁴.

Figure 27 Hydro scheme topologies of other existing hydro power stations

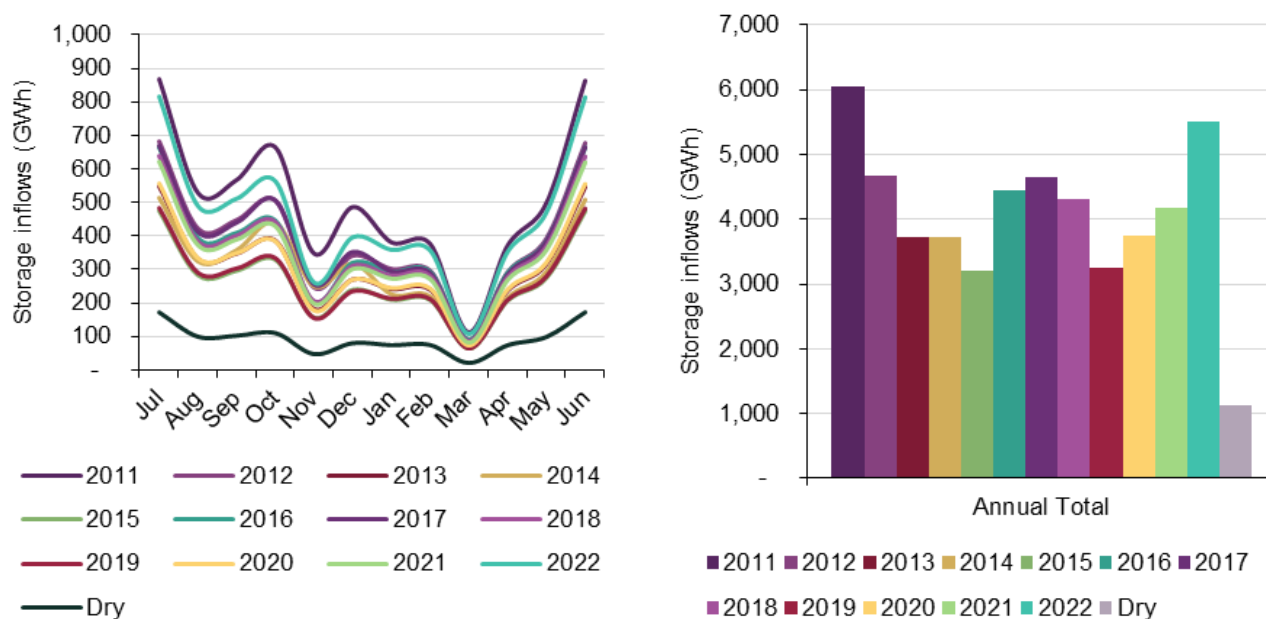


*Energy storage at Fitzroy Falls includes full drop through both power stations.

¹²⁴ Storage capacities are defined in megalitres (ML).

The Draft 2025 *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 28 below, for Snowy Hydro. The data will be updated in the 2025 IASR; it is updated based on observed inflows and participant received data, similar to other historical data.

Figure 28 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 Government¹²⁵.

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 17 for the *Step Change* scenario, as an example. Other scenario hydro climate factors are available in the Draft 2025 *Inputs and Assumptions Workbook*.

Table 17 Median hydro climate factors, Step Change scenario

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

¹²⁵ See <https://www.climatechangeinaustralia.gov.au/en/projects/esci/>.



3.5 New entrant generator assumptions

3.5.1 Committed and anticipated projects

Input vintage	October 2024
Status	Current view
Source	Participant survey responses
Update process	Quarterly updated
Updates since 2023 IASR	Updated to incorporate the October 2024 Generation Information.

New generator or storage developments that are announced to market are assessed against commitment criteria published in AEMO’s Generation Information page¹²⁶. The commitment criteria cover five areas of a project’s development, covering:

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

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

- **In Commissioning** are those projects that have met the requirements of the first commissioning hold point (typically at least 30% capacity commissioned).
 - For reliability and ISP assessment purposes, projects in commissioning are modelled as becoming fully available at the Full Commercial Use Date (FCUD) submitted by the project proponent.
- **Committed projects** are projects that have fully met all commitment criteria but have not yet met the requirements of their first commissioning hold point.
 - For reliability assessment purposes, committed projects are included in the modelling at six months after the FCUD submitted by the project proponent.
 - For ISP assessment purposes, committed projects are assumed to proceed at the FCUD submitted by the project proponent.

¹²⁶ See <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>.

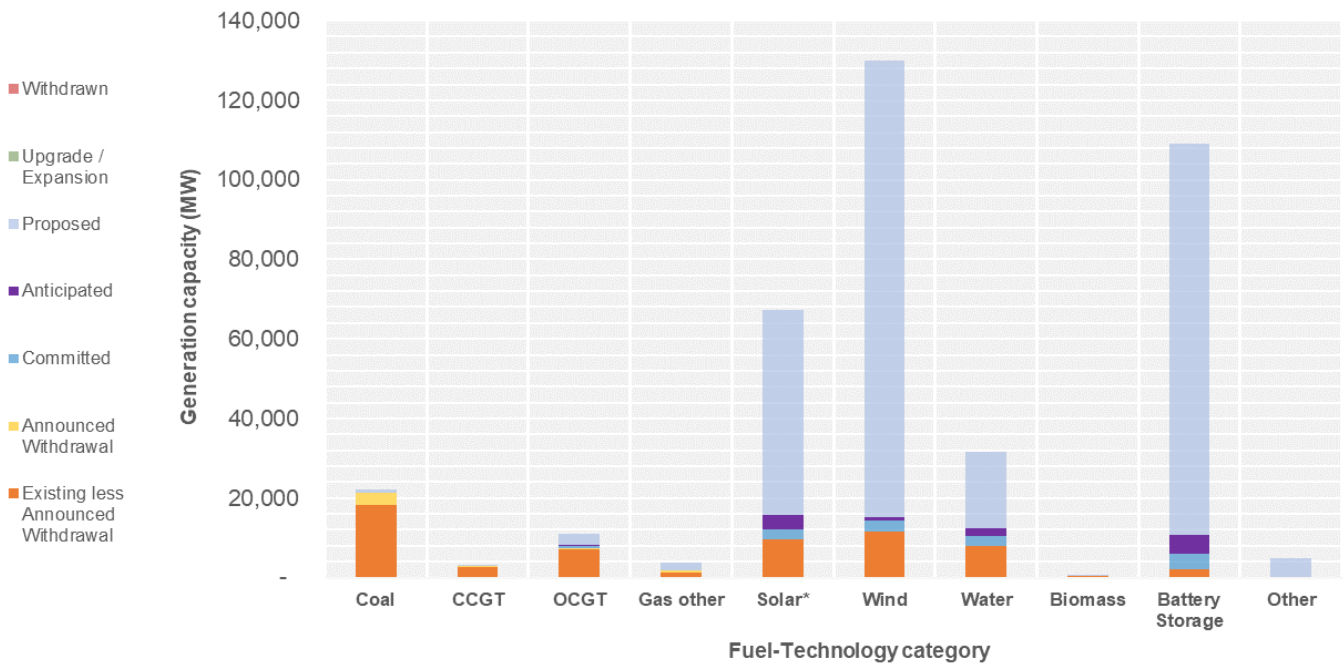
- **Committed* projects** are those projects that satisfy land, finance and construction criteria plus either planning or contracts criteria. Progress towards meeting the final criteria is also evidenced and construction or installation has also commenced.
 - For reliability assessment purposes, committed* projects are included in the modelling at six months after the FCUD submitted by the product proponent.
 - For ISP assessment purposes, committed* projects are assumed to proceed at the FCUD submitted by the project proponent.
- **Anticipated projects** are those projects that have demonstrated progress towards meeting at least three of the commitment criteria and have updated their submission to AEMO in the previous six months.
 - For reliability assessment purposes:
 - To reflect the uncertainty in the commissioning of these projects, anticipated projects which have provided an expected commissioning date are assumed to become fully available at the latest date of either: one year after the date provided by the project proponent, or the first day after the T-1¹²⁷ year for Retailer Reliability Obligation (RRO) purposes.
 - Anticipated projects that are not yet sufficiently progressed to provide an expected commissioning date are assumed to become fully available on the first day after the T-3¹²⁸ year for RRO purposes.
 - For ISP assessment purposes:
 - Anticipated projects for which an expected commissioning date has been provided are assumed to proceed at the FCUD submitted by the project proponent.
 - Anticipated projects for which an expected commissioning date has not been provided are assumed to become fully available two years after the publication of the IASR (that is, July 2027 for the purposes of this IASR), subject to technology development lead time assumptions.
- **Proposed projects** are those projects that have not progressed sufficiently to meet the requirements of an Anticipated or Committed project.
 - Proposed projects are not considered explicitly in AEMO's reliability or ISP assessments but may be considered in sensitivities if relevant.

The Draft 2025 IASR uses the Generation Information as at October 2024. A summary of existing, committed, and anticipated projects included in that release is provided in Figure 29 below.

¹²⁷ T-1 refers to reliability assessments one year out. For example, for a reliability assessment conducted in August 2023, the T-1 period refers to the 2024-25 financial year.

¹²⁸ T-3 refers to reliability assessments three years out. For example, for a reliability assessment conducted in August 2023, the T-3 period refers to the 2026-27 financial year.

Figure 29 Generation and storage projects in October 2024 Generation Information page (MW)



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

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

3.5.2 Candidate technologies

Input vintage	December 2024
Source	<ul style="list-style-type: none">CSIRO: <i>GenCost 2024-25 Consultation Draft</i>Aurecon: <i>2024 Energy Technology Costs and Technical Parameter Review</i>GHD: <i>2018-19 Costs and Technical Parameters Review</i>
Updates since 2023 IASR	Updated to reflect Aurecon’s 2024 Energy Technology Cost and Technical Parameter Review

For the 2026 ISP’s capacity outlook modelling, a reduced list of technologies is considered based on technology maturity, resource availability, and energy policy settings.

Table 18 below presents the list of technologies that will be used in 2024-25 publications.

Table 18 List of generation and storage technology candidate

List of technologies for consideration in the 2026 ISP	Commentary
CCGT – with CCS	-
CCGT – without CCS	-
OCGT – dual fuel, without CCS, small unit size	As discussed in Aurecon's <i>2024 Energy Technology Costs and Technical Parameters Review</i> there is a trend for gas turbine developments to move towards low emission solutions with either blending or firing completely on hydrogen. All new open cycle gas turbine (OCGT) projects are expected to include provision/capability for hydrogen blending. As such, AEMO is now modelling all OCGTs as capable of dual fuel.
OCGT – dual fuel, without CCS, large unit size	As discussed in Aurecon (2024) there is a trend for gas turbine developments to move towards low emission solutions with either blending or firing completely on hydrogen. All new OCGT projects are expected to include provision/capability for hydrogen blending. And as such, AEMO is now modelling all OCGTs as capable of dual fuel.
Solar PV – single axis tracking	-
Solar thermal central receiver with storage (16 hr)	The storage component will be increased from 15 hours to 16 hours, aligned with the <i>2024 Energy Technology Costs and Technical Parameter Review</i>
Wind – onshore	-
Wind – offshore (both fixed and floating)	Both fixed and floating offshore wind turbine structures will continue to be considered as distinct candidate options, with consideration for the ocean depth of the offshore REZ.
Biomass generation – electricity and heat	Since the <i>GenCost 2022-23 Final report</i> and following stakeholder feedback, heat generated from biomass generation for electricity has now been reflected; however, as AEMO's capacity outlook modelling does not consider demand for heat or location explicitly, it is not able to consider the value of the heat generated from biomass.
Lithium-Ion battery storage	AEMO includes storage sizes from one to 8 hours in its models. No geographical limits will apply to available battery capacity given its small land footprint.
Pumped hydro energy storage (PHES)	<p>AEMO includes 10-hour (unlike in previous IASRs, which proposed an 8-hour option), 24-, and 48-hour PHES options across the NEM. Six- and 12-hour PHES options are consolidated into a 10-hour option to reflect likely future PHES developments across the NEM. The increase in depth from 8-hour to 10-hour reflects Aurecon's feedback on developer interest.</p> <p>These options are supplemented by announced projects where appropriate, for example the 20-hour Cethana project in Tasmania.</p> <p>This portfolio of candidates complements deep storage initiatives (such as the committed Snowy 2.0 and the anticipated Borumba Dam Pumped Hydro) and existing traditional hydro schemes.</p>

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

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

- **New brown coal generation (with or without carbon capture and storage [CCS]) and advanced ultra-supercritical pulverised black coal (with and without CCS)** – given federal and state existing policies regarding net zero emissions, including this technology would present an internal inconsistency with those policy requirements. Considering also that there are lower cost dispatchable alternatives offering greater system flexibility, investment risks for new coal developments are therefore assumed to be too high to be commercially viable.
- **Reciprocating internal combustion engines** – reciprocating engines fuelled by natural gas/diesel are not modelled due to their high capital cost relative to open cycle gas turbines (OCGTs), as discussed in Aurecon's *2024 Energy Technology Cost and Technical Parameters Review*.

- **Hydrogen-only reciprocating engines or OCGTs** – as discussed in Table 18, AEMO proposes not to model hydrogen-only or natural gas-only technologies. Instead, dual fuel technologies that can run on natural gas or hydrogen are proposed to be modelled, in line with current trends as discussed in Aurecon's *2024 Energy Technology Cost and Technical Parameters Review*.
- **Nuclear generation, including small-modular reactors** – currently, Section 140A of the *Environment Protection and Biodiversity Conservation Act 1999*¹²⁹ prohibits the development of nuclear installations.
- **Geothermal technologies** – geothermal technologies are considered too costly and too distant from existing transmission networks to be considered a bulk generation technology option in the NEM.
- **Solar PV fixed flat plate (FFP) and dual-axis tracking (DAT) technologies** – while the best solar configuration depends on each individual project, single-axis tracking (SAT) generally presents greater value on a cost-per-energy-delivered basis given current cost assumptions. Presently, announced SAT projects also provide more proposed capacity than DAT and FFP projects, and almost all recent project commitments for large-scale solar are SAT¹³⁰. Given this preference and the relative cost advantage, AEMO models all future solar developments using SAT configuration.
- **Tidal / wave technologies** – this is not sufficiently advanced or economic to be included in the modelling.
- **Hybrid technologies** – these are not explicitly considered but the *ISP Methodology* sets out how AEMO considers the benefits of co-locating VRE and storage in the assessment of potential actionable REZ augmentations.

3.5.3 Candidate technology build costs

Capital cost trajectories

Input vintage	December 2024
Status	Draft
Source	<ul style="list-style-type: none"> • CSIRO: <i>GenCost 2024-25 Consultation Draft</i> • Aurecon: <i>2024 Energy Technology Costs and Technical Parameters Review</i> • Hydro Tasmania information on Cethana project
Update process	Dependent on feedback received in this Draft 2025 IASR and the GenCost 2024-25 Consultation Draft
Updates since 2023 IASR	Updated to reflect CSIRO's <i>GenCost 2024-25 Consultation Draft</i>

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

To support this forecast, Aurecon provided estimates of the current capital cost of each generation technology. CSIRO uses these current capital cost estimates in the Global and Local Learning Model (GALLM) to produce capital cost forecasts that are a function of global and local technology deployment.

¹²⁹ At <https://www.legislation.gov.au/Details/C2012C00248>.

¹³⁰ 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>.

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

The build cost projections are given for three *GenCost 2024-25 Consultation Draft* scenarios: "Global NZE by 2050", "Global NZE post 2050" and "Current Policies". These scenarios are described in greater detail in CSIRO's *GenCost 2024-25 Consultation Draft*. AEMO maps the Draft 2025 IASR scenarios to the *GenCost 2024-25 Consultation Draft* scenarios based on the fit of the narratives against each other, as shown in Table 19.

Table 19 Mapping AEMO scenario themes to the *GenCost 2024-25 Consultation Draft* report scenarios

ISP scenario	<i>GenCost 2024-25 Consultation Draft</i> scenario	Explanation
Progressive Change	<i>Current Policies</i> *	Consistent with current commitments to the Paris Agreement, leading to the lowest global emissions reduction ambition and a 2.5°C warming future.
Step Change	<i>Global NZE post 2050</i>	Consistent with global action to limit temperature rises to less than 2°C, and with industrialised countries targeting net zero emissions by 2050.
Green Energy	<i>Global NZE by 2050</i>	The most ambitious global emissions reduction scenario, consistent with limiting temperature rises to less than 1.5°C.

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

Figure 30, Figure 31 and Figure 32 below present a comparison of *GenCost 2024-25 Consultation Draft*'s *Global NZE post 2050* compared with *GenCost 2023-24 Final Report*'s *Global NZE post 2050* build cost projections (excluding connection costs) for selected technologies. Cost projections for each technology and scenario are available in the accompanying Draft 2025 *Inputs and Assumptions Workbook*.

In line with findings in the previous GenCost, costs over the period to 2030 are driven by short-term supply pressures which result in higher costs relative to the cost paths determined by the CSIRO's learning model. As these impacts ease, costs converge closer to previous estimates in the longer term.

As detailed in Aurecon's accompanying *Energy Technology Cost and Technical Parameter Review*¹³¹, since last year, fixed offshore wind has seen a more significant drop in costs. Some caution needs to be applied when translating these costs to an Australian context given these developments would be first-of-a-kind as highlighted in both Aurecon's *Energy Technology Cost and Technical Parameter Review* and the *GenCost 2024-25 Consultation Draft*.

In recognition of this, AEMO proposes to modify the costs (as provided by GenCost) of offshore wind (both fixed and floating) and CCS technologies by applying a first-of-its-kind premium as build cost multipliers. They reflect the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit. As discussed in GenCost, these are observable when a proponent fails to deliver the first project for the cost that had been planned, and as such, they are difficult to estimate. AEMO proposes that these factors, presented in Table 20 below, would be applied to offshore wind and technologies with CCS. These factors have been sourced from the US Energy Information Administration (US EIA)¹³².

¹³¹ At <https://aemo.com.au/consultations/current-and-closed-consultations/2025-iasr>.

¹³² More detail available at https://www.eia.gov/outlooks/aeo/assumptions/pdf/EMM_Assumptions.pdf.

Table 20 First-of-its-kind generation cost premiums

Technology	Factor	Commentary
Wind - offshore (fixed)	1.25	It is proposed that this factor is applied to the year of built capacity of fixed offshore wind developed by the model, and then reduced to 0.
Wind - offshore (floating)	1.25	It is proposed that this factor is applied to the year of built capacity of floating offshore wind developed by the model, and then reduced to 0.
Technologies with CCS	1.04	Aligned with their use by the US EIA, This factor would be applied to the first year of built capacity that is developed by the model, and then reduced to 0.

In recognition of the recent inflationary cycle and the resulting cost pressures, CSIRO modified its modelling approach to better account for this influence. Taking Aurecon figures as a starting point, *GenCost 2024-25 Consultation Draft* now applies 'basket-of-costs' factors over the period to 2030 or 2027 (depending on the scenario) as less deployment in new technology in *GenCost's Current Policies* (applied in *Progressive Change*) sees slower learning and less pressures on technology costs and a relaxation of supply chain constraints earlier.

In the medium and longer term, the technology costs reflect forecast cost savings due to learning rates that are achieved through deployment.

Certain technologies – including but not limited to batteries, PV, and fixed offshore wind – have been observed to have returned to pre-pandemic levels. As a result, these technologies do not apply the supply chain constraint impacts, and rather apply the standard learning rate approach described in *GenCost 2024-25 Consultation Draft*.

Additionally, projections have been adjusted to recognise the fundamental scarcity of land and easements following stakeholder feedback. Projections will be adjusted using locational cost factors published in the report by Mott Macdonald underpinning figures in AEMO's Transmission Cost Database in 2023 for the land and easement component of the project cost.

As seen in Figure 31, *GenCost 2024-25 Consultation Draft* incorporates hydrogen fuel readiness for gas generation, which results in an increase in costs relative to previous estimates. Figure 32 shows a decrease in the cost of batteries, which, as discussed in *GenCost 2024-25 Consultation Draft*, are now at pre-pandemic levels in real terms. Finally, build cost estimates from pumped hydro have been updated based on Aurecon's assessment, with 10-hour pumped hydro considered more expensive than 24-hour, and more in line with estimates for 48-hour durations.

More information on methodology adjustments from *GenCost 2023-24* to *GenCost 2024-25 Consultation Draft* can be found in the *GenCost 2024-25 Consultation Draft*.

Figure 30 2023 vs 2024 Global NZE post 2050: build cost trajectories forecasts for wind and large-scale solar

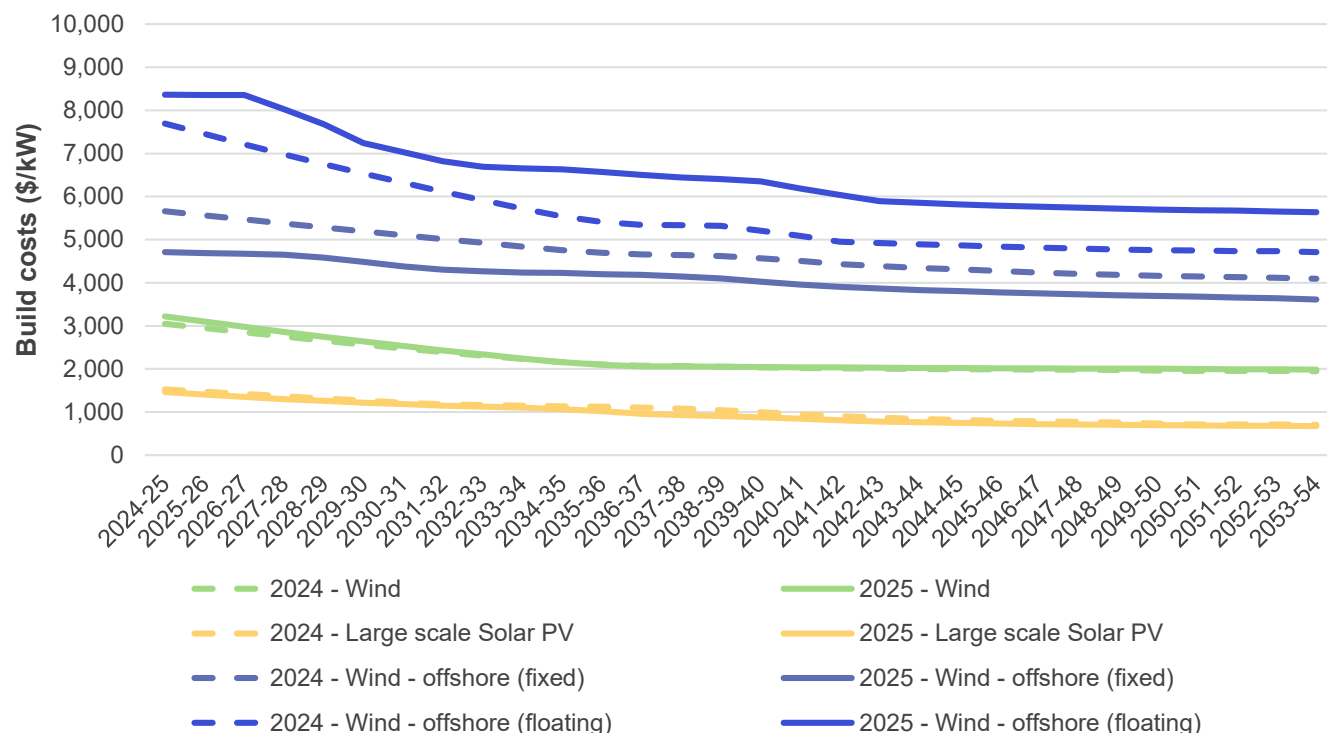


Figure 31 2023 vs 2024 Global NZE post 2050: build cost trajectories forecasts for gas generation

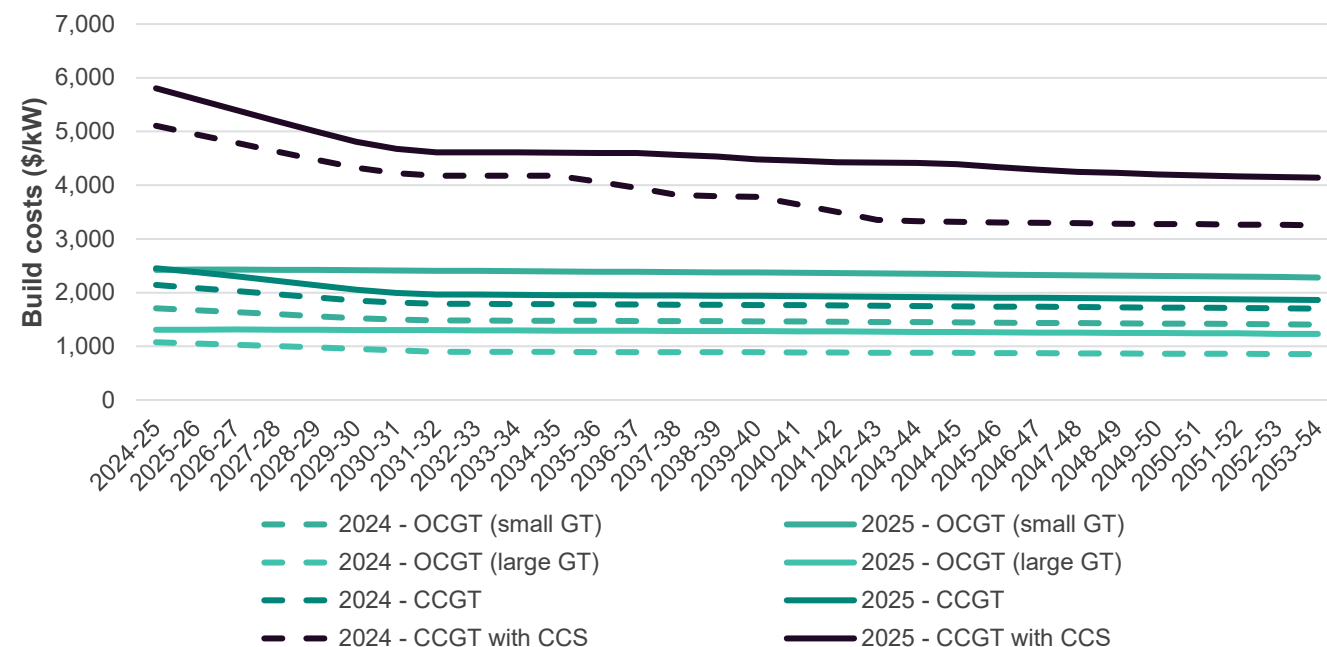
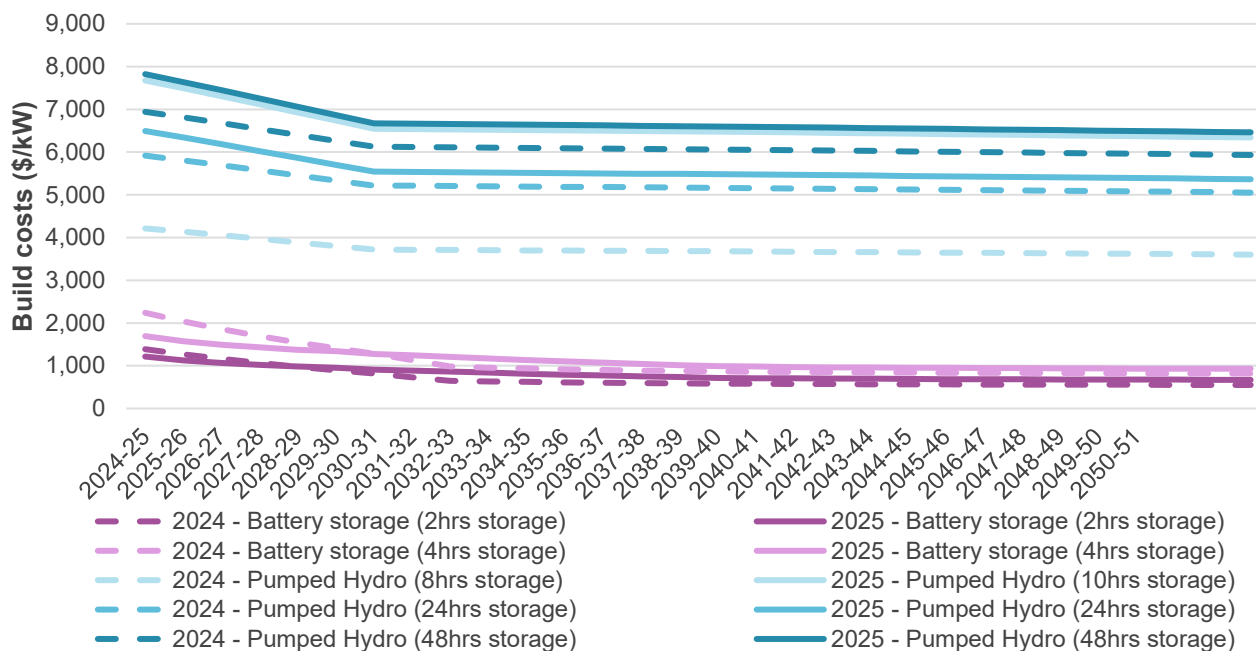


Figure 32 2023 vs 2024 Global NZE post 2050: build cost trajectories forecasts for selected storage technologies

Note: As discussed in Table 19, pumped hydro 8-hour has been replaced with 10-hour following advice from Aurecon.

In *GenCost 2024-25 Consultation Draft*, current costs (a key input to develop the projections) represent current typical contracting costs or costs demonstrated to have been incurred for projects completed in the current financial year and does not represent quotes for potential projects or project announcements.

It should also be noted that when comparing *GenCost 2024-25 Consultation Draft*'s capital costs in \$/kW with Aurecon, the latter does not include the cost of land in its presentation of \$/kW capital costs, whereas this is included in the *GenCost 2024-25 Consultation Draft* and therefore by AEMO¹³³.

Capital costs are not applied for existing, committed, and anticipated projects. AEMO does not have specific estimates for the cost of these projects. Importantly, as these projects are included in all ISP development pathways, including the counterfactual, the calculation of net market benefits are not influenced by the costs or benefits of these projects, as they are netted off.

Matters for consultation

- Do you support the implementation of first-of-a-kind premiums for technologies that have not been deployed in Australia and with the underlying assumptions appropriate?
- Do you have any comments regarding the draft build cost projections?

If you have more substantive feedback to CSIRO's *GenCost 2024-25 Consultation Draft* report, please separate feedback to it from feedback to this Draft 2025 IASR, so that AEMO (and CSIRO as needed) may process both submissions as appropriate.

¹³³ 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	December 2024
Source	<ul style="list-style-type: none"> • Aurecon: <i>2024 Energy Technology Cost and Technical Parameters Review</i> • AEMO revisions
Update process	<p>Locational cost factors have been updated based on Aurecon's <i>2024 Energy Technology Cost and Technical Parameters Review</i>, proposed for consultation and feedback in response to this Draft 2025 IASR.</p> <p>Land and development factors have been modified to reflect those applied from the 2023 update to AEMO's Transmission Cost Database, and will be updated again for the Final 2025 IASR following consultation on the <i>2025 Network Expansion Options Report</i>.</p>
Updates since 2023 IASR	<p>Locational cost factors have been proposed to be updated to be REZ-specific as presented in Aurecon's <i>2024 Energy Technology Cost and Technical Parameters Review</i>. Locational cost factors for pumped hydro have been modified to reflect greater disaggregation in Victoria and South Australia.</p>
Get involved	<i>2025 Network Expansion Options Report</i> consultation

The breakdown of cost components for each technology is informed by updated data from Aurecon's *2024 Energy Technology Cost and Technical Parameters Review*, in line with the approach followed in previous IASRs. These figures do not capture site-specific aspects of costs that are only known when detailed feasibility investigations have been implemented. If site-specific cost information on particular projects becomes available, AEMO may shift to adopting these values as appropriate. The updated breakdown of cost components is available in the Draft 2025 *Inputs and Assumptions Workbook*.

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

In 2023, AEMO commissioned Aurecon to update the locational cost factors as part of the *2023 Energy Technology Cost and Technical Parameters Review*. The factors now account for greater granularity by providing a factor at a REZ level, relative to metropolitan areas in the NEM region, and are intended to be a multiplier to the cost components resulting in a technology and location-specific multiplier.

The locational cost factors below, updated in the *2024 Energy Technology Cost and Technical Parameters Review*, consider the indicative cost of local accommodation, cost for resources, mobilisation and demobilisation based on project duration, cost for materials delivery, and labour productivity in each of the REZs. REZ locational cost factors were provided for a number of sub-regional areas within each REZ, which have been averaged to arrive at the REZ-level estimates.

The factors for land and development have been updated from those provided by Aurecon to those underpinning the update to AEMO's Transmission Cost Database used in the 2023 IASR. AEMO will update these factors again for the 2025 IASR following consultation through the *2025 Network Expansion Options Report*, to ensure consistent treatment of land and development factors across transmission, generation and storage.

Locational cost factors are relative to metropolitan areas with a de facto factor of one. AEMO proposes to assign a locational factor of one to builds in sub-regional reference nodes. This will impact all/most builds not located within a REZ. Offshore REZs also have a factor of one (although as discussed above, it is proposed that offshore wind build costs will now be subject to a temporary first-of-a-kind premium).

The accompanying Draft 2025 *Inputs and Assumptions Workbook* provides additional details of these locational cost factors, including the resulting regional technology cost adjustment factors.

Figure 33 shows the effective impact of the changes in locational cost factors for all REZs for onshore wind generation. The greatest variance is in Queensland, with North Queensland Clean Energy Hub being 50% higher than the benchmark, and in South Australia, where Roxby Downs is 19% higher than the benchmark. This represents greater variation than in the 2023 IASR, with the change largely due to the factors being benchmarked to the capital cities and rather than the nearest major port, due to greater differences for labour, installation, and O&M cost components. Additionally, disaggregation by REZs (rather than more coarse regional segmentation) further highlights underlying differences that may be masked by higher geographical aggregation. Further detail on differences to previous values is in Aurecon's accompanying 2024 *Energy Technology Cost and Technical Parameters Review* report (see Appendix A2).

Figure 33 Weighted REZ locational cost factors for wind in the 2023 IASR and the 2025 Draft IASR

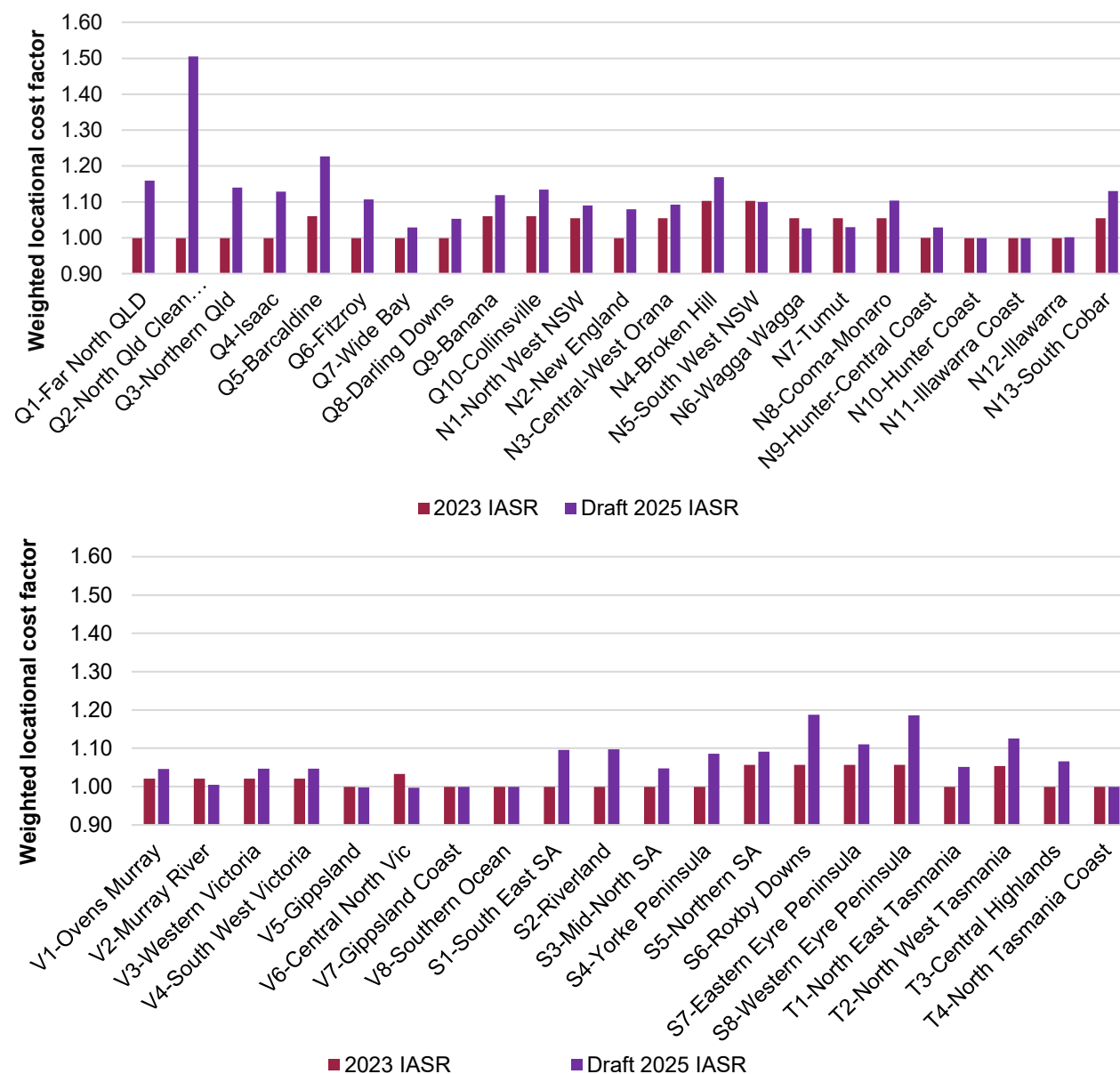
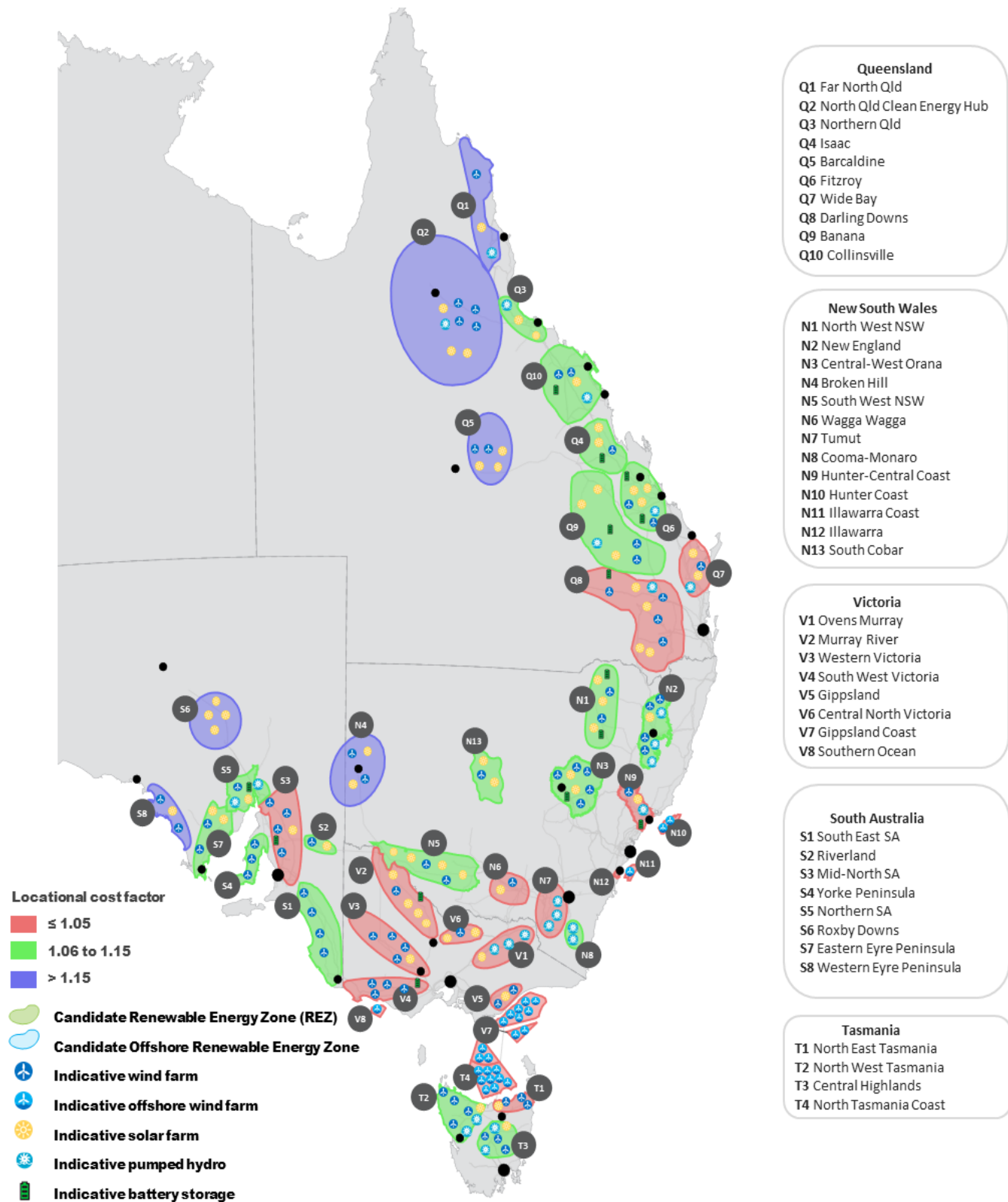


Figure 34 Weighted REZ locational cost factors for wind in the 2025 Draft IASR



AEMO proposes to further update the locational cost factors for the land and development cost component using the updates that will be made to the AEMO Transmission Cost Database through the consultation process on the

Draft 2025 *Network Expansion Options Report*. These updated factors would be used in the Final 2025 IASR for the land and development cost component of generation and storage technologies in REZs.

Matters for consultation

- Is it appropriate for modelling to shift to locational cost factors derived at a REZ level?
- Are the proposed values assigned to REZ locational cost factors reasonable (if relevant, refer to the additional information provided in the accompanying consultant report)?

Locational cost factors for pumped hydro energy storages

In line with all other new entrant technologies, sub-regional locational cost factors are applied to PHES options. Unlike those for other technologies, locational cost factors for PHES have been derived based on the relative cost of the natural resource and geology available within each location for PHES development. The factors have been sourced from Entura's 2018 *Pumped Hydro Cost Modelling* report and remain consistent with previous IASRs.

These factors do not capture site-specific aspects of costs that are only known when detailed feasibility investigations have been implemented. If site-specific cost information on particular projects becomes available, AEMO may shift to adopting these values as appropriate. AEMO has adjusted these factors to account for the further disaggregation of Victoria and South Australia to more sub-regions.

Table 21 presents the locational cost factors for PHES. Tasmanian facilities¹³⁴ are at least approximately 25% lower cost than Victorian alternatives, and the cost advantages of pumped hydro in Tasmania increase for deeper storage sizes.

Table 21 Pumped hydro energy storage locational cost factors

ISP sub-region	Region	PHES: 10-hour	PHES: 24-hours	PHES: 48-hour
Northern Queensland (NQ)	Queensland	1.02	0.88	0.86
Central Queensland (CQ)	Queensland	1.02	0.88	0.86
Gladstone Grid (GG)	Queensland	Not applicable*	Not applicable*	Not applicable*
South Queensland (SQ)	Queensland	1.10	0.96	0.88
Northern New South Wales (NNSW)	New South Wales	0.87	0.82	0.62
Central New South Wales (CNSW)	New South Wales	1.05	1.08	1.12
South New South Wales (SNSW)	New South Wales	1.02	1.00	0.91
Sydney, Newcastle, Wollongong (SNW)	New South Wales	Not applicable*	Not applicable*	Not applicable*
West and North Victoria (WNV)	Victoria	1.00	1.00	1.00
Greater Melbourne and Geelong (MEL)	Victoria	Not applicable*	Not applicable*	Not applicable*
South East Victoria (SEV)	Victoria	Not applicable*	Not applicable*	Not applicable*
Northern South Australia (NSA)	South Australia	1.43	1.67	Not applicable*
Central South Australia (CSA)	South Australia	1.43	1.67	Not applicable*

¹³⁴ These factors apply only to generic Tasmanian projects, as specific cost assumptions are used for the Cethana project.

ISP sub-region	Region	PHES: 10-hour	PHES: 24-hours	PHES: 48-hour
South East South Australia (SESA)	South Australia	Not applicable*	Not applicable*	Not applicable*
Tasmania (TAS)	Tasmania	0.75	0.62	0.46

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

3.5.4 Storage-specific assumptions

Input vintage	December 2024
Source	<ul style="list-style-type: none"> Aurecon: <i>2024 Energy Technology Cost and Technical Parameters Review</i> CSIRO: <i>GenCost 2024-25 Consultation Draft</i> Entura: <i>2018 Pumped Hydro Cost Modelling</i> Hydro Tasmania information on Cethana project
Updates since 2023 IASR	Updated to reflect latest <i>Energy Technology Cost and Technical Parameters Review</i> , and <i>GenCost 2024-25 Consultation Draft</i> . Modified to reflect greater disaggregation in Victoria and South Australia.

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

Pumped hydro energy storage build limits

AEMO applies build limits for pumped hydro expansion candidates based on sub-regional estimates detailed by the Entura 2018 *Pumped Hydro Cost Modelling* report¹³⁵, modified where appropriate to reflect the latest generator development announcements in Generation Information (or announced government development policies).

AEMO has adjusted the limits to consider proposed projects across NEM regions since the publication of the Entura report. AEMO subtracted the generation capacity of these projects from the relevant original limit while maintaining Entura's sub-regional breakdown. AEMO also disaggregated the limits to account for the new sub-regions proposed for Victoria and South Australia, and adjusted limits to account for the modelling of 10-hour PHES.

The effective PHES sub-regional limits are shown in Table 22.

Table 22 Pumped hydro sub-regional limits (in MW of generation capacity)

ISP sub-region	Region	PHES: 10-hour	PHES: 24-hour	PHES: 48-hour
Northern Queensland (NQ)	Queensland	1,000	5,000	111
Central Queensland (CQ)	Queensland	960	1,250	89
Gladstone Grid (GG)	Queensland	-	-	-
South Queensland (SQ) ^A	Queensland	2,400	600	300
Northern New South Wales (NNSW)	New South Wales	1,020	500	500
Central New South Wales (CNSW)	New South Wales	2,006	167	83
South New South Wales (SNSW) ^B	New South Wales	2,000	583	167

¹³⁵ 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.

ISP sub-region	Region	PHES: 10-hour	PHES: 24-hour	PHES: 48-hour
Sydney, Newcastle, Wollongong (SNW)	New South Wales	-	-	-
West and North Victoria (WNV)	Victoria	2,160	700	400
Greater Melbourne and Geelong (MEL)	Victoria	-	-	-
South East Victoria (SEV)	Victoria	-	-	-
Northern South Australia (CSA)	South Australia	540	200	0
Central South Australia (CSA)	South Australia	135	-	-
South East South Australia (SESA)	South Australia	-	-	-
Tasmania (TAS) ^C	Tasmania	1,300	1,200	371

A. The South Queensland limits do not include Borumba Dam Pumped Hydro (2 GW), which will be modelled as a specific project.

B. Total value excludes the contribution of Snowy 2.0.

C. 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 Roadmap¹³⁶. The limits have been further adjusted to provide sufficient capacity to reflect five projects that have been awarded funding under the New South Wales Pumped Hydro Recoverable Grants Program¹³⁷.
 - 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 submissions to Generation Information.
 - Where applicable, PHES limits have been adjusted above Entura estimates to ensure proposed projects in Generation Information submissions can be accommodated.

Batteries

AEMO employs the following assumptions pertaining to large-scale 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 *2024 Energy Technology Cost and Technical Parameter Review*.
- Battery storage degradation, which Aurecon indicates is 1.8% annually, has been factored in by reducing the storage capacity of all battery storage by 16% which is an estimate of the average storage capacity over the battery life of 20 years after taking into account this degradation and estimated operating levels.
- AEMO's technology cost assumptions consider the usable storage capacity in defining project costs as sourced from Aurecon, and its modelling assumes a minimum and maximum state of charge of 0% and 100% respectively in line with Aurecon's advice.

¹³⁶ See <https://www.energy.nsw.gov.au/nsw-plans-and-progress/major-state-projects/pumped-hydro-roadmap#-pumped-hydro-roadmap->.

¹³⁷ See <https://www.nsw.gov.au/media-releases/pumped-hydro>.

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

Solar thermal technology

AEMO models new entrant solar thermal generators as a central tower and receiver with thermal storage. Based on previous stakeholder feedback reflected in CSIRO’s *GenCost 2022-23 Consultation Draft report*, the capacity of the thermal storage component remains at 16 hours.

AEMO’s capacity outlook modelling for previous ISPs used static discharge traces to represent operation. Following stakeholder feedback, AEMO modified the static discharge traces such that they 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.

3.5.5 Other technical and cost parameters for new entrants

Input vintage	December 2024
Source	<ul style="list-style-type: none">Aurecon: <i>2024 Energy Technology Cost and Technical Parameters Review</i>CSIRO: <i>GenCost 2024-25 Consultation Draft</i>Entura: <i>2018 Pumped Hydro Cost Modelling</i>Hydro Tasmania information on Cethana project2024 October update Generation Information
Updates since 2023 IASR	Updated inputs

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

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

Details of these parameters are published in the Draft 2025 *Inputs and Assumptions Workbook* as well as in the supporting material from Aurecon.

For new entrant generators (assets that are not existing and are developed over the modelling horizon), the technical life of each asset is observed such that new capacities will be decommissioned at the end of their respective technical lives. Replacement may not require a ‘greenfield’ solution (a ‘brownfield’ redevelopment may be appropriate for some assets), but technology improvements often mean that much of the original engineering

footprint of a project may require redevelopment. Given that a brownfield solution would likely require site-by-site assessments and a more bespoke approach, AEMO applies no discount to asset redevelopments, with costs consistent with new entry greenfield developments. Likewise, there is no requirement for a retired generator to be replaced at similar location (except for a policy setting requiring a local response to meet a renewable energy target, for example) so a retirement could be effectively replaced at another NEM location if that minimises costs.

The technical life assumed for new wind and solar projects is 30 years. This assumption has been validated through the October 2024 Generation Information dataset, which shows that, on average, committed and anticipated VRE projects have submitted a technical life (reflecting the time between commissioning date and the expected closure year) of 31 years (solar projects) and 28 years (wind projects). AEMO considers this an appropriate and supportive benchmark of the assumption.

3.6 Fuel and renewable resource assumptions

3.6.1 Fuel prices

AEMO sourced updated fuel price forecasts from ACIL Allen in November 2024, including natural gas, coal and diesel prices. Biomethane and hydrogen projections are not available for this stage of the IASR’s release, and may be included in the Stage 2 release. This section summarises key insights for each fuel; more information on the derivation of these forecasts is provided in the accompanying ACIL Allen fuel price report (see Appendix A2).

Gas prices

Input vintage	November 2024
Source	ACIL Allen Consulting
Updates since the 2023 IASR	New gas price forecasts based on market analysis and modelling as at mid-2024

AEMO sourced updated natural gas price forecasts from ACIL Allen in November 2024. The gas price forecasts consider fundamental inputs such as forecast gas production costs from existing and upcoming fields, reserves, infrastructure and pipelines, in addition to international gas prices, oil prices and measures of the domestic economy. The forecasts are also based on assumptions about the influence of international prices on east coast gas prices through LNG netback pricing, and the local level of competition.

The Australian Domestic Gas Supply Mechanism (ADGSM) reforms commenced 1 April 2023 and are designed to make the ADGSM more responsive to domestic gas shortfalls, while protecting established long-term contracts. The effect of the ADGSM reforms and the Heads of Agreement with east coast gas exporters are considered in the gas price forecasts.

These forecasts also consider the impact of the Federal Government’s mandatory Gas Market Code (Code). The Code¹³⁸ was published in July 2023, and includes a reasonable pricing framework of a \$12/GJ price cap for wholesale gas contracts and pricing rules for non-urgent transactions (outside three days) at the Gas Supply Hubs. Small producers (less than 100 PJ per year) supplying the domestic market are exempt from the pricing

¹³⁸ See <https://www.energy.gov.au/government-priorities/energy-markets/gas-markets/mandatory-gas-code-conduct>.

rules, while other producers can apply for conditional exemptions. A review of the Code must occur by 1 July 2025.

Figure 35 compares industrial gas price forecasts at Melbourne across the scenarios against forecasts presented in the 2023 IASR. The scenarios differ based on longer-term underlying costs of supply for each scenario and international demand for LNG. The forecast gas prices are higher than those presented in the 2023 IASR, primarily due to observed wholesale contract pricing since the introduction of the gas price cap in July 2023. Wholesale contract prices have been anchored at or around the \$12/GJ price cap since it was introduced, and this market dynamic is expected to continue given tight supply conditions. Combined with rising costs of production, this results in domestic gas prices remaining steadier throughout the 2020s, despite an expected decrease in global LNG price due to increased supply from the United States and Qatar during this period.

All other regions are provided in the Draft 2025 *Inputs and Assumptions Workbook*.

Figure 35 Forecast industrial gas prices by scenario – Melbourne, 2024-25 to 2054-55 (\$AUD/GJ)

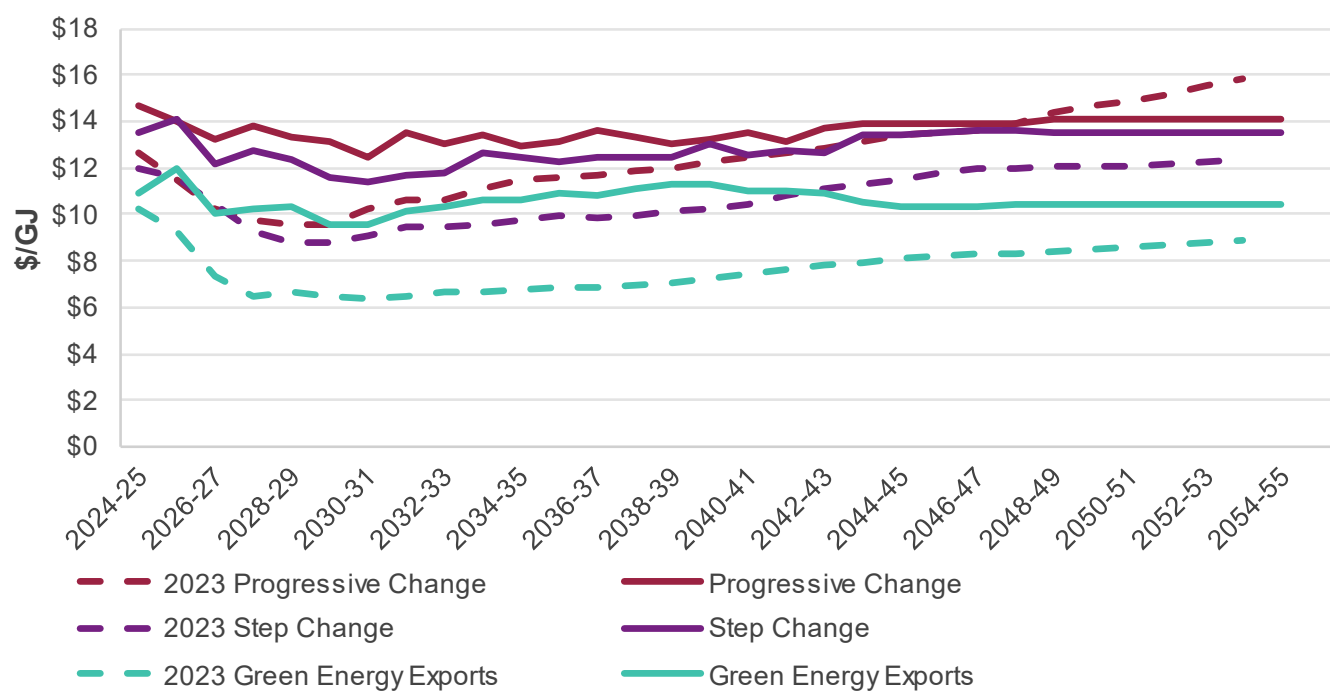
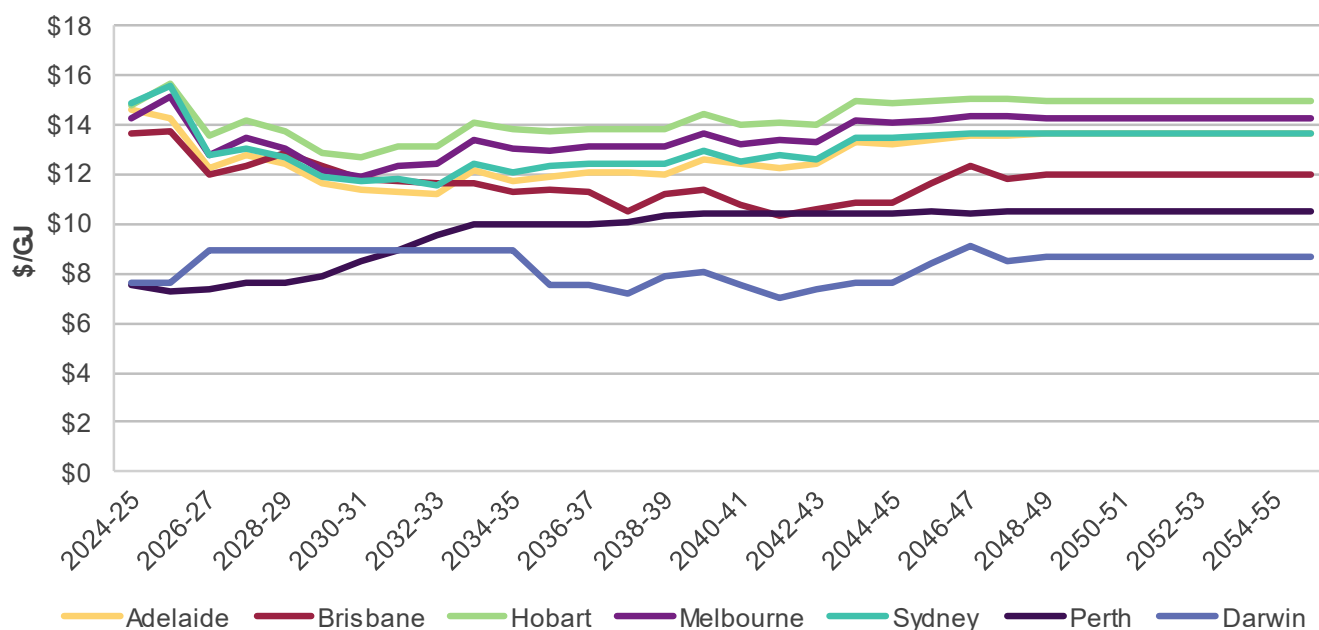


Figure 36 demonstrates the relationship between regions for the *Step Change* scenario.

Figure 36 Forecast industrial gas prices by location – Step Change, 2024 to 2055 (\$AUD/GJ)

In the short term, prices are expected to remain largely influenced by the Federal Government's Code and gas price cap, with tight market conditions resulting in some price increases through 2026. Following this, the price forecasts decline to a minimum in the early 2030s, largely driven by a forecast reduction in LNG netback prices¹³⁹. Gas prices in the long term are forecast to gradually increase, resulting from the combination of decreasing supply and increasing real production costs. Brisbane prices diverge from Southern markets over the long term as a result of the source of local gas supply assumed to concentrate in Queensland and the Northern Territory in these projections, resulting in higher transportation costs and potential reliance upon higher cost LNG imports for southern markets (depending on the infrastructure that is developed to provide access to additional supply to southern customers).

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

The gas prices associated with each gas-powered generator are provided in the Draft 2025 *Inputs and Assumptions Workbook* and the ACIL Allen fuel price report. The costs include regional pricing, considering the supply options and the relevant cost of pipeline transmission.

Coal prices

Input vintage	November 2024
Source	ACIL Allen Consulting
Updates since the 2023 IASR	Forecasts updated to reflect expiry of coal price cap

¹³⁹ See <https://www.accc.gov.au/regulated-infrastructure/energy/gas-inquiry-2017-25/lng-netback-price-series>.

ACIL Allen's approach considers each generator's unique situation and takes into account mining costs, unique mine operational processes (such as wash plant, open cut, underground), export price, and freighting/handling costs.

In late 2022, the New South Wales and Queensland Governments agreed to implement temporary coal price caps of \$125 per tonne for power stations as part of the Federal Government's Energy Price Relief Plan. This temporary measure expired on 30 June 2024 and as a result the coal price forecasts for export exposed black coal generators now reflect their estimated apparent contract positions.

Coal generators across the NEM source coal in various ways. The three typical pathways are coal sourced from own mining supply, coal from netback linked contracts, and coal from export linked international spot markets. Estimated coal prices for each generator consider the specific sources of supply because not all coal generators are exposed to export pricing dynamics, particularly if they operate from captive mines, or are not using export or near-export grade black coal.

In setting long run coal prices, the forecasts refer to the IEA 2024 WEO for the Japanese and Coastal China regions which are most applicable to Australia.

The IEA coal forecasts are aligned to AEMO's three scenarios as follows:

- *Step Change* – aligned to the IEA's STEPS scenario.
- *Progressive Change* – aligned to the IEA's APS scenario.
- *Green Energy Exports* – aligned to the IEA's NZE scenario.

ACIL Allen's analysis indicates that for the NZE scenario post 2030, and the APS scenario post 2040, the prices forecast by the IEA are likely to be sub-economic under the assumed macroeconomic settings. As such, prices for the preceding period are held constant for the remainder of the price projection representing an expectation that a supply side response will occur to stabilise prices.

The coal price forecasts are provided in more detail in the Draft 2025 *Inputs and Assumptions Workbook*.

Figure 37 Forecast coal prices for existing generators in New South Wales, Step Change, 2024 to 2055 (\$AUD/GJ)

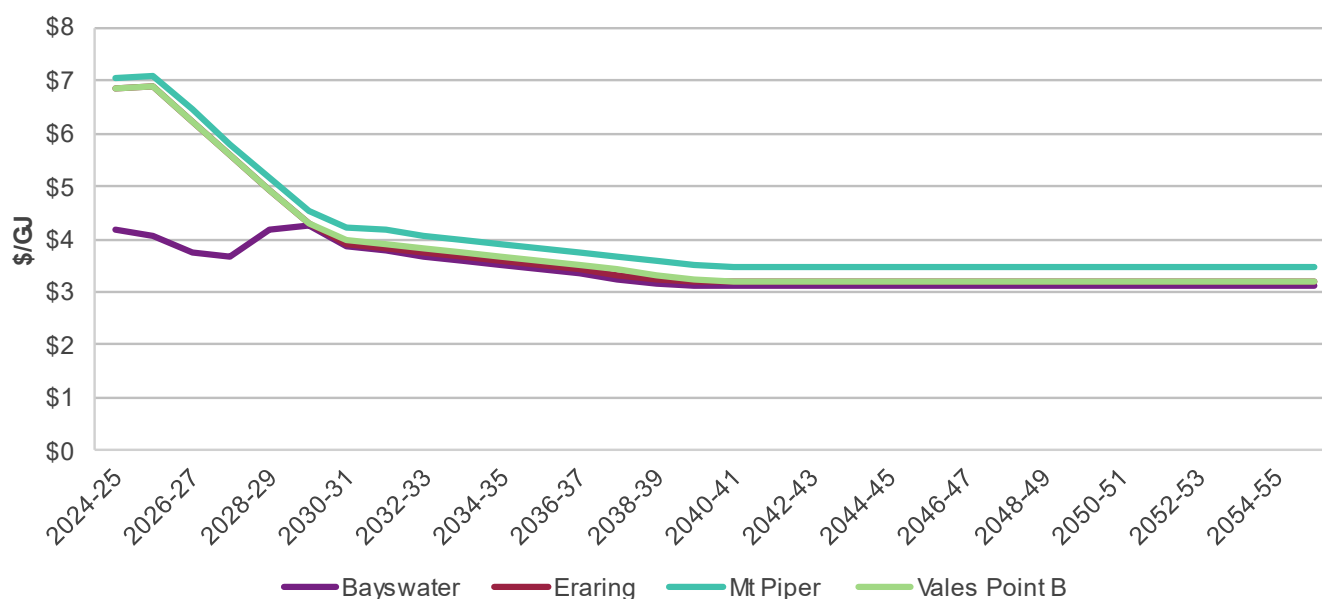
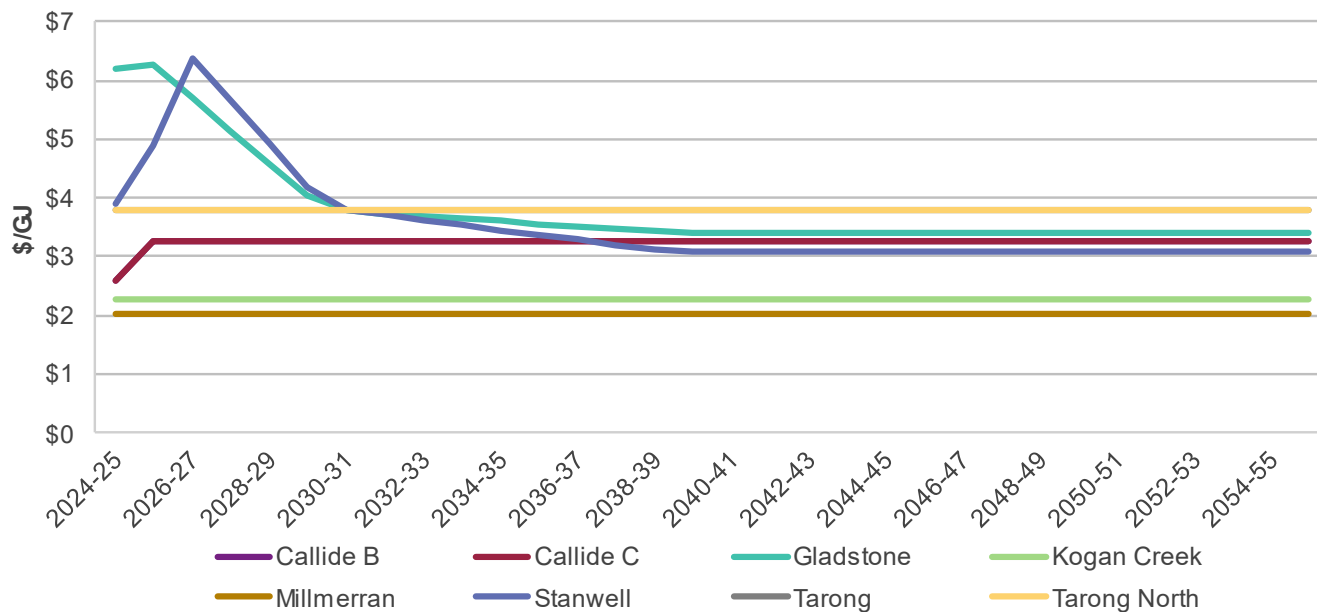


Figure 38 Forecast coal prices for existing generators in Queensland – Step Change, 2024 to 2055 (\$AUD/GJ)

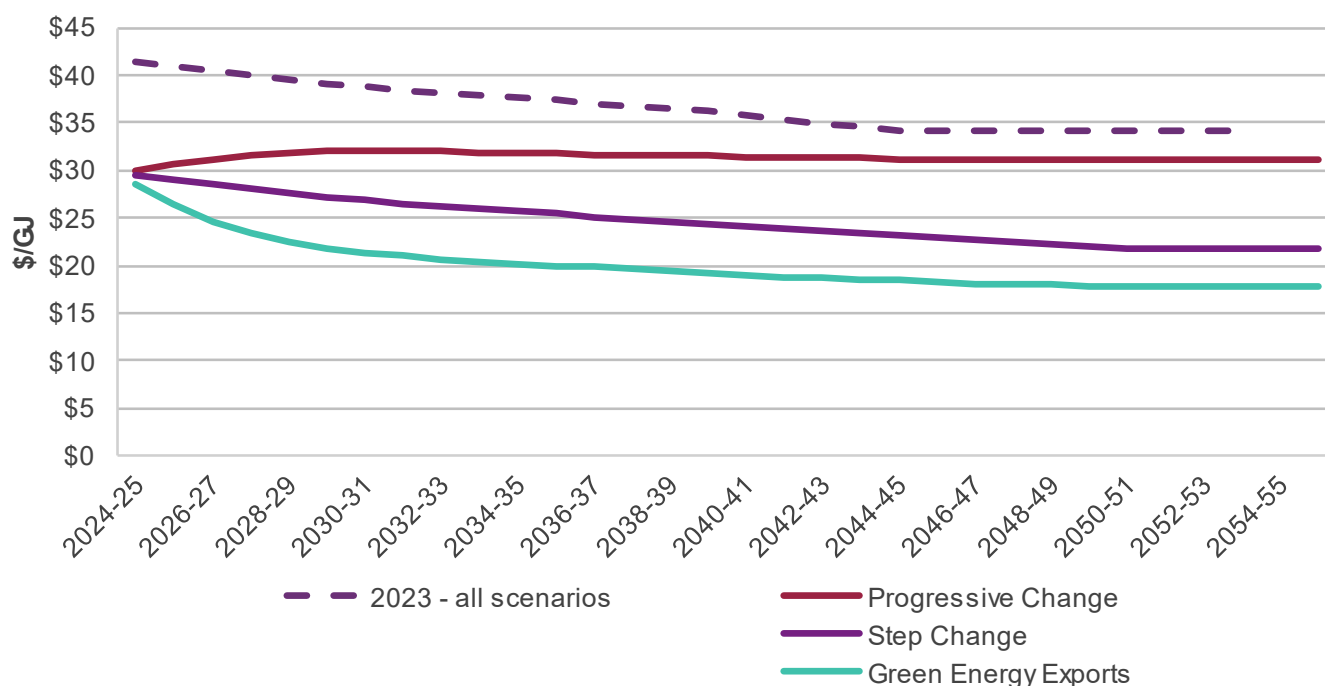
Diesel prices

AEMO sourced diesel price forecasts from ACIL Allen to represent appropriate costs for the use of diesel at power stations in the NEM that can, or could, use liquid fuels as a primary, secondary or backup fuel. ACIL Allen's approach evaluates projections of crude oil prices to provide projections of Terminal Gate Prices for automotive diesel oil. A distributors' margin is added to the price and a charge for transport from the nearest petroleum terminal to the power station is calculated.

International oil price is the key consideration in forecasting diesel price, with the crude oil market in a period of transition and experiencing a decline in the rate of growth in demand for oil globally. Uncertainties considered in the price forecasts are:

- Outlook for economic growth in advanced, emerging market and developing economies.
- Rates of adoption of EVs, PHEVs and Hybrid light passenger vehicles.
- Progress in improving fuel efficiency in all modes of transport.
- Fuel-switching to biofuels, hydrogen in the longer term and oil to gas switching in the power sector in Middle Eastern Countries over the medium to longer term.
- Strategies of producers in the Middle East to shore up their national budgets over the medium to longer term.

Figure 39 compares Victorian price forecasts for terminal gate plus distributors margin across the scenarios against the single forecast presented in the 2023 IASR. Lower forecast diesel prices compared to the 2023 IASR are due to a lower crude oil price outlook.

Figure 39 Forecast price for diesel by scenario – terminal gate price plus distributors margin, Victoria, 2024 to 2055 (\$AUD/GJ)

3.6.2 Renewable resources

Input vintage	December 2024
Source	<ul style="list-style-type: none"> Solcast irradiance and PV output analysis BoM AEMO SCADA data Other relevant reanalysis providers
Updates since 2023 IASR	Updated to include the 2023-24 reference year, added additional REZs

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

- Wind speed (at a relevant hub height) from ERA5¹⁴⁰ reanalysis data from European Centre for Medium-Range Weather Forecasts.
- Solar irradiance reanalysis data from Solcast.
- Temperature and ground-level wind speed observation data from the BoM.
- Historical generation and weather measurements from SCADA data provided by participants.

AEMO uses resource-to-power conversion models to estimate VRE generation potential as a function of meteorological inputs, and calibrates this to historical production levels for existing wind farms. Wind generation

¹⁴⁰ At <https://www.ecmwf.int/en/forecasts/dataset/ecmwf-reanalysis-v5>.

availability modelling, for example, uses an empirical machine learning model to estimate generator output as a function of wind speed and temperature, capturing the impacts of high wind and high temperature events observed in historical data (which may typically lead to generator cut-off protections). Participant information on generator capabilities during summer peak demand temperatures are overlayed on top of these models. Further detail on how AEMO estimates half-hourly generation availability profiles for existing, committed and anticipated VRE generators is provided in the *ESOO and Reliability Forecast Methodology*¹⁴¹.

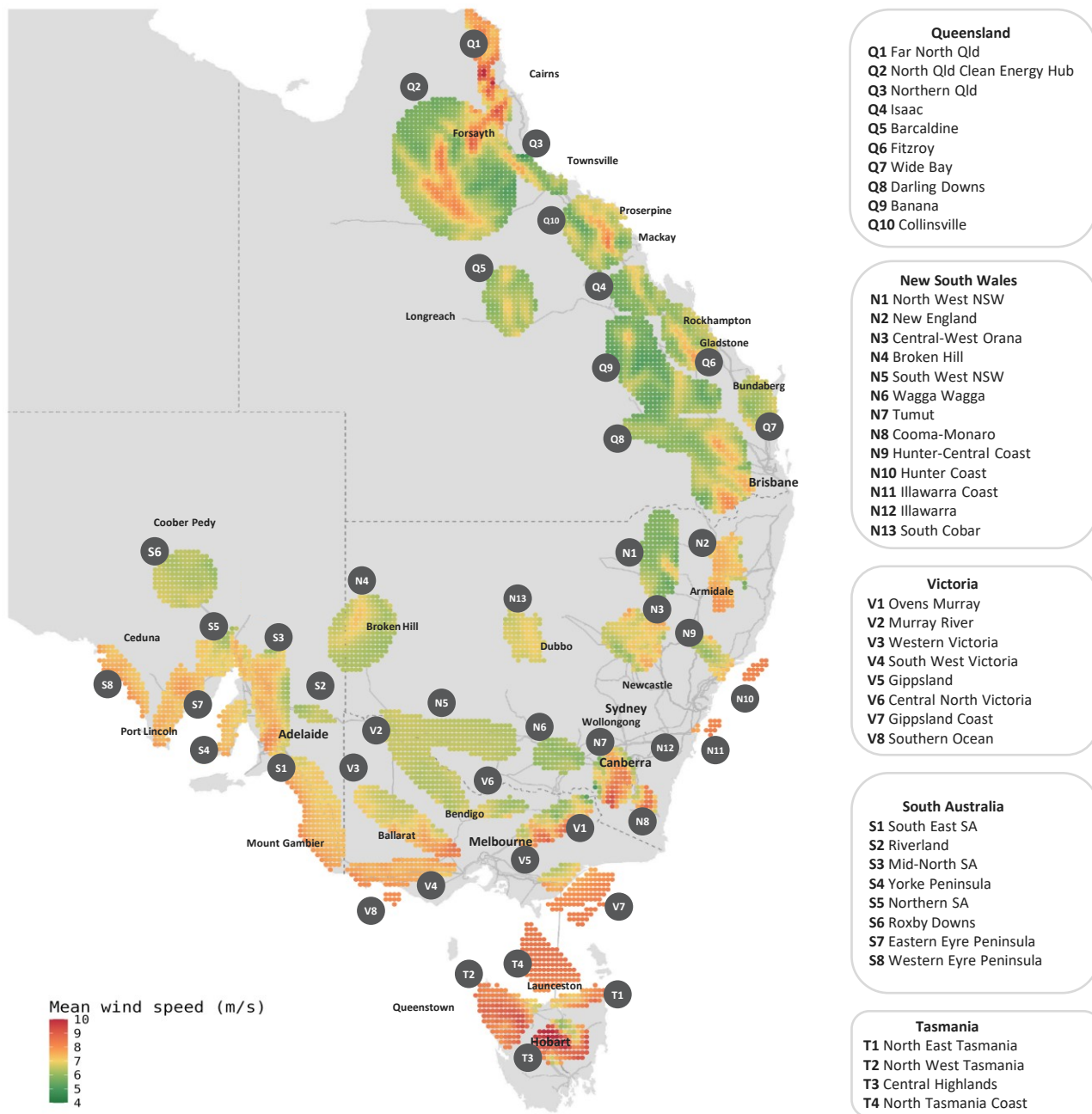
For new entrant VRE generators, AEMO represents onshore wind resource quality in each REZ in tranches representing sites of differing quality (typically two tranches per REZ), based on an assessment of all available datapoints that are considered suitable for wind development. AEMO represents solar resource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

Capacity factors representing the resource potential for each REZ and technology are provided in the Draft 2025 *Inputs and Assumptions Workbook*. The methodology used to derive these will be further detailed and consulted on in the *2025 ISP Methodology*.

Wind and solar resource quality for each REZ is shown below in Figure 40 and Figure 41 respectively.

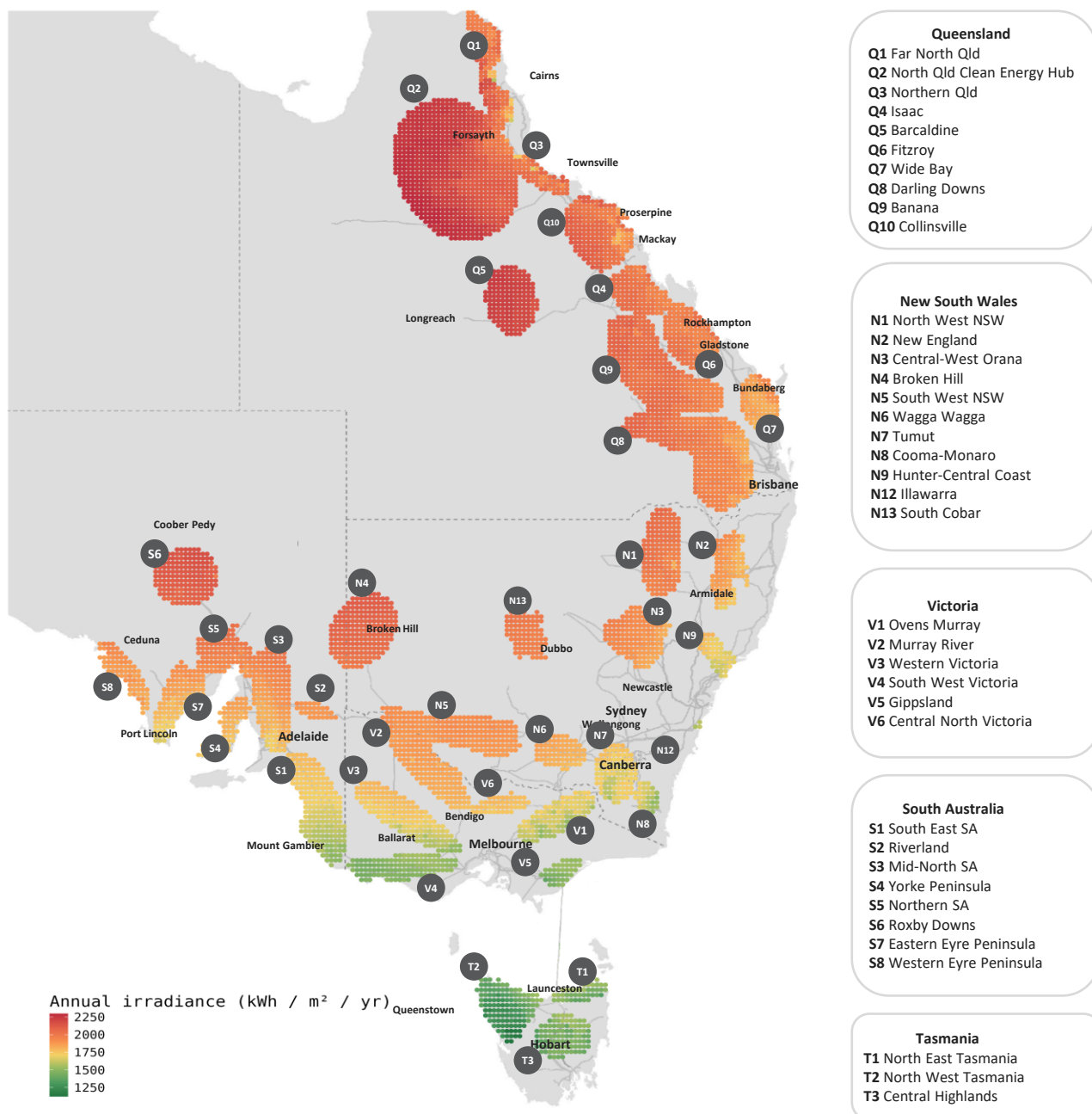
¹⁴¹ At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2023/esoo-and-reliability-forecast-methodology-document.pdf.

Figure 40 Wind resource quality map – average wind speed (m/s) at 150 m hub height



*Three sets of renewable energy resource profiles will be developed for REZ Q8 Darling Downs. They will be Darling Downs, Western Downs, and Southern Downs.

Figure 41 Solar resource quality map – average annual global horizontal irradiance (GHI) (kWh/m²/year)



*Three sets of renewable energy resource profiles will be developed for REZ Q8 Darling Downs. They will be Darling Downs, Western Downs, and Southern Downs.

3.7 Financial parameters

3.7.1 Weighted average cost of capital and discount rate

Input vintage	December 2024
Source	Oxford Economics Australia
Updates since 2023 IASR	A macro-economic analysis and confidential survey of empirical cost of capital from across NEM stakeholders.

In the ISP, the weighted-average cost of capital (WACC) for a project is used in combination with the project's economic life to calculate the annuity payments required. As WACC reflects the cost of financing a project, it impacts the overall project cost and the overall system costs. On the other hand, a discount rate is used to compare costs and benefits received at different points in time as well as to calculate the present value of future cash flows, accounting for the time value of money.

The AER's Cost Benefit Analysis Guidelines¹⁴² 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 previously used the same rate as both the discount rate for costs and benefits (to calculate the net present value) and the WACC for annualising capital costs across all generation and transmission investments.

A WACC reflecting an average investor view about required return on investments in the NEM has been employed in previous IASRs¹⁴³. Following stakeholder feedback and using insights from a survey of developers in the NEM regarding their cost of capital and other inputs¹⁴⁴, AEMO proposes to use different values for WACCs for different technologies to capture different financial assumptions appropriate for each technology. While WACCs may vary by technology, the ISP must use a singular discount rate that promotes competitive neutrality between network and non-network options, as required by the AER Cost Benefit Analysis Guidelines.

AEMO engaged Oxford Economics Australia (OEA) to examine three alternative approaches to determine the latest WACC for each technology across the ISP forecast horizon, and to provide the appropriate discount rate. OEA's analysis revealed that some technologies may face higher hurdle rates if they are deemed risky due to either the perceived lesser role in the energy transition such as coal plant and high-emitting assets, perceived merchant risks such as battery energy storage systems, or higher construction risks such as pumped hydro energy storages. Some technologies that have yet to be developed and penetrate the Australian market such as offshore wind farms are considered lower risk due to available government offtake agreements.

The survey identified merchant risk and construction risk to be important considerations for greenfield non-network energy projects. A project's capital structure also impacts on the WACC. The other risk drivers identified are revenue risk, grid connection risk, policy risk, and social licence. Survey results of pre-tax real WACC estimates across asset types are shown in Table 23 below.

¹⁴² At https://www.aer.gov.au/system/files/2023-10/AER%20-%20CBA%20guidelines%20-%20final%20amendments%20%28clean%29%20-%206%20October%202023_0.pdf.

¹⁴³ At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/isp/2021/synergies-discount-rate-report.pdf?la=en.

¹⁴⁴ See OEA's discount rate report – listed in Appendix A2.

Given these findings, AEMO considers it appropriate to set different WACCs for different technology options as it reflects the reality observed in capitals markets. Table 23 below shows the proposed lower, central, and upper WACC for relevant technologies.

Table 23 Pre-tax real weighted average cost of capital

Technology	Lower bound	Central estimate	Upper bound
OCGT (small gas turbine)	7.0%	9.0%	12.0%
OCGT (large gas turbine)	7.0%	9.0%	12.0%
CCGT ^A	8.5%	10.5%	13.5%
CCGT with CCS ^A	8.5%	10.5%	13.5%
Biomass ^A	8.5%	10.5%	13.5%
Large scale Solar PV	5.0%	7.0%	10.0%
Solar Thermal (16hrs storage)	8.5%	10.5%	13.5%
Battery storage (1hr storage)	6.5%	8.0%	11.5%
Battery storage (2hrs storage)	6.5%	8.0%	11.5%
Battery storage (4hrs storage)	6.5%	8.0%	11.5%
Battery storage (8hrs storage)	6.5%	8.0%	11.5%
Pumped Hydro Energy Storage (10 hrs)	6.5%	8.5%	11.5%
Pumped Hydro Energy Storage (24 hrs)	6.5%	8.5%	11.5%
Pumped Hydro Energy Storage (48 hrs)	6.5%	8.5%	11.5%
Wind - onshore	5.5%	7.5%	10.5%
Wind - offshore (fixed)	5.5%	7.5%	10.5%
Hydrogen Electrolysers	6.0%	8.0%	11.0%
Electricity - Transmission and Distribution (Regulated)	3.0%	3.0%	4.5%
Electricity - Transmission and Distribution (Unregulated)	4.5%	6.5%	9.5%
Gas - Transmission and Distribution (Regulated)	3.0%	3.0%	4.5%
Gas - Transmission and Distribution (Unregulated)	5.5%	7.5%	10.5%

A. AEMO assumes that the WACC for CCGT, CCGT with CCS and Biomass are the same.

Considering the insights provided from the WACC survey, OEA has recommended that the appropriate discount rate, for use in the 2025 IASR and 2026 ISP, that promotes competitive neutrality is 7% – based on their macro-economic assessment. This choice of discount rate aligns with Infrastructure Australia’s guideline for economic appraisal¹⁴⁵, and is commensurate with commercially-orientated investments considered for technologies included in the ISP.

Analysis of survey results and macro-economic studies found the pre-tax real WACC for non-regulated assets to be 6.98%, which further reinforces that the assumption of 7.0% is reasonable. In addition, OEA found pre-tax real WACC estimates ranged between 3% to 15% across asset types, with the WACC being reflective of the level of risk of each technology.

¹⁴⁵ At <https://www.infrastructureaustralia.gov.au/sites/default/files/2021-07/Assessment%20Framework%202021%20Guide%20to%20economic%20appraisal.pdf>.

For the lower bound of the discount rate, AEMO will base it on the most recent AER revenue determination at the time of the final ISP. In the August 2024 return on debt update¹⁴⁶, the AER set the pre-tax real WACC to be 3.00%. This is consistent with the discretionary guidance in the AER's CBA Guidelines. For the upper bound of the discount rate, AEMO proposes to adopt 10% from Infrastructure Australia's guideline for economic appraisal.

Table 24 presents the values for discount rates in this Draft 2025 IASR, with 2024 ISP values for comparison.

Table 24 Pre-tax real discount rates

	Lower bound	Central estimate	Upper bound
2024 ISP	3.0%	7.0%	10.5%
Draft 2025 IASR	3.0%	7.0%	10.0%

Matters for consultation

- Is the proposed application of technology-specific WACC's for different technology types appropriate and reasonable for the ISP?
- Is the discount rate, including its upper and lower bounds, reasonable?

3.7.2 Value of customer reliability

Input vintage	December 2023
Source	<ul style="list-style-type: none"> • AER: 2019 Values of Customer Reliability Review • AER Values of Customer Reliability – Annual adjustment – December 2023
Updates since 2023 IASR	VCR updated to reflect AER December 2023 update and adjusted to real June 2024 values.

Values of Customer Reliability (VCRs) are usually expressed in dollars per kilowatt hour (kWh) and reflect the value different customer types place on reliable electricity supply. VCRs are used in cost benefit analysis to quantify market benefits arising from changes in involuntary load shedding when comparing investment options.

In accordance with the AER's Cost Benefit Analysis Guidelines, AEMO is required to use the AER's most recent VCRs at the time of publishing the ISP Timetable. The AER releases annual updates to its VCRs based on the Consumer Price Index for that year, with the most recent adjustment coming in December 2023¹⁴⁷. The current VCRs are summarised in Table 25 below.

Table 25 AER Values of distribution and transmission customer load-weighted VCR by state

	New South Wales	Victoria	Queensland	South Australia	Tasmania
VCR (\$/MWh)	50,359	49,271	47,861	51,687	38,451

¹⁴⁶ Based on AER - Transgrid FD PTRM - 2024-25 RoD update - Humelink S2 - August 2024 - Public, at <https://www.aer.gov.au/documents/aer-transgrid-fd-ptm-2024-25-rod-update-humelink-s2-august-2024-public>.

¹⁴⁷ At <https://www.aer.gov.au/industry/registers/resources/reviews/values-customer-reliability-2019>.

3.7.3 Value of greenhouse gas emissions reduction (VER)

Input vintage	February 2024
Source	Value of greenhouse gas emission reduction (VER) to 2050 as agreed by Australia’s Energy Ministers and set out in the AER Guidance May 2024.
Updates since 2023 IASR	Interpolated to convert to financial years and adjusted to account for inflation.

Emissions reduction is a new class of benefits in the ISP and the RIT-T framework. This new benefit class reflects the appropriate consideration of the amendments to the NEO and NER. The VER is calculated consistent with the method agreed to by Australia’s Energy Ministers in February 2024, and set out in the AER’s explanatory statement¹⁴⁸.

Table 26 Value of greenhouse gas emissions reduction

Year	VER (\$/tonne CO ₂ -e)	Year	VER (\$/tonne CO ₂ -e)
2024-25	75.26	2037-38	194.64
2025-26	80.45	2038-39	208.14
2026-27	85.12	2039-40	222.15
2027-28	89.80	2040-41	237.21
2028-29	95.51	2041-42	253.30
2029-30	103.81	2042-43	269.91
2030-31	113.67	2043-44	287.55
2031-32	123.53	2044-45	306.76
2032-33	134.43	2045-46	327.00
2033-34	145.85	2046-47	348.28
2034-35	157.27	2047-48	371.12
2035-36	169.21	2048-49	395.52
2036-37	181.67	2049-50	421.99

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.

AEMO recognises that a changing climate may also lead to greater potential challenges in maintaining the operability of a NEM that is predominantly reliant on intermittent generation for its electricity production, particularly during long periods of dark and still conditions that would lower renewable generation output. AEMO recognises that geographic and technological diversity are key means to lower the impact of extreme conditions in

¹⁴⁸ AER. *Valuing emissions reduction – AER guidance and explanatory statement*, at <https://www.aer.gov.au/system/files/2024-05/AER%20-%20Valuing%20emissions%20reduction%20-%20Final%20guidance%20and%20explanatory%20statement%20-%20May%202024.pdf>.

this regard, however it is possible that weather extremes will still impact the resilience of a renewable energy system and increase the magnitude of extreme demand conditions as well, beyond that which is already considered in AEMO’s forecasting approach which passes through forecast average temperature rise over time (as described in the following section).

3.8.1 Temperature change impacts

Input vintage	January 2019 (CMIP5)
Source	BoM, CSIRO, ESCI (see Climatechangeinaustralia.gov.au)
Updates since 2023 IASR	No update since the 2023 IASR

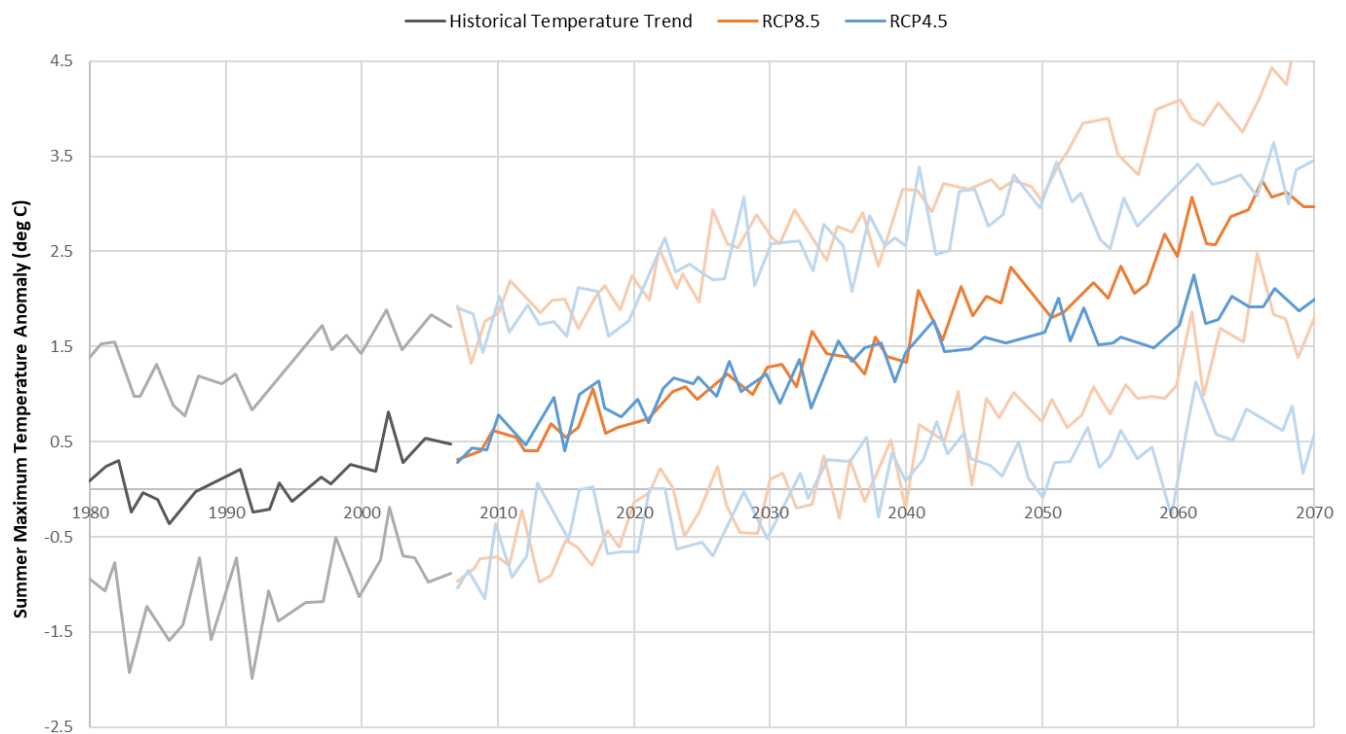
AEMO incorporates climate change temperature change factors in its demand forecasts and transmission line thermal ratings in forecasting models where constraints are applied. For demand, AEMO adjusts historical weather outcomes to apply in future years based on the outcomes projected by forecast climate models. Climate data is collected from ESCI data published on the CSIRO and BoM’s website Climate Change in Australia¹⁴⁹. For more information on this, see Appendix A.2.3 of the *Electricity Demand Forecasting Methodology*¹⁵⁰.

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 ratings¹⁵¹, 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, so adjustments do not vary substantially between scenarios to 2050. Where the physical impacts associated with the RCPs 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 42 shows the change to summer maximum temperature anomaly ranges expected for Southern Australia under two atmospheric greenhouse gas concentrations relevant to the scenario definitions¹⁵². 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.

¹⁴⁹ At <https://www.climatechangeinaustralia.gov.au/en/climate-projections/explore-data/data-download/station-data-download/>.
¹⁵⁰ 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.
¹⁵¹ See <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/network-data/transmission-equipment-ratings>.
¹⁵² Data sourced from www.climatechangeinaustralia.gov.au.

Figure 42 Southern Australia summer maximum temperature anomaly

3.9 Renewable energy zones (REZs)

REZs are areas where clusters of large-scale renewable energy can be developed using economies of scale. REZs may include onshore and offshore areas and will be subject to jurisdictional land and environmental planning approval processes. With the relevant government support, AEMO could trigger REZ Design Reports to require the local TNSP to explore and report on any technical, economic or social issues that will need to be addressed for the REZ to be a valuable, sustainable and welcome development. However, most states are currently exploring state-based development schemes in preference to REZ Design Reports. AEMO will continue to coordinate with jurisdictions as REZ plans develop, to ensure planning alignment.

An efficiently located REZ can be identified by considering a range of factors, primarily:

- The quality of its renewable resources, diversity relative to other renewable resources, and correlation with demand.
- The cost of developing or augmenting transmission connections to transport the renewable generation produced in the REZ to consumers.
- Its proximity to load, and the network losses incurred to transport generated electricity to load centres.
- The critical physical must-have requirements to enable the connection of new resources (particularly inverter-based equipment) and ensure continued power system security.

REZ candidates were initially developed in consultation with stakeholders for the 2018 ISP, and used as inputs to the ISP model. To connect renewable projects beyond the current transmission capacity, additional transmission infrastructure will be required (for example, increasing thermal capacity, system strength, and developing robust

control schemes). Since the 2018 ISP, the REZ candidates have been continuously refined through the ISP consultation process every two years up to and including the 2024 ISP. AEMO now proposes another evolution to the candidate REZs.

This section describes the proposed parameters for REZs for input to the 2026 ISP. These parameters are:

- Geographic boundaries and resource areas – 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 and resource areas

Input vintage	December 2024
Status	Draft
Source	AEMO – based on 2018 DNV-GL report, ISP workshops, consultation with TNSPs and jurisdictions, and written feedback to every ISP up to and including the 2024 ISP.
Update process	Updates will be dependent on feedback received on this Draft 2025 IASR.
Updates since 2023 IASR	Updated following joint planning and collaboration with TNSPs, jurisdictional bodies and governments. The following revisions are proposed: <ul style="list-style-type: none"> • New South Wales: Additional candidate REZ called South Cobar. • Queensland: Additional candidate REZ called Collinsville, boundary changes for Far North Queensland and Isaac candidate REZs, and addition of more wind resource tranches within the Darling Downs candidate REZ. • South Australia: Expansion of Northern South Australia candidate REZ to include the Whyalla West area, and removal of South East South Australia Coast and Leigh Creek candidate REZs.

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 ISP consultation every two years up to and including the 2024 ISP.

Geographic Information Systems (GIS) data

GIS data defining the candidate REZ boundaries is available on the 2025 IASR consultation page¹⁵³. 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 43 below).
- 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.

¹⁵³ See <https://aemo.com.au/en/consultations/current-and-closed-consultations/2025-iasr>.

In some cases, jurisdictional REZ plans are still under development and boundaries may not have been identified. Where updated REZ boundaries are available, AEMO will update its GIS data accordingly.

Candidate REZ identification

Ten development criteria were used to identify candidate REZs¹⁵⁴:

- **Wind resource** – a measure of high wind speeds (above 6 m/s).
- **Solar resource** – a measure of high solar irradiation (above 1,600 kW/m²).
- **Demand matching** – the degree to which the local resources correlate with demand.
- **Electrical network** – the distance to the nearest transmission line.
- **Cadastral parcel density** – an estimate of the average property size.
- **Land cover** – a measure of the vegetation, waterbodies, and urbanisation of areas.
- **Roads** – the distance to the nearest road.
- **Terrain complexity** – a measure of terrain slope.
- **Population density** – the population within the area.
- **Protected areas** – exclusion areas where development is restricted.

Using the resource quality and development criteria, along with feedback received from all four ISP consultations as well as recent joint planning and consultation with TNSPs, jurisdictional bodies and governments, AEMO is proposing 43 candidate REZs for inclusion in the 2026 ISP.

Proposed changes since the 2024 ISP

Based on AEMO analysis and recent feedback from existing and intending TNSPs and state and federal governments, the following changes to the 2024 ISP candidate REZs are proposed:

- AEMO has revised the southern border of the Far North Queensland REZ to better cover locations with good wind resources, as well as to better match the Queensland Government's REZ Roadmap¹⁵⁵ identification of a Far North Queensland REZ location.
- AEMO has changed the boundary of the Isaac REZ, and added a nearby new candidate REZ – Collinsville REZ. These changes allow for mapping of these REZs to the proposed revised Central and Northern Queensland sub-region definitions (see Section 3.10.1), and to align with the Queensland Government's REZ Roadmap identification of REZs in that area.

¹⁵⁴ See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Multi-Criteria-Scoring-for-Identification-of-REZs.pdf.

¹⁵⁵ Queensland Government, Queensland Renewable Energy Zone roadmap, March 2024. At https://www.epw.qld.gov.au/_data/assets/pdf_file/0036/49599/REZ-roadmap.pdf

- AEMO proposes to include multiple resource areas for Darling Downs REZ¹⁵⁶, as well as expansion of the north-west border, to better reflect the diversity of wind resource available across its large geographical area, as identified in the Queensland Government's REZ Roadmap.
- South Cobar, a new candidate REZ in the vicinity of Central West New South Wales, is proposed following joint planning with Transgrid and EnergyCo, and in recognition of concepts explored in Transgrid's 2024 Transmission Annual Planning Report. This new candidate REZ would allow exploration of the benefits of a more westerly additional REZ in that jurisdiction.
- An expansion of the Northern South Australia REZ is proposed to include the Whyalla West area in the vicinity of Central West South Australia. This is proposed to assess the potential benefits of renewable energy in the areas identified in the South Australian Government's land release framework for renewable energy.
- Removal of the offshore candidate REZ South East South Australia Coast, in recognition that this area is not one of the Federal Government's priority areas for offshore wind¹⁵⁷, and in recognition of the South Australian Government's statement that its immediate focus will be the identification of onshore locations for wind and solar resource development, and that offshore renewable energy policy will not commence until after the first onshore release areas have progressed¹⁵⁸.
- Removal of the Leigh Creek REZ in acknowledgement of environmental, cultural and social concerns relating to this location and recognising that it did not feature in the 2024 ISP under any scenario.
- Adjustment of the Northern South Australia and Mid North South Australia REZ borders to ensure they align with the new Northern South Australia and Central South Australia sub-regional boundaries.

Further consultation on Victorian REZs

VicGrid is a division within the Victorian Government's Department of Energy, Environment and Climate Action, and is responsible for coordinating the planning and development of REZs in Victoria. VicGrid recently carried out public consultation on a REZ study area for potential future REZs for inclusion in the 2025 Victorian Transmission Plan (VTP)¹⁵⁹. AEMO recognises that candidate REZs for inclusion in the 2026 ISP may need to change as the VTP is finalised, and will continue to work closely with VicGrid between the release of the draft and final 2025 IASR and as the 2025 VTP is prepared. VicGrid will publish a draft 2025 VTP for feedback in early 2025, and stakeholders may wish to engage in that consultation process. AEMO will engage closely with VicGrid as the VTP consultation is finalised and as the VTP outcomes are prepared, and will incorporate VTP outcomes in the final 2025 IASR where appropriate.

¹⁵⁶ This change is subject to the completion of AEMO's review of its *ISP Methodology*. AEMO is proposing to change the methodology to permit the use of additional wind resource tranches within a REZ, for example to reflect resource diversity across large geographical areas. For more information about the *ISP Methodology* review, see <https://aemo.com.au/consultations/current-and-closed-consultations/2026-isp-methodology>.

¹⁵⁷ Federal Government. 'Australia's offshore wind areas', accessed in November 2024. At <https://www.dcceew.gov.au/energy/renewable/offshore-wind/areas>.

¹⁵⁸ South Australia Government. 'Offshore renewable energy development in South Australia', August 2024. At [Statement-on-offshore-renewable-energy-generation August-2024.pdf](https://www.southaustralia.gov.au/media/2024/08/08/offshore-renewable-energy-generation-august-2024.pdf).

¹⁵⁹ VicGrid. 'Developing the 2025 Victorian Transmission Plan', accessed in November 2024. At <https://engage.vic.gov.au/victransmissionplan>.



Modelling renewable energy outside of REZs

When determining the economic benefits of a development path, AEMO must compare system costs against a counter-factual where no transmission is built. In this counter-factual, transmission that expands the capacity of REZs will generally not be allowed.

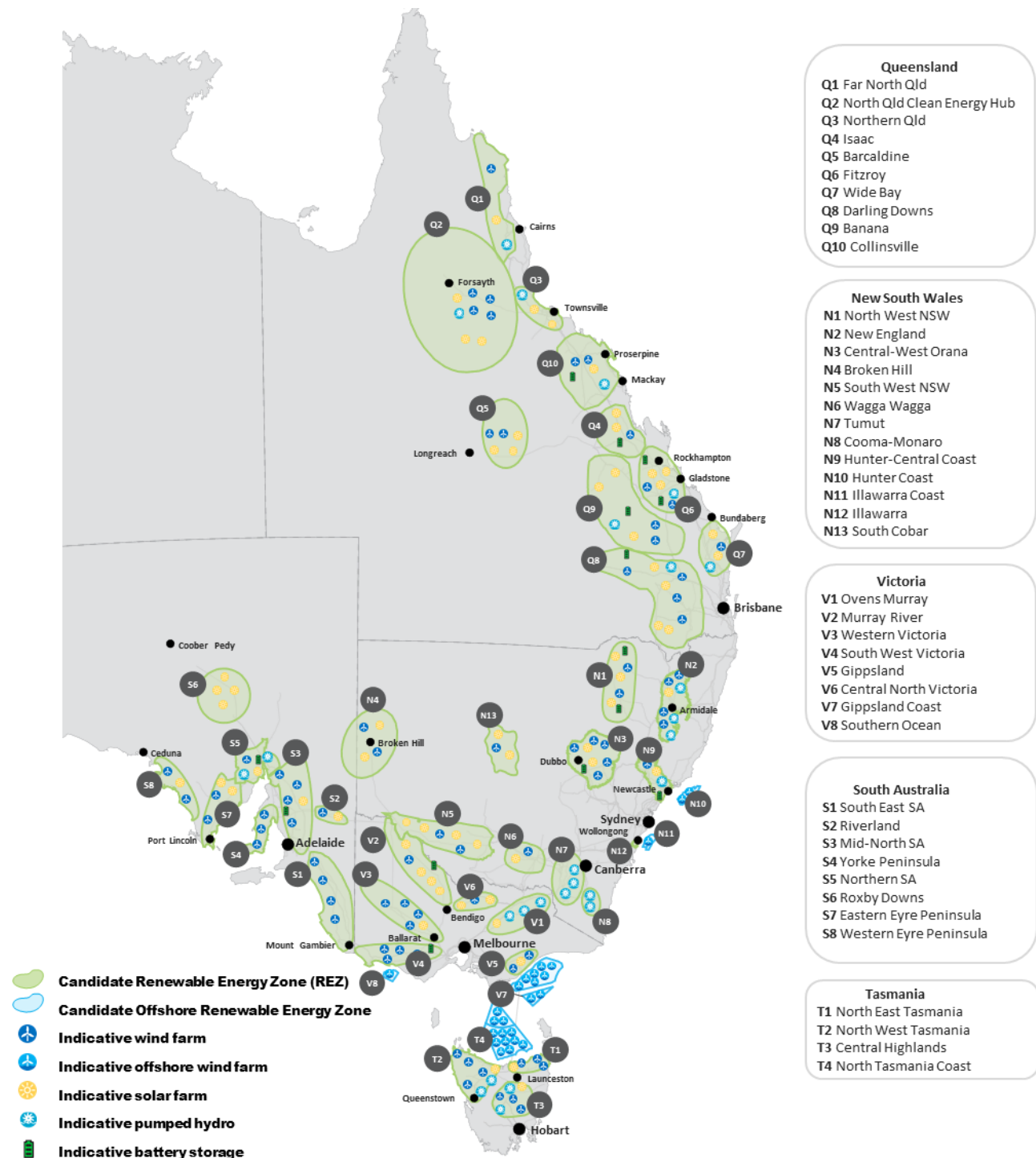
To conduct this analysis, it will become necessary to model renewable generation connecting to areas with existing network hosting capacity, but which may also have lower quality resources. For this reason, resource limits, resource quality, and network capacity are also determined for areas of the network that have existing hosting capacity, or where generation retirement is expected to result in additional network capacity. These areas are known as “non-REZs”. These lower quality resource areas are included in all simulations, 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.

No changes have been made for non-REZs since the 2024 ISP. The inputs and assumptions relating to non-REZs are provided in detail in the Draft 2025 *Inputs and Assumptions Workbook*.

Candidate REZ geographic boundaries

Figure 43 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 43 Candidate renewable energy zone map



Matters for consultation

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

3.9.2 REZ resource limits and social licence

Input vintage	December 2024
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 every ISP up to and including the 2024 ISP.
Update process	Updates will be dependent on feedback received on this Draft 2025 IASR.
Updates since 2024 ISP	<p>The following revisions have been made to align resource limits with the proposed amendments to the REZ geographic boundaries, and/or to reflect updated information received from TNSPs and jurisdictional bodies:</p> <ul style="list-style-type: none"> • New South Wales: Resource limits provided for the new South Cobar candidate REZ. • Queensland: Revised resource limits for Isaac and Darling Downs candidate REZs, as well as limits for the new Collinsville candidate REZ. • South Australia: Resource limits amended to reflect revised boundary for the Northern South Australia candidate REZ to extend to the Whyalla West area. • Victoria: Addition of a wind resource limit for the Murray River candidate REZ.

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

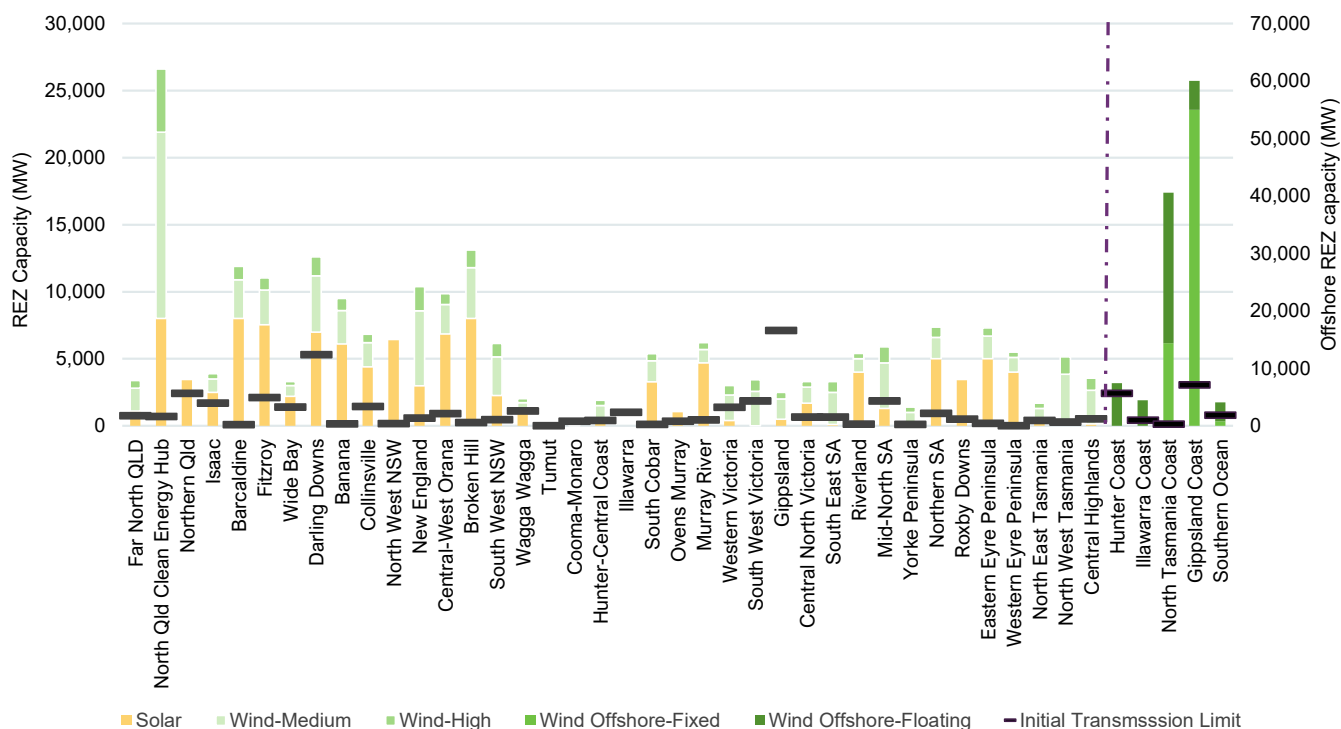
AEMO adjusts REZ resource limits when the boundary of a REZ changes or when appropriate evidence becomes available from localised consultation and studies. As desktop studies and stakeholder engagement have already been completed to prepare the existing REZ resource limits, AEMO expects that any further changes will need to be based on localised evidence as REZ projects are developed and delivered.

AEMO proposes the following changes since the 2024 ISP:

- Revised resource limits for Isaac REZ to reflect proposed updates to its geographical boundary, and included resource limits for Collinsville REZ based on the original REZ resource limits, but scaled for the new land areas.
- Included resource limits for the additional proposed wind resource tranches in the Darling Downs REZ based on advice from Powerlink with respect to diversity of resources and connection interest.
- Included resource limits for the proposed South Cobar REZ in New South Wales based on advice from Transgrid, EnergyCo and developer interest.
- Included revised resource limits for the expanded Northern South Australia REZ to extend to the Whyalla West area, based on advice from jurisdictional bodies.
- Added a wind resource limit for Murray River REZ based on updated TNSP advice around increased connection interest from wind farm proponents in this zone.

The updated resource limits are shown in Figure 44 and provided in detail in the Draft 2025 *Inputs and Assumptions Workbook*.

Figure 44 REZ resource limits and initial transmission limits



Note: Offshore REZ capacities use right axis scale. The dotted purple line is to separate offshore and onshore REZs.

Onshore wind farm resource limits

Maximum REZ wind generation resource limits were initially calculated based on a DNV-GL¹⁶⁰ estimate of:

- Typical wind generation land area requirements.
- Land available that has a resource quality of high (in the top 10% of sites assessed), and medium (in the top 30% of sites assessed, excluding high quality sites), and an assumption that only 20% of this land area will be able to be utilised for wind generation, considering competing land and social limitations.

These resource limits have evolved through each ISP since the 2018 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 REZ¹⁶¹ (see Section 3.5.1 for more information on classification of generation projects). In response to the latest updates of the committed and anticipated generation¹⁶², AEMO proposes to add an onshore wind resource limit to Murray River REZ in Victoria in recognition of increased connection interest since the 2023 IASR.

The resource limits are shown above in Figure 44, and are further detailed in the Draft 2025 *Inputs and Assumptions Workbook*.

¹⁶⁰ 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.

¹⁶¹ 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.

¹⁶² AEMO, NEM Generation Information October 2024, at <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information>.

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 each ISP since the 2018 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 REZ¹⁶⁰.

No changes are proposed for the existing REZ resource limits for the 2026 ISP. The resource limits are shown in Figure 44 above and are further detailed in the Draft 2025 *Inputs and Assumptions Workbook*.

Offshore wind resource limits

After considering announced projects and stakeholder feedback, AEMO included six candidate offshore REZs for the 2024 ISP. These zones were broadly located based on public information on offshore wind projects. AEMO now proposes to remove the South East South Australia Coast offshore candidate REZ for the 2026 ISP in recognition of that this area is not currently listed as an offshore wind area on the Australian Government's offshore wind website.

Table 27 provides the specific resource limits for each offshore REZ for both fixed and floating offshore wind turbine structures, prepared with consideration of the ocean depth of each offshore REZ.

Table 27 Offshore REZ resource limits

Offshore REZ	Resource limits – fixed structures (MW)	Resource limits – floating structures (MW)	REZ area (km ²)
N10 – Hunter Coast	0	7,420	1,854
N11 – Illawarra Coast	148	5,696	1,022
V7 – Gippsland Coast	54,996	5,000	14,999
V8 – Southern Ocean	780	3,330	1,030
T4 – North Tasmania Coast	14,400	26,150	10,136

The maximum offshore REZ wind generation resource limit in Table 27 was calculated based on:

- Assumed turbine capacity density of 5 MW/km².
- Allowing for 80% of the offshore REZ area to be developed.
- Fixed offshore wind turbine structures assumed to be built up to a depth of 70 metres.
- Floating offshore wind turbine structures are assumed at a depth above 70 metres but less than 1,000 metres.

Land use penalty factors in REZs allow for increases in resource limits

Land use reviews with governments indicate that the expansion of REZs is likely to become constrained by social licence factors, as opposed to purely on land availability (although varying between REZs).

In the 2024 ISP, AEMO applied an additional land use penalty factor of \$0.29 million/MW to all new VRE build costs in a REZ, which applies only if generation is modelled above the original REZ total resource limits. This penalty factor was applied to capture the expected increase in land costs or difficulties in obtaining land.

For the 2026 ISP, AEMO proposes a land use penalty factor of \$0.3 million/MW, which has been adjusted to account for inflation since the 2023 IASR.

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 2024 ISP, this was based on 5% of land area within a REZ for wind resources and 1% of land area for solar resources, which AEMO proposes to apply for the 2026 ISP also.

The land area within a REZ can be found in the Draft 2025 *Inputs and Assumptions Workbook*.

Social licence

In early 2024, Energy Ministers published their *Response to the Review of the Integrated System Plan* which included an action on AEMO to have regard to community sentiment when identifying the ISP's optimal development path (see Breakout box 1).

Breakout box 1 – Actions in the Energy Ministers' response to the Review of the ISP – Incorporating community sentiment

AEMO should have regard to community concerns or sensitive locations in the identification of the ODP, and consider existing and available data on community sentiment, where available for the 2026 ISP (for example, from CSIRO surveys or as the result of Transmission Network Service Providers' community engagement as part of preparatory activities).

'Social licence' is commonly used to refer to local community acceptance of new infrastructure development. The efficient and effective transition of the energy sector will rely on both government and the energy industry understanding and delivering the community's ambition and needs for the future power system, both broadly in the community, and in the places that host new development. Conversely, a lack of social licence could lead to

significant project delays and increased cost. Information about ‘community sentiment’ can broadly be considered as one indicator of social licence relating to new infrastructure development.

AEMO will include input and feedback from external stakeholders in its overall consideration of social licence and community sentiment matters for the ISP. In November 2022, AEMO established an Advisory Council on Social Licence (ACSL), consisting of a diverse cohort of consumer and community organisation representatives and respected advocates with expertise and understanding in the energy sector, to serve as a strategic advisory body on social licence matters, including the 2024 ISP. In July 2024, the ACSL evolved into a new format known as the Consumer and Community Reference Group (CCRG), and membership for a new cohort of the CCRG was finalised in September 2024. AEMO proposes to seek input and advice from the CCRG for the 2025 IASR and 2026 ISP where appropriate, in addition to undertaking extensive joint planning with TNSPs on this matter.

In the 2024 ISP, AEMO included social licence and community sentiment in a number of ways, as listed below. In this Draft 2025 IASR, AEMO welcomes stakeholder views and advice on how any of these considerations can be enhanced for the 2026 ISP.

- Selection of **forecasting and planning scenarios**, and their narratives (see Section 2).
- Selection of **sensitivity analyses**, including a ‘social licence’ sensitivity for the Draft 2024 ISP.
- Selection of **transmission augmentation options**, including cost, estimates, conceptual design and broad location, and application of transmission network augmentation costs and generator connection costs. For example, 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.
- Consideration of community engagement in **project lead times**.
- Selection of **locations for candidate REZs** through consultation, and through map overlay with the ‘National Native Title Tribunal, Native Title Determinations and Claimant Applications’.
- Preparation of **REZ parameters**, including **land use limits (and a land use penalty factor for exceedance)** (see above), and **resource limits** (above). For example, the use of land-use penalty factors is a reflection that REZ development is likely to be limited by social licence rather than renewable resources.

AEMO will consult on transmission and distribution augmentation cost, generator connection costs and project lead times in the 2025 *Network Expansion Options Report* consultation (formerly known as the *Transmission Expansion Options Report*). However, AEMO is also seeking stakeholders’ views on how community sentiment can be incorporated in the development of these parameters in this Draft 2025 IASR consultation.

Matters for consultation

- Do you have specific feedback on the proposed REZ resource limits?
- Is the maximum land use assumption of 5% for the REZ hard limits appropriate?
- Do you have specific feedback on the incorporation of community sentiment in the development of REZs?

3.9.3 REZ transmission limits

Input vintage	December 2024
Status	Draft
Source	Based on the 2023 <i>Transmission Expansion Options Report</i> and feedback to the 2023 <i>ISP Methodology</i> consultation
Update process	Updates will be dependent on feedback received on this Draft 2025 IASR.
Updates since 2024 ISP	<p>The following revisions have been made to align REZ transmission limits with the proposed amendments to the REZ geographic boundaries, sub-regional flow path definitions, and/or to reflect updated information received from TNSPs and jurisdictional bodies:</p> <ul style="list-style-type: none"> • New South Wales: transmission limits provided for the new South Cobar candidate REZ and the SWNSW1 secondary transmission limit has been updated to incorporate the N4 Broken Hill REZ contribution. South West NSW REZ limit has been revised consistent with updates to SWNSW1. • Queensland: transmission limits for Isaac REZ have been updated to reflect the new REZ boundary, and the Northern Queensland REZ limit will be represented by NQ1 group constraint, replacing NQ2. A new group constraint CQ1 has been added to account for generation south of Isaac REZ. Limits for the new Collinsville REZ will be modelled with the CQ-NQ sub regional limit. Finally, the SWQLD1 group constraint has been updated to reflect the additional resource traces in Darling Downs REZ. • South Australia: transmission limits amended to reflect revised boundary for the Northern South Australia REZ to extend to the Whyalla West area. The MN1 North and S1-TBMO limits have been replaced respectively by the new CSA-NSA and SESA-CSA flow paths. Eastern Eyre Peninsula REZ has been updated based on revised line ratings. • Victoria: the SEVIC1 group constraint has been replaced by the new SEV-MEL flow path limit.

Individual REZ transmission limits

Network studies were undertaken to identify REZ transmission limits of the existing network. Since the 2022 ISP, REZ transmission limits have reflected total transmission limits rather than surplus hosting capacity. The REZ transmission limit is expressed as an inter-temporal generation constraint. The purpose of the constraint is to limit the generation dispatch up to the transmission limit which can be increased when it is economically optimal.

Where flows across the transmission limit in a REZ are affected by generation, AEMO applies a generation constraint to reflect this dependency within the REZ. This was consulted on through the 2023 *ISP Methodology*.

The following changes are proposed to the 2025 IASR transmission limits and generation constraints:

- The new Collinsville REZ limit will be modelled as part of the Central Queensland – North Queensland sub-regional limit.
- The Isaac REZ modelling has been revised to consider the updated REZ boundary and will be modelled as part of the CQ1 group constraint limit.
- Northern Queensland REZ limit will now be modelled as part of the NQ1 group constraint limit.
- Limits are now provided for the new South Cobar REZ.
- The South West NSW REZ limit has been updated consistent with updates to the SWNSW1 secondary transmission limit.
- The Eastern Eyre Peninsula REZ limit has been reviewed based on updated ratings.
- In some cases, offshore REZ resources are anticipated to connect through to the transmission network via an onshore REZ. These resources will all be modelled within the individual REZ transmission limit for the onshore REZ.

Table 28 REZ transmission limit constraints

Transmission constraint name	REZ	Co-efficient	Constraint terms	Transmission-limited total build (MW)
SWQLD1	Darling Downs	0.12	Generation in Western Downs area	2,600
		0.36	Generation in Darling Downs area	
		0.95	Generation in Southern Downs area	
		0.78	North New South Wales to South Queensland flow (Queensland – New South Wales Interconnector [QNI])	
		-0.09	South Queensland to Central Queensland flow	

Secondary transmission limits within a REZ

Where there are significant transmission limits that apply to only a subset of generation within a REZ, a secondary transmission limit can be modelled. It is noted that the inclusion of an additional limit can significantly impact on simulation complexity. These are only included where impacts are deemed significant, such as where existing generation is already seeing network congestion. No new additional secondary limits are proposed.

The following change is proposed to the 2025 IASR Secondary transmission limits:

- The SWNSW1 secondary limit has been updated to incorporate the Broken Hill REZ contribution as an explicit term, based on TNSP feedback.

Table 29 REZ secondary transmission limits

REZ	Constraint terms	Transmission constraint	Transmission limit (summer peak/summer typical/winter reference) in MW
N5 (Existing)	<ul style="list-style-type: none"> Limondale 1 & 2 Solar Farm Sunraysia Solar Farm Coleambally Solar Farm Finley Solar Farm Darlington Point Solar Farm and Battery Energy Storage System (BESS) Hillston Sun Farm Riverina BESS 1 and 2 	SWNSW1	1,200/1,200/1,200
N4 (Existing)	<ul style="list-style-type: none"> Broken Hill Solar Farm and BESS Silverton Wind Farm Silver City Energy Storage 		
V3	Refer to Draft 2025 <i>Inputs and Assumptions Workbook</i> for full constraint definitions	V3-EAST	600/600/800
		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 network is a complex and interconnected system. Transmission flows are influenced by generation and system services across multiple locations. Within AEMO's capacity outlook model, simplifications are needed to represent the power system to keep the optimisation problem tractable, which may rely on flow limits being influenced by single REZ outcomes.

To address this need, "group constraints" are applied. These constraints combine either the generation from more than one REZ, or the generation within a REZ with the power flow along a flow path, to reflect network limits that apply to multiple areas of the power system. Table 30 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 are proposed:

- With the Central Queensland – Northern Queensland (see Section 3.10.5) sub-region boundary regional reference node shifting south from Chalumbin 275 kV to Ross 275 kV, the NQ2 group constraint will be removed and the Northern Queensland limits will be represented by the NQ1 group constraint previously included in the 2022 ISP.
- A new group constraint CQ1 will be added to reflect the network limits south of Q4 Isaac.
- The SEVIC1 group constraint will be removed and instead represented via the new South East Victoria – Greater Melbourne and Geelong (SEV-MEL) flow path.
- The MN1 North group constraint will be replaced by the new Central South Australia – North South Australia (CSA-NSA) flow path.
- The MN1 South group constraint will be updated to include an NSA to CSA sub-regional flow term.
- The SWQLD Darling Downs REZ Group Constraint will be updated to include separate terms and coefficients for the additional resource trace locations.
- The S1-TMBO limit will be removed as the change to the SESA-CSA boundary now incorporates this cut-set limit.

Table 30 REZ group transmission constraints

Generator/REZ ID/ Flow path	Generator / REZ name/Flow path name	Group constraint name	Transmission-limited total build (MW) (summer peak/summer typical/winter reference)
Q1	Far North Queensland	NQ1	2,420/2,420/2,650
Q2	North Queensland Clean Energy Hub		
Q3	Northern Queensland		
-1 x CQ-NQ	Central Queensland - North Queensland	CQ1	1,700/1,700/2,070
Q4	Isaac		
-0.5 x SQ-CQ	Central Queensland - South Queensland	SQ1(Before Queensland SuperGrid)	1,400/1,400/1,400
Q7	Wide Bay		

Generator/REZ ID/ Flow path	Generator / REZ name/Flow path name	Group constraint name	Transmission-limited total build (MW) (summer peak/summer typical/winter reference)
Q7	Wide Bay	SQ1 (After Queensland SuperGrid)	-
0.42 x Q8	Darling Downs		
-0.82 x CQ-SQ	CQ-SQ sub-regional flow		
0.75 x BPH	Borumba Pumped Hydro		
0.51 x Q8_Coal	Existing South West Queensland coal and gas generation (Tarong, Tarong North, Kogan Creek, Darling Downs, Braemar)		
-VIC-SA	Heywood Interconnector	SWV1	1,850/1,850/1,850
V4	South West Victoria		
V8	Southern Ocean		
S3	Mid-North SA	MN1	1,630/1,630/1,860
S4	Yorke Peninsula		
NSA-CSA	Flow from NSA to CSA		
0.75 x S5	Northern SA new entrant VRE	NSA1	585/585/585
S5 West	Existing generation in west of S5		
S7	Eastern Eyre Peninsula		
S8	Western Eyre Peninsula		
-CSA Export Electrolyser load	H2 Electrolyser load in NSA area		
-0.34 NSA demand	Industrial load in NSA area	NSA1 North	590/590/590
- 0.75 x S5	Northern SA new entrant VRE		
- S7	Eastern Eyre Peninsula		
- S8	Western Eyre Peninsula		
- S5 West	Existing generation in west of S5		
CSA Export Electrolyser load	H2 Electrolyser load in NSA area		
0.34 NSA demand	Industrial load in NSA area	NET1	1,600/1,600/1,600
T1	North East Tasmania		
T4	North Tasmania Coast		

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 2025 *Inputs and Assumptions Workbook*. Committed and anticipated transmission augmentation projects are defined in Section 3.10.3 and Section 3.10.4.

3.9.4 REZ augmentations and network cost

Input vintage	July 2024
Source	AEMO internal – Based on the Transmission Cost Database and TNSP data
Update process	Transmission Cost Database update and the 2025 <i>Network Expansion Options Report</i> consultation
Get involved	2025 <i>Network Expansion Options Report</i> consultation

For the 2024 ISP, AEMO published the 2023 *Transmission Expansion Options Report* with an expanded scope of the earlier 2021 *Transmission Cost Report*. This report included:

- 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.

For the 2026 ISP, AEMO will continue this initiative by publishing a *Network Expansion Options Report* with a scope including transmission network augmentation options and costs as well as some aggregated distribution network augmentation information. This expanded scope responds to an action on AEMO in the Energy Ministers’ Response to the ISP Review, to optimise demand-side modelling and enhance demand forecasting (see Breakout box 2, Section 3.10.8). The draft report will be published in early May 2025, followed by a period of consultation. AEMO will then publish the final 2025 *Network Expansion Options Report* alongside the 2025 IASR in July 2025.

For the 2025 IASR, AEMO is proposing to allocate the efficient level system strength remediation costs to REZ connection costs, to form a collective connection point limit cost. This proposed change seeks to align with the

recently updated system strength framework¹⁶³, which states that generally, system strength remediation schemes must be implemented behind connection points where NSPs are required to undertake system strength impact assessments. Minimum fault level remediation costs are proposed to also be modelled, in addition to the efficient level of system strength costs, and are detailed in Section 3.11.1.

Matters for consultation

- Do stakeholders agree with the proposed approach to allocate system strength remediation costs to REZ connection costs, consistent with the updated System Strength Impact Assessment Guidelines?

3.10 Network modelling

This section outlines the key inputs and assumptions relating to notional power transfers between different parts of the electricity transmission and distribution networks, as well as the status of nominated network projects and the capabilities and costs of potential augmentation of the networks. 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 15 sub-region structure is proposed to provide more granularity of diverse load patterns for optimisations that were previously assessed across 12 sub-regions across the NEM (see Section 3.10.1).
- **Existing network capacity** – this section summarises the existing capacity of the transmission network with relation to transferring power between sub-regions and includes the changes proposed for the revised sub-regional definition (see Section 3.10.2).
- **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 (see Section 3.10.3).
- **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).
- **Flow path augmentation options** – this will be consulted on through the Draft 2025 *Network Expansion Options Report* and will include transmission upgrades that are not committed or anticipated, which will be assessed in the 2026 ISP (see Section 3.10.5).
- **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 2025 *Network Expansion Options Report* (see Section 3.10.6).
- **Preparatory activities** – the 2024 ISP did not trigger preparatory activities for any of the identified future ISP projects (see Section 3.10.7).

¹⁶³ AEMO. System Strength Impact Assessment Guidelines, June 2024, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/ssia/system-strength-impact-assessment-guidelines-v22.pdf?la=en.

- **Distribution capabilities and potential augmentations** – the 2026 ISP will include analysis of distribution network capabilities and opportunities for CER and other distributed resources. Distribution network service provider (DNSP) inputs will be consulted on through the Draft 2025 *Network Expansion Options Report* (see Section 3.10.8).
- **Non-network options** – AEMO considers potential non-network options alongside network solutions to develop an efficient power system strategy (see Section 3.10.9).
- **Loss flow equations** – loss flow equations are used to reflect the energy lost when transferring energy between regions, and between sub-regions where appropriate (see Section 3.10.10).
- **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 (see Section 3.10.11).
- **Transmission line unplanned outage rates** – forced outage rates of inter-regional transmission elements are critical inputs for AEMO’s reliability assessments (see Section 3.10.12).

3.10.1 ISP sub-regions

Input vintage	December 2024
Status	Draft
Source	AEMO internal – based on 2024 ISP inputs, and adjusted based on AEMO assessments, supplemented by advice from TNSPs via joint planning
Update process	Updates will be dependent on feedback received on this Draft 2025 IASR
Updates since 2023 IASR	Updates proposed to: <ul style="list-style-type: none">• Create three sub-regions for the Victoria region.• Create a third sub-region in South Australia and amend the definition between the existing sub-regions in South Australia.• Amend the definitions of the North Queensland and Central Queensland sub-regions.

The power system is modelled in different ways depending on the analysis being performed. In market and economic modelling, the electricity network is 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 proposes to make the following changes to the sub-regional topology since the 2024 ISP:

- **Separating Victoria into three sub-regions** – AEMO proposes to divide the Victorian region from the 2024 ISP into three sub-regions, namely Greater Melbourne and Geelong (MEL), South East Victoria (SEV) and West and North Victoria (WNV). These changes are intended to improve visibility of constraints in the network for meeting Greater Melbourne and Geelong demand, and better represent the load diversity in different parts of Victoria.

- **Separating Central South Australia sub-region into two sub-regions** – AEMO proposes to divide the Central South Australia sub-region into two sub-regions, Northern South Australia (NSA) and Central South Australia (CSA). This new sub-regional model would better represent the load diversity and patterns in Northern South Australia distinct from the rest of South Australia, and assist to better capture network limitations on power transfers towards Northern South Australia and the Eyre Peninsula region.
- **Amending the sub-regional boundary of Central Queensland (CQ) to Northern Queensland (NQ)** – AEMO proposes to change the sub-regional boundary between Central Queensland and Northern Queensland, to move the border to be south of Nebo. This updated boundary is to align and maintain consistency for measuring and reporting flows on flow paths across planning documents for Queensland. It is also expected to better represent flows from potential pumped hydro projects into the Northern Queensland sub-region.
- **Amending the sub-regional boundary of South East South Australia (SESA) to Central South Australia (CSA)** – AEMO proposes to change the sub-regional boundary between South East South Australia and Central South Australia, to better align the sub-regional and REZ boundary of South East South Australia and provide improved visibility of constraints between the South East South Australia REZ and the Adelaide load centre.

Table 31 lists all the regions and sub-regions that AEMO proposes to use in its studies (and their corresponding reference nodes). The nodes in **bold** are those used as reference nodes in the regional topology.

Table 31 NEM regions, ISP sub-regions, reference nodes and REZs

NEM region	ISP sub-region	Reference node	REZs
Queensland	Northern Queensland (NQ)	Ross 275 kV	Q1, Q2, Q3 and Q10
	Central Queensland (CQ)	Broadsound 275 kV	Q4, Q5 and Q6
	Gladstone Grid (GG)	Calliope River 275 kV	-
	South Queensland (SQ)	South Pine 275 kV	Q7, Q8 and Q9 ^A
New South Wales	Northern New South Wales (NNSW)	Armidaale 330 kV	N1 and N2
	Central New South Wales (CNSW)	Wellington 330 kV	N3, N9 and N13
	Southern New South Wales (SNSW)	Canberra 330 kV	N4, N5, N6, N7 and N8
	Sydney, Newcastle, Wollongong (SNW)	Sydney West 330 kV	N10, N11 and N12
South Australia	Northern South Australia (NSA)	Davenport 275 kV	S5, S6, S7 and S8
	Central South Australia (CSA)	Torrens Island 66 kV	S2, S3, S4
	South East South Australia (SESA)	South East 132 kV	S1
Tasmania	Tasmania (TAS)	George Town 220 kV	T1, T2, T3 and T4
Victoria	Greater Melbourne and Geelong (MEL)	Thomastown 66 kV	-
	South East Victoria (SEV)	Hazelwood 500 kV	V5 and V7
	West and North Victoria (WNV)	Moorabool 220 kV	V1, V2, V3, V4, V6 and V8

Note: Bold reference nodes are those used for whole of region modelling, for example in the ESOO. In such studies, all regional loads are represented at the regional reference nodes.

A. In scenarios with large hydrogen export development, Q9 will be modelled within CQ.

Capacity outlook model representation

In the 2024 ISP, AEMO used a 12-area sub-regional model for capacity outlook modelling. For the 2026 ISP, AEMO is proposing a 15-area sub-regional model. The sub-regional model provides more granular information on key intra-regional transmission limitations and augmentations which are not well approximated by interconnectors and REZ limits. The sub-regional representation and flow paths are presented and described in Figure 45 and Table 32. For each flow path, AEMO models the alternating current (AC) and direct current (DC) interconnectors separately, which can result in multiple parallel flow paths.

Figure 45 ISP sub-regional model



Table 32 Existing network flow path representation between sub-regions

Flow path definition	Inter-zonal flow path (forward direction of power flow)
CQ – NQ	Bouldercombe – Nebo 275 kV (1 circuit)

Flow path definition	Inter-zonal flow path (forward direction of power flow)
	Broadsound – Nebo 275 kV (3 circuits) Dysart – Peak Downs/Moranbah 132 kV (1 circuit) Dysart – Eagle Downs 132 kV (1 circuit)
CQ – GG	Bouldercombe – Calliope River 275 kV (1 circuit) Raglan – Larcom Creek 275 kV (1 circuit) Calvale – Wurdong 275 kV (1 circuit) Gin Gin – Calliope River 275 kV (2 circuits) Teebar Creek – Wurdong 275 kV (1 circuit)
SQ – CQ	Woolooga – Teebar Creek 275 kV (1 circuit) Woolooga – Gin Gin 275 kV (2 circuits) Halys – Calvale 275 kV (2 circuits)
NNSW – SQ (QNI)	Dumaresq – Bulli Creek 330 kV (2 circuits)
NNSW – SQ (Terranora)	Terranora – Mudgeeraba 110 kV (2 circuits)
CNSW – NNSW	Muswellbrook – Tamworth 330 kV (1 circuit) Liddell – Tamworth 330 kV (1 circuit) Hawks Nest tee – Taree 132 kV line (1 circuit) Stroud – Taree 132 kV line (1 circuit)
SNSW – CNSW	Crookwell – Bannaby 330 kV (1 circuit) Yass – Marulan 330 kV (1 circuit) Collector – Marulan 330 kV (1 circuit) Capital – Kangaroo Valley 330 kV (1 circuit) Yass – Cowra 132 kV (2 circuits)
CNSW – SNW	Wallerawang – Ingleburn 330 kV (1 circuit) Wallerawang – Sydney South 330 kV (1 circuit) Bayswater – Sydney West 330 kV (1 circuit) Bayswater – Regentville 330 kV (1 circuit) Liddell – Newcastle 330 kV (1 circuit) Liddell – Tomago 330 kV (1 circuit) Bannaby – Sydney West 330 kV (1 circuit) Marulan – Avon 330 kV (1 circuit) Marulan – Dapto 330 kV (1 circuit) Kangaroo Valley – Dapto 330 kV (1 circuit) Stroud – Brandy Hill 132 kV (1 circuit) Stroud – Tomago 132 kV (1 circuit) Hawks Nest tee – Tomago 132 kV (1 circuit) Singleton – Rothbury 132 kV (1 circuit which is normally open)
WNV – 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 (2 circuits) Jindabyne – Guthega 132 kV (1 circuit) Geehi Dam – Guthega 132 kV (1 circuit)
SNSW – CSA	Buronga – Bundy 330 kV (2 circuits)
MEL – WNV	Sydenham – Moorabool 500 kV (2 circuits) Sydenham – Bulgana 500 kV (2 circuits) – post Western Renewables Link (WRL) Geelong – Moorabool 220 kV (2 circuits) South Morang – Dederang 330 kV (2 circuits) Thomastown – Eildon 220 kV (1 circuit) Geelong – Winchelsea 66 kV (1 circuit)

Flow path definition	Inter-zonal flow path (forward direction of power flow)
	Brooklyn – Bacchus Marsh 66 kV (1 circuit)
SEV – MEL	Hazelwood – South Morang 500 kV (2 circuits) Hazelwood – Rowville 500 kV (1 circuit) Hazelwood – Cranbourne 500 kV (1 circuit) Hazelwood – Rowville 220 kV (2 circuits) Yallourn – Rowville 220 kV (4 circuits)
WNV – SESA (Heywood)	Heywood – South East 275 kV (2 circuits)
WNV – CSA (Murraylink)	Red Cliffs – Monash HVDC cable
SESA – CSA	Tailem Bend – Tungkillo 275 kV (2 circuits) Tailem Bend – Mobilong 132 kV (1 circuit)
CSA – NSA	Bungama – Davenport 275 kV (1 circuit) Brinkworth – Davenport 275 kV (1 circuit) Mt Lock – Davenport 275 kV (1 circuit) Belalie – Davenport 275 kV (1 circuit)
TAS – SEV	George Town – Loy Yang HVDC cable

Representation of load and generation within each of the sub-regions is presented in Table 33. Sub-region loads are represented at the sub-region reference node. The reference node for each sub-region is located close to the sub-region's major load centre, except in North and Central Queensland where the nodes have been selected to capture intra-regional loss equations, and in West and North Victoria where the node has been proposed to support enhanced visibility of constraints in the network for meeting Greater Melbourne and Geelong demand.

Table 33 Load and generation representation within the sub-regional model

Sub-region	Sub-region reference node	Load and generation representation
Northern Queensland (NQ)	Ross 275 kV	All load and generation including and north of Nebo, Eagle Downs, Peak Downs and Moranbah.
Central Queensland (CQ)	Broadsound 275 kV	All load and generation including and north of Calvale, Gin Gin and Teebar Creek substations, except load and generation in GG and NQ sub-regions.
Gladstone Grid (GG)	Calliope River 275 kV	All load and generation at Calliope River, Boyne Island, Larcom Creek and Wurdong substations.
South Queensland (SQ)	South Pine 275 kV	All Queensland load and generation except load and generation in CQ, GG and NQ sub-regions.
Northern New South Wales (NNSW)	Armidale 330 kV	Within New South Wales, all load and generation including and north of Tamworth substation.
Central New South Wales (CNSW)	Wellington 330 kV	Within New South Wales, all load and generation including west of Wallerawang, Wollar, Bayswater, Liddell, Muswellbrook and Bannaby substations.
South New South Wales (SNSW)	Canberra 330 kV	Within New South Wales, all load and generation including and south of Gullen Range, Marulan and Kangaroo Valley substations. All load and generation in South West New South Wales.
Sydney, Newcastle and Wollongong (SNW)	Sydney West 330 kV	All New South Wales region load and generation except load and generation in CNSW, SNSW and NNSW sub-regions.
West and North Victoria (WNV)	Moorabool 220 kV	Within Victoria, all load and generation including and north and west of Moorabool, Eildon, Dederang, Winchelsea and Bacchus Marsh substations.

Sub-region	Sub-region reference node	Load and generation representation
South East Victoria (SEV)	Hazelwood 500 kV	Within Victoria, all load and generation in Gippsland region including at Hazelwood, Loy Yang, Yallourn, Jeeralang and Morwell substations.
Greater Melbourne and Geelong (MEL)	Thomastown 66 kV	All load and generation within Victoria, except in WNV and SEV sub-regions.
Northern South Australia (NSA)	Davenport 275 kV	All load and generation including and north of Davenport and Eyre Region.
Central South Australia (CSA)	Torrens Island 66 kV	All load and generation within South Australia except NSA and SESA sub-regions load and generation.
South East South Australia (SESA)	South East SA 132 kV	All load and generation including and 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?

Detailed transmission constraint representation for time-sequential models

In the ESOO, and where required in the ISP time-sequential models, AEMO applies a more detailed transmission representation that is overlaid to the regional model. The NEM transmission network is represented using detailed transmission constraint equations over a regional topology, similar to what is used in the NEM Dispatch Engine (NEMDE). These constraints:

- Consider the NEM's network at 220 kV or above, and other transmission lines under this voltage level that run parallel to the network at 220 kV or above.
- Calculate the network flow capability (intra- and inter-regional) and the available generator output capacity in every dispatch interval of the model.
- Are constantly updated to reflect changing power system conditions and outages.
- Are modified to cater for different transmission development pathways and scenarios assessed in an ISP.

3.10.2 Existing transmission capability

Input vintage	December 2024
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 2025 IASR
Updates since 2024 ISP	Updated to reflect the transmission capability of the flow paths proposed to define the boundaries between the new and amended sub-regions discussed in section 3.10.1. These transmission capabilities were prepared by reviewing historical transfer performance and undertaking power system analysis, as well as through joint planning with TNSPs.

Transfer capability across the transmission network is determined by thermal capacity, voltage stability, transient stability, small signal stability, frequency stability and system strength. It varies throughout the day with generation

dispatch, load and weather conditions. In time-sequential market modelling, limits are represented through network constraint equations. For capacity outlook modelling, notional transfer limits between the regions or sub-regions are represented at the time of maximum demand in the importing region or sub-region.

AEMO proposes the following changes since the 2024 ISP:

- Revision of flow path limits between Central Queensland (CQ) and Northern Queensland (NQ) to align with the proposed updated sub-region boundaries.
- Revision of flow path limits between Northern New South Wales (NNSW) and Southern Queensland (SQ) to reflect the change in Queensland – New South Wales Interconnector (QNI) and Terranora limits (consistent with the April 2024 Interconnector Capabilities¹⁶⁴ report).
- Inclusion of flow path limits between Greater Melbourne and Geelong (MEL) and West and North Victoria (WNV) to align with the proposed new sub-region boundaries.
- Inclusion of flow path limits between South East Victoria (SEV) and Greater Melbourne and Geelong (MEL) to align with the proposed new sub-region boundaries.
- Revision of flow path limits between South East South Australia (SESA) and Central South Australia (CSA) to align with the proposed updated sub-region boundaries.

The proposed Draft 2025 IASR notional transfer limits are in Table 34. They reflect current assessments and may change as further power system analysis is undertaken, or as the sub-regional representation is refined.

Interconnector transfer capabilities are a subset of this information, and are listed in the *Draft 2025 Inputs and Assumptions Workbook*.

Table 34 Notional transfer capabilities between the sub-regions of the existing network (December 2024)

Flow paths (forward power flow direction)	Forward direction capability (MW)			Reverse direction capability (MW)			Comments
	Summer peak	Typical summer	Winter reference	Summer peak	Typical summer	Winter reference	
CQ – NQ	1,200	1,200	1,400	1,440	1,440	1,910	Amended flow path boundary proposed in this Draft 2025 IASR. No change to CQ – NQ forward capability since 2024 ISP. Limits were determined with the inclusion of a minor Strathmore to Ross line upgrade. AEMO is working with Powerlink to further investigate possible voltage or transient stability limits associated with CQ – NQ reverse flow capability.
CQ – GG	700	700	1,050	750	750	1,100	No changes to 2024 ISP.
SQ – CQ	1,100	1,100	1,100	2,100	2,100	2,100	The maximum power transfer from CQ to SQ grid section is limited by transient or voltage stability following a Calvale to Halys 275 kV circuit contingency. It is assumed Powerlink will establish a new substation at

¹⁶⁴ AEMO. *Interconnector Capabilities*, April 2024. At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/2024/interconnector-capabilities.pdf.

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	
							<p>Karana Downs for teeing-in both Blackwall – Rocklea 275 kV lines to South Pine.</p> <p>The maximum transfer capability from SQ to CQ is limited by thermal capacity of the Blackwall – South Pine 275 kV line following a credible contingency.</p>
NNSW – SQ ("QNI")	950	950	950	1,450	1,450	1,450	<p>These amended transfer limits include the completion of the QNI minor project. QNI Minor is currently undergoing inter-network testing to release the designed maximum capacity.</p> <p>Queensland to New South Wales transfer limit is influenced by generation output from Sapphire Wind Farm and Tilbuster Solar Farm.</p> <p>AEMO is working with Transgrid to further refine this limit for the final 2025 IASR.</p>
NNSW – SQ ("Terranora")	0	50	50	130	150	200	<p>No changes to 2024 ISP.</p> <p>The maximum transfer capability from NNSW to SQ is limited by thermal capacity of Lismore – Dunoon 132 kV lines and from SQ to NNSW is limited by thermal capacity of Mudgeeraba 275/110 kV transformers.</p>
CNSW – NNSW	910	910	910	930	930	1,025	<p>No changes to 2024 ISP.</p> <p>These transfer limits include the completion of the QNI Minor project.</p> <p>AEMO is working with Transgrid to further refine this limit for the final 2025 IASR.</p>
SNSW – CNSW	2,700	2,700	2,950	2,320	2,320	2,590	No changes to 2024 ISP.
CNSW – SNW Northern limit	4,490	4,490	4,730	4,490	4,490	4,730	<p>No changes to 2024 ISP.</p> <p>This limit has been formulated for the detailed long term capacity outlook model and should not be used for other applications. For detailed long term capacity outlook modelling, the CNSW-SNW transfer limit can be represented as two limits. One as CNSW-SNW_South and other as CNSW-SNW_North. For DLT modelling, this limit is to be represented with generator coefficients for generators in NNSW, CNSW and SNSW. These generator coefficients are presented in the "Network capability" worksheet in the Draft 2025 <i>Inputs and Assumptions Workbook</i>.</p>

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	
							<p>See the Draft 2025 <i>Inputs and Assumptions Workbook</i> for more details on CNSW-SNW transfer limit improvement with Waratah Super Battery (WSB) network augmentations and System Integrity Protection Scheme (SIPS) control and Central-West Orana REZ Network Infrastructure Project.</p> <p>Power is not expected to frequently flow from SNW to CNSW since the major load centre is SNW. Forward direction transfer limit will be assessed if of material importance.</p>
CNSW – SNW Southern limit	2,540	2,540	2,720	2,540	2,540	2,720	<p>No changes to 2024 ISP.</p> <p>This limit has been formulated for the DLT model and should not be used for other applications. For detailed long term capacity outlook modelling, CNSW-SNW transfer limit can be represented as two limits. One as CNSW-SNW_South and other as CNSW-SNW_North. For detailed long term capacity outlook modelling, this limit is to be represented with generator coefficients for generators in NNSW, CNSW and SNSW. These generator coefficients are presented in the “Network capability” worksheet in the Draft 2025 <i>Inputs and Assumptions Workbook</i>.</p> <p>See the Draft 2025 <i>Inputs and Assumptions Workbook</i> for more details on CNSW-SNW transfer limit improvement with Waratah Super Battery (WSB) network augmentations and System Integrity Protection Scheme (SIPS) control and Central-West Orana REZ Network Infrastructure Project.</p> <p>Power is not expected to frequently flow from SNW to CNSW since the major load centre is SNW. Forward direction transfer limit will be assessed if of material importance.</p>
WNV – SNSW	870	1,000	1,000	400	400	400	<p>No changes to 2024 ISP.</p> <p>WNV-SNSW transfer limits assumes the full capacity provided by VNI Minor.</p> <p>Victoria SIPS with 250 MW battery storage in western side of Melbourne raises the thermal capacity in the reverse direction of Victoria – New South Wales interconnector. SNSW to WNV</p>

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	
							transfer limit during summer peak periods reduces to 250 MW from 400 MW on conclusion of the VNI SIPS agreement 31 March 2032.
MEL – WNV	2,300	2,550	4,880	2,300	2,550	4,880	<p>New flow path proposed in this Draft 2025 IASR.</p> <p>Generation from MEL is not expected to supply WNV (Forward direction) at times of high demand periods. The forward direction transfer limits are assumed to be equal to reverse direction limits. These limits will be reviewed in collaboration with AEMO (Victorian Planning) and VicGrid.</p> <p>Transfer limits associated with post Western Renewables Link are available in the “Network Capability” worksheet in the Draft 2025 <i>Inputs and Assumptions Workbook</i>.</p>
SEV – MEL	7,100	7,430	8,170	7,100	7,430	8,170	<p>New flow path proposed in this Draft 2025 IASR.</p> <p>This limit is applicable for the existing network before retirement of Yallourn Power Station.</p> <p>Power is not expected to frequently flow from MEL to SEV since the major load centre is MEL. Reverse direction transfer limit will be assessed if material importance.</p> <p>Transfer limits with Western Renewables Link and post Yallourn power station closure are available in the “Network Capability” worksheet in the Draft 2025 <i>Inputs and Assumptions Workbook</i>.</p>
WNV – SESA (“Heywood”)	650	650	650	650	650	650	<p>No changes to 2024 ISP.</p> <p>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.</p>
WNV – CSA (Murraylink)	165	220	220	100	200	200	<p>Murraylink forward direction is limited by HVDC cable thermal capability which is provided in the “Network Capability” worksheet in the Draft 2025 <i>Inputs and Assumptions Workbook</i>.</p>
SNSW – CSA	150	150	150	150	150	150	<p>This is the design limit of Project EnergyConnect Stage 1. WNV - CSA and SNSW - CSA combined</p>

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	
(Project EnergyConnect Stage 1)							maximum transfer limit is 750 MW in forward direction (import into SA) and 700 MW in reverse direction (export from SA). This transfer limit will increase with full capacity release of Project EnergyConnect (Stage 2 completion). Additional transfer capacity after Stage 2 are available in the “Network Capability” worksheet in the Draft 2025 <i>Inputs and Assumptions Workbook</i> .
SESA – CSA	750	750	800	790	790	820	Amended flow path boundary proposed in this Draft 2025 IASR. This transfer limit considers Project EnergyConnect Stage 1 in service. The transient and oscillatory stability limits may be applicable on this flow path. AEMO is working with ElectraNet to refine this limit for the final 2025 IASR.
CSA – NSA	1,070	1,070	1,230	1,150	1,150	1,200	New flow path proposed in this Draft 2025 IASR. A transient or voltage stability limit lower than the thermal limit may be applicable for this flow path. AEMO is working with ElectraNet to further refine this limit for the final 2025 IASR.
TAS – SEV	594	594	594	478	478	478	No changes to 2024 ISP. Basslink interconnector currently operates at a peak transfer capability of 594 MW in forward direction and 478 MW in the reverse direction with allowable capability limited by a daily energy throughput limit as outlined in the Draft 2025 <i>Inputs and Assumptions Workbook</i> .

Committed and anticipated projects may increase the capability of flow paths or result in new flow paths. The flow path uplift factors and new flow paths as a result of committed and anticipated projects are presented in the ‘Network capability’ tab of the Draft 2025 *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 2024
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 committed status, these are updated in the Input and Assumptions Workbook and the Transmission Augmentation Information page.
Updates since 2024 ISP	Yass-Wagga Line Overload Scheme (LOLS) Expansion (NCIPAP) project by Transgrid received committed status.

AEMO applies the five-criteria definition of a committed project from the AER’s regulatory investment test¹⁶⁵; specifically, a committed transmission project must meet all the following criteria:

- The proponent has obtained all required planning consents, construction approvals and licences, including completion and acceptance of any necessary environmental impact statement.
- Construction has either commenced or a firm commencement date has been set.
- The proponent has purchased/settled/acquired land (or commenced legal proceedings to acquire land) for the purposes of construction.
- Contracts for supply and construction of the major components of the necessary plant and equipment (such as transmission towers, conductors, terminal station equipment) have been finalised and executed, including any provisions for cancellation payments.
- Necessary financing arrangements, including any debt plans, have been finalised and contracts executed.

This Draft 2025 IASR applies the committed projects listed in the Transmission Augmentation Information page¹⁶⁶, December 2024 release. For further details on these projects please see the Draft 2025 *Inputs and Assumptions Workbook* or the Transmission Augmentation Information 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.

¹⁶⁵ At <https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20-%202025%20August%202020.pdf>.

¹⁶⁶ At <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information>.

3.10.4 Anticipated transmission projects

Input vintage	December 2024
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 Workbook and the Transmission Augmentation Information page.
Updates since 2024 ISP	HumeLink has advanced to anticipated status.

Anticipated transmission projects are transmission augmentations that are not yet committed but are highly likely to proceed and could become committed soon. AEMO applies the criteria set out in the AER’s regulatory investment test to determine anticipated projects. These projects must be in the process of meeting three out of the five committed project criteria (described in Section 3.10.3). Such projects could be network or non-network augmentations and could be regulated or non-regulated assets.

The Reliability Forecasting Methodology¹⁶⁷ 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.

This Draft 2025 IASR applies the anticipated projects listed in the Transmission Augmentation Information page¹⁶⁸, December 2024 release. For further details on these projects please see the Draft 2025 *Inputs and Assumptions Workbook* or the Transmission Augmentation Information page.

3.10.5 Flow path augmentation options

Input vintage	June 2024
Status	Interim
Source	AEMO, 2024 ISP, TNSP
Updates process	2025 <i>Network Expansion Options Report</i> consultation and through further TNSP engagements
Get involved	2025 <i>Network Expansion Options Report</i> 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

¹⁶⁷ 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>.

¹⁶⁸ At <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information>.

developed, 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 increase the transfer capability between ISP sub-regions. Each option is a candidate to be built during capacity expansion modelling. While many flow path augmentation options increase REZ network capacities, distinct options to expand the network capacity within individual REZs are modelled through a separate process, outlined in Section 3.9.

When identifying flow path augmentation options across ISP sub-regions to connect REZs and pumped hydro storage, AEMO considers credible options including the following technologies:

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

AEMO will consult on flow path augmentation options, including the capacity gained and lead time to deliver the project, through the Draft 2025 *Network Expansion Options Report*. Please see Section 3.9.4 for more details.

3.10.6 Transmission augmentation costs

Input vintage	June 2024
Status	Interim
Source	<ul style="list-style-type: none">• Actionable projects: RIT-T data with factors applied• Projects with Preparatory activities: TNSP cost data, cross checked with AEMO’s Transmission Cost Database• Future projects: AEMO’s Transmission Cost Database
Update process	2025 <i>Network Expansion Options Report</i> consultation
Get involved	2025 <i>Network Expansion Options Report</i> consultation

For the 2024 ISP, AEMO engaged independent expert consultant Mott MacDonald to update AEMO’s Transmission Cost Database for use by AEMO in developing cost estimates. It comprised a Cost and Risk Databook and cost estimation tool, as well as a transmission cost forecasting methodology.

For the 2026 ISP, to reflect the latest changes in the market, AEMO has engaged expert consultant GHD 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.
- Review and update the cost forecasting tool and methodology.
- Incorporate the latest transmission project information in the update and calibrate escalation factors.
- Prepare an updated Cost and Risk data workbook and forecasting tool, and associated reporting.

AEMO is undertaking extensive joint planning and collaboration with TNSPs and jurisdictional bodies to update the Transmission Cost Database. The updated Transmission Cost Database will be used to develop draft cost estimates for transmission augmentation options for use in the 2026 ISP.

AEMO will release the draft updated Transmission Cost Database, and associated cost estimates, for consultation as part of the Draft 2025 *Network Expansion Options Report* in April 2025. Outcomes of the consultation will be

incorporated in the final 2025 *Network Expansion Options Report* and final 2025 *Inputs and Assumptions Workbook*.

3.10.7 Preparatory activities

Input vintage	June 2024
Status	Final
Source	TNSPs
Update process	Not applicable

Preparatory activities are activities to design and investigate the costs and benefits of actionable ISP projects, future ISP projects and REZ stages (as applicable)¹⁶⁹, including:

- Detailed engineering design.
- Route selection and easement assessment work.
- Cost estimation based on engineering design and route selection.
- Preliminary assessment of environmental and planning approvals.
- Engagement with stakeholders who are reasonably expected to be affected by the development of the actionable ISP project, future ISP project, or project within a REZ stage (including local landowners, local council, local community members, local environmental groups and traditional owners) in accordance with the community engagement expectations¹⁷⁰.

While TNSPs must commence preparatory activities as soon as practicable for actionable ISP projects (if not yet already commenced)¹⁷¹, an ISP may specify whether preparatory activities must be carried out for future ISP projects and the timeframes for carrying out those activities. 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. The initial high-level design and costing in preparatory activities reports is necessarily approximate, as the detailed requirements for robust costings and plant design will not yet have been undertaken.

AEMO did not trigger preparatory activities for any of the future ISP projects identified in the 2024 ISP. The TNSPs identified as a RIT-T proponent for a newly actionable ISP project in the 2024 ISP should commence preparatory activities as soon as practicable, if not already commenced.

The projects for which preparatory activities reports have been previously made available by TNSPs are outlined in Table 35. The TNSPs’ preparatory activities reports are published on the AEMO website¹⁷².

¹⁶⁹ These terms are defined in NER 5.10.2 and Chapter 10. At <https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules>.

¹⁷⁰ Preparatory activities and community engagement expectations are both defined in NER 5.10.2.

¹⁷¹ NER 5.22.6(c)&(d)(1)

¹⁷² At <https://aemo.com.au/consultations/current-and-closed-consultations/2023-transmission-expansion-options-report-consultation>.

Table 35 Preparatory activities

Project	Indicative timing (2024 ISP)	Responsible TNSP(s)
South East South Australia REZ expansion	N/A	ElectraNet
Darling Downs REZ Expansion	2030-31 to 2034-35	Powerlink
Gladstone Grid Reinforcement	2030-31	Powerlink
Mid-North South Australia REZ Expansion	2029-30 to 2030-31	ElectraNet
QNI Connect (500 kV option)	2034-35	Powerlink and Transgrid
QNI Connect (330 kV option – New South Wales scope)		Transgrid
South West Victoria REZ Expansion	2032-33 to 2033-34	AEMO Victorian Planning (AVP)
Sydney Ring South (Reinforcing Sydney, Newcastle and Wollongong Supply)	2028-29 to 2029-30	Transgrid

3.10.8 Distribution network capabilities

Input vintage	April 2025
Status	Not started
Source	DNSPs
Update process	2025 <i>Network Expansion Options Report</i>
Updates since 2024 ISP	These inputs have not been included in previous ISPs
Get involved	2025 <i>Network Expansion Options Report</i>

AEMO considers CER to be of critical importance to the energy transition. By investing in CER, households and businesses are playing a transformative role in the future energy system, and will need to be supported by distribution networks, coordination systems and markets.

Energy Ministers' response to the Review of the ISP¹⁷³ included an action for AEMO to consider the role of distribution network capabilities and opportunities to support CER and other distributed resources in the future energy system (see: Breakout Box 2). The AEMC is currently considering a rule change to implement information provision arrangements to support the delivery of this action¹⁷⁴. As such, AEMO is currently considering how to introduce representation of distribution network capabilities and opportunities into the ISP models.

¹⁷³ ECMC. *Response to the Review of the Integrated System Plan*, April 2024. At <https://www.energy.gov.au/energy-and-climate-change-ministerial-council/energy-ministers-publications/energy-ministers-response-review-integrated-system-plan>.

¹⁷⁴ AEMC. Improving consideration of demand-side factors in the ISP. At <https://www.aemc.gov.au/rule-changes/improving-consideration-demand-side-factors-isp>.

Breakout box 2 – Actions in the Energy Ministers’ response to the Review of the ISP – Enhanced demand forecasting, and optimising for the demand side

AEMO should enhance demand forecasting in the 2026 ISP by:

- Undertaking targeted stakeholder engagement to enhance assumptions underpinning CER and distributed resources projections in the ISP. The assumptions should reflect a comprehensive view of initiatives affecting CER and distributed resources uptake and evaluate the implications for operational demand.
- Subject to available information, analysing how DNSP investments, programs and annual plans, may impact CER and distributed resources development, and thereby the ODP for transmission, and include these findings in the ISP in order to send clearer signals to inform DNSP planning.

AEMO will engage extensively with DNSPs to understand existing and future distribution network capabilities and opportunities for incorporating CER and other distributed resources. This will include the existing distribution network capabilities as they relate to the operation of CER such as rooftop solar and batteries – that is, understanding how network capabilities may impact CER operation with respect to exporting generation, as well as charging and discharging where relevant. The representation of these capabilities will be informed by inputs from the DNSPs, to be gathered and consulted on through AEMO’s Draft 2025 *Network Expansion Options Report*, which will also include cost curves for potential distribution network augmentations associated with accommodating higher levels of CER operation. AEMO expects that this data will necessarily evolve and improve over successive ISPs.

3.10.9 Non-network options

Input vintage	September 2024
Status	Draft
Source	Previous projects, stakeholder submissions
Update process	2025 IASR and progression of RIT-Ts
Get involved	2025 <i>Network Expansion Options Report</i>

Non-network options are defined in the NER (Chapter 10, glossary) as a means by which an identified need can be fully or partly addressed other than by a network option. 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.

AEMO will seek input on and consider non-network options in preparing the 2026 ISP.

As per Section 3.4.3 of the CBA Guidelines, prior to the Draft ISP, AEMO is required to:

- Undertake early engagement with non-network proponents to gather information in relation to non-network options, and

- If there are any credible non-network options identified through early engagement and joint planning, but not included in a TAPR, include these in its process for selecting development paths.

AEMO must seek proposals for non-network options for actionable ISP projects identified in a Draft 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.

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?

3.10.10 Network losses

Input vintage	December 2024
Status	<ul style="list-style-type: none">• 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 <i>Marginal Loss Factors Report</i> 2024-25 Financial Year and internal processes
Update process	<ul style="list-style-type: none">• Updated in line with AEMO's <i>Marginal Loss Factors Report</i> published in July 2024.• For existing network intra-regional loss factor equations, loss equations and proportioning factors, the Draft 2025 <i>Inputs and Assumptions Workbook</i> has been updated.• For future augmentation options, the draft and final 2025 <i>Network Expansion Options Report</i>.
Updates since 2024 ISP	<ul style="list-style-type: none">• Added new intra-regional loss and loss factor equation for Central South Australia (CSA) to Northern South Australia (NSA).• Updated the Central Queensland (CQ) to Northern Queensland (NQ) and Southern Queensland (SQ) to Central Queensland (CQ) loss and loss factor equations to reflect the revised sub-regional boundary definition.
Get involved	2025 <i>Network Expansion Options Report</i> consultation

This section describes the loss equations, loss factor equations and proportioning factors inter-regional and intra-regional flows 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. Where inter-regional losses do not sufficiently account for geographically remote sub-regional flow paths (for example Far North Queensland, Central Queensland and Northern South Australia), additional sub-regional losses have been modelled.

Inter-regional loss equations, loss factor equations and proportioning factors

Inter-regional loss equations are used to determine the amount of losses on an interconnector for any given transfer level. These are used to determine net losses for different levels of transfer between regions so NEMDE or AEMO's capacity expansion model and time-sequential market model can ensure the supply-demand balance includes losses between regions.

Inter-regional loss factor equations describe the variation in loss factor at one regional reference node (RRN) with respect to an adjacent RRN. These equations are necessary to cater for the large variations in loss factors that may occur between RRNs as a result of different power flow patterns. This is important in minimising the distortion of economic dispatch of generating units.

Interconnector loss proportioning factors are used to separate the inter-regional losses into the amount belonging to each of the two regions. The existing network inter-regional loss equations, loss factor equations and proportioning factors are sourced from the *Marginal Loss Factors for the 2024-25 Financial Year*¹⁷⁵ report and are presented in the 'Network losses' tab of the Draft 2025 *Inputs and Assumptions Workbook*.

For committed, anticipated and future projects that impact interconnector flows, AEMO will be consulting on these inter-regional loss equations, loss factor equations and proportioning factors through the 2025 *Network Expansion Options Report*, for inclusion in the final 2025 *Inputs and Assumptions Workbook*.

Intra-regional loss and loss factor equations

Inter-regional loss factor equations describe the variation in loss factor at one RRN with respect to an adjacent RRN. These equations are necessary to cater for the large variations in loss factors that may occur between RRNs as a result of different power flow patterns. This is important in minimising the distortion of economic dispatch of generating units.

In addition, AEMO models intra-regional loss equations in some cases 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. Another instance for defining an intra-regional loss equation is to capture the change in network losses when a new sub-region is created which is remotely located from the reference node of that region.

In the 2024 ISP, AEMO identified Northern Queensland as being remote from load centres under all scenarios except *Green Energy*, based on insights from the 2022 ISP's *Hydrogen Superpower* scenario outcomes. AEMO used the sub-regional model to capture the network losses through intra-regional equations, between the

¹⁷⁵ At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/loss_factors_and_regional_boundaries/2024-25-financial-year/mlfs-for-the-2024-25-financial-year.pdf.

Northern Queensland, Central Queensland and Southern Queensland sub-regions. This approach was applied to Far North Queensland and Queensland Clean Energy Hub in all scenarios except the *Green Energy* scenario.

In this Draft 2025 IASR, AEMO is proposing the addition of a new Northern South Australia (NSA) sub-region. In this case, AEMO has identified that the sub-regional reference node for NSA would be remote from the regional reference node for South Australia. As such, AEMO proposes to add a new intra-regional loss equation between Northern South Australia and Central South Australia to ensure losses associated with the transfers between these two sub regions are catered for.

The Draft 2025 *Inputs and Assumptions Workbook* ‘Network losses’ worksheet captures the proposed intra-regional loss factor equations.

3.10.11 **Marginal loss factors (MLFs)**

Input vintage	April 2024
Status	Current view
Source	AEMO <i>Marginal Loss Factors Report</i> 2024-25 Financial Year and internal processes
Update process	Updated in line with AEMO’s latest <i>Marginal Loss Factors Report</i>

Network losses occur as power flows through transmission lines and transformers. Increasing the amount of renewable energy connected to the transmission network remote from load centres will increase network losses. As more generation connects in a remote location, the power flow over the connecting lines and on the AC system increases, and so do losses.

Electrical losses are a transport cost that need to be priced and factored into electrical energy prices. MLFs are used to adjust the price of electricity in a NEM region, relative to the RRN, in a calculation that aims to recognise the relationship between a generator’s output and the energy that is actually delivered to consumers. The NEM uses marginal costs as the basis for setting spot prices in line with the economic principle of marginal pricing. The spot price for electrical energy is determined, or is set, by the incremental cost of additional generation (or demand reduction) for each dispatch interval. Consistent with this, the marginal loss is the incremental change in total losses for each incremental unit of electricity. The MLF of a connection point therefore represents the marginal losses to deliver electricity to that connection point from the RRN.

In dispatch and settlement in the NEM, the local price of electricity at a connection point is equal to the regional price multiplied by the MLF. A renewable generator’s revenue in the NEM wholesale market is directly scaled by its MLF, through both electricity market transactions and any revenue derived from large-scale renewable generation certificates (LGCs) created if accredited under the Large-scale Renewable Energy Target (LRET).

MLFs are an outcome of applying the methodology for the calculation of Forward-Looking Transmission Loss Factors (updated in December 2024), and are updated every financial year with the publication of AEMO’s *Marginal Loss Factors* report¹⁷⁶. AEMO updated the MLFs to reflect the latest available version of this report. Where a committed or anticipated generator does not have an MLF calculated in the *Forward-Looking Transmission Loss Factors* report, a ‘shadow’ generator is used. This is a generator which is located electrically

¹⁷⁶ At <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries>.

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' worksheet in the Draft 2025 *Inputs and Assumptions Workbook*.

3.10.12 Transmission line unplanned outage rates

Input vintage	June 2024
Status	Current view
Source	AEMO Network Outage Schedule and other AEMO sources
Update process	Updated in June 2024 as part of data collection process for the ESOO
Get involved	FRG Consultation in June 2025

AEMO models some outages on a limited selection of transmission flow paths that are required for inter-regional power transfer. Information is collected on the timing, duration, and severity of the transmission outages to inform transmission unplanned outage rate forecasts. Table 36 shows the rates and method used in the 2024 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 36 Inter-regional transmission flow path outage rates

Flow path	ESOO 2024 transmission UOR (%)	ESOO 2024 Mean time to repair (hours)	Outage rate method
Liddell – Bulli Creek (QNI) Credible Contingency	0.2	16	Annual static
Liddell – Bulli Creek (QNI) Reclassification	1.62	4	Annual static
Murraylink – Credible Contingency	1.37	72	Annual static
Basslink – Credible Contingency	5.27	192	Annual static
Mortlake – South East (Victoria to South Australia) Credible Contingency	0.03	2	Annual, set to 0% post Project EnergyConnect (PEC) stage 2
Mortlake – South East (Victoria to South Australia) Reclassification	0.01	5	Annual, set to 0% post PEC stage 2

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 generation towards inverter-based resources (IBR)¹⁷⁷, creates both challenges and opportunities for planning the future power system.

¹⁷⁷ 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.

Planning assumptions for power system security are applied when developing the ISP. These must cater to uncertainties in future operation of synchronous generating units, demand levels, regulatory change, operational measures, emerging technology, and new innovations that may enable IBR to provide sought-after system services. AEMO's *Power System Requirements* document¹⁷⁸ 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:

- System strength requirements and costs.
- Inertia requirements.
- Other system security limits.

3.11.1 System strength requirements and cost

Input vintage	December 2024
Status	Draft
Source	AEMO internal, <i>System Strength Report</i> , Transmission Cost Database, and <i>Network Expansion Options Report</i>
Update process	Minimum system strength requirements updated to reflect latest <i>System Strength Report</i> and the 100% renewable study in the <i>2023 NSCAS Report</i> , costs and technology options will be updated to reflect the latest Transmission Cost Database and <i>Network Expansion Options Report</i> .
Update since 2024 ISP	<ul style="list-style-type: none"> • Assumptions and methodology updated to explicitly model fault current requirements and the cost impacts of system strength solutions towards meeting both the minimum and efficient level requirements. • 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 <i>System Strength Report</i> (or subsequent updates to requirements in response to changing circumstances). The Draft 2025 <i>Inputs and Assumptions Workbook</i> has been updated with latest system strength remediation costs.

System strength describes the ability of the power system to maintain and control the voltage waveform at a given location, both during steady state operation and following a disturbance. System strength is often approximated by the amount of electrical current available during a network fault (fault level), however the concept also encompasses a collection of broader electrical characteristics and power system interactions.

Key aspects of system strength include steady state voltage management, voltage dips, fault ride-through, power quality and operation of protection.

Under the current system strength framework, AEMO assesses and maintains a system strength specification for the NEM, updated annually. This defines a set of physical locations on the transmission network (system strength nodes) at which AEMO must specify two system strength requirements:

- A **minimum fault level requirement** – intended to represent a secure operability requirement that, when met, ensures correct operation of network protection systems, appropriate operation of voltage control devices, and overall system stability following credible contingencies or protected events.
 - This requirement is specified as a fault level value and must be met by solutions capable of delivering protection-quality fault current. Technology options may include synchronous condensers, contracts with

¹⁷⁸ At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power-system-requirements.pdf.

market participants to provide fault level services, or the conversion of existing thermal units into synchronous condensers.

- An **efficient level requirement** – intended to deliver additional investment in system strength, at optimised network locations, sufficient to accommodate and encourage future IBR connections near those locations.
 - This requirement is specified as a capacity of IBR that must be able to connect without voltage stability or synchronisation issues, assuming all other generator performance standards are met. As such, it can be met by any existing or new technology capable of improving the resilience of the local voltage waveform. This could include synchronous machines, as well as dynamic reactive devices, network reconfigurations, or grid-forming technology customised to the needs of specific network locations.

There are currently 23 system strength nodes defined in the NEM, and the process AEMO follows to develop minimum and efficient level requirements for each is outlined in the System Strength Requirements Methodology¹⁷⁹. From 1 December 2025, regional System Strength Service Providers (SSSPs) are required to take all necessary steps to ensure both requirements are met at all times.

As part of the 2026 ISP, AEMO is proposing to model the cost of both components of system strength.

Minimum fault level requirements

The 2024 ISP used a set of declining unit commitment constraints to reflect an initial need to rely on thermal generation for meeting minimum fault level requirements. This constraint was relaxed over time to reflect that SSSPs will gradually procure or contract with alternative sources of fault current to meet their obligations. SSSPs may source from a portfolio of network solutions (in the form of synchronous condensers), or non-network solutions (in the form of commercial arrangements with gas, hydro, or eventually new grid-forming battery energy storage system [BESS] providers).

For the 2026 ISP, AEMO proposes to continue to use a declining unit commitment constraint, and to also include an additional cost component to retiring thermal generation to represent the cost of replacing their fault current contributions towards the minimum fault level requirements. This has the effect of providing the optimisation engine with a more reflective system security cost impact when withdrawing existing thermal units from service.

To calculate the effective system strength remediation cost component for each unit, AEMO will implement outcomes from the 2022 and 2023 Network Support and Control Ancillary Services (NSCAS) reports, which found a need for approximately 22 strategically located synchronous condensers¹⁸⁰ to operate the system under 100% renewable conditions (that is, without coal-fired generation online).

The cost of these synchronous condensers is allocated to the retirement cost of existing coal-fired generating units in proportion to its rated fault current contribution, as a percentage of the total regional requirement.

Although AEMO expects that a mixture of technologies will be applied to meet minimum fault level requirements, synchronous condenser costs are being used as a proxy to represent an upper bound as a known and proven

¹⁷⁹ See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf.

¹⁸⁰ This is additional to synchronous condensers being added in the network for committed augmentations such as Project Energy Connect and Central-West Orana REZ Network Infrastructure Project, as well as no fossil fuel units such as hydro being online.

technology. Options such as retrofitting existing units, adding clutches to gas turbines, or leveraging grid-forming technology in the medium term¹⁸¹ are all likely to contribute towards these requirements.

The Power System Security tab of the Draft 2025 *Inputs and Assumptions Workbook* presents the assumed cost of system strength remediation for the minimum fault level requirements over time required to replace each coal unit. The average of this cost in the NEM is approximately \$50 million per coal unit retirement. These costs, and the underlying technical parameters of synchronous condensers, will be updated to reflect the latest Transmission Cost Database and *Network Expansion Options Report*.

See the ‘Power System Security’ worksheet in the Draft 2025 *Inputs and Assumptions Workbook*.

Efficient level requirements

In the ISP modelling, AEMO incorporates a \$/kW efficient level cost as an addition to the IBR connection costs within a REZ, noting that in practice these would be funded directly by the TNSP rather than the connecting party themselves.

AEMO proposes to use a weighted¹⁸² cost trajectory approach to model these remediation costs as an added component to IBR connections. The effectiveness of grid-forming BESS towards these requirements is assumed to be 1.7 times lower than an equivalently sized synchronous condenser (that is, a 17 megavolt ampere [MVA] grid-forming BESS provides equivalent voltage stabilisation to a 10 MVA synchronous condenser). This is based on analysis undertaken in Transgrid’s recent System Strength RIT-T¹⁸³. This 1.7 factor is used to scale the cost of both technologies relative to each other when producing the weighted sum.

Grid-forming BESS technology is assumed to be available to provide efficient level services immediately.

The system strength costs tab of the Draft 2025 *Inputs and Assumptions Workbook* presents the assumed cost of network and non-network solutions, their relative effectiveness and mixture over time, and the resulting efficient level system strength costs (in \$/kW) to apply for new IBR connections. The input technology costs and parameters will be updated to reflect the latest Transmission Cost Database and *Network Expansion Options Report*.

See the ‘Power System Security’ worksheet in the Draft 2025 *Inputs and Assumptions Workbook*.

Synchronous unit commitment assumptions

Input vintage	December 2024
Status	Current
Source	AEMO internal
Updates since 2024 ISP	Updated timing

¹⁸¹ Based on work done for the Transgrid System Strength RIT-T, grid-forming BESS are assumed to be capable and sufficiently demonstrated to provide protection quality fault current from 2032-33.

¹⁸² The weighting reflects what percentage of the solution built per year can IBR based. This starts at 20% of IBR in 2024-25, and increases 10% per year until it reaches 90%.

¹⁸³ See Section 4.1.3 at https://www.transgrid.com.au/media/wphjea0f/2406-baringa_meeting-system-strength-requirements-in-nsw-padr-modelling-report.pdf.

As described in the previous section, an ongoing synchronous unit commitment constraint trajectory is used as a proxy for the required contribution of these units towards meeting system security requirements in the initial years of the 2026 ISP modelling.

The trajectory initially reflects the current operational minimum unit requirements that apply in the NEM and then progressively relaxes this requirement over a five-year period from 2027-28. This reflects decreasing reliance on these sources of system strength as TNSPs progressively procure alternative solutions via their active RIT-T processes. This trajectory does not force units to withdraw as the value decreases, rather it prevents units from retiring until the value decreases, at which point it allows retirements where economic (including the need to pay for replacement system strength services). For the *Green Energy* scenario, AEMO assumes a faster decline in this trajectory to align with the rapid transformation of the economy and rapid decarbonisation assumed by the scenario.

A short-term two-unit constraint is applied in South Australia until Project EnergyConnect (PEC) stage 2 is fully commissioned, with all necessary protection and control schemes in place to manage credible loss of either PEC or the Heywood interconnector, at which point this constraint is relaxed. This approximately mirrors expected operational requirements, although there may be some operational periods prior to PEC stage 2 where 1 unit is allowed (this granularity would be difficult to capture in an ISP model). AEMO does not use a fixed assumption for unit commitment requirements in Tasmania, because the region has a large number of small, distributed hydroelectric generators and a large number of machine combinations that can be used for power system security purposes.

Figure 46 and Figure 47 provide the minimum synchronous unit commitment trajectories derived through the above approach. These assumptions are developed for the purpose of ISP planning studies, and should not be used as operational advice.

Figure 46 Minimum synchronous unit commitment requirements, all scenarios except Green Energy

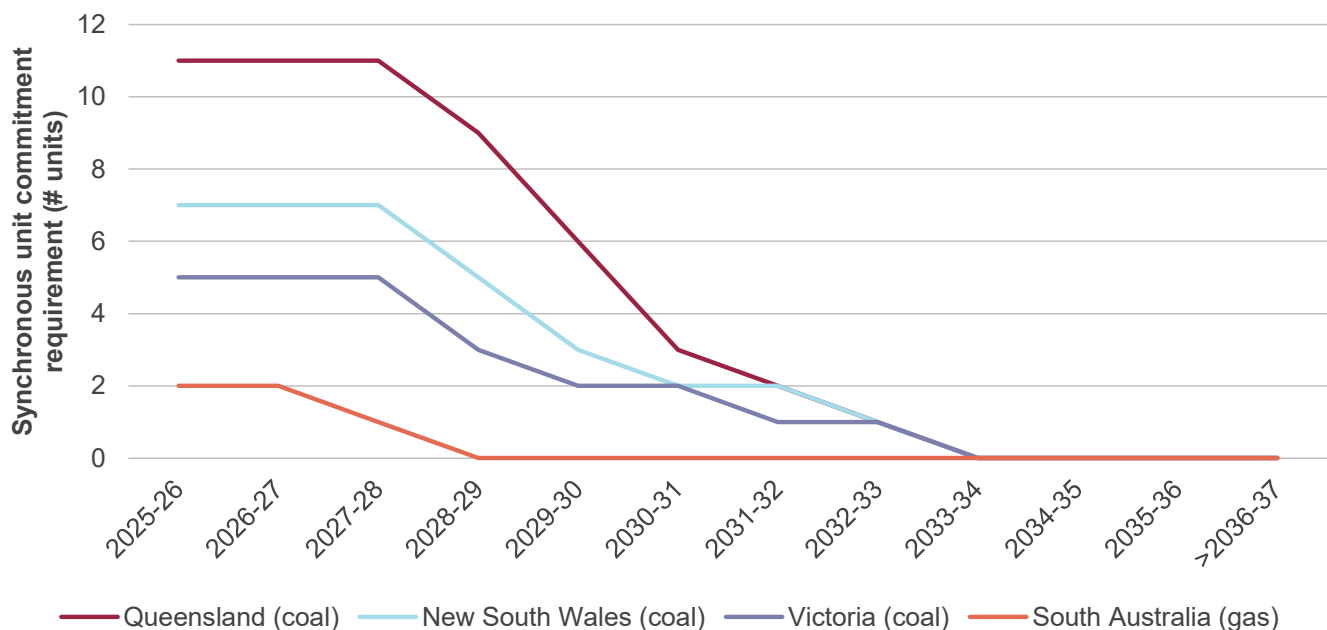
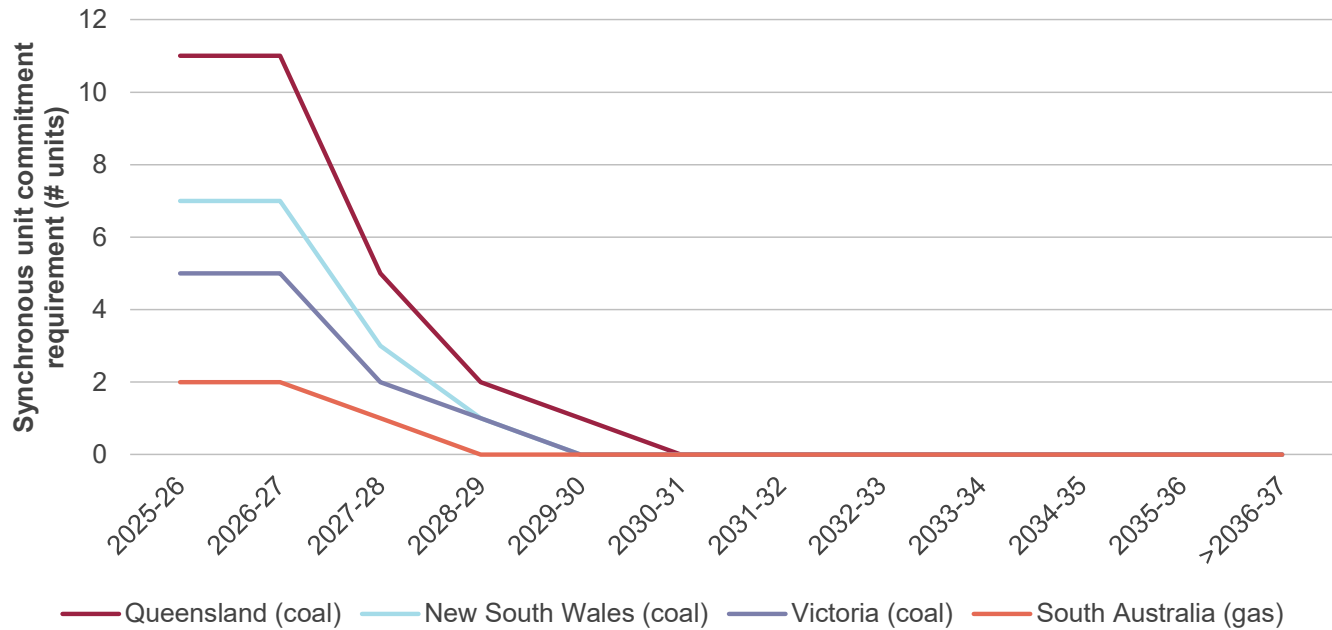


Figure 47 Minimum synchronous unit commitment requirements, Green Energy scenario



3.11.2 Inertia requirements

Input vintage	December 2024
Status	Current
Source	Annual AEMO <i>Inertia Report</i> , applying the <i>Inertia Requirements Methodology</i>
Updates since 2024 ISP	Updated annually according to the latest inertia requirements calculation for each region of the NEM at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning

Inertia allows the power system to resist large changes in frequency arising from an imbalance in power supply and demand due to a contingency event. Forecast inertia is continuing to decline across the NEM as synchronous generator behaviour changes, penetration of IBR increases, and minimum demand projections decline.

AEMO is required to assess and publish minimum inertia requirements for each region, under both islanded and interconnected operating conditions. AEMO’s process for assessing these requirements is outlined in AEMO’s *Inertia Requirements Methodology*¹⁸⁴ and AEMO’s assessments for each region are published at least annually on AEMOs website¹⁸⁵.

Requirements are currently calculated based on the size of the largest credible contingency event in each region (or combination of regions). The full process AEMO follows to produce inertia requirements is outlined in the *Inertia Requirements Methodology*.

From 1 December 2027, regional TNSPs are required to take all necessary steps to ensure both the islanded and interconnected inertia requirements are satisfied in each region under the relevant system conditions.

¹⁸⁴ See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf.
¹⁸⁵ At <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/system-security-planning>.

AEMO’s security assessments as part of the 2022 and 2023 NSCAS reports concluded that system strength would be the most onerous security requirement over the coming decades, and that delivering adequate services to meet those needs was likely to substantially resolve the need for additional inertia or voltage control investment. For example, technology solutions may include assets such as high-inertia synchronous condensers, or grid-forming technologies capable of providing both voltage stabilisation and synthetic inertia services.

In the ISP, AEMO will validate that all modelled outcomes satisfy the latest inertia requirements as published on AEMO’s website. The costs associated with meeting these requirements are assumed to be second order, and therefore captured as part of delivering adequate system strength solutions (e.g. by ensuring some synchronous condensers have flywheels).

3.11.3 Other system security limits

Input vintage	July 2023
Status	Current
Source	AEMO internal and TNSP limits advice
Updates since 2024 ISP	None – consistent network constraint-based approach.

In NEMDE, a series of network constraint equations control dispatch solutions to ensure that satisfactory and secure network limitations are considered. The time-sequential model used in long-term planning studies contains a subset of the NEMDE network constraint equations to achieve the same purpose. This subset of network constraint equations is included in the ISP model to reflect power system operation within other security limits. In addition to system strength and inertia limits which are considered above, these include:

- Voltage stability – for managing transmission voltages so that they remain at acceptable levels after a credible contingency.
- Transient stability – for managing continued synchronism of all generators on the power system following a credible contingency.
- Oscillatory stability – for managing damping of power system oscillations following a credible contingency.
- Rate of change of frequency (RoCoF) – for managing the rate of change of frequency following a credible contingency.

The effect of committed transmission and generation projects on the network is implemented in NEMDE as modifications to the network constraint equations that control power flow. The methodology for formulating these constraints is in AEMO’s Constraint Formulation Guidelines¹⁸⁶.

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.

¹⁸⁶ At <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource>.

3.12 Gas infrastructure

Input vintage	Incomplete in this stage of the Draft 2025 IASR
Status	In progress
Source	CSIRO: <i>GenCost 2024-25 Consultation Draft</i>
Updates since 2023 IASR	PEM Cost has been updated to reflect <i>GenCost 2024-25 Consultation Draft</i>
Get involved	Formal consultation on this input in Stage 2 of the Draft 2025 IASR

This section outlines key inputs and assumptions related to hydrogen and biomethane production technologies, as well as infrastructure needs where potential for development of domestic and export production locations for hydrogen, biomethane and natural gas infrastructure are explored within ISP modelling.

Hydrogen demand assumed across scenarios is discussed in Section 3.3.6.

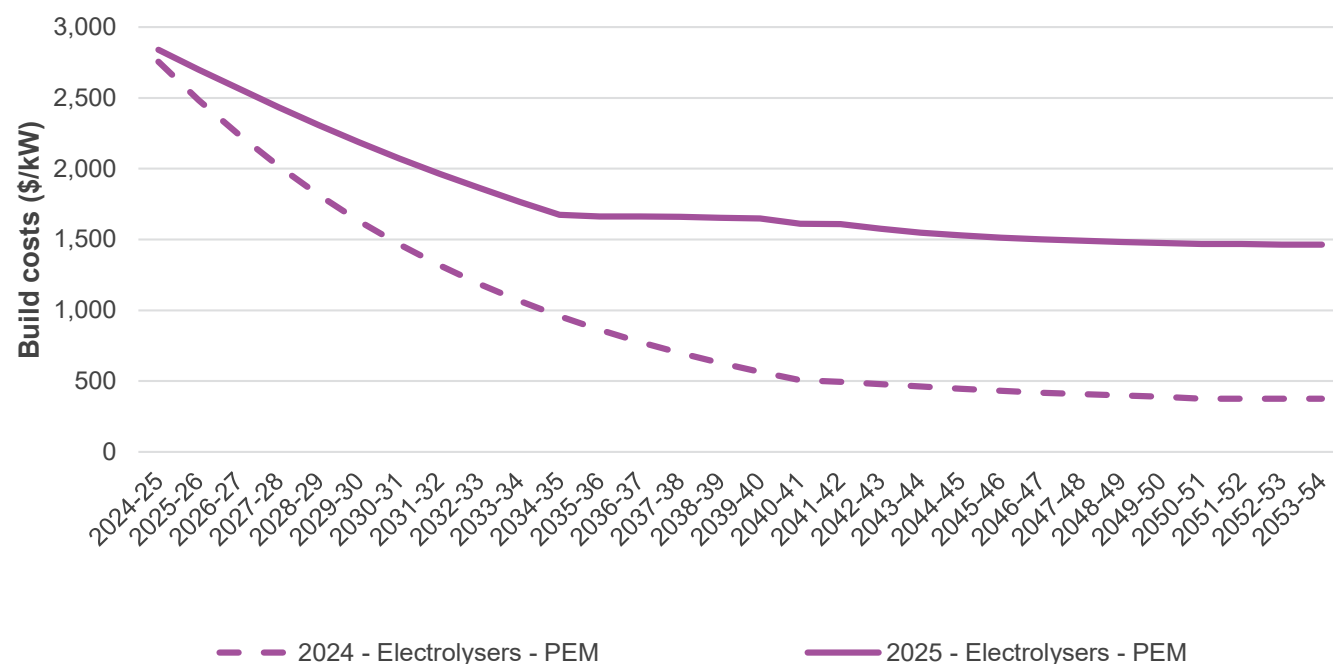
3.12.1 Production costs and capabilities

Hydrogen production

To produce hydrogen, AEMO’s forecasts include production potential from electrolysis only. Electrolysis uses electricity to split water molecules into hydrogen and oxygen. If this electricity is sourced from renewable generation it creates “green hydrogen”. Proton exchange membrane (PEM) technology is most commonly proposed for development in the NEM, and AEMO’s forecasts apply this technology choice.

Figure 48 below presents the capital cost projections for new PEM installations as forecast in *GenCost 2024-25 Consultation Draft* for its Global NZE post 2050 scenario, compared to GenCost 2023-24 projections. Relatively, there has been an increase in hydrogen electrolysis cost, driven by updated analysis of balance of plant costs. See Section 3.5.3 for more detail on these cost adjustments, as well as detail on scenario mappings between the *GenCost 2024-25 Consultation Draft* and Draft 2025 IASR scenarios.

Cost projections for PEM electrolysis for each scenario are available in the accompanying Draft 2025 *Inputs and Assumptions Workbook*.

Figure 48 Forecast build cost trajectories for electrolyzers (PEM), 2023 vs 2025 Global NZE post 2050 scenario (\$/kW)

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 electrolyzers with a flexible technical operating envelope with a minimum baseload component, and with a hydrogen production target to achieve. In this sense, the ISP modelling that forecasts the appropriate electrolyser capacity can select the degree of capacity (and therefore flexibility) to meet the production volume targets, meaning that the economic consequences of either highly flexible (with high installed capacity) or minimal flexibility (with low surplus production capacity) is considered, considering the capital investment costs and operating costs of each.

Reported performance derived from Bloomberg New Energy Finance (BNEF) indicates a baseload of 5.4%¹⁸⁷. AEMO assumes a baseload of 5.4% for both domestic-focused and export-focused electrolyzers, in line with the BNEF data.

Matters for consultation

- Do you have any alternative views on the electrolyser cost curve?

Natural gas and biomethane production

AEMO will use relevant information developed for the GSOO to support biomethane and natural gas production cost and technical capabilities.

For information that is outside of the GSOO data, this section will be updated in Stage 2 of the Draft 2025 IASR release.

¹⁸⁷ Bloomberg New Energy Finance (BNEF) report: Electrolyzer Price Survey 2024: Rising Costs, Glitchy Tech (March 2024).

3.12.2 Gas infrastructure

Hydrogen

This section will be updated in Stage 2 of the Draft 2025 IASR release.

Natural gas and biomethane infrastructure needs

AEMO's gas supply model evaluates the reserves, production, and transportation capacity of Australia's East Coast Gas System to calculate the delivery of gas supply to gas consumers. The gas supply model can be incorporated with gas expansion options for pipeline, gas storage, and/or production augmentations, informed by industry engagement, to identify natural gas infrastructure needs.

The gas production capacities, mid-stream gas delivery limits, production cost and potential costs of augmentation projects are key input assumptions into the gas supply model. They are provided from gas industry participant surveys, publicly available data or gas specialist consultants. The summary of key inputs and related data sources for the gas supply model are as in Table 37 below.

Table 37 Key inputs and the related data sources for the gas supply model

Input	Source
Demand projections	AEMO Forecasting Portal, at http://forecasting.aemo.com.au
Capacity of reserves and resources	Gas industry participants, and publicly available data (in case of lack of data, Rystad Energy estimates), at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo
Production costs	Rystad Energy and publicly available data; Rystad Energy data at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo
Transmission costs	Gas industry participants and publicly available data
Pipeline, processing, storage facility capabilities and daily rates	Gas industry participants Gas Bulletin Board (GBB), and publicly available data GBB available at: http://gbb.aemo.com.au/
Annual and daily field production limits	Gas industry participants, and internal AEMO analysis

Further information on inputs to be used in developing gas development projects will be consulted on in Stage 2 of the Draft 2025 IASR, or in the *Network Expansion Options Report* consultation.

3.13 Employment factors

Input vintage	September 2024
Source	Rutovitz, J., Gerrard, E., Lara, H., and Briggs, C. (2024). <i>The Australian Electricity Workforce for the 2024 Integrated System Plan: Projections to 2050</i> . Prepared by the Institute for Sustainable Futures for RACE for 2030 ¹⁸⁸ .
Update process	Updates will be dependent on feedback received on this Draft 2025 IASR.
Updates since 2023 IASR	Updated job-years for generation, storage and transmission development per outcomes of 2024 ISP.

¹⁸⁸ Rutovitz, J., Gerrard, E., Lara, H., and Briggs, C. *The Australian Electricity Workforce for the 2024 Integrated System Plan: Projections to 2050*. September 2024. At https://aemo.com.au/-/media/files/major-publications/isp/2024/electricity-sector-workforce-projections/nem-2024-workforce_final.pdf.

Electricity sector employment is forecast to increase by 74% by 2050 (from 33,300 full time workers¹⁸⁹ in 2024 to 57,900 in 2050), in the *Step Change* scenario from the 2024 ISP¹⁹⁰. This growth will challenge engineering, procurement and construction (EPC) firms and regional communities, particularly if there are boom-and-bust cycles or if workers and contractors are engaged project-to-project. Governments are aware of these challenges in shaping new and existing labour force and skills policies¹⁹¹ and 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. The focus on workforce requirements in this estimation is focused on infrastructure development requirements; it does not include the workforce requirements to deliver electrification developments or other factors affecting the evolution of the consumer load in the energy transition.

AEMO sourced employment factors for generation, transmission and storage from "The Australian Electricity Workforce for the 2024 Integrated System Plan: Projections to 2050", a renewable energy industry report prepared by the Institute for Sustainable Futures (ISF) for Reliable Affordable Clean Energy (RACE) for 2030.

Employment factors are derived from industry surveys of developers, installers and original equipment manufacturers conducted by the ISF. These surveys collect a breakdown of occupational data across sectors for construction, installation, operations and maintenance of recent actual projects and activities.

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.

Table 38 Generation and storage employment factors

	Construction time ^A	Construction/in stallation ^B	Manufacturing ^B	Australian Manufacturing ^B	Operations and Maintenance (O&M) ^B	Fuel ^B
	Years	Job-years/MW ^C	Job-years/MW	Job-years/MW	Jobs/MW	Job-years/GWh
Black coal	5	11.08	5.41	1.62	0.22	0.04
Brown coal	5	11.08	5.41	1.62	0.22	0.01
Gas	2	1.27	0.92	0.28	0.14	0.07
Wind (onshore)	2	2.65	1.54	0.35	0.21	-
Wind (offshore)	3	1.50	13.68	0.90	0.20	-
Utility-scale PV	1	1.61	3.08	0.07	0.09	-
Rooftop PV	1	4.19	2.86	0.12	0.13	-
Utility-scale batteries	1	0.53	0.50	0.08	0.03	-

¹⁸⁹ These numbers represent number of full time equivalent jobs.

¹⁹⁰ At <https://aemo.com.au/-/media/files/major-publications/isp/2024/2024-integrated-system-plan-isp.pdf>.

¹⁹¹ SGS Economics and Planning Pty Ltd & UTS Institute for Sustainable Futures. *Towards A Renewable Energy Superpower*. April 2024. At <https://www.uts.edu.au/sites/default/files/2024-04/Renewable%20Energy%20Superpower%20Report%202024%2060pp%20WEB%20SPREAD%201.pdf>.

	Construction time ^A	Construction/in installation ^B	Manufacturing ^B	Australian Manufacturing ^B	Operations and Maintenance (O&M) ^B	Fuel ^B
	Years	Job-years/MW ^C	Job-years/MW	Job-years/MW	Jobs/MW	Job-years/GWh
Distributed batteries	1	4.44	0.50	0.08	0.23	-
Pumped hydro	4	7.18	3.48	0.70	0.08	-
Hydro	5	7.36	3.48	1.04	0.14	-

A. Rutovitz, J., Langdon, R., Mey, F., Briggs, C. *The Australian Electricity Workforce for the 2022 Integrated System Plan: Projections to 2050. Revision 1.* January 2023. At <https://aemo.com.au/-/media/files/major-publications/isp/2022/supporting-materials/the-australian-electricity-workforce-for-the-2022-isp.pdf>.

B. Rutovitz, J., Gerrard, E., Lara, H., and Briggs, C. *The Australian Electricity Workforce for the 2024 Integrated System Plan: Projections to 2050.* September 2024. At https://aemo.com.au/-/media/files/major-publications/isp/2024/electricity-sector-workforce-projections/nem-2024-workforce_final.pdf.

C. One job-year represents one job over the course of the year at full-time capacity.

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 39 Transmission employment factors

Transmission build	Construction/installation
Transmission line: single circuit	0.70 (job-years/km) ^A
Transmission line double circuit	3.7 (job-years/km)
Transmission (other)	1.90 (job-years/\$million)

A. One job-year represents one job over the course of the year at full-time capacity.

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. ISP Review implementation measures

Over 2023 and early 2024, the Federal Government undertook a review of the ISP (Review of the ISP), and on 5 April 2024 the Energy and Climate Change Ministerial Council (ECMC) published its *Response to the Review of the Integrated System Plan*¹⁹² (Energy Ministers’ response to the Review of the ISP).

The response outlined a series of actions to enable the ISP to set a direction for the energy system as a whole, while maintaining the critical function of the ISP in transmission planning. The Review of the ISP focused on supporting emissions reduction, integrating gas and electricity planning, enhancing demand considerations, transforming Australia’s energy mix, jurisdictional policy interactions, and supporting the timely delivery of ISP projects.

The Federal Minister for Climate Change and Energy made three rule change requests to the AEMC to implement some of the review recommendations. The AEMC is currently considering its final determinations and rules for the rule change requests, which have been consolidated into two rule changes¹⁹³.

AEMO’s approach to implementing new methods to address the actions identified in the Energy Ministers’ response to the Review of the ISP will be documented in the *ISP Methodology*, while new inputs needed to apply AEMO’s updated methods will have been outlined in this Draft 2025 IASR (in either this stage of its release, or in the second release stage in 2025). Stakeholders can provide feedback on potential implementation measures through the relevant consultation processes for each of these.

Table 40 below summarises the AEMO publications which AEMO proposes to amend to implement the actions identified in the Energy Ministers’ response to the Review of the ISP.

¹⁹² See <https://www.energy.gov.au/sites/default/files/2024-04/ecmc-response-to-isp-review.pdf>.

¹⁹³ See <https://www.aemc.gov.au/rule-changes/better-integrating-gas-and-community-sentiment-isp> and <https://www.aemc.gov.au/rule-changes/improving-consideration-demand-side-factors-isp>.

Table 40 Proposed implementation for actions in the Energy Ministers' response to the Review of the ISP

Action in the response to the Review of the ISP	Process for implementation			
	2025 IASR	ISP Methodology	2025 Network Expansion Options Report ^A	Enhanced Locational Information report ^B
Integrating gas into the ISP	✓	✓	[✓]	
Enhanced demand forecasting and optimising for the demand-side	✓	✓	✓	
Better data on industrial and consumer electrification				
Coal-fired generation shutdown scenarios		✓		
Improving locational information				✓
Enhanced analysis of system security	✓	✓		
Jurisdictional policy transparency	✓ ^D			
Clarifying policy inclusions	✓ ^D			
Improving the accessibility of the ISP ^C	✓			
Incorporating community sentiment			✓	
Additional planning inputs	✓			

A. The *Network Expansion Options Report* is consulted on as part of the IASR. This was previously known as the Transmission Expansion Options Report, but has been renamed to reflect the inclusion of both transmission and distribution in future ISPs.

B. The *Enhanced Locational Information* report provides a consolidated set of locational information about where to locate projects in the NEM.

C. AEMO will consider opportunities throughout the ISP development process to enhance consumer understanding of key elements.

D. These actions are to be implemented, in parallel with the IASR process, through the publication of a guideline on AEMO's policy inclusion consultation process with jurisdictions.

A2. Supporting material

In addition to the Draft 2025 *Inputs and Assumptions Workbook*, Table 41 documents additional information related to AEMO's inputs and assumptions.

Table 41 Additional information and data sources

Organisation	Document/source	Link
AEMO	Generation Information	https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information
AEMO	AEMO's Transmission Cost Database	https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios/transmission-cost-database
AEMO	2024 GSOO Stakeholder Surveys and gas supply input data	https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo
AEMO	2025 IASR Scenarios Consultation Summary Report	https://aemo.com.au/-/media/files/major-publications/isp/2025/2025-IASR-Scenarios-Consultation-Summary-Report
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/industry/registers/resources/reviews/values-customer-reliability-2024
Aurecon	2024 Energy Technology Costs and Technical Parameter Review	https://aemo.com.au/-/media/files/major-publications/isp/2025/Aurecon-2024-Energy-Technology-Costs-and-Technical-Parameter-Review
Deloitte Access Economics	Economic forecast 2024-25	https://aemo.com.au/-/media/files/major-publications/isp/2025/Deloitte-Access-Economics-2024-Economic-Forecast
CSIRO	2024 Multi-sector modelling	To be uploaded with Stage 2
CSIRO	<i>GenCost 2024-25 Consultation Draft</i>	https://www.csiro.au/en/research/technology-space/energy/GenCost
CSIRO	2024 Projections for solar PV and battery systems	https://aemo.com.au/-/media/files/major-publications/isp/2025/CSIRO-2024-Solar-PV-and-Battery-Projections-Report
CSIRO	2024 Electric Vehicle Projections	To be uploaded with Stage 2
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
Green Energy Markets	2024 Projections for solar PV and stationary energy battery systems	https://aemo.com.au/-/media/files/major-publications/isp/2025/GEM-2024-Solar-PV-and-Battery-Projections-Report
ACIL Allen	Gas, liquid fuel, coal and renewable gas projections	https://aemo.com.au/-/media/files/major-publications/isp/2025/ACIL-Allen-2024-Fuel-price-forecast-report
Oxford Economics Australia	Discount rates for energy infrastructure	https://aemo.com.au/-/media/files/major-publications/isp/2025/Oxford-Economics-Australia-2024-Discount-Rate-report

List of tables and figures

Tables

Table 1	Stakeholder engagement on the 2025 IASR	14
Table 2	Key parameters, by scenario	20
Table 3	Summary of policies included in the Draft 2025 IASR	27
Table 4	State-level economy-wide emission reduction ambitions relative to 2005 levels (in financial year unless otherwise stated)	31
Table 5	The 2024 IEA WEO scenario summaries	43
Table 6	Mapping of scenarios between studies	44
Table 7	Weather stations used in forecasting consumers electricity use (regional)	48
Table 8	Weather stations used in forecasting consumers electricity use (sub-regional)	48
Table 9	Consultant scenario mapping for CER	57
Table 10	Economic forecast details by scenario	64
Table 11	Retail price input settings by scenario	77
Table 12	Price elasticities of demand for various appliances and sectors	77
Table 13	Mapping of DSP settings to scenarios	79
Table 14	Sources for technical and cost parameters for existing generators	81
Table 15	Existing generators – long duration outages	83
Table 16	Unplanned outage assumptions (excluding long duration outages) for 2024-25 financial year	83
Table 17	Median hydro climate factors, <i>Step Change</i> scenario	91
Table 18	List of generation and storage technology candidate	95
Table 19	Mapping AEMO scenario themes to the <i>GenCost 2024-25 Consultation Draft report</i> scenarios	97
Table 20	First-of-its-kind generation cost premiums	98
Table 21	Pumped hydro energy storage locational cost factors	104
Table 22	Pumped hydro sub-regional limits (in MW of generation capacity)	105
Table 23	Pre-tax real weighted average cost of capital	118
Table 24	Pre-tax real discount rates	119
Table 25	AER Values of distribution and transmission customer load-weighted VCR by state	119
Table 26	Value of greenhouse gas emissions reduction	120
Table 27	Offshore REZ resource limits	130
Table 28	REZ transmission limit constraints	134
Table 29	REZ secondary transmission limits	134

Table 30	REZ group transmission constraints	135
Table 31	NEM regions, ISP sub-regions, reference nodes and REZs	140
Table 32	Existing network flow path representation between sub-regions	142
Table 33	Load and generation representation within the sub-regional model	144
Table 34	Notional transfer capabilities between the sub-regions of the existing network (December 2024)	146
Table 35	Preparatory activities	155
Table 36	Inter-regional transmission flow path outage rates	160
Table 37	Key inputs and the related data sources for the gas supply model	169
Table 38	Generation and storage employment factors	170
Table 39	Transmission employment factors	171
Table 40	Proposed implementation for actions in the Energy Ministers' response to the Review of the ISP	173
Table 41	Additional information and data sources	174

Figures

Figure 1	Map of weather stations used in forecasting consumers electricity use, per NEM sub-region	49
Figure 2	Aggregate ONSG capacity, by NEM region (MW)	51
Figure 3	Forecast NEM-wide other non-scheduled generation capacity (MW)	52
Figure 4	Forecast utilisation of the four pillars of decarbonisation, by scenario	53
Figure 5	ACIL Allen biomethane available volume and production cost estimates by feedstock and scenario	56
Figure 6	Actual and forecast rooftop PV installed capacity (NEM and WEM), 2016-17 to 2054-55 (GW [degraded])	58
Figure 7	Actual and forecast PVNSG capacity (NEM and WEM), 2016-17 to 2054-55 (GW [degraded])	59
Figure 8	Actual and forecast distributed PV installed capacity (NEM and WEM), 2016-17 to 2054-55 (GW [degraded])	60
Figure 9	Actual and forecast rooftop PV and PVNSG installed capacity (NEM and WEM) for the <i>Step Change</i> scenario, 2016-17 to 2054-55 (GW [degraded])	60
Figure 10	Distributed battery capacity forecast for the NEM+WEM (GW), including non-aggregated and aggregated batteries	61
Figure 11	Aggregated VPP capacity for NEM+WEM (GW)	63
Figure 12	Economic composition of the NEM, <i>Step Change</i> scenario	65
Figure 13	Population growth in the NEM by scenario	65
Figure 14	NEM household disposable income per capita by scenario	66

Figure 15	NEM aggregated Gross State Product by scenario	67
Figure 16	2024 Actual and forecast NEM residential connections, all scenarios, compared to the 2023 forecast	68
Figure 17	2024 NEM LIL electricity consumption forecast compared to the 2023 forecast (TWh)	70
Figure 18	2024 WEM LIL electricity consumption forecast compared to the 2023 forecast (TWh)	71
Figure 19	LNG electricity consumption forecast	72
Figure 20	Residential appliance uptake trajectories for the NEM, consumption change relative to base year (2024), 2023-24 to 2054-55 (TWh)	75
Figure 21	NEM Residential retail price forecasts, 2024-25 to 2054-55	76
Figure 22	Equivalent full unplanned outage rate projections for coal-fired generation technologies	84
Figure 23	Equivalent full unplanned outage rate projections for OCGT, CCGT and steam turbine generation and small peaking plant technologies	85
Figure 24	Equivalent full unplanned outage rate projections for battery and hydro technologies	85
Figure 25	Hydro Tasmania scheme topology	88
Figure 26	Snowy Hydro scheme topology	89
Figure 27	Hydro scheme topologies of other existing hydro power stations	90
Figure 28	Hydro inflow variability across reference weather years – Snowy Hydro	91
Figure 29	Generation and storage projects in October 2024 Generation Information page (MW)	94
Figure 30	2023 vs 2024 <i>Global NZE post 2050</i> : build cost trajectories forecasts for wind and large-scale solar	99
Figure 31	2023 vs 2024 <i>Global NZE post 2050</i> : build cost trajectories forecasts for gas generation	99
Figure 32	2023 vs 2024 <i>Global NZE post 2050</i> : build cost trajectories forecasts for selected storage technologies	100
Figure 33	Weighted REZ locational cost factors for wind in the 2023 IASR and the 2025 Draft IASR	102
Figure 34	Weighted REZ locational cost factors for wind in the 2025 Draft IASR	103
Figure 35	Forecast industrial gas prices by scenario – Melbourne, 2024-25 to 2054-55 (\$AUD/GJ)	109
Figure 36	Forecast industrial gas prices by location – <i>Step Change</i> , 2024 to 2055 (\$AUD/GJ)	110
Figure 37	Forecast coal prices for existing generators in New South Wales, <i>Step Change</i> , 2024 to 2055 (\$AUD/GJ)	111
Figure 38	Forecast coal prices for existing generators in Queensland – <i>Step Change</i> , 2024 to 2055 (\$AUD/GJ)	112
Figure 39	Forecast price for diesel by scenario – terminal gate price plus distributors margin, Victoria, 2024 to 2055 (\$AUD/GJ)	113
Figure 40	Wind resource quality map – average wind speed (m/s) at 150 m hub height	115
Figure 41	Solar resource quality map – average annual global horizontal irradiance (GHI) (kWh/m ² /year)	116
Figure 42	Southern Australia summer maximum temperature anomaly	122
Figure 43	Candidate renewable energy zone map	127
Figure 44	REZ resource limits and initial transmission limits	129
Figure 45	ISP sub-regional model	142

Figure 46	Minimum synchronous unit commitment requirements, all scenarios except <i>Green Energy</i>	164
Figure 47	Minimum synchronous unit commitment requirements, <i>Green Energy</i> scenario	165
Figure 48	Forecast build cost trajectories for electrolyzers (PEM), 2023 vs 2025 Global NZE post 2050 scenario (\$/kW)	168

Abbreviations

Abbreviation	Meaning
ACCC	Australian Competition and Consumer Commission
ACCU	Australian carbon credit unit
ACSL	Advisory Council on Social Licence
ADGSM	Australian Domestic Gas Supply Mechanism
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
APS	Announced Pledges Scenario
BESS	battery energy storage system
BMM	business mass market
BNEF	Bloomberg New Energy Finance
BoM	Bureau of Meteorology
CBA	cost benefit analysis
CBD	Commercial Building Disclosure
CCGT	closed cycle gas turbine
CCRG	Consumer and Community Reference Group
CCS	carbon capture and storage
CEFC	Clean Energy Finance Corporation
CER	consumer energy resources
CNSW	Central New South Wales
CQ	Central Queensland
CSA	Central South Australia
CWC	ClimateWorks Centre
DAC	direct air capture
DAE	Deloitte Access Economics
DAT	dual-axis tracking
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DISER	Department of Industry, Science, Energy and Resources
DSP	demand side participation
DSP IP	DSP Information portal
E3	Equipment Energy Efficiency
EAAP	Energy Adequacy Assessment Projection
ECMC	Energy and Climate Change Ministerial Council
EFOR	equivalent full forced outage rate
EMMS	electricity market management system
ESCI	Electricity Sector Climate Information
ESOO	Electricity Statement of Opportunities
ESS	Energy Savings Scheme (New South Wales)

Abbreviation	Meaning
EV	electric vehicle
FBT	fringe benefits tax
FCUD	Full Commercial Use Date
FERC	Federal Energy Regulatory Commission
FERM	Firm Energy Reliability Mechanism
FFP	fixed flat plate
FRG	Forecasting Reference Group
GALLM	Global and Local Learning Mode
GCM	global climate model
GEM	Green Energy Markets
GEMS	Greenhouse and Energy Minimum Standards
GG	Gladstone Grid
GIS	Geographic Information Systems
GJ	gigajoule/s
GSOO	Gas Statement of Opportunities
GVA	Gross Value Added
GW	gigawatt/s
GWh	gigawatt hour/s
HDI	Household Disposable Income
HEUF	Household Energy Upgrades Fund
IASR	Inputs, Assumptions and Scenarios Report
IBR	inverter-based resource/s
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
ISP	Integrated System Plan
kW	kilowatt/s
kWh	kilowatt hour/s
LIL	large industrial load
LOR	lack of reserve
LPG	liquefied petroleum gas
LRET	Large-scale Renewable Energy Target
LTESA	Long-Term Energy Service Agreement
MEL	Greater Melbourne and Geelong
MLF	marginal loss factor
MT PASA	Medium Term Projected Assessment of System Adequacy
MtCO ₂ -e	million tonnes of carbon dioxide equivalent
MVA	megavolt ampere/s
MW	megawatts
MWh	megawatt hours
NABERS	National Australian Built Environment Rating System

Abbreviation	Meaning
NatHERS	Nationwide House Energy Rating Scheme
NCC	National Construction Code
NDC	Nationally Determined Contribution
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	NEM Dispatch Engine
NEO	national electricity objective
NEPS	National Energy Performance Strategy
NER	National Electricity Rules
NEVA	<i>National Electricity (Victoria) Act 2005</i>
NMI	National Metering Identifier
NNSW	Northern New South Wales
NQ	Northern Queensland
NSA	North South Australia
NSCAS	network support and control ancillary services
NSW EII Act	New South Wales Electricity Infrastructure Investment Act 2020
NZE	Net Zero Emissions by 2050
OCGT	open cycle gas turbine
OEA	Oxford Economics Australia
ONSG	other non-scheduled generation
PDRS	Peak Demand Reduction Scheme
PEC	Project EnergyConnect
PEM	proton exchange membrane
PHES	pumped hydro energy storage
PJ	petajoule/s
POE	probability of exceedance
PV	photovoltaic
PVNSG	PV non-scheduled generation
QNI	Queensland – New South Wales Interconnector
QRET	Queensland Renewable Energy Target
QREZ	Queensland Renewable Energy Zone
RCP	Representative Concentration Pathway
RET	Renewable Energy Target
REZ	renewable energy zone
RIT-T	regulatory investment test for transmission
RoCoF	rate of change of frequency
RRN	regional reference node
RRO	Retailer Reliability Obligation
SA REPS	South Australian Retailer Energy Productivity Scheme
SAT	single-axis tracking

Abbreviation	Meaning
SESA	South East South Australia
SEV	South East Victoria
SNSW	South New South Wales
SNW	Sydney, Newcastle, Wollongong
SPR	Strategy. Policy. Research.
SQ	South Queensland
SRES	Small-scale Renewable Energy Scheme
SSSP	System Strength Service Provider
STC	small-scale technology certificate
STEPS	Stated Policies Scenario
TAS	Tasmania
TNSP	transmission network service provider
TRET	Tasmanian Renewable Energy Target
UNFCCC	United Nations Framework Convention on Climate Change
UOR	unplanned outage rate
US EIA	US Energy Information Administration
V2G	vehicle-to-grid
VCR	Value of Customer Reliability
VEU	Victorian Energy Upgrades
VNI	Victoria – New South Wales Interconnector
VPP	virtual power plant
VRE	variable renewable energy
VRET	Victorian Renewable Energy Target
WACC	weighted-average cost of capital
WDR	Wholesale Demand Response
WEM	Wholesale Electricity Market
WEO	World Energy Outlook
WNV	West and North Victoria
ZEV	zero emission vehicle