



2021 Inputs, Assumptions and Scenarios Report

July 2021

Final report

For use in Forecasting and Planning studies and analysis

Important notice

PURPOSE

AEMO publishes this 2021 Inputs, Assumptions and Scenarios Report (IASR) pursuant to National Electricity Rules (NER) 5.22.8. This report includes key information and context for the inputs and assumptions used in AEMO's Forecasting and Planning publications for the National Electricity Market (NEM).

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VERSION CONTROL

Version	Release date	Changes
1.0	30/7/2021	Initial release
1.1	4/8/2021	Added a snapshot summary of scenarios at 2040 into the Executive Summary and Section 2.5
1.2	10/8/2021	Updated Figure 53 and Table 41 to correct line name (Liddell – Bulli Creek) and updated values in Table 8

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Executive summary

The 2021 *Inputs, Assumptions and Scenarios Report* (IASR) details how AEMO will model the future in its forecasting and planning publications for the rest of 2021 and into 2022. It has been developed through 10 months of deep collaboration with a broad range of industry participants, governments, and consumer representatives. It reflects stakeholder feedback and significant refinement of inputs and assumptions from workshops, webinars, public forums, other engagements and more than 40 submissions.

Compared to the 2020 ISP scenarios, these scenarios have been refined with respect to the economic and technological change expected over the coming decades, specifically the pace of economy-wide decarbonisation, the ongoing consumer investment in distributed energy resources (DER), and the growth of transport and industry electrification.

Background and consultation

AEMO, through its forecasting and planning functions:

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

To read AEMO's forecasts and planning documents, it is important to understand what inputs and assumptions have gone into the modelling. It is also critical that stakeholders join AEMO in developing the scenarios, inputs and assumptions, so industry has confidence in the modelling and the forecasts that come out of the models.

AEMO updates inputs, assumptions and scenarios as new data becomes available, government policy settings evolve, and stakeholders – including industry, governments, and consumers – provide feedback.

The 2022 *Integrated System Plan* (ISP) will use all the information in the 2021 IASR to present an updated 20-year outlook for the NEM in mid-2022. The 2021 *Electricity Statement of Opportunities* (later this year) and 2022 *Gas Statement of Opportunities* (in March 2022) will use a selection of the same scenarios, inputs and assumptions as relevant to their forecasts of demand and supply for electricity and gas.

AEMO published the 2021 IASR in draft form in December 2020, and has used feedback from 47 written submissions and a series of workshops, webinars and public forums in preparing the final 2021 IASR.

A separate consultation summary report¹ provides AEMO's response to the feedback received from a broad range of stakeholders covering industry, academia, individuals and small business, and explains how AEMO has taken this feedback into account.

What the 2021 IASR contains

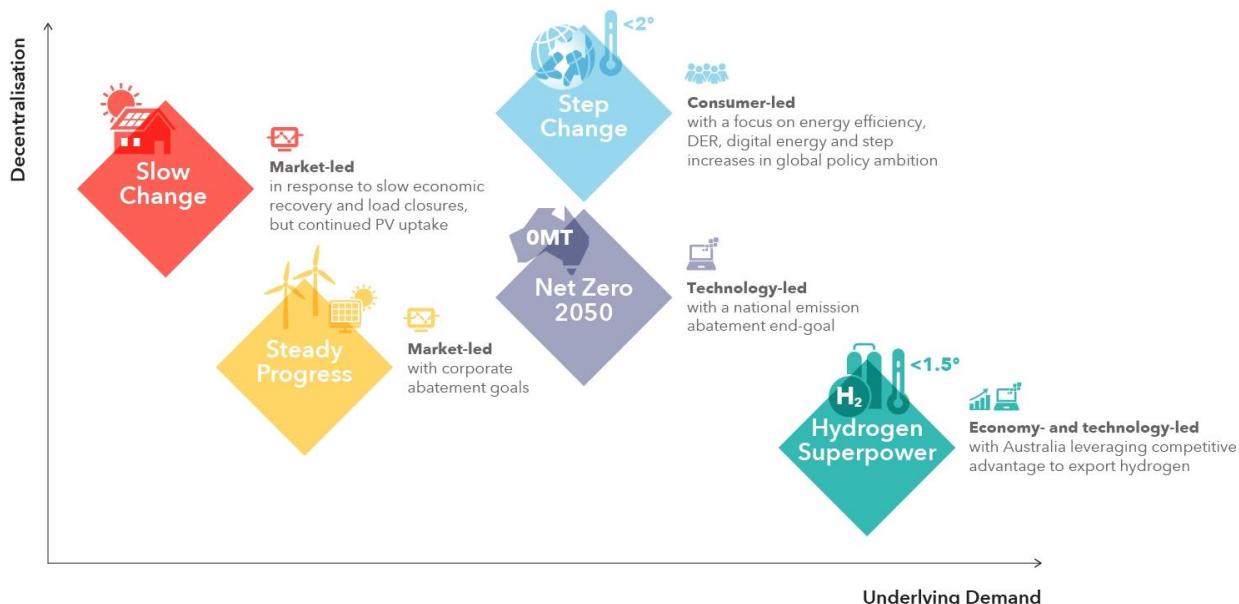
Through the consultation, five scenarios have been developed and refined that show a range of plausible futures for growth in electricity demand, and in decentralisation as business and household consumers manage their own energy (see Figure 1). The pace of decarbonisation varies across the scenarios, meaning

¹ AEMO. 2021 IASR Consultation Summary Report, at <https://aemo.com.au/en/newsroom/news-updates/draft-2021-inputs-assumptions-and-scenarios-report-released>.

that the scenario narratives are broadly similar to those used in the 2020 ISP, but with inputs and assumptions updated to reflect latest market trends and policy developments.

For the first time, modelling to assess the NEM impacts of economy-wide decarbonisation and extent of transport and industry electrification has informed the assumptions attributed to each scenario.

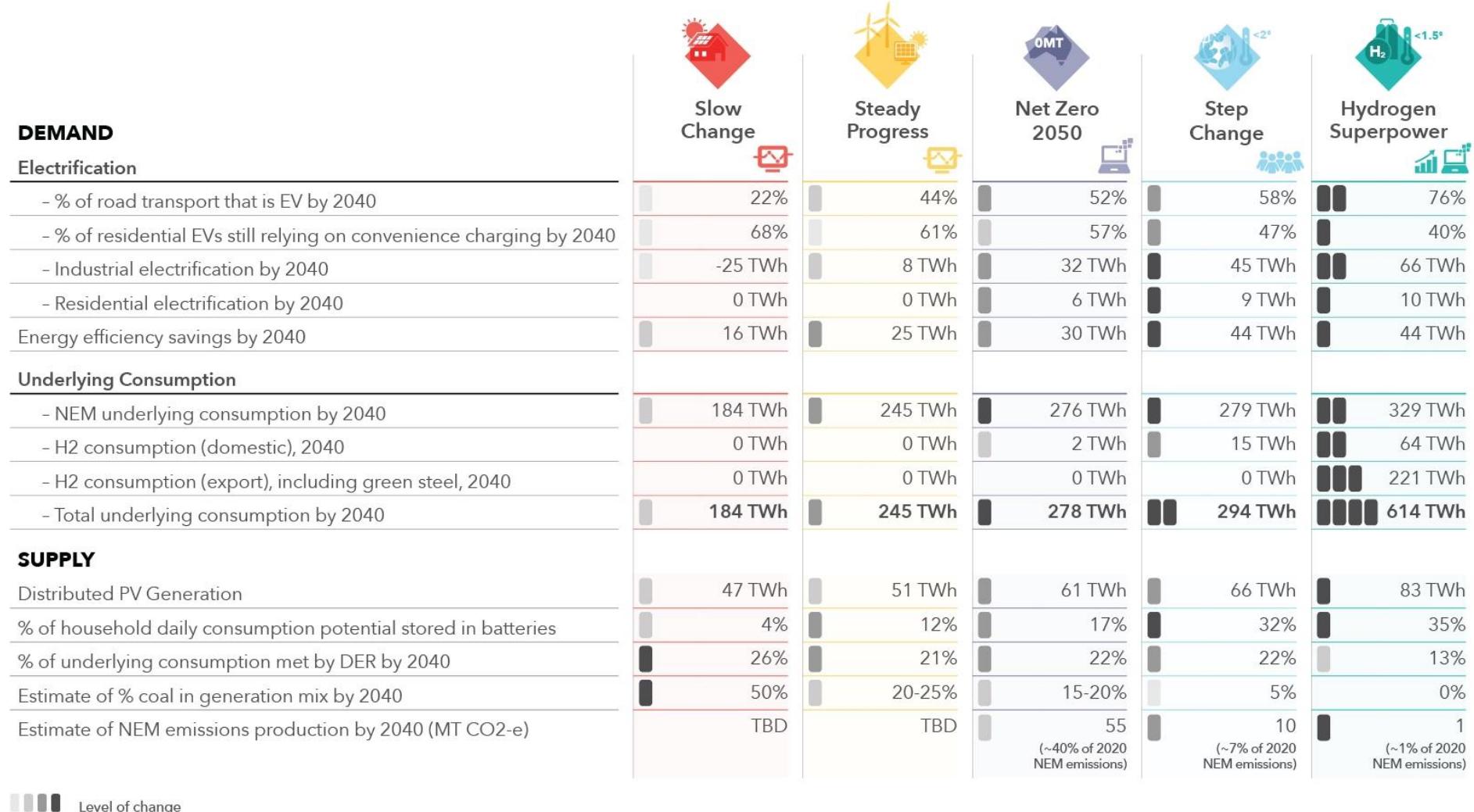
Figure 1 2021-22 scenarios



Slow Change	Challenging economic environment following the COVID-19 pandemic, with greater risk of industrial load closures, slower decarbonisation action, and consumers proactively managing energy costs through continuing investments in DER, particularly distributed photovoltaics (PV).
Steady Progress	Future driven by existing government policy commitments, continuation of current trends in consumer investments such as DER and corporate emission abatement, and technology cost reductions. Renewable generation, complemented by firming capacity, remains the least-cost option to replace ageing coal-fired generation. By 2050, many consumers are still relying on gas for heating.
Net Zero 2050	Action towards an economy-wide net zero emissions objective by 2050 through technology advancements. Short-term activities in low emission technology research and development enable deployment of commercially viable alternatives to emissions-intensive activities in the 2030s and 2040s, with stronger economy-wide decarbonisation, particularly industrial electrification, as 2050 approaches. Electric vehicles become more prevalent over time and consumers gradually switch to using electricity to heat their homes and businesses.
Step Change	Rapid consumer-led transformation of the energy sector, and co-ordinated economy-wide action that efficiently and effectively tackles the challenge of rapidly lowering emissions. This requires a step change in global policy commitments to achieve the Paris Agreement's minimum objectives, supported by rapidly falling costs of energy production, including consumer devices. Increased digitalisation helps consumers manage energy use while also providing grid flexibility, and technologies and buildings become more energy efficient. Electric vehicle adoption is strong, with early decline in manufacturing of internal-combustion vehicles. By 2050, most consumers rely on electricity to heat their homes and businesses.
Hydrogen Superpower	Strong global action towards emissions reduction, with significant technological breakthroughs and social change to support low and zero emissions technologies. Emerging industries such as hydrogen production present unique opportunities for domestic developments in manufacturing and transport, and renewable energy exports via hydrogen become a significant part of Australia's economy. New household connections tend to rely on electricity for heating and cooking, but those households with existing gas connections progressively switch to using hydrogen – first through blending, and ultimately through appliance upgrades to use 100% hydrogen.

Figure 2 compares the five scenarios in a snapshot of 2040 projections, with a high-level comparison of key inputs affecting energy demand and supply.

Figure 2 Scenario comparison at 2040



The use of scenario planning is an effective practice to manage investment and business risks when planning in highly uncertain environments, particularly through disruptive transitions. Scenarios are a critical aspect of forecasting, enabling the assessment of future risks, opportunities, and development needs in the energy industry. It is vital that the dimensions of scenarios chosen cover the potential breadth of plausible futures impacting the energy sector and capture the key uncertainties and material drivers of these possible futures in an internally consistent way.

Sensitivities serve a different purpose; they are designed to test the materiality of uncertainty associated with individual input parameters or assumptions. They aim to increase confidence in investment decisions, by testing the sensitivity of outcomes to various input uncertainties. This IASR identifies a number of sensitivities that will be applied to the 2022 ISP including variations in gas price projections, discount rates, uptake of distributed photovoltaics (PV), and future policy positions.

In addition to the five core scenarios, event-driven scenarios have been identified to explore clearly observable and reasonably probable independent events or investment decisions that may materially change the market benefits of a candidate development path identified in the ISP. These include decisions that may directly influence the commercial feasibility or commitment status of projects such as Marinus Link, HumeLink, and VNI West, that were identified as actionable projects in the 2020 ISP.

Summary of key inputs and assumptions

The 2021 IASR and associated IASR Assumptions Workbook provide detail about the inputs and assumptions associated with each scenario out to 2050. Below is a summary of some of the key inputs and assumptions.

Expanded public policy settings

AEMO is using – in all scenarios – the following public policies²:

- Australia's 2030 emissions reduction target.
- Large-scale Renewable Energy Target (LRET).
- Victorian Renewable Energy Target (VRET).
- Victoria's 2020-21 budget initiatives affecting REZs and energy efficiency.
- Queensland Renewable Energy Target (QRET).
- Queensland Renewable Energy Zone (QREZ).
- Tasmanian Renewable Energy Target (TRET).
- New South Wales Electricity Infrastructure Roadmap.
- *National Electricity (Victoria) Act* (NEVA).
- Various jurisdictional DER and energy efficiency policies.

In some scenarios, AEMO will explore the impacts of faster rates of energy transition through the inclusion of NEM carbon budgets.

Rooftop photovoltaics (PV) and other distributed PV

AEMO's 2021 DER forecasts reflect higher investment by consumers in distributed photovoltaics (PV) than was expected last year. The COVID-19 pandemic has seen household consumers redirecting discretionary income into assets that reduce their exposure to energy costs.

² These policies meet the criteria in National Electricity Rules clause 5.22.3(b), which outlines which environmental or energy policies AEMO may consider in developing the ISP.

Electrification and the four pillars of decarbonisation

The scenarios lead to different levels of action in four areas of decarbonisation: energy efficiency, electricity sector decarbonisation, consumers switching away from fossil fuels, and carbon offsets/sequestration.

AEMO has modelled Australia's economy across a range of sectors to assess the potential impact of action in these areas on demand for electricity. The various scenarios highlight the potential for demand to grow if:

- Residential, commercial, industrial and transport sectors switch to electricity (as the power system is decarbonised, relying less on fossil fuels and more on renewables) and away from fossil fuel supplies.
- New zero emissions/renewable energy export industries expand. The IASR looks particularly at opportunities in hydrogen production and export, and green steel manufacturing.

Technology and fuel costs

The Gencost 2020-21 report, published by CSIRO and AEMO, confirms that the costs of inverter-based resources like wind, solar (grid-scale and rooftop) and batteries are expected to keep falling, while costs for mature technologies such as coal, gas and hydro generation (pumped storage and conventional) remain flat. The scenarios explore different fuel cost assumptions, and AEMO will especially focus on making sure investments recommended as actionable in the ISP will be robust under a range of different gas prices outlooks.

Renewable energy zones

Stakeholders including state governments have helped AEMO refine and expand modelling inputs related to REZs. Inputs have been updated to consider new data, developer interest, how policy may affect transmission availability, and offshore wind zones are now also included in the REZ resource framework.

Transmission augmentation options and costs

Stakeholders asked for more transparency and accuracy in assumptions about transmission costs, so AEMO is releasing new information with the 2021 IASR:

- *Transmission Cost Report*.
- Transmission Cost Database, which includes a Cost and Risk Databook and a cost estimation tool.

This extra information will improve transparency on the AEMO's estimation process and the data used.

Social license for transmission projects is a critical enabler for infrastructure projects and cannot be taken for granted. Significant community impacts by projects can increase cost and delivery timeframes. Social license considerations have therefore been included at a high level in the REZ assessments to inform the selection process. Detailed assessments of the impacts of new infrastructure and the most effective mitigation measures of community impacts are, however, expected to be addressed as part of the existing planning and delivery processes, which best position project developers to understand local benefits and impacts and directly engage with communities.

Why is the IASR important?

The IASR aims to help investors and policy-makers decide on prudent investments in generation, transmission, and storage that can minimise the cost of developing, operating, and consuming energy.

AEMO will use these inputs in its future work to identify system improvements in the long-term interests of consumers. Future work includes the 2021 *Electricity Statement of Opportunities* in August 2021, along with the Draft ISP due in December and the next Final ISP due in June 2022.

1. Introduction

AEMO produces several publications that use the inputs, assumptions and scenarios documented in this report, including the following:

- **Electricity Statement of Opportunities (ESOO)** – provides information about the National Electricity Market (NEM) over a 10-year outlook period, with focus on electricity supply reliability. The ESOO includes a reliability forecast identifying any potential reliability gaps in the coming five years, as defined according to the Retailer Reliability Obligation (RRO). The final five years of the 10-year ESOO forecast provide an indicative forecast of any future material reliability gaps. The ESOO also includes 20-year forecasts of annual consumption, maximum demand, and demand side participation (DSP). It is published annually, with updates if required.
- **Gas Statement of Opportunities (GSOO)** – assesses the adequacy of gas reserves, resources, and infrastructure to meet the needs of domestic and export demands in gas over a 20-year outlook period. It includes 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. It is published annually, with updates if required.
- **Integrated System Plan (ISP)** – is a whole-of-system plan, assessing the need for generation, storage and transmission investments that efficiently achieve the power system needs of a transforming energy system in the long-term interests of consumers. It serves the regulatory purpose of identifying actionable and future ISP projects, as well as the broader purposes of informing market participants, investors, policy decision-makers and consumers. It provides a transparent, dynamic roadmap of an evolving electricity system's infrastructure requirements over a planning horizon extending to 2050, managing the risks associated with change. It is published at least every two years, with updates if required.

Many uncertainties face the energy sector:

- The role of consumers in the energy market is evolving as distributed energy resources (DER) continue to be developed, new technological innovations influence consumption patterns, and consumers' energy-related behaviours change. The COVID-19 pandemic is also contributing to a "new normal", with increased telepresence and flexibility for work, and increasing reliance on digital technologies for day-to-day life.
- Other industries, such as the transportation sector, are increasingly electrifying their energy supply in an attempt to reduce costs and decarbonise, and are thus having a direct impact on the electricity sector. Furthermore, opportunities for hydrogen production in Australia could have a transformative impact on the domestic energy sector if the Federal Government's vision for Australia to become a world leader in hydrogen production and export is realised.
- Existing supply sources, particularly thermal generators, are ageing and approaching the end of their technical lives. Expected closure years are provided by participants, but risks of earlier than expected closures need to be managed. These resources must be replaced in a timely manner to maintain a reliable and secure power system that meets consumer demand at an affordable cost as well as achieving public policy requirements. Depending on the preferred replacement resources, this may require investment in network infrastructure to enable delivery of new energy production to consumers.

AEMO uses a scenario analysis approach to investigate the direction and magnitude of shifts impacting the energy sector, the economically efficient level of infrastructure investment necessary to support the future energy needs of consumers in presence of uncertainty, and the risks of over- or under-investment.

This 2021 *Inputs, Assumptions and Scenarios Report* (2021 IASR) outlines the scenarios that have been developed through stakeholder consultation that AEMO will use in upcoming forecasting and planning publications, including the 2021 ESOO, 2022 GSOO, and 2022 ISP.

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

The information in this report is supported by the 2021 Inputs and Assumptions Workbook (the IASR Assumptions Book)³, which provides more granular detail for the inputs and assumptions under construction for use in 2021-22 forecasting, modelling, and planning processes and analysis. The *IASR Consultation Summary Report*⁴ (Consultation Report) complements this report's release, highlighting the breadth of stakeholder feedback received throughout the development of this 2021 IASR, including AEMO's considerations of the feedback.

All dollar values provided in this report are in real June 2021 Australian dollars unless stated otherwise.

1.1 Consultation process

AEMO considers that leveraging expertise from across the industry is pivotal to the development of a robust plan that supports the long-term interests of energy consumers. AEMO is committed to facilitating a stakeholder engagement process that ensures a collaborative approach to developing the 2022 ISP and values the extensive stakeholder collaboration and input that has informed the development of this IASR.

In developing this IASR, AEMO has consciously sought to meet and exceed the requirements⁵ to develop, consult on, and publish the IASR in accordance with the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines⁶. While these Guidelines require AEMO to follow a "single stage consultation process", the consultation has been far more frequent, using both formal and informal channels to seek and to consider stakeholder feedback, improve transparency and clarity around the ISP decision-making process, and validate that changes made in response to stakeholder feedback are appropriate.

AEMO released the Draft IASR on 11 December 2020 and received 47 formal written and verbal submissions from a wide range of stakeholders, including representatives of household and large consumers, market participants and project developers, industry associations, governments, advisory firms, academics, and environmental groups. Much of the feedback in these submissions focused on the set of scenarios proposed in the Draft IASR.

After considering the feedback received, and taking into consideration continued developments in the market, AEMO proposed several amendments to the scenarios in March 2021. These amendments were subsequently consulted on over a further two-week consultation window.

The Consultation Report published alongside this IASR provides a detailed summary of the consultation process undertaken in the development of this report. The Consultation Report explains how engagement with stakeholders has shaped the scenarios, as well as the inputs and assumptions. The report provides

³ Also at <https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-ispl/2022-integrated-system-plan-ispl/current-inputs-assumptions-and-scenarios>.

⁴ AEMO. 2021 IASR Consultation Summary Report, at <https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-ispl/2022-integrated-system-plan-ispl/current-inputs-assumptions-and-scenarios>.

⁵ Clause 5.22.8(a) of the NER.

⁶ AER. *Forecasting Best Practice Guidelines*, at <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable/final-decision>.

detailed responses to all material issues raised in written submissions and in verbal feedback sessions with consumer representatives. This IASR should be read in conjunction with that Consultation Report.

Table 1 below summarises the consultation activities undertaken in the IASR process.

Further consultation on a range of inputs and assumptions has been progressed through AEMO's Forecasting Reference Group (FRG) meetings held at least monthly, as well as through a consultation on Transmission Costs⁷ and targeted consultation on discount rates.

Table 1 Stakeholder engagement on the IASR

Activity	Date
Forecasting and Planning Scenarios Workshop	14 October 2020
Forecasting and Planning Scenarios Webinar	22 October 2020
Forecasting and Planning IASR - Scenarios Webinar	11 November 2020
Forecasting and Planning IASR Workshop	20 November 2020
Release of Draft IASR	11 December 2020
Submissions closed on Draft IASR	1 February 2021
Release of amended Draft Scenarios and Draft IASR submissions webinar	3 March 2021
Further submissions close on revised scenarios	17 March 2021

⁷ AEMO. *Transmission costs for the 2022 Integrated System Plan*, at <https://aemo.com.au/en/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan>.

2. Scenarios

AEMO uses scenario modelling to assess the costs, risks, opportunities, and development needs through the energy transition, in the long-term interests of consumers. To do so, the selected scenarios must cover a broad range of plausible operating environments for the energy sector, and the potential changes in those environments, in an internally consistent way.

The scenarios AEMO will apply achieve this objective, by intentionally varying inputs associated with major sectoral uncertainties, including but not limited to:

- Economic growth trajectories.
- Rates of change affecting existing and new technology deployment.
- Scales of investment by consumers in DER, as well as investments in devices, technologies, and processes that improve the efficiency of energy consumption.
- Speed of decarbonisation, and the degree of electrification from other sectors as decarbonisation objectives influence electricity system developments.
- Deployment potential of new technologies, such as hydrogen production.

2.1 Core scenarios

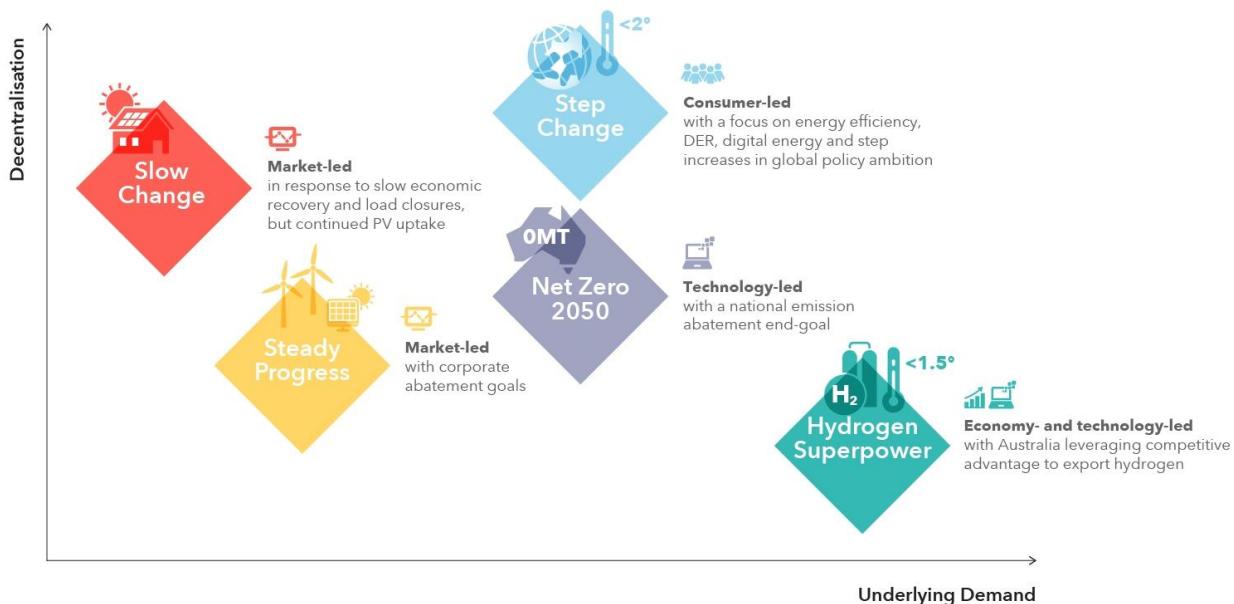
For 2021-22 forecasting and planning purposes, AEMO has identified five plausible, distinct, internally consistent scenarios that cover a broad range of potential future worlds that could materially impact the energy sector. Each future world, described through a scenario narrative, decreases the carbon intensity of the energy sector (and Australia's economy more broadly) at a different rate.

The scenario narratives remain broadly consistent with those used in the 2020 ISP, updated with the latest information, although some are new. In several of the 2021 scenarios, the electrification impact from progressively decarbonising all sectors of Australia's economy has been considered in greater detail than previous scenario analysis, including:

- Changes in the transport sector that affect electricity requirements, with greater electric vehicle (EV) deployment.
- Increased electrification of commercial and industrial sectors and growing investments in energy efficiency to reduce reliance on other emissions-intensive primary fuels (such as gas, oil, coal, and other fuel sources) as the economy reduces its emissions intensity.
- Emerging industries such as hydrogen production through electrolysis that may present new and significant opportunities for Australia's energy system and economy.

These transformative influences directly impact the magnitude, seasonality, and daily profile of demand on the NEM. Generation supply sources are also continuing to change, switching away from fossil fuels to zero or near-zero alternatives either behind-the-meter (in the form of distributed photovoltaics [PV]) or at grid scale.

Figure 3 2021-22 scenarios



Therefore, the scenarios are differentiated not only by the rate of decarbonisation, but also by variations in the level of electricity consumed in the future and extent of electricity supply decentralisation (see Figure 3):

- The **Slow Change** scenario reflects a challenging economic environment following the COVID-19 pandemic, with greater risk of industrial load closures. The weaker commercial environment slows decarbonisation action, but consumer investments in DER continue at pace as consumers proactively manage their energy bills.
- The **Steady Progress** scenario considers a future driven by existing government policy commitments, continuation of current trends in consumer energy investments such as distributed PV uptake and corporate emission abatement goals, and technology cost reductions. Renewable generation, complemented by firming capacity, continues to be the least-cost option to replace ageing coal-fired generation. By 2050, many consumers are still relying on gas for heating.
- The **Net Zero 2050** scenario represents a future that delivers action towards an economy-wide net zero emissions objective by 2050 through technology advancements. This transition focuses on short-term activities in low emission technology research and development to enable deployment of commercially viable alternatives to emissions-intensive activities in the 2030s and 2040s. Stronger economy-wide decarbonisation, particularly industry electrification, occurs in later years as the 2050 deadline approaches. Consumers are initially continue to heat their homes in the same manner they do today, but by the mid-2030s nearly half the current gas heating has been electrified, and in the final years of the horizon nearly all residential heating is electrified.
- The **Step Change** scenario represents a future with rapid consumer-led transformation of the energy sector, and a coordinated economy-wide approach that efficiently and effectively tackles the challenge of rapidly lowering emissions. This requires a step change in global policy commitments to achieve the minimum objectives of the Paris Agreement, supported by rapidly falling costs of energy production, including consumer devices. Increased digitalisation enhances the role consumers can play in managing their energy use, along with advancements in energy efficient technologies and buildings. EV adoption is strong, with early decline in manufacturing of internal-combustion vehicles. By 2050, most consumers rely on electricity to heat their homes and businesses. Carbon sequestration in the land use sector helps offset hard-to-abate emissions.
- The **Hydrogen Superpower** scenario reflects strong global action towards emissions reduction, with significant technological breakthroughs and social change to support low and zero emissions

technologies. Emerging industries such as hydrogen production present unique opportunities for domestic developments in manufacturing and transport, while NEM-connected renewable energy exports via hydrogen become a significant part of Australia's economy. New household connections tend to rely on electricity for heating and cooking, but those households with existing gas connections progressively switch to using hydrogen – first through blending, and ultimately through appliance upgrades to use 100% hydrogen.

All five scenarios will be used in AEMO's 2022 ISP. The 2021 ESOO for the NEM and 2022 GSOO for eastern and south-eastern Australia will use a selection of the same scenarios.

Sensitivities that could materially impact outcomes of the ISP, ESOO or GSOO will be crafted for the specific purposes of each publication as appropriate.

The scenario narratives describing each scenario in more detail are covered in this section in order of increasing rates of decarbonisation economy-wide.

2.1.1 Slow Change

Market-led change with a slow economic recovery from COVID-19, and load closures

Narrative summary

This scenario includes lower assumed forecast economic growth than historical trends following the global COVID-19 pandemic, with more challenging economic conditions leading to the greatest risk of industrial load closures. Strong uptake of distributed PV continues, particularly in the short term in response to a number of incentives assumed to be implemented as part of a COVID-19 recovery plan.

This scenario reflects slower technology advancements, and fewer direct policy drivers beyond what is already legislated than other scenarios. Therefore, while there is still progress on decarbonisation, it is slower than in any other scenario.

Purpose

- To assess the risk of over-investment in the power system, in a future where operational demand is much lower.
- To explore some of the system security risks and investment opportunities associated with high penetration of distributed PV and corresponding decline in minimum demand.

In this scenario:

- The COVID-19 recovery is slow, suppressing global growth, investment, and employment levels, and resulting in lower levels of growth in Australia. More insular trade policies and increased protectionism take hold globally. Australia's population growth is relatively lower than other scenarios, with falling birth rates and immigration levels, partly due to sustained impacts on global travel.
- In search of cost savings, and in response to low interest rates, consumers continue to install distributed PV at high rates, continuing the trends observed during 2020 where uptake has held up and in many regions increased to record levels, despite adverse economic conditions. In this scenario, this strong uptake is further boosted by a government-funded roll out of distributed PV for social housing. Over time these impacts dissipate and distributed PV uptake moderates.
- In contrast, investment in household battery storage and EVs do not grow as fast as forecast in other scenarios, due to more muted cost reductions, the impact of lower disposable incomes, softening in price signals for peak demand management, and longer vehicle replacement cycles. Consumers' choice for heating remains unchanged compared to today.

- Currently legislated or materially funded state-based variable renewable energy (VRE) policies and targets are achieved. Future investment in VRE, beyond current policies, is driven by commercial decision-making.
- Government policy focuses on supporting the ailing domestic economy, with decarbonisation policy being less of a priority. Market forces and reductions in operational consumption result in natural emission reductions. The same is true internationally, where insufficient action is taken globally to achieve the objectives of the Paris Agreement.
- With less focus on decarbonisation and greater focus on economic stability and recovery, the scale of transition across the economy is less than other scenarios, with lower electrification investments proceeding. Emerging investments in hydrogen production are lowest in this scenario.

2.1.2 Steady Progress

Market-led change with corporate abatement goals

Narrative summary

The Steady Progress scenario reflects a future energy system based around current state and federal government environmental and energy policies and best estimates of all key drivers.

In this scenario, the energy market transition is led by continued strong consumer energy advocacy including strong uptake of DER, market forces driving coal-fired generation retirements, continued strong private interest in developing VRE, and state government support for renewable energy zones (REZs). This scenario reduces the carbon intensity of the energy sector over time, but does not achieve economy-wide net zero emissions by 2050.

Purpose

To assess the needs for development of the energy sector under currently funded, legislated, or otherwise committed policies and commitments, using central estimates for technological and macroeconomic influences affecting other market inputs, and representing current trends in consumer investments and technology cost reductions.

In this scenario:

- Uptake of DER, energy efficiency measures, and the electrification of the transport sector proceed in line with AEMO's current best estimates to 2030, reflecting continued strong trends in distributed investments as consumers benefit from reducing investment costs and relatively short payback periods.
- Moderate growth in the global and domestic economy is assumed, in light of the global COVID-19 economic recovery.
- Global decarbonisation efforts are in line with current global commitments, including Australia's nationally determined commitment to the Paris Agreement by reducing emissions by 26-28% on 2005 levels by 2030. Beyond 2030, Australia continues to make steady progress towards achieving net zero emission outcomes as early as practicable, and no later than the second half of this century.
- Currently legislated or materially funded state-based VRE policies and targets are achieved. Future investment in VRE, beyond current policies, is driven by commercial decision-making and corporate emission abatement aspirations.
- Decarbonisation in the electricity sector is primarily due to the reduced operation of ageing power stations, with closures in line with current commitments, and earlier if economic. Ageing power stations

face more challenging conditions with increasing competition from increasing VRE (and DER) investments to meet various state and federal renewable energy targets.

- Without early and effective coordination of Australia's broader economy towards a lower carbon intensity, electrification of other sectors is more gradual, driven by potential cost savings from fuel switching, appliance and building improvements, and the steady shift towards electrification in the transportation sector. Industrial electrification is relatively low as incentives are more limited, with corporate and technological advancements providing the primary stimulus. New household gas connections are progressively phased out.
- In the long term, global carbon reduction commitments and ambitions are slower than may be needed to avoid rise in global and domestic temperatures above the Paris Agreement's objectives.

2.1.3 Net Zero 2050

Technology-led change, with a national emissions abatement end-goal

Narrative summary

The Net Zero 2050 scenario reflects a future energy system based around current state and federal government environmental and energy policies, and transitioning Australia's economy to a net zero level of emissions by 2050. Other key drivers such as population and economic growth, and technology cost reductions, adopt best estimate forecasts.

Similar to the Steady Progress scenario, in the next decade the energy sector transition is generally led by continued strong uptake of DER, and state government support for the development of REZs. Over time, as technological research and development delivers commercially viable alternatives to emission-intensive activities, broader economy-wide transformative investment gradually increases.

The key distinction between Net Zero 2050 and the Steady Progress scenario is observed particularly in the 2030s and 2040s, as greater cross-sectoral electrification and investment in energy efficiency supports the transition of the entire domestic economy towards net zero emissions by 2050, in line with global actions to decarbonise. Consumers rely on electricity for heating and cooking.

This scenario considers a growing role for energy efficiency and fuel shifting that increases the productivity of energy use, with some use of land-use sector sequestration offsets to complement explicit actions within the energy sector.

Purpose

To assess the needs for development of the energy sector as Australia not only achieves its currently funded and/or legislated policies and commitments, but extends these after 2030 towards net zero economy-wide by 2050.

In this scenario:

- Uptake of DER, energy efficiency measures, and the electrification of the transport sector proceed in line with AEMO's current best estimates to 2030, reflecting continued strong trends in distributed investments. Beyond 2030, energy efficiency measures gradually increase in response to progressive tightening of emission targets.
- Moderate growth in the global and domestic economy is observed, in light of the global COVID-19 economic recovery.
- Australia achieves its nationally determined Paris Agreement 2030 commitment of reducing emissions by 26-28% on 2005 levels, and currently legislated or materially funded state-based VRE policies and targets are achieved.

- Early focus on technological research and development leads to commercialisation of new and emerging low emissions technologies over time. This allows the pace of decarbonisation to accelerate in Australia after 2030, eventually reducing emissions economy-wide to net zero by 2050.
- The costs of VRE and storage technologies continue to fall and are increasingly competitive with existing fossil-fuelled generation. This continued adoption, and increasing focus on the net zero goal by 2050 economy-wide, puts greater pressure on the electricity sector to decarbonise earlier than other sectors, enabling greater progressive electrification of fossil-fuel intensive loads. This impacts the ongoing operation of ageing coal-fired power stations.
- The role for carbon sequestration, particularly in the land-use sector, grows slowly initially, leading to a lower cumulative sequestration effect by 2050 than in other scenarios with stronger and faster decarbonisation ambitions.
- As the net zero 2050 goal approaches, and the electricity sector reaches near-zero emissions, there is increased electrification of industrial, commercial, and residential energy use, and the majority of consumers switch to using electricity for heating. The cumulative effect of relatively gradual transitions towards more energy efficient appliances and building designs, and carbon sequestration activities, mean there is heavier reliance on electrification of some of the more challenging industrial processes than needed in other scenarios to achieve the same net zero emission target by 2050.
- In the long term, global carbon reduction commitments and ambitions are slower than may be needed to avoid rise in global and domestic temperatures above the Paris Agreement's objectives, but faster than assumed in the Steady Progress scenario.

2.1.4 Step Change

Consumer-led change with focus on energy efficiency, DER, digitalisation and step increases in global emissions policy ambition

Narrative summary

This scenario includes a *global step change* in response to climate change, supported by technology advancements and a coordinated cross-sector plan that efficiently and effectively tackles the adaptation challenges. Domestic and international action rapidly increases to achieve the objectives of the Paris Agreement, to limit global temperature rise to well below 2° compared to pre-industrial levels. To achieve this, economy-wide net zero emissions are expected on or before 2050.

Faster decarbonisation ambitions to achieve the scale of temperature control assumed in this scenario, relative to the Net Zero 2050 scenario, are supported by rapidly falling costs for battery storage and VRE, which drive consumers' actions and higher levels of electrification of other sectors. The transformation of the transport sector in particular is influenced by a combination of technology cost reductions affecting zero emissions vehicles, and manufacturing change to eliminate internal-combustion vehicles from new vehicle production lines (and eventually remove them from the road entirely).

Advancements in digital trends increase the role of consumer technologies to manage energy use efficiently and provide flexibility to the system. Sustainability has a very strong focus, with consumers, corporations, developers, and government also supporting the need to reduce the collective energy footprint through adoption of greater energy efficiency measures.

This scenario also considers a *step change* in energy consumption through technology breakthroughs in energy efficiency and fuel switching that increase the productivity of energy use. Diverse sustainability solutions include land-use sector sequestration offsets (for sectors that are harder to decarbonise), biofuel developments, and hydrogen production. Distinct from other scenarios with strong decarbonisation towards net zero emissions, the scale of energy efficiency improvement is greatest in this scenario, with changes in building design, smart appliances, and digitilisation helping consumers manage their energy use wisely.

Purpose

To understand the needs in the power system to support faster decarbonisation, resulting in earlier and greater DER uptake than the Net Zero 2050 and Steady Progress scenarios, with greater digital advancements increasing the technological complexity of consumer energy management solutions and the way electricity is used across a broader cross-section of the domestic economy. In particular, the scenario will explore the potential economic risk facing consumers regarding under- or over-investment in the infrastructure required for this transition.

In this scenario:

- There is moderate growth in the global and domestic economy, in light of the global COVID-19 economic recovery.
- High levels of awareness towards the impacts of climate change from increasingly energy literate consumers result in a greater degree of individual consumer action to reduce emissions. DER uptake is driven by consumers taking greater ownership over their consumption, increasing the level of active participation by consumers in energy use. This is aided by continued technological advances, innovation in digital trends, and market reforms that extend the strong uptake in DER technologies, including greater demand management and other opportunities to support coordinated energy management.
- Strong climate action underpins rapid transformation of the energy sector (and broader global economy) to achieve the Paris Agreement's goal of limiting global temperature rises to well below 2°C, ideally by 1.5°C, relative to pre-industrial levels. Domestically, government policy and corporate objectives are aligned with the need to decarbonise the Australian economy, going beyond existing climate policy.
- Currently legislated or materially funded state-based VRE policies and targets are achieved, with future electricity sector investments influenced by policy measures that reduce cumulative emissions over time. Limiting emissions may lead to earlier withdrawals of emissions-intensive generation sources, and increased shifts towards low-emission electrical alternatives to coal, gas, oil, and diesel-powered processes.
- Decarbonisation ambition provides some opportunity for domestic hydrogen or biofuel substitution for traditional gas users as manufacturing and other sectors innovate to decarbonise. A growing biofuel industry provides important support to domestic hydrogen production to enable industries and sectors (such as non-road transport) that have greater reliance on the thermal properties of fossil fuels to lower their emissions intensity.
- This scenario assumes that the scale of hydrogen production connected to the NEM is limited, either technically or economically, such that hydrogen production does not materially impact the NEM's investment or operation. No hydrogen export facilities are connected to the NEM in this scenario.
- Electrification potential is high, particularly from the transport sector, where EVs soon become the dominant form of road passenger transportation. This includes continued innovation in transport services, such as ride-sharing and autonomous vehicles, that may influence charge and discharge behaviours of the EV fleet, including vehicle-to-home discharging trends. Consumers switch from gas to electricity to heat their homes. Strong electrification from other sectors is expected as a means to decarbonise manufacturing and other industrial activities.
- The scenario assumes relatively stronger rates of technology cost decline, particularly affecting maturing renewable energy electricity generation technologies. Lower cost consumer devices such as DER, and energy efficiency and management systems penetrate much more into mainstream technology adoption.
- The scenario incorporates early growth in carbon sequestration, particularly within the land-use sector that offset emissions that are hardest to abate, to maintain a pathway towards net zero emissions more rapidly

than the Net Zero 2050 scenario, and without needing to rely so heavily on electrification of the most challenging industrial processes.

2.1.5 Hydrogen Superpower

Technology-led change with Australia leveraging competitive advantages in renewable energy to grow the economy through hydrogen and other zero-emissions exports

Narrative summary

This scenario represents a world with very high levels of electrification and hydrogen production, fuelled by strong decarbonisation targets and technology cost improvements. These technology cost reductions improve Australia's capacity to expand domestic exports to global consumers, supporting stronger domestic economic outcomes relative to other scenarios, including hydrogen and other energy-intensive products such as green steel.

Key features of this scenario include:

- Strong international decarbonisation ambition, with faster actions enabling the achievement of the ambition of the Paris Agreement, limiting global temperature rise to 1.5°C by 2100 over pre-industrial levels. This is matched domestically with strong economy-wide actions that lead to the fastest decarbonisation requirement in the NEM across the scenarios. To achieve this temperature goal, economy-wide net zero emissions is expected before 2050.
- Strong economic activity and higher population growth.
- Continued improvements in the economics of hydrogen production technologies that enable the development of a significant renewable hydrogen production industry in Australia for both export and domestic consumption. Strong global decarbonisation action provides a high level of international demand for this production capacity, supplementing declining exports of traditional emissions-intensive resources in this scenario.
- High levels of electrification and energy efficiency investments across many sectors. Increased access to domestic hydrogen production increases the competitiveness of hydrogen fuel-cell vehicles, although EV growth is still strong with earlier replacement of internal-combustion vehicles. Fewer homes switch to electricity for their heating requirements, relying instead on hydrogen to replace existing gas heating systems.
- Greater use of land-use sector sequestration offsets is assumed relative to other scenarios, with biofuel developments complementing the availability of hydrogen for alternative industrial feedstocks.

Purpose

- To understand the implications and needs of the power system under conditions that enable the development of a renewable generation export economy which significantly increases grid consumption and necessitates developments in significant regional renewable energy generation.
- To assess the impact, and potential benefits, of large amounts of flexible electrolyser load.

In this scenario:

- Strong global support to tackle climate change and reduce emissions hasten action to decarbonise. Globally the effort is focused on meeting the preferred objective of the Paris Agreement to limit global temperature rise to 1.5°C. To achieve this, and as part of commensurate global action, Australia targets net zero emissions before 2050.

- Capitalising on significant renewable resource advantages and economic and technological improvements in hydrogen production, Australia establishes strong hydrogen export partnerships to meet international demand for clean energy.
- Both domestic and export hydrogen demand is fuelled, at least in part, by NEM-connected electrolysis powered by additional VRE development.
- Strong economy-wide decarbonisation objectives provide significant opportunities to fuel switch towards electricity and hydrogen. The energy transition in Australia is embraced by consumers, as they seek clean energy and energy efficient homes and vehicles.

2.2 Event-driven scenarios

Event-driven scenarios explore clearly observable and reasonably probable independent events or investment decisions that may materially change the market benefits of a candidate development paths.

These events may occur in any future world, and may serve as a sign-post to pivot from one development path to another. Development pathways that retain flexibility to pivot at low risk to consumers may be more valuable than pathways that do not have that flexibility.

Event-driven scenarios hold equivalent stature as the five core scenarios, enabling AEMO to allocate these to any RIT-T assessments conducted by TNSPs, if mitigation of any risk associated with the event is material to the RIT-T cost benefit assessment. As these events represent risks that may need to be considered by TNSPs in their RIT-T process to assess option value of actionable ISP projects, the investment impacts of the event may be tested in AEMO's ISP under one or more core scenarios.

For the 2022 ISP, AEMO will examine event-driven scenarios related to decisions that may be made outside the regulatory framework but could influence whether or not an actionable ISP project identified in the 2020 ISP appears in the 2022 ISP ODP. Such decisions could impact the funding or cost recovery arrangements and consequently the commercial feasibility of projects such as Marinus Link, Victoria – New South Wales Interconnector (VNI) West, and Humelink.

2.3 Comparing to the 2020 ISP scenarios

Where possible, this new set of scenario narratives align with the scenarios previously used to inform forecasting and planning activities (including the 2020 ISP), leveraging the familiarity stakeholders have with the previous scenarios to aid understanding of this new scenario collection.

Refinements to scenario narratives have been made in response to stakeholder feedback to increase scenario utility, plausibility and breadth, and new scenarios have been added where appropriate:

- The **Slow Change** scenario is most similar to the 2020 *Slow Change* scenario, with the energy transition over the longer term occurring at a slower pace than the other scenarios. However, unlike the 2020 scenario, decarbonisation still progresses in the 2021 Slow Change scenario, although more slowly than in any other scenario. No existing policy commitments are abandoned and life-extending refurbishments of coal-fired generation are no longer considered. This reflects the scale of current investment in DER and VRE, recent legislative changes that support ongoing VRE development in almost all NEM regions, and earlier closure declarations by existing coal generators. This scenario assumes slower economic recovery from COVID-19, coupled with continued near-term strength in DER investments, reflecting recently observed consumer preferences.
- The **Steady Progress** scenario is similar conceptually to the 2020 *Central scenario*, updated to include new government policy commitments such as expanded state-based VRE targets and current market trends such as distributed PV uptake and corporate emission abatement intent. These updated settings will lead to hastened transformation relative to the 2020 ISP.

- The **Net Zero 2050** scenario is similar conceptually to the *2020 Central scenario* in the first decade to 2030, updated to include the same growth considerations affecting DER and VRE as apply to the Steady Progress scenario. In the following decades, however, the pace of transition progressively increases, driven by a commitment to achieve economy-wide net zero emissions by 2050. This targeted decline in carbon intensity and resulting electrification of other sectors was not explicitly included in any of the 2020 scenarios.
- The **Step Change** scenario is similar to the *2020 Step Change* scenario, with strong action on climate change leading to a step change reduction of greenhouse gas emissions. This year, the scenario includes greater consideration of broader decarbonisation objectives affecting the scale of electrification from other sectors of Australia's economy. Compared to the 2020 Step Change scenario, the scenario assumes moderate or central levels of economic and population growth (whereas in 2020 it applied a higher population and economic growth outlook).
- The **Hydrogen Superpower** scenario reflects a bookend far beyond the 2020 scenario collection, considering much stronger decarbonisation objectives and examines the potential economic growth that strong global decarbonisation ambitions may deliver to Australia's economy through strong renewable energy export products, particularly hydrogen and green steel.

While the characteristics describing a future world that is represented by a particular scenario may not have changed materially, key inputs and assumptions have been updated to reflect the latest market data, trends, and policy developments. Most notably:

- Development of consumer-driven DER continues to outpace historical forecasts. COVID-19 has not slowed investment, and in some cases has assisted in emphasising government support of these consumer investments.
- Policy expansions across multiple states have supported strong large-scale renewable energy investments.
- Coal-fired power station retirements have in some instances been brought forward, relative to originally signalled closure years.

All scenarios therefore consider a stronger scale of activity, and continue to include a spread of drivers diverging from current best estimates to capture the future spread.

2.4 Key scenario parameters

Table 2 consolidates key demand drivers, technological improvements, investment considerations, and climatic assumptions to apply for each of the scenarios, considering the impact of public policy.

This table provides the qualitative relativity of each scenario to other scenarios, across the collection of scenario parameters, and maps AEMO scenarios to other published scenarios of relevance that are used to guide the selection of AEMO's scenario inputs. The parameters are described quantitatively throughout this report, and in the IASR Assumptions Book.

Table 2 2021-22 scenario settings

Scenario	Slow Change	Steady Progress	Net Zero 2050	Step Change	Hydrogen Superpower
Economic growth and population outlook*	Low	Moderate	Moderate	Moderate	High
Energy efficiency improvement	Low	Moderate	Moderate	High	High
DSP growth	Low	Moderate	Moderate	High	High
Distributed PV	Moderate, but elevated in the short term	Moderate	Moderate	High	High
Battery storage installed capacity	Low	Moderate	Moderate	High	High
Battery storage aggregation / virtual power plant (VPP) deployment	Low	Moderate	Moderate	High	High
Battery Electric Vehicle (BEV) uptake	Low	Moderate	Moderate	High	Moderate/High
BEV charging time switch to coordinated dynamic charging	Low	Moderate	Moderate	High	Moderate/High
Electrification of other sectors (expected outcome)	Low	Low/Moderate	Moderate	Moderate/High	Moderate/High
Hydrogen consumption	Minimal	Minimal	Potential for domestic consumption	Potential for domestic consumption	Large NEM-connected export and domestic consumption
Shared Socioeconomic Pathway (SSP)	SSP3	SSP2	SSP2	SSP1	SSP1
International Energy Agency (IEA) 2020 World Energy Outlook (WEO) scenario	Delayed Recovery Scenario (DRS)	Stated Policy Scenario (STEPS)	Stated Policy Scenario (STEPS), transitioning to action in line with the Sustainable Development Scenario (SDS) in the 2030's and 2040's	Sustainable Development Scenario (SDS)	Net Zero Emissions by 2050 case (NZE2050)

Scenario	Slow Change	Steady Progress	Net Zero 2050	Step Change	Hydrogen Superpower
Climate change impacts based on assumed Representative Concentration Pathway (RCP) (mean temperature rise by 2100)*	RCP7.0 (~4°C)	RCP4.5 (~2.6°C)	RCP4.5 (~2.6°C)	RCP2.6 (~1.8°C)	RCP1.9 (<1.5°C)
Decarbonisation target	26-28% reduction by 2030 No explicit decarbonisation target beyond 2030	26-28% reduction by 2030 Further decarbonisation influenced by technology and economic improvements	26-28% reduction by 2030 Economy-wide net zero target by 2050	Economy-wide net zero before 2050, exceeding 26-28% reduction by 2030 Pace of decarbonisation consistent with limiting temperature rise to 2 degrees, in line with global activities	Economy-wide net zero by early 2040s, exceeding 26-28% reduction by 2030 Pace of decarbonisation consistent with limiting temperature rise to 1.5 degrees, in line with global activities
Generator and storage build costs	CSIRO GenCost Central	CSIRO GenCost Central	CSIRO GenCost Central	CSIRO GenCost High VRE	CSIRO GenCost High VRE†
Generator retirements	In line with expected closure years, or earlier if economic to do so.	In line with expected closure years, or earlier if economic.	In line with expected closure years, or earlier if economic or driven by decarbonisation objectives beyond 2030.	In line with expected closure year, or earlier if economic or driven by decarbonisation objectives	In line with expected closure year, or earlier if economic or driven by decarbonisation objectives

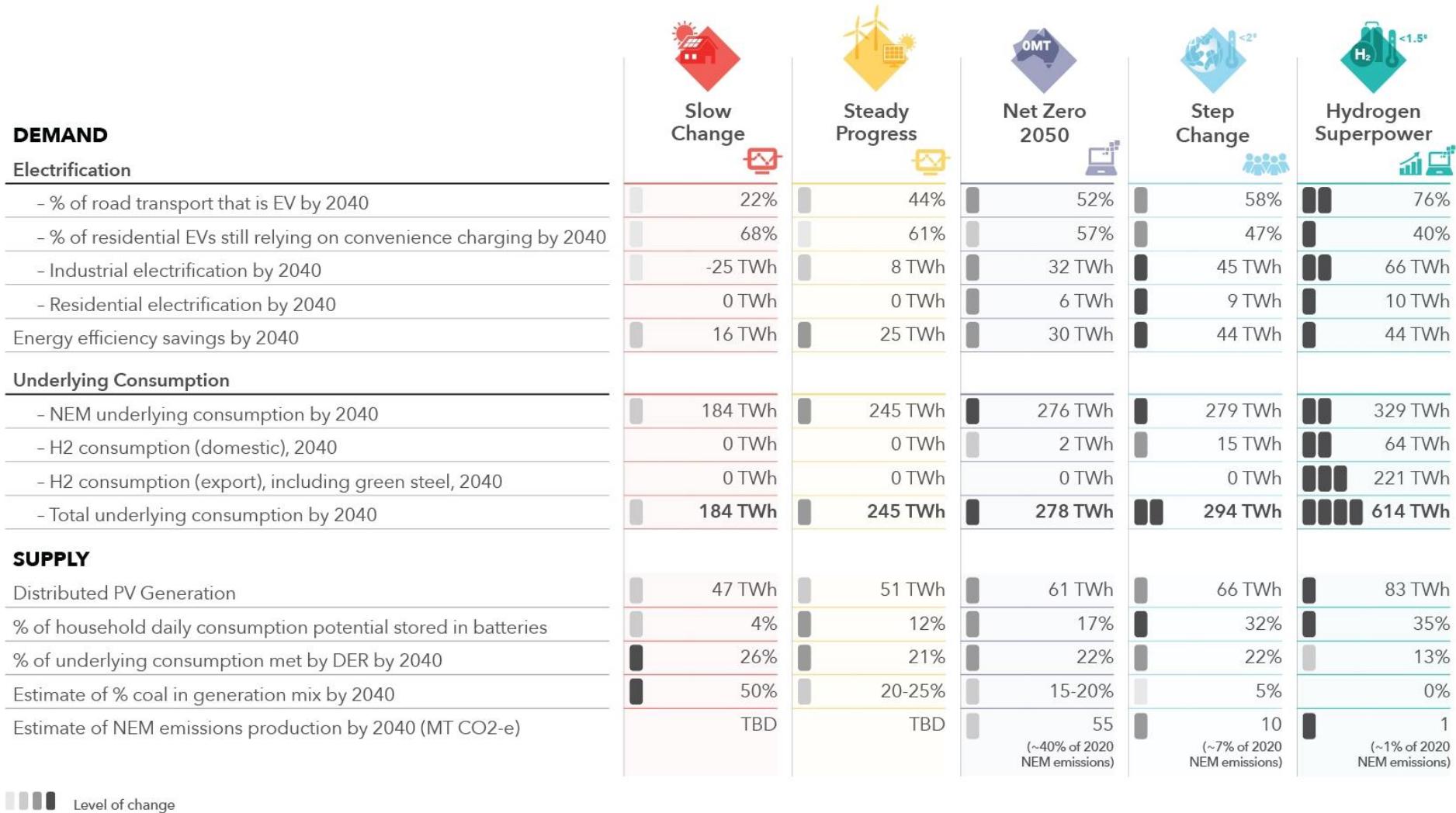
* The modelling will not target a specific global temperature objective, but in applying more rapid decarbonisation activities, it is assumed that a lower RCP is more relevant.

† The Hydrogen Superpower scenario assumes accelerated capital cost reductions for large-scale solar PV compared to the High VRE GenCost scenario, as a key enabler of hydrogen expansion for export.

2.5 A snapshot at 2040

Figure 4 below compares the five scenarios in a snapshot of 2040 projections, with a high-level comparison of key inputs affecting energy demand and supply. The inputs are described in detail in Section 3, and estimates presented here will be confirmed in the 2022 ISP.

Figure 4 Scenario comparison at 2040



2.6 Sensitivities

The five core scenarios capture a range of possible and plausible futures to assess the development needs of the future NEM and risks to consumers associated with over- or under-investment.

Sensitivities serve a different purpose; they are designed to test the materiality of uncertainty associated with individual input parameters or assumptions. They aim to increase the confidence in investment decisions, by testing the sensitivity of outcomes to various input uncertainties.

The approach to sensitivity analysis in the ISP is outlined in the *ISP Methodology*⁸. At a high level, the approach explores the impact of a change in an input or assumption on the ranking of candidate development paths (CDPs), and the magnitude of benefits, across a subset of the scenarios. This approach provides insights which can be used to determine the robustness of the ODP, as well as individual actionable projects within the ODP.

Key input assumptions to be examined in the 2022 ISP via sensitivity analysis include, but are not limited to:

- Lower gas prices – by applying the gas prices in the Low gas price sensitivity across the scenarios (see Section 3.6.1 for further details).
- High and lower discount rates – through the application of the upper and lower bound estimates informed by expert guidance outlined in Section 3.7.1, and a higher value (10%) that AEMO considers prudent to test, considering stakeholder feedback on this input.
- Higher DER uptake rates – applying the CER’s latest distributed solar uptake trajectories (to be published) with the Step Change scenario’s EV and battery DER uptake trajectories to other scenarios deemed most likely.
- Strong electrification – representing a high emissions-reduction future, aligned with the decarbonisation objectives of the Hydrogen Superpower scenario, only in this future, hydrogen uptake is limited and energy efficiency is also more muted. This leaves the majority of the emissions reductions to be achieved through electrification, testing the outer bounds of the existing system. No export hydrogen or associated green steel manufacturing facilities are therefore included in this sensitivity. Other assumptions are by default consistent with the Hydrogen Superpower scenario, unless explicitly identified as unique for this sensitivity in the IASR Assumptions Book, and in this IASR.
- Queensland REZ – assuming the establishment of three Queensland REZs (Northern, Central and Southern QREZ – see Figure 46 in Section 3.9) no later than 2040. The assumed scale of REZ development in these zones is informed by discussions with Queensland Government and Powerlink.

The details of the assumptions applying in these sensitivities are provided in the accompanying IASR Assumptions Book.

AEMO will be guided by modelling outcomes both in the Draft and final ISP in understanding what other sensitivity analysis could be insightful. This could include testing the impact of early coal closures, noting that variations in these outcomes are explored through the core scenarios.

For the 2021 ESOO, sensitivity analysis may examine different assumptions that have a greater impact on the reliability of the power system, as opposed to the future development options over the short, medium, and long term. In this sense, sensitivity analysis is developed and implemented as appropriate within the scope of modelling being conducted.

⁸ At <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isps/2022-integrated-system-plan-isps/isps-methodology>.

3. Inputs and assumptions

3.1 Public policy settings

Input vintage	Policy settings are based on current state and federal government policy commitments.
Source	Australian governments.
Update process	The inclusion of policy settings in the scenarios continue to evolve as initiatives progress through funding and/or legislative processes.

Policy settings are constantly evolving as governments progress policy initiatives. These policies need to be reflected in the settings applied across the scenarios.

AEMO applies the ‘public policy clause’ (National Electricity Rules [NER] 5.22.3(b)) in determining whether a policy is included in scenarios. Some scenarios include parameters that extend beyond the set of policies that satisfy the public policy clause if reflected in the scenario narrative. For a policy to be included in scenarios, it must be sufficiently developed to enable AEMO to identify its impacts on the power system.

There are also five criteria that indicate government commitment to a policy:

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

For the 2021 IASR, having considered policy certainty, scenario narratives, and the public policy clause, AEMO will apply these policies in all scenarios:

- Australia’s 2030 emissions reduction target.
- Large-scale Renewable Energy Target (LRET).
- Victorian Renewable Energy Target (VRET).
- Victoria’s 2020-21 budget initiatives affecting REZs and energy efficiency.
- Queensland Renewable Energy Target (QRET) and associated Queensland Renewable Energy Zones (QREZs).
- Tasmanian Renewable Energy Target (TRET).
- New South Wales Electricity Infrastructure Roadmap.
- *National Electricity (Victoria) Act* (NEVA).
- Various jurisdictional DER and energy efficiency policies.

In some scenarios, AEMO will also explore the impacts of faster rates of energy transition through the inclusion of NEM carbon budgets (see Section 3.2).

The following sections outline in greater detail the various policy settings that will apply, provide reasoning for applying these policies across all scenarios, and explain how the carbon budgets are derived.

Australia's 2030 emissions reduction target

The Federal Government has set a target to reduce greenhouse gas emissions economy-wide to 26% - 28% below 2005 levels by 2030. This was submitted to the United Nations Framework Convention on Climate Change (UNFCCC) in 2015, in Australia's first Nationally Determined Contribution (NDC) under the Paris Agreement. It was then resubmitted in 2020, with the next NDC due for submission to the UNFCCC in 2025, with a post-2030 target⁹. As such, this target currently represents the latest Australian commitment under the Paris Agreement, and is implemented as a constraint on Australian emissions in the multi-sectoral modelling (further details provided in Section 3.2).

Large-scale Renewable Energy Target (LRET)

The national LRET is a legislated policy that provides a form of stimulus to renewable energy development.

In modelling the LRET, AEMO takes account of the legislated target (33,000 gigawatt hours [GWh] by 2020), as well as commitments to purchase Large-scale Generation Certificates (LGCs) from the Green Power scheme and Australian Capital Territory (ACT) reverse auction programs.

The LRET is generally considered to have been met¹⁰ and the incentive it provides to construct additional VRE is minimal. As such, no explicit accounting for the policy is included in the modelling.

Victorian Renewable Energy Target (VRET)

The VRET mandates 40% of the region's generation be sourced from renewable sources by 2025, and 50% by 2030. The target is measured against Victorian generation, including renewable DER. Currently in the region there are over 7,100 megawatts (MW) of committed or proposed wind generation projects, and over 3,800 MW of committed or proposed solar generation projects¹¹. The VRET is legislated¹² and sufficiently developed to enable assessment of impacts on the power system, and is therefore included in all scenarios.

AEMO linearly interpolates the required developments to meet the objective of the VRET between forecast levels of existing, committed and anticipated renewable energy (including forecast distributed PV) and the 2030 target.

Victorian 2020-21 budget initiatives affecting REZs and energy efficiency

In the Victorian 2020-21 budget¹³, Victoria has set aside significant funding – a \$1.6 billion investment – for the establishment of clean energy initiatives and energy efficiency upgrades to homes. This includes \$540 million to establish six REZs.

The spending package also contains investments in energy efficiency, including \$335 million to enable 250,000 gas to electric heater conversions for low income households. Additional funding is available for increased rebates for solar panel installations, extending the Government's existing Solar Homes program, as well as battery installation rebates. Funding support is also provided to enable energy innovation, such as to support hydrogen projects and offshore wind generation in Victoria. As outlined in the later sub-section regarding energy efficiency policies, these funding commitments are captured within the public policy settings.

⁹ See <https://www.industry.gov.au/policies-and-initiatives/australias-climate-change-strategies/international-climate-change-commitments>.

¹⁰ See <http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/Large-scale-Renewable-Energy-Target-market-data>.

¹¹ AEMO May 2021 Generation Information release, at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

¹² Section 7 *Renewable Energy (Jobs and Investment) Act 2017 (Vic)*

¹³ See <https://www.premier.vic.gov.au/making-victoria-renewable-energy-powerhouse>.

At the time of publication of this IASR, policy mechanisms to establish Victorian REZs are not sufficiently detailed for AEMO to identify the specific impacts on the power system. AEMO will continue to work with the Victorian Government to ensure that all policy impacts and funding commitments can be appropriately captured in the ISP, either in the Draft or final ISP.

Queensland Renewable Energy Target (QRET)

The Queensland Government has committed to a 50% renewable energy target by 2030. The target is measured against Queensland energy consumption, including renewable DER. Currently in the region there are over 4,300 MW of committed or proposed wind generation projects, and over 15,300 MW of committed or proposed solar generation projects (nearly 45% of all committed or proposed solar generation projects across the NEM)¹¹. Given that the Queensland Government has committed material funding to the delivery of the QRET in the 2020-21 Queensland Budget Papers¹⁴, the policy is included in all scenarios.

The Queensland Government has also committed material funding to the establishment of three QREZs – Northern, Central and Southern QREZ (see Figure 46 in Section 3.9). The Northern QREZ is most advanced (see Section 3.10.4), with the Queensland Government working with Powerlink to identify strategic investments to upgrade transmission infrastructure between Cairns and Townsville and support generation investments in Queensland's north, including newly committed projects in the area¹⁵.

AEMO linearly interpolates the required developments to meet the objective of the QRET between forecast levels of existing, committed and anticipated renewable energy (including forecast distributed PV) and the 2030 target.

Tasmanian Renewable Energy Target (TRET)

The Tasmanian Government has recently legislated¹⁶ a 200% renewable energy target by 2040, with an interim target of 150% by 2030. This extends the Tasmanian Government's existing commitment for 100% renewable energy by 2022. As the targets are legislated and sufficiently developed to enable assessment of impacts on the power system, the TRET is included in all scenarios. The legislation provides that the target is for 15,750 GWh per year from Tasmanian renewable energy sources by 2030, and 21,000 GWh by 2040. This includes generation provided by distributed PV and larger non-scheduled renewable generation.

AEMO linearly interpolates the required developments to meet the objective of the TRET between forecast levels of existing, committed and anticipated VRE (including forecast distributed PV) and the first interim target. AEMO then applies a linear interpolation of the development requirements to achieve the policy outcomes between the interim and 2040 target.

New South Wales Electricity Infrastructure Roadmap

The New South Wales Government has released an Electricity Infrastructure Roadmap¹⁷ and enabling legislation, the *Electricity Infrastructure Investment Act 2020 (NSW)*, providing a plan to decarbonise New South Wales' electricity system reliably and affordably. The *Electricity Infrastructure Investment Act 2020 (NSW)* sets out minimum statutory objectives that, by the end of 2029, enough renewable generation infrastructure has been constructed to produce at least the same amount of electricity in a year as:

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

¹⁴ Queensland Budget Papers 2020-21 tabled in State Parliament Tuesday 1 December 2020.

¹⁵ See <https://www.epw.qld.gov.au/about/initiatives/renewable-energy-zones>.

¹⁶ *Energy Co-ordination and Planning Amendment (Tasmanian Renewable Energy Target) Act 2020 (Tasmania)* received the Royal Assent 27 November 2020 (see section 3C).

¹⁷ Energy New South Wales, Electricity Infrastructure Roadmap, at <https://energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap>.

Although the capacities are specified in these REZs, the generation is not required to be located in those REZs, or any REZ if the project demonstrates “outstanding merit”, nor to match the capacities specified.

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

The New South Wales objectives exclude any generation capacity that was either existing or committed at or before AEMO’s November 2019 Generation Information page. Therefore, any generation that has progressed to committed or existing since that time is included as contributing to the objectives of the *Electricity Infrastructure Investment Act 2020 (NSW)*.

AEMO will apply a development trajectory at least as fast as the trajectory of energy generating and storage capability specified in the Consumer Trustee’s 2021 Infrastructure Investment Opportunities (IIO) Report over the period until the minimum objective is met¹⁸, provided the report is published in time to be incorporated in the modelling. AEMO will add details of this trajectory to the IASR Assumptions Book that accompanies the IASR once the report is available.

The Central-West Orana REZ transmission project is well progressed with support from New South Wales Government and will be treated as anticipated in 2022 ISP. Any additional transmission investments beyond committed or anticipated projects that may be identified in the IIO as necessary enablers to meet the New South Wales objectives are considered as options which can be developed if identified as delivering market benefits using the cost-benefit analysis (CBA) framework set out in AEMO’s ISP Methodology.

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

The amendment to the NEVA in February 2020 was made to facilitate expedited approval of transmission system upgrades. The Victorian Act enables the Minister to approve augmentations of the Victorian transmission system. For the purpose of the ISP, any Ministerial order that has progressed to the point of approval will be considered as a committed investment, and therefore included in all scenarios.

At the time this IASR was published, one project supported under the Act was considered committed – 300 MW/377 megawatt hours (MWh) battery storage at Moorabool¹⁹.

Distributed energy resources policies

Various policies and initiatives exist across NEM jurisdictions to support uptake of DER, including:

- South Australia – Home Battery Scheme²⁰.
- Victoria – Solar Homes Scheme²¹.
- New South Wales – Clean Energy Initiatives²².
- Emission Reduction Fund and Victorian Energy Saver Incentive Scheme (additional PV non-scheduled generation [PVNSG] revenue stream via Victorian Energy Efficiency Certificates [VEECs] or Australian Carbon Credit Units [ACCUs])²³.
- Australian Capital Territory Next Generation Energy Storage program²⁴.

¹⁸ The development trajectory from the IIO Report may require faster investments in some scenarios.

¹⁹ See https://www.energy.vic.gov.au/_data/assets/pdf_file/0034/495079/Second-VNI-Ministerial-Order.pdf.

²⁰ Details at <https://homebatteryscheme.sa.gov.au/>.

²¹ Details at <https://www.solar.vic.gov.au/>.

²² Details at <https://energy.nsw.gov.au/renewables/clean-energy-initiatives>.

²³ For details see pages 30 to 33 of https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/green-energy-markets-der-forecast-report.pdf?la=en.

²⁴ Details at <https://www.actsmart.act.gov.au/what-can-i-do/homes/discounted-battery-storage>.

- Trial programs to integrate virtual power plants (VPPs) and explore how a network of small-scale PV and batteries can be collectively controlled and fed into the grid²⁵.

AEMO incorporates each of these schemes in its DER uptake and behavioural analysis. They impact both the operational energy consumption forecasts and the load shape (refer to Appendix A3 of the *Electricity Demand Forecasting Methodology*²⁶ for details of the current approach to incorporate DER).

Electric vehicle policies

The EV policies within NEM jurisdictions are included in electricity demand forecasts. These policies support and encourage the investment and uptake of zero emission vehicles that will lower energy carbon intensity in Australia. In 2021, the New South Wales and Victorian Governments both introduced their zero emissions vehicle strategies. The electricity demand forecasts consider these EV schemes and they are applied to all scenarios, with Slow Change following the targets, but ultimately falling short in a slower economy:

- Australian Capital Territory's Transition to Zero Emissions Vehicles Action Plan²⁷ which offers financial incentives for the purchase and registration of zero emissions passenger vehicles.
- New South Wales' Electric Vehicle Strategy²⁸, which aims to increase EV sales to more than 50% of new cars sold in New South Wales by 2030 and for EVs to be the majority of new cars sold by 2035.
- South Australia's Electric Vehicle Action Plan²⁹, which aims to make EVs the common choice for motorists in 2030, and the default choice by 2035.
- Victoria – Zero Emissions Vehicle Roadmap³⁰, which sets a target of 50% of new light vehicle sales being zero emissions by 2030.

More details on the EV forecasts applied in each scenario are provided in Section 3.3.5 and in CSIRO's *Electric Vehicle Projections 2021* report, as outlined in Table 56.

Energy efficiency policies

In all scenarios, the energy efficiency assessment that forms part of electricity demand forecasts considers federal and state-based policies that encourage investments in activities that will lower energy consumption, including:

- Building energy performance requirements contained in the Building Code of Australia (BCA) 2006, BCA 2010, and the National Construction Code (NCC) 2019. The NCC Futures program, which proposes higher building performance requirements in the future, is applied to Step Change and Hydrogen Superpower.
- Building rating and disclosure schemes of existing buildings such as the National Australian Built Environment Rating System (NABERS) and Commercial Building Disclosure (CBD).
- The Equipment Energy Efficiency (E3) program (or Greenhouse and Energy Minimum Standards [GEMS]) of mandatory energy performance standards and/or labelling for different classes of appliances and equipment. Step Change and Hydrogen Superpower also contain proposed programs and those that have currently stopped but may continue in future.
- State-based schemes, including the New South Wales Energy Savings Scheme (NSW ESS), the Victorian Energy Upgrades (VEU) program, and the South Australian Retailer Energy Efficiency Scheme (SA REES). Variations that extend existing savings initiatives are explored in scenarios that have greater

²⁵ Further details on AEMO's VPP integration trials are at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program/Virtual-Power-Plant-Demonstrations>.

²⁶ At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-demand-forecasting-methodology/final-stage/electricity-demand-forecasting-methodology.pdf?la=en.

²⁷ See https://www.environment.act.gov.au/_data/assets/pdf_file/0012/1188498/2018-21-ACTs-transition-to-zero-emissions-vehicles-Action-Plan-ACCESS.pdf.

²⁸ Details at <https://www.nsw.gov.au/initiative/nsw-governments-electric-vehicle-strategy>.

²⁹ Details at <http://www.renewablessa.sa.gov.au/topic/zero-emission-vehicles>.

³⁰ Details at <https://www.energy.vic.gov.au/renewable-energy/zero-emissions-vehicles>.

decarbonisation objectives. In addition, ‘hypothetical’ schemes are considered for regions that do not currently have a state-based scheme.

- Other state measures, including the Victorian House Energy Savings Package and the Victorian Business Recovery Energy Efficiency Fund (BREEF).
- Other national schemes, such as the Commonwealth Emissions Reduction Fund (ERF) and the Clean Energy Finance Corporation (CEFC).
- A hypothetical industrial assessment program for the higher ambition scenarios, modelled on the former Energy Efficiency Opportunities (EEO) program.

State-based emissions targets

Most Australian states have some form of ambition or policy that targets emissions reduction; a number of these are framed around targeting net zero emissions. However, in most cases, these policies have limited detail, funding, or underpinning legislative framework to enable assessment of how they will impact the power system. The emissions reduction targets for Victoria³¹ and the Australian Capital Territory³² are legislated, however have not been explicitly included. This is because they lack sufficient detail in how they should be applied, particularly in how they relate to geographical boundaries – for example, the treatment of offsets outside the jurisdiction. The ambitions of these jurisdictions are, however, considered across the set of scenarios, in particular through those that achieve Australia-wide net zero emissions. Specific policies which would contribute to meeting emissions targets, such as EV policies or energy efficiency policies, have been captured and are addressed above.

3.2 Emissions and climate assumptions

The scenarios in this IASR are aligned to global narratives to ensure they are consistent with possible future developments, as well as to anchor them to be consistent with potential global developments.

For this IASR, AEMO’s scenarios have been aligned to both the International Energy Agency’s (IEA’s) World Energy Outlook (WEO) 2020³³, as well as to a framework comprised of Shared Socio-Economic Pathways (SSPs) and Relative Concentration Pathways (RCPs)³⁴.

SSPs act as potential baseline scenarios, with different energy, land-use, and projected emission changes that arise as a result of different world narratives. SSPs can then be associated with different greenhouse gas trajectories and corresponding temperature increase projections (based on the RCPs). AEMO’s scenarios have been aligned to SSP/RCP pairings within the group of pairings that will underpin future work by the Intergovernmental Panel on Climate Change (IPCC) on the Sixth Assessment Report (AR6), to be published over 2021-22. AR6 will contain the latest assessment of the scientific basis of climate change, its impacts and future risks, as well as adaptation and mitigation options.

The IEA WEO and the special Net Zero by 2050 report

In its latest WEO, the IEA presented four scenarios varying in how the global energy system may recover following the COVID-19 pandemic and evolve over the coming decades. The latest WEO focused in particular over the period to 2030, which it identified as a pivotal decade for the energy sector. In May 2021, the IEA

³¹ See the Victorian Climate Change Act 2017, which results in five-yearly emissions reduction targets with the aim of reaching net zero by 2050. The Victorian Government has announced interim targets for 2025 (28-33% below 2005 levels) and 2030 (45-50% below 2005 levels).

³² Under the *Climate Change and Greenhouse Gas Reduction Act 2010*, the Australian Capital Territory set a target to achieve net zero emissions by 2045, as well as an interim 40% reduction target over 1990 emissions by 2020. The *Climate Change and Greenhouse Gas Reduction (Interim Targets) Determination 2018* also sets a range of interim reduction targets over 1990 emissions: 50-60% less by 2025, 65-75% less by 2030, and 90-95% less by 2040.

³³ Further information on the IEA’s World Energy Outlook scenarios can be accessed at <https://www.iea.org/reports/world-energy-outlook-2020>.

³⁴ SSP data can be accessed via the SSP database (<https://tntcat.iiasa.ac.at/SspDb/dsd?Action=htmlpage&page=50>).

also published a special Net Zero by 2050 (NZ2050) report³⁵, which presented a roadmap for the global energy sector and extended its focus over the period to 2050. This report drew on findings from the WEO2020, as well as from the IEA's Energy Technology Perspectives 2020 (which also examined whether net zero emissions could be achieved by 2050).

The latest scenario narratives from the IEA are summarised in Table 3 below, showing that the IEA's Net Zero by 2050 scenario goes beyond AEMO's Net Zero 2050 scenario, as it sets both a target level of emissions by 2050 as well as a goal to limit temperature rise to no more than 1.5°C, and is more akin to AEMO's Hydrogen Superpower scenario.

Table 3 Latest IEA scenario narratives

IEA scenario	Summary narrative
Stated Policies Scenario (STEPS)	COVID-19 is brought under control and the global economy returns to pre-crisis levels in 2021. This scenario reflects all of today's announced policy intentions and targets if they are backed up by detailed measures for their realisation. It is consistent with temperature increases of around 2.7°C in 2100.
Delayed Recovery Scenario (DRS)	This scenario has similar policy assumptions as STEPS, but with a late economic recovery, and therefore lower energy demand growth. Emissions as a result are also lower than STEPS, due to lower levels of activity.
Sustainable Development Scenario (SDS)	This scenario sees increased investment in low carbon technologies, and a surge in clean energy policies. With similar economic assumptions to STEPS, SDS is also consistent with meeting the Paris Agreement goal of 1.5°C and 2°C (depending on assumptions on the deployment of negative emission technologies). Countries with net zero targets by 2050 successfully meet them, and global net zero is achieved by 2070.
Net Zero by 2050 (NZ2050)	This scenario goes beyond SDS by targeting <i>global</i> net zero emissions by 2050, consistent with meeting a 1.5°C target without the need for large net negative emissions globally. The IEA's special report expanded the analysis for this scenario beyond 2030. Global net zero by 2050 requires unprecedented action, including a global boom in clean energy and energy infrastructure investment, and a very sharp adjustment away from investments in fossil fuel supply, with no new oil and gas fields approved for development beyond 2021.

The SSP/RCP framework

Table 4 provides a summary of the SSP narratives³⁶ that AEMO has linked to its scenarios (see Table 5), and the relevant RCP that will be used by the IPCC for AR6.

These SSP narratives and associated RCPs provide a global backdrop to the domestic outlooks examined in the scenarios, while the linkages are intended to keep the scenarios as internally consistent as possible. The different RCPs chosen influence various forecast components, including the global carbon budgets in the multi-sector modelling (described in Section 3.3.4), and the temperature settings that inform climate parameters (described in Section 3.8).

³⁵ The Net Zero by 2050 report can be accessed at <https://iea.blob.core.windows.net/assets/4482cac7-edd6-4c03-b6a2-8e79792d16d9/NetZeroby2050-ARoadmapfortheGlobalEnergySector.pdf>.

³⁶ More detail on SSP narratives can be accessed at <https://www.sciencedirect.com/science/article/pii/S0959378016300681?via%3Dihub>.

Table 4 Relevant SSP narratives and associated RCPs

SSP title	Narrative	Associated RCPs to be considered in AR6 (temperature target by 2100) [†]
SSP1. Sustainability – Taking the Green Road (Low challenges to mitigation and adaptation)	The world shifts gradually, but pervasively, towards a more sustainable path, emphasizing more inclusive development that respects perceived environmental boundaries. Inequality falls both within and between countries, and consumption adjusts towards low material growth and lower resource and energy intensity.	RCP1.9 (<1.5°C) and/or RCP2.6 (~1.8°C)
SSP2. Middle of the Road (Medium challenges to mitigation and adaptation)	The world follows a path in which social, economic, and technological trends do not markedly shift from historical patterns. While some environmental systems experience degradation, overall, they improve, while the resource intensity and energy use declines.	RCP4.5 (~2.6°C)
SSP3. Regional Rivalry – A Rocky Road (High challenges to mitigation and adaptation)	Policy reorients to focus more on national and regional issues, while investments in education and technological development decline. Economic development is slow, with material-intensive consumption and increased inequality. Strong environmental degradation occurs in some regions, as environmental policy loses importance.	RCP7.0 (~4.0°C)

[†] Mean temperature increases for each RCP sourced from the SSP database, available at <https://tntcat.iiasa.ac.at/SspDb/dsd?Action=htmlpage&page=50>, IAM Scenarios tab.

Mapping the IASR scenarios

Table 5 below summarises the mapping of each 2021 IASR scenario to the WEO and to SSP/ RCP scenarios. The 2021 IASR scenarios are also mapped to GenCost global scenarios discussed further in Section 3.5. Anchoring the 2021 scenarios to global narratives reframes them to consider broader energy, social, economic, and demographic trends across the globe.

Table 5 Scenario mappings

2021 IASR scenario	WEO scenario	SSP	RCP	GenCost (CSIRO)
Steady Progress	STEPS	SSP2 – Middle of the Road	RCP4.5 (around 2.6°C increase in temperatures by the end of the century)	Central (assumes global climate policy ambition does not prevent a greater than 2.6°C increase in temperature)
Net Zero 2050	STEPS (pre-2030), transitioning to SDS	SSP2 – Middle of the Road	RCP4.5 (around 2.6°C increase in temperatures by the end of the century)	Central (assumes global climate policy ambition does not prevent a greater than 2.6°C increase in temperature)
Slow Change	DRS	SSP3 – Regional Rivalry	RCP7.0 (around 4°C increase in temperatures)	Central (assumes global climate policy ambition does not prevent a greater than 2.6°C increase in temperature)
Step Change	SDS	SSP1 – Sustainability	RCP2.6 (consistent with a less than 2°C increase in temperatures, in line with the Paris Agreement)	High VRE (assumes strong global climate policy consistent with maintaining temperature increases below 2°C)
Hydrogen Superpower	NZ2050	SSP1 – Sustainability	RCP1.9 (consistent with limiting temperature increases to 1.5°C)	High VRE (assumes strong global climate policy consistent with maintaining temperature increases below 2°C)

In mapping the scenarios in this 2021 IASR to the IEA's and the SSP/RCP framework, AEMO provides the following observations:

- The **Steady Progress** scenario aligns suitably to the IEA's STEPS, as it reflects currently legislated and/or funded policy positions. It is also aligned to SSP2 (which represents a continuation of current trends) and reflects an average temperature rise of 2.6 °C by 2100.
- AEMO's **Net Zero 2050** scenario is best aligned with STEPS over the period to 2030, given its close alignment to Steady Progress over that period while greater research and development activity seeks to commercialise the technologies needed to decarbonise. Technology deployment is anticipated in the next decade to lower emissions to meet a 2050 net zero target, which will require increasing action over the remaining two decades to 2050. Increasing action and investments effectively transition towards a narrative most aligned with the SDS scenario, which sees countries with individual 2050 net zero targets meet them successfully. As such, given the scenario represents a "commercialise then deploy" approach, the Net Zero 2050 scenario is assumed not to be sufficient to achieve the temperature emission increases consistent with the SDS scenario (less than 2°C), and is therefore best aligned with a temperature rise of approximately 2.6°C by 2100.
- The **Step Change** scenario is best aligned to the IEA's SDS scenario, and RCP2.6 (both consistent with a temperature rise less than 2°C by the end of the century, in line with the Paris Agreement), as well as to SSP1 (with the fastest transition towards low carbon technologies).
- The **Slow Change** scenario is aligned with the IEA's DRS and SSP3, as the narrative of these scenarios sees less of a decarbonisation drive and lower levels of economic growth.
- The **Hydrogen Superpower** scenario is most closely aligned to the IEA's NZ2050, given the scale of transformation to support the achievement of the Paris Agreement, underpinned by the commercial deployment at significant scale of hydrogen technologies, domestically and globally. The deployment enables significant structural changes in global energy consumption and generation towards low carbon energy. It is therefore consistent with a temperature rise of less than 1.5 °C by 2100.

Carbon budgets in the scenarios

To ensure that the scenarios adopt emissions abatement outcomes consistent with the narratives and approach described above, AEMO deployed whole-of-economy multi-sectoral modelling to inform the pace and breadth of energy transformation across the scenarios, performed by CSIRO and ClimateWorks. Two key outcomes from these forecasts were:

- Carbon budgets for the electricity sector.
- The scale of fuel switching as industrial, commercial, and residential loads shift fuel use towards lower emissions energy sources, particularly electrification.

CSIRO and ClimateWorks' detailed methodology and insights can be found in the supplementary materials to this 2021 IASR, as outlined in Table 56.

To determine the appropriate pace and scale of energy transformation, AEMO's consultants deployed a model to determine economy-wide energy demands at the minimum total system cost, subject to physical, technological, and policy constraints, the temperature goals described above, and assuming appropriate reductions in carbon intensity from technological improvement and deployment. This model considered end-use demand sectors including agriculture, mining, manufacturing, other industry, commercial and services, residential, transport (road and non-road), and land use, including forestry.

Consistent with the scenario narratives, the modelling identified investments consistent with global emissions reductions.

In determining the electrification (see Section 3.3.5) and overall carbon budget, the modelling considers the cost-effectiveness of various abatement options to lower emissions, including alternative technologies and fuels, energy efficiency investments, and land-use sector sequestration.

NEM carbon budgets

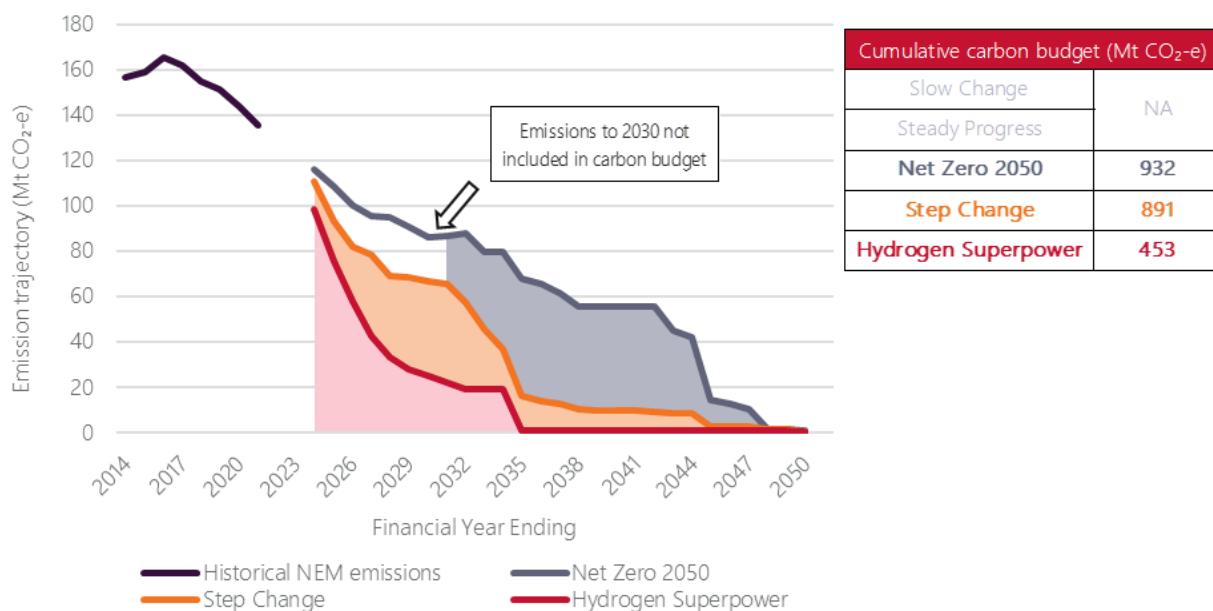
AEMO's scenarios capture both increased electrical load via electrification within the electricity demand forecasts of each scenario (see Chapter 2), and the emissions trajectory that the NEM must remain within to maintain a consistent level of abatement as forecast by the broader economic model. These emissions trajectories are converted into carbon budgets for the NEM for scenarios that capture increased action within the scenario definition.

For the Slow Change and Steady Progress scenario, no coordinated whole-of-economy decarbonisation strategy exists sufficient to deliver net zero emissions on or before 2050, with decarbonisation in the NEM primarily driven by the commercial decisions of consumers and industry.

Carbon budgets are deployed within AEMO's ISP Methodology rather than a specific decarbonisation trajectory, giving AEMO's models the flexibility to identify the most efficient means to meet the long-term carbon budget while minimising costs.

Figure 5 below presents the NEM emission trajectories from 2024 to 2050 (financial year ending) that are produced by the multi-sectoral modelling, compared to historical NEM emissions. Given the higher detail and granularity in AEMO's models, NEM emissions from the multi-sectoral modelling are then aggregated and imposed as cumulative budgets in the modelling. The figure also presents the cumulative carbon budgets that will be imposed onto each scenario. These carbon budgets are applied within AEMO's models as described in the ISP Methodology³⁷.

Figure 5 NEM emission trajectories from multi-sectoral modelling and the resulting cumulative carbon budgets



As evidenced in Figure 5, a cumulative carbon budget will be used in Step Change and Hydrogen Superpower from 2024 onwards (in line with the ISP modelling horizon). The Net Zero 2050 scenario will only impose a carbon budget derived from the multi-sectoral modelling for the period 2031-50. Before 2031, the Net Zero 2050 scenario has been designed such that the emissions over the period to 2030 must meet, or fall below, the Federal Government's 2030 target.

Given the similarity of inputs between Steady Progress and Net Zero 2050 over the period to 2030 (as outlined in Section 2.5), NEM emissions are expected to follow a similar trajectory in both scenarios.

³⁷ At <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isps/2022-integrated-system-plan-isps/isps-methodology>.

The emissions intensity of each generator and new entrant technology is detailed in the IASR Assumptions Book.

3.3 Consumption and demand: historical and forecasting components

AEMO uses a range of historical data to train and develop its models, and forecast input data series (component forecasts) to project future outcomes using these models.

Historical components are updated at varying frequencies, from live metered data to monthly, quarterly, or annual batch data. Key historical data includes:

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

AEMO updates its projections of energy consumption and demand at least annually³⁸, and includes significant stakeholder consultation through the Forecasting Reference Group (FRG), industry engagement via surveys, consultant data and recommendations, and AEMO's internal forecasting of each sector and sub-sector affecting energy consumption and peak demands.

Key components in the forecasts include:

- DER uptake and generation/charging/discharging patterns, including the potential aggregation and coordinated charging / discharging opportunities for DER (such as VPPs):
 - Distributed PV.
 - Customer energy storage systems (ESS).
 - EVs.
- Economic and population growth drivers, including meter connections.
- Climate.
- Stakeholder surveys, including for large industrial loads (LILs) across various sectors, including liquified natural gas (LNG) exports.
- Energy efficiency and fuel switching, both policy-driven and in the context of possible electrification pathways that Australia can take.

The specific detail about how these inputs are applied to develop electricity forecasts (consumption and maximum/minimum demand) is outlined in the *Electricity Demand Forecasting Methodology*³⁹. For gas demand forecasting, the GSOO's demand forecasting methodology⁴⁰ also outlines the usage of these key inputs.

³⁸ Updated forecasts within a year can be issued in case of material change to input assumptions.

³⁹ At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-demand-forecasting-methodology/final-stage/electricity-demand-forecasting-methodology.pdf?la=en.

⁴⁰ At https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2021/2021-gas-statement-of-opportunities-methodology-demand-forecasting.pdf?la=en.

AEMO's 2021 energy consumption forecasts, maximum and minimum demand forecasts, and detailed component forecasts will be published in AEMO's Forecasting Portal⁴¹when the ESOO is published in August 2021.

The following sections describe the individual component inputs that are used by the component forecasting methodologies deployed in preparing the electricity consumption, maximum and minimum demand forecasts. Where appropriate, comparisons are made with this IASR's scenarios against 2020 scenarios (Step Change, Slow Change and Central).

3.3.1 Historical demand data

Input vintage	<ul style="list-style-type: none">March 2021May 2021 for loss data
Source	<ul style="list-style-type: none">SCADA/EMMS/NMI DataGeneration Information pageAER and network operators
Updates since Draft IASR	Updated to use latest available information.

Operational demand

Operational demand as-generated is collected through the electricity market management system (EMMS) by AEMO in its role as the market operator.

Operational demand as generated includes generation from scheduled generating units, semi-scheduled generating units, and some non-scheduled generating units⁴².

Generator auxiliary load

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

Network losses

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

Large industrial loads

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

Residential and business demand

The split of historical consumption data into business and residential segments is performed using a combination of sampling of AEMO residential meter data and annual ratios between the two segments provided by electricity distribution businesses to the AER as part of their processes in submitting a regulatory information notice. Further details of the approach are in Appendix 7 (Data Segmentation) of the *Electricity Demand Forecasting Methodology*.

⁴¹ At <http://forecasting.aemo.com.au>.

⁴² A small number of exceptions are listed in Section 1.2 of https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/2020/demand-terms-in-emms-data-model.pdf.

Distributed PV uptake and generation

AEMO sources historical PV installation data from the Clean Energy Regulator (CER) and applies a solar generation model to estimate the amount of power generation at any given time. Refer to Section 3.3.6 for details. The DER Register data⁴³ is used for validating the historical PV installation data.

3.3.2 Historical weather data

Input vintage	Daily currency
Source	Bureau of Meteorology (BoM)
Updates since Draft IASR	Updated to use latest information from live data stream from the BoM

AEMO uses historical weather data for training the annual consumption and minimum and maximum demand models as well as forecast reference year traces. The historical weather data comes from the Bureau of Meteorology (BoM)⁴⁴, using a subset of the weather stations available in each region, as shown in Table 6.

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

Table 6 Weather stations used in consumption, minimum and maximum demand

Region	Station name	Data range
New South Wales	BANKSTOWN AIRPORT AWS	1989/01 ~ Now
Queensland	ARCHERFIELD AIRPORT	1994/07 ~ Now
South Australia	ADELAIDE (KENT TOWN)	1993/10 ~ 2020/07
South Australia	ADELAIDE (WEST TERRACE)	2020/07 ~ Now
Tasmania	HOBART (ELLERSLIE ROAD)	1882/01 ~ Now
Victoria	MELBOURNE (OLYMPIC PARK)	2013/05 ~ Now
Victoria	MELBOURNE REGIONAL OFFICE	1997/10 ~ 2015/01

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

Input vintage	Daily currency
Source	<ul style="list-style-type: none"> • Generation Information page • Settlements data • NMI data • DER Register • DSP Information Portal
Updates since Draft IASR	Updated to use May 2021 Generation Information page and take into consideration submissions to DER Register and DSP Information Portal (to May 2021).

⁴³ DER Register, at <https://aemo.com.au/en/energy-systems/electricity/der-register>.

⁴⁴ Bureau of Meteorology Climate Data, at <http://www.bom.gov.au/climate/data/>.

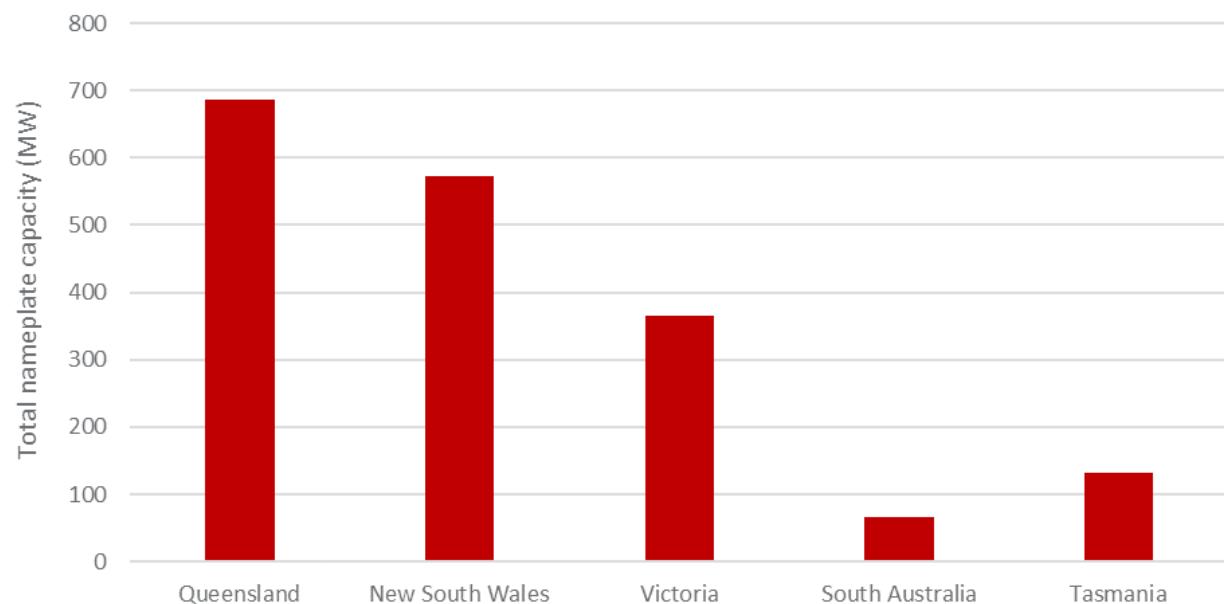
AEMO reviews its list of other non-scheduled generators using information from AEMO's Generator Information dataset obtained through surveys, as well as through submissions from network operators (to assist with connection point forecasting) and publicly available information.

Through these three sources of information, AEMO collects withdrawn, committed, and proposed ONSG (non-scheduled generation that excludes distributed PV⁴⁵) connections and site information. AEMO uses the generator's Dispatchable Unit Identifier (DUID) or NMI to collect generation output at half-hourly frequency.

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

AEMO's current view of ONSG is contained in the Generation Information page. As at the May 2021 release, which was used in the development of the demand and energy forecasts, aggregated ONSG by NEM region is shown in Figure 6, noting that changes to aggregated non-scheduled generation capacity since this release are minimal.

Figure 6 Aggregate other non-scheduled generation capacity, by NEM region



3.3.4 Multi-sectoral modelling influences to demand forecasts

Input vintage	<ul style="list-style-type: none">Updated forecast finalised in June 2021.
Source	CSIRO and ClimateWorks Australia
Updates since Draft IASR	New section outlines the impact of multi-sectoral modelling. Draft forecasts were presented to FRG in April 2021, and final forecasts in June 2021.

AEMO engaged consultants CSIRO and ClimateWorks Australia to conduct multi-sectoral modelling to establish least-cost pathways for Australia's economy to achieve emissions targets while meeting the scenario-based demand parameters (such as the economic growth forecasts, DER uptake, and road transport EV forecast). The scenarios and sensitivities considered in this multi-sectoral modelling were the Net Zero

⁴⁵ Distributed PV is discussed in Section 3.3.4.

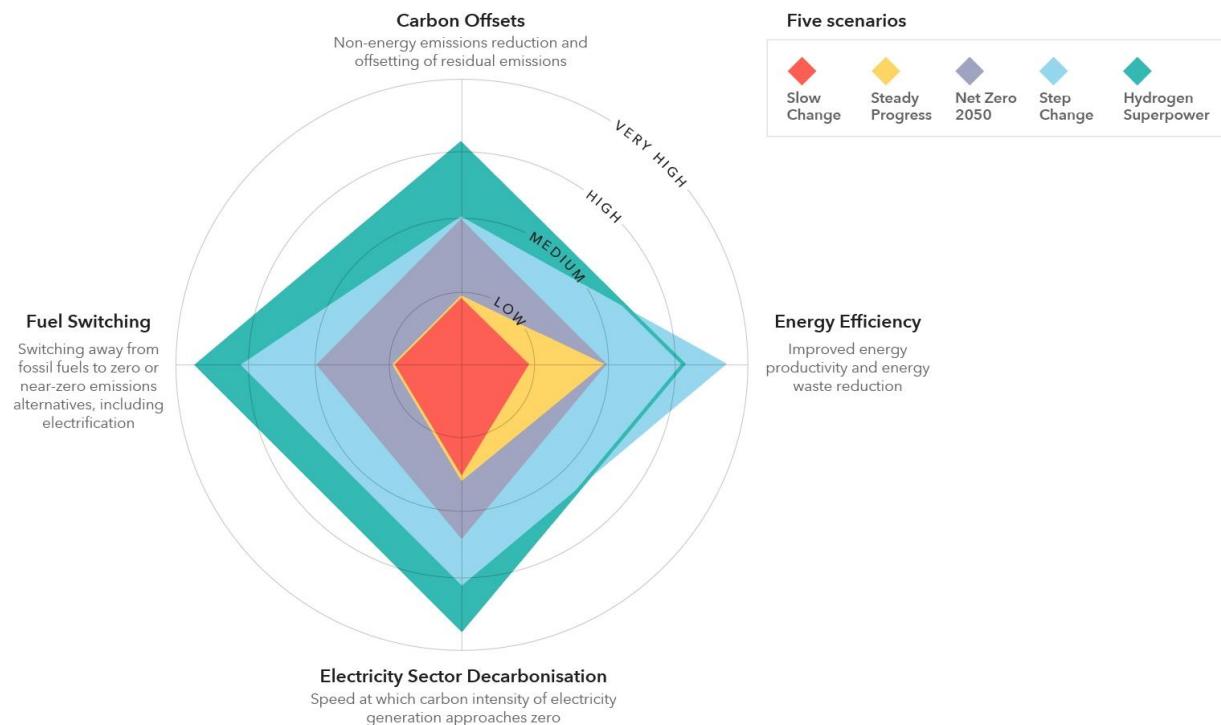
2050 scenario, Step Change scenario, Hydrogen Superpower scenario and the Strong Electrification sensitivity. These scenarios all reach comparable levels of economy-wide carbon intensities by 2050, but the rate of decarbonisation differs significantly. The Slow Change and Steady Progress scenarios do not impose specific economy-wide emissions reduction targets, so no multi-sectoral modelling outputs influence those scenarios' consumption forecasts.

CSIRO's AusTIMES economy-wide model simultaneously considers a range of options to meet the scenario-specific temperature goals or emission targets discussed in Section 3.2 at the least cost. These options broadly fall under the four pillars of decarbonisation:

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

While all four pillars of decarbonisation are considered in all scenarios, some are favoured more than others to reflect uncertainty around future technology improvements, costs, and barriers to deployment, and to align with scenario narratives. The scenario variations, with more or less emphasis on any one of the four pillars, are depicted in Figure 7.

Figure 7 Four pillars of decarbonisation, and the scale of utilisation of each across scenarios



This multi-sectoral modelling complements the component forecasts of electricity consumption outlined in subsequent sections, providing a broader consideration of the wider economy that may use other sources of energy in futures that have carbon constraints within the scenario narratives. The potential for electrification of those loads, the broad magnitude of energy efficiency savings opportunities, and the energy intensity of the future economy are all key drivers that may influence the future NEM. The modelling aims to capture these changing medium- to long-term drivers of the NEM that may not be captured by trend-based or historical regression modelling.

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

- Future energy consumption trends:
 - Electricity consumption forecasts by sector (such as commercial, industrial, agriculture, manufacturing and mining) to inform the changing long-term energy intensity of the business sector electricity consumption forecasts produced using AEMO's *Electricity Demand Forecasting Methodology*.
 - Electrification forecasts by sector that encompass new electricity growth, added to traditional forecast components in the residential and business forecasts.
 - Magnitude of the use of each decarbonisation pillar for the scenarios, to inform the appropriate relativity of energy efficiency forecasts, as developed bottom-up considering the influence of energy efficiency policies, as outlined in Section 3.3.10. This perspective enabled improved consideration of the relativity of each scenario narrative with regards to these pillars, and provided independent validation of the scale of energy efficiency savings.
- National and NEM emissions pathways for scenarios that incorporate carbon constraints. (See Section 3.2 for further details).
- Domestic hydrogen production as a substitute for other energy sources, complementing any assumed export demand (in the Hydrogen Superpower scenario only).

Summary of outcomes

At a high level, the key assumptions and outcomes from the multi-sectoral forecasts across the scenarios are described in Table 7. More detail is provided in the CSIRO/ClimateWorks supporting report (See Table 56).

Fuel switching includes electrification and/or use of alternative fuels such as hydrogen or bio-fuel, the latter particularly used for aviation.

Table 7 Key assumptions and outcomes from the multi-sectoral modelling

	Net Zero 2050	Step Change	Hydrogen Superpower	Strong Electrification
Electrification (Section 3.3.5)	<p>Initial focus on research and development rather than deployment across a range of low and zero emissions technologies in the 2030s. Minimal electrification until the mid-2030s when electrification becomes more cost-effective. To meet the target of net zero emissions economy-wide by 2050, a late push in climate action in the 2040s results in a steep acceleration of electrification, particularly industrial electrification.</p> <p>Residential gas heating remains fairly consistent until it approximately halves in the mid-2030s and is almost entirely electrified in the final years of the horizon.</p> <p>Electrification adds 70 terawatt hours (TWh) of new consumption by 2040 (see Section 3.3.5).</p>	<p>This scenario shows a steady rate of electrification, as early coordinated action in response to the tight carbon budget allows a smoother transition.</p> <p>To meet emissions targets in this scenario, all gas heating is electrified over the modelling horizon.</p> <p>Electrification adds 91 TWh of new consumption by 2040 (see Section 3.3.5).</p>	<p>This scenario shows a variable rate of electrification. From 2025 to 2040 there is strong electrification before slowing down in 2040 once hydrogen becomes more competitive.</p> <p>Residential gas heating is not so strongly electrified in this scenario, with the existing gas connections preferring to switch to hydrogen.</p> <p>Electrification adds 117 TWh of new consumption by 2040 (see Section 3.3.5).</p>	<p>This sensitivity includes a strong and enduring rate of electrification.</p> <p>To meet emissions targets in this scenario, all gas heating is electrified over the modelling horizon.</p> <p>Electrification adds 148 TWh of new consumption by 2040 (see Section 3.3.5).</p>

	Net Zero 2050	Step Change	Hydrogen Superpower	Strong Electrification
Energy efficiency (Section 3.3.10)	Lowest energy efficiency uptake of the modelled scenarios.	This scenario has the strongest energy efficiency measures per unit of demand.	This scenario has increased demand and also strong energy efficiency measures.	Compared with Hydrogen Superpower, this sensitivity has slightly muted energy efficiency measures.
Hydrogen development (Section 3.3.14)	Continued research and development and demonstration projects lowers technology costs for electrolyzers. These cost reductions enable some transport, pipeline and (later) industrial uptake as the push to decarbonise to net zero emissions by 2050 is accelerated. By 2050 the hydrogen consumption is around 180 PJ.	Continued research and development and demonstration projects lowers technology costs for electrolyzers. These cost reductions, and faster decarbonisation ambition, sees greater and earlier uptake of hydrogen in industry, compared with the Net Zero 2050 scenario. By 2050 the hydrogen consumption is still around 180 PJ.	Accelerated breakthroughs in technology cost reductions, consistent with the Government's Technology Roadmap ambition of achieving \$2/kg hydrogen costs. Hydrogen development is a defining factor for this scenario, seeing increasing use in transport, industry, and residential heating with some pipeline gas. It also sees new export industries for green steel and hydrogen as an export commodity. The domestic demand, including green steel, grows to over 700 PJ. The energy exports grow to 1,800 PJ.	In this scenario the hydrogen breakthroughs do not occur and while hydrogen sees some uptake in heavy transport, it plays no other role.
Carbon sequestration (see below)	Land-use sector sequestration is not material until 2030, then from that time there is an almost linear increase through to 140 million tonnes (Mt) carbon dioxide equivalent (CO ₂ e) by 2050.	This scenario sees a gradual need for sequestered emissions, with land-use sector sequestration accelerating to 25 Mt CO ₂ e per annum by 2030. From there, there is a linear growth to reach 140 Mt CO ₂ e by 2050.	A challenging carbon budget requires early action with steep increases to reach almost 170 Mt CO ₂ e per annum by the late 2030s. At this point, with a notably decarbonised economy, the need for carbon sequestration reduces.	A challenging carbon budget requires early action with steep increases to reach almost 140 Mt CO ₂ e per annum by the late 2030s. At this point, with a notably decarbonised economy, the need for carbon sequestration reduces.
Fuel switching to bioenergy (see below)	Bioenergy grows strongly in non-road transport, growing from 0 to 40% of energy share. It grows in industry from around 7.5% to 10.5% share and in residential from 12% to 21% share. It is not projected to play a major role in either pipeline gas injection or electricity generation.	Bioenergy grows strongly in non-road transport, growing from 0 to 38% of energy share. It grows marginally in industry from around 7.5% to 8.5% share and in residential from 12% to 22% share. It is not projected to play a major role in either pipeline gas injection or electricity generation.	Bioenergy grows strongly in non-road transport, growing from 0 to 35% of energy share. It grows in industry from around 7.5% to 10% share and in residential from 12% to 21% share. It is not projected to play a major role in either pipeline gas injection or electricity generation.	Bioenergy grows strongly in non-road transport, growing from 0 to 35% of energy share. It grows in industry from around 7.5% to 10.5% share and in residential from 12% to 21% share. It is not projected to play a major role in either pipeline gas injection or electricity generation.

	Net Zero 2050	Step Change	Hydrogen Superpower	Strong Electrification
NEM emissions (Section 3.2)	NEM is projected to approximately halve emissions by the late 2030s, and reduce to near-zero emissions by the late 2040s.	The NEM emissions are projected to halve by around 2030 and reduce down to 10% by the late 2030s. By the mid-2040s, emissions are near-zero.	The NEM emissions are projected to halve by 2026, before almost entirely decarbonising by 2035.	The NEM emissions are projected to halve by 2026, before almost entirely decarbonising by 2035.

While the table above provides references to following sub-sections, which translate the multi-sectoral modelling outputs into AEMO's inputs and assumptions, carbon sequestration (a key pillar for decarbonisation) and fuel switching to bioenergy are not discussed elsewhere and so are addressed below. AEMO incorporates varying levels of carbon offsets within the scenario narratives and in the carbon budgets that apply in net zero emission futures. Carbon offsets and fuel switching from oil to bioenergy are broadly outside AEMO's forecasting and planning models and methodologies. The following sections provide a summary of their influences in the broader economy, with more detail available in the companion CSIRO report⁴⁶.

Carbon sequestration

The multi-sectoral model considers carbon sequestration both in terms of technology advances to capture and store carbon from emitting processes as well as land-use sector sequestration to capture carbon from the air through biological processes.

The multi-sectoral modelling selects a small amount of technology-based carbon sequestration; the volume is small compared with land-use sector sequestration, accounting for between 3% and 10% of all sequestered carbon (depending on scenario).

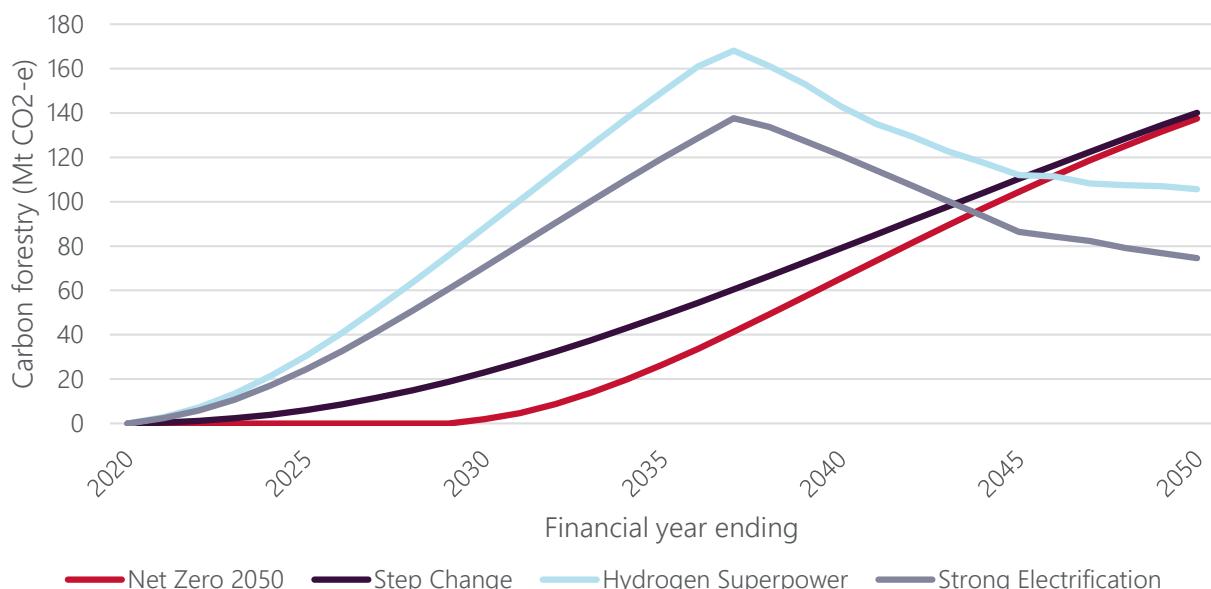
Figure 8 shows the forecast amount of carbon sequestration due to both land-use sector sequestration and process-based carbon capture and storage.

The Hydrogen Superpower scenario (and the Strong Electrification sensitivity which targets the same decarbonisation ambition) show that early investment in sequestration is necessary to achieve the tighter carbon budgets of these cases. Post 2030s, investment in carbon capture and storage is expected to be maintained, although new investments in land-use sector sequestration could be more muted (unless used to offset emissions globally), particularly once a net zero economy is achieved in Australia. This is observed by the reduction in total sequestration in the last decade in these scenarios.

In terms of understanding scale, the peak land use sequestration ranges from 8.6 million hectares (Mha) in Net Zero 2050 to 10.9 Mha in Hydrogen Superpower.

⁴⁶ CSIRO, *Multi-sector Energy Modelling Report*, at <https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isps/2022-integrated-system-plan-isps/current-inputs-assumptions-and-scenarios>.

Figure 8 Carbon sequestration due to land-use sector sequestration and process-based carbon capture and storage



Fuel switching to bioenergy

Bioenergy has a range of uses and forms across the economy that are captured in the multi-sectoral modelling, ranging from wood for residential heating through to aviation fuel replacements. While strong growth is projected in some areas, most significantly in aviation (non-road transport), the model does not identify opportunities for material impact for electricity generation or pipeline gas. The effective impact of bioenergy on the IASR is to limit the scale of electrification and hydrogen in some of the sectors as some of the opportunity will be more easily and cost-efficiently transferred to bioenergy resources.

3.3.5 Electrification

Input vintage	• Updated forecast finalised in July 2021.
Source	• CSIRO and ClimateWorks Australia (multi-sector modelling) • CSIRO (road transport modelling)
Updates since Draft IASR	New section outlines the modelling of electrification of other sectors from both the multi-sector modelling and the EV forecasts. The multi-sector modelling is outlined in Section 3.3.4. The road transport modelling outcomes were presented to the FRG in February 2021, draft forecasts were presented in March 2021, followed by a two-week consultation period, and final results were presented in April 2021.

AEMO considers electrification of residential load, business load (comprised of both commercial and industrial), and transport load. As forecast in multi-sectoral modelling, some existing energy usage can be met with alternative energy sources through fuel switching; one of these options that is expected to be highly material in a transforming energy sector is electrification. Figure 9 shows the total electrification across the modelled scenarios, including the impact of projected EV uptake.

In the residential and commercial (building) sectors, appliances that service space heating, cooking, and hot water are all able to be electrified, shifting from gas or liquefied petroleum gas (LPG) demand into electricity demand. The cost-efficiency of electrification is uncertain, and will depend on many factors, including appliance replacement costs, electricity infrastructure capabilities and costs, and the availability of alternative fuels, such as hydrogen or blended hydrogen-natural gas. AEMO has therefore considered a range of

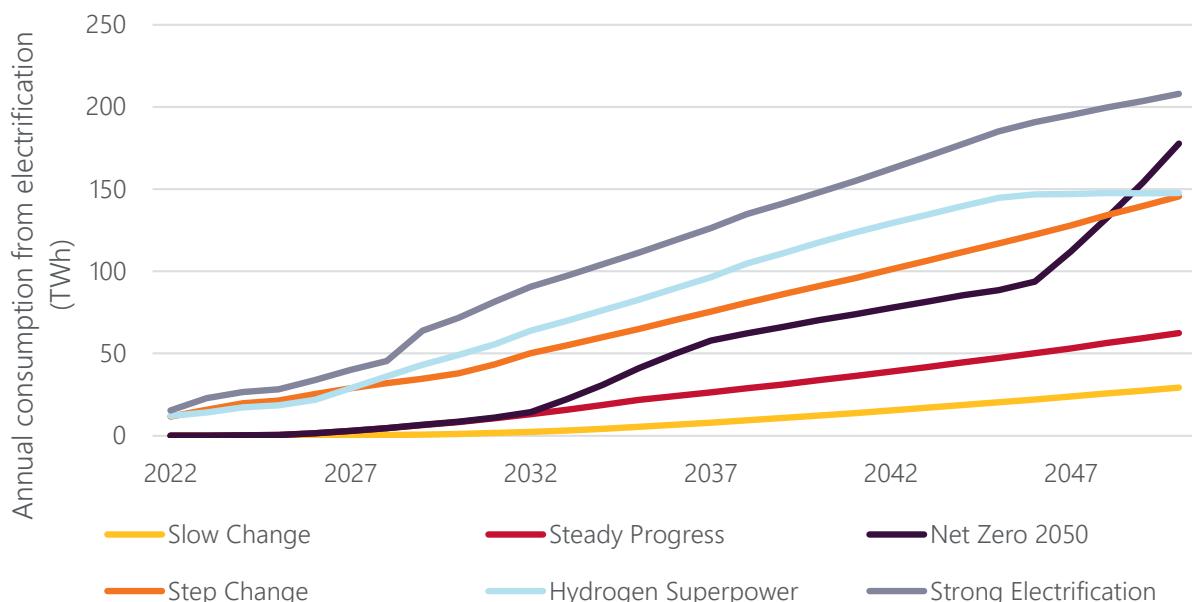
electrification outcomes for these sectors, with the Hydrogen Superpower scenario applying greater hydrogen fuel substitution as an alternative to electrification.

In the industrial sector there is a wide range of subsectors considered, each of which have their own fuel consumption profiles. Broadly speaking, most oil and gas demands can be electrified (or switched to biofuels, as recognised in the previous section). In addition, through some technological advances, such as the direct reduction process for iron and steel, it may be possible to convert from high temperature blast furnaces to lower temperature electric arc furnaces. Investment in these technological advances may be economically efficient in scenarios with more ambitious emissions reductions, to help decarbonise more challenging industrial processes and lower broader economy costs associated with alternative investments or offsets.

Electrification of transport is expected in all scenarios.

Figure 9 demonstrates the magnitude of electrification forecast for each scenario, including transport, showing that by 2050 in scenarios with net zero emissions, at least 150 terawatt hours (TWh) of new electricity consumption is forecast – almost, if not exceeding, the current operational consumption of the NEM. Early investments in the Hydrogen Superpower and Step Change scenarios enable a relatively smooth trajectory for electrification. Conversely, as the Net Zero 2050 scenario focuses more on research and development prior to deployment, a faster pace of electrification is forecast approaching 2050. Total electrification in 2050 is highest in this scenario, with heavier reliance on electrification of some of the more challenging industrial processes, due to the cumulative impact of not having started to decarbonise the economy early. For example, relatively late changes to building codes or appliance standards to improve energy efficiency results in less energy efficiency savings being realised by 2050 once replacement rates are taken into account.

Figure 9 Electrification of other sectors based on multi-sector modelling and EV projections



Note: for Slow Change and Steady Progress scenarios, the electrification shown is solely from EV uptake.

Impact of electrification on daily and seasonal load shape

In converting the electrification consumption (excluding the transport sector) into half-hourly data, AEMO assumes:

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

weather-induced consumption patterns on a daily basis, ensuring higher winter heating load than summer.

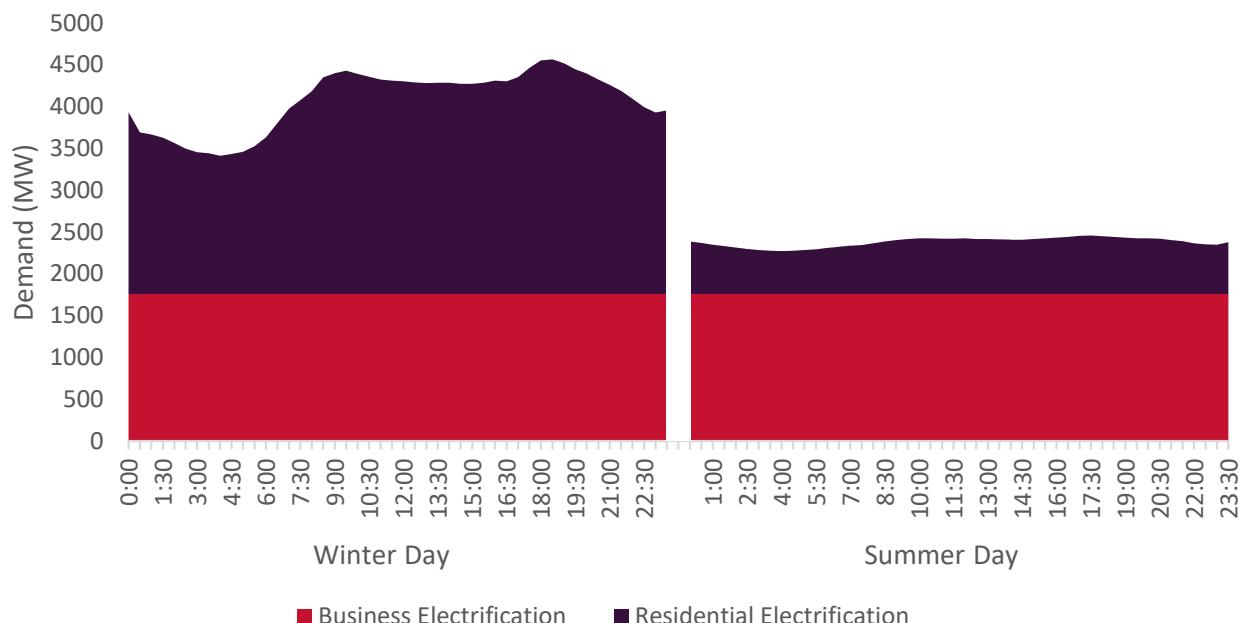
- To apply half-hourly temporal resolution, the shape of the newly electrified loads is assumed to mirror existing electricity consumption patterns for that day, generally with more load in the day than overnight.

Figure 10 contrasts two example daily load profiles of residential and business electrification (excluding the transport sector). The business electrification load is assumed to be flat across the year and across the day as large industrial loads electrify their processes. The residential load profile varies across the day and is much higher in winter compared to summer due to a large proportion of it being heating load.

The electrification component only captures the energy needed to perform the activities previously performed by alternative forms, with inherent efficiency gains in fuel-conversion as appropriate. It does not contain the changes in the efficiency of the individual appliances over time, which is captured within the Energy Efficiency component (See 3.3.10).

The resulting traces for each scenario, incorporating the impacts of electrification, will be published with the 2021 ESOO.

Figure 10 Example electrification day shape contrasting winter and summer (Victoria 2050, Net Zero 2050)



Battery electric vehicle uptake

Input vintage	<ul style="list-style-type: none"> Updated forecast finalised in May 2021.
Source	<ul style="list-style-type: none"> CSIRO
Updates since Draft IASR	Forecasts have been updated through a consultancy. Draft assumptions were presented to the FRG in February 2021, draft forecasts were presented in March 2021, followed by a 2-week consultation period, and final results were presented in April 2021.

Electrification of the transport sector will increase electricity consumption in future.

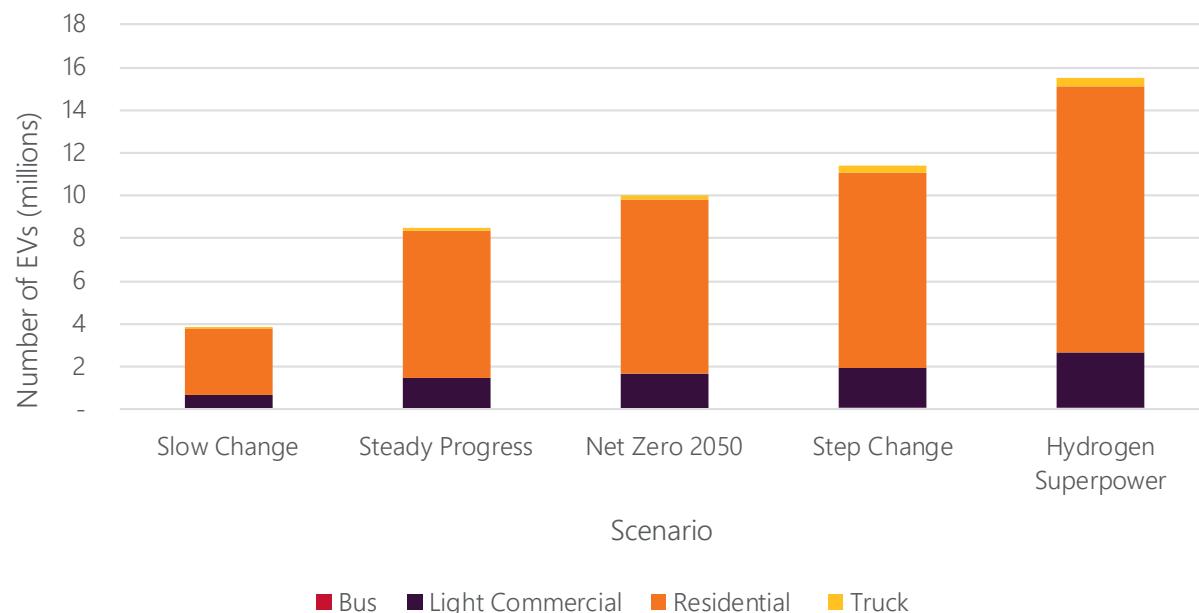
Key factors for battery EV (BEV) adoption (including battery and plug-in hybrid EVs) are outlined in CSIRO's *Electric Vehicle Projections 2021* report⁴⁷, and include:

- Government policies (see Section 3.1 for policies included in the 2021 forecasts).
- The difference between levelised cost of driving of BEVs and internal combustion engine vehicles (ICEs).
- Substitutes and alternatives to BEVs (such as public transport, rideshare services, and hydrogen fuel-cell vehicles).
- Commercial fleet ownership.
- Access to charging infrastructure.
- The availability of different BEV models and sizes in Australia.
- Competing developments – vehicle availability, technology improvement and infrastructure deployment – of hydrogen fuel-cell vehicles (FCVs).

Currently, BEVs are estimated to represent less than 1% of the total vehicle fleet across the NEM. Based on the current level of uptake, AEMO's central outlook applied in the Net Zero 2050 and Steady Progress scenarios assumes that the uptake of EVs across the NEM will reach approximately 8.5%, of the total road transport fleet or about one and a half million BEVs, by 2029-30. Growth is forecast to accelerate in the late 2020s through to 2035, due to policy incentives, assumed falling of costs of BEVs and greater access to more model and size choices, and charging infrastructure. By the end of 2040, about 50% of the total road transport fleet of approximately 10 million vehicles is expected to be BEVs for both the Net Zero 2050 and Steady Progress scenarios.

Figure 11 shows the projected uptake of BEVs by vehicle type across AEMO's scenarios in 2040, with residential vehicles forecast to be the largest BEV sector for all scenarios, followed by light commercial vehicles and trucks. More detail on the projected uptakes for each scenario is provided in the accompanying IASR Assumptions Book.

Figure 11 NEM forecast number of BEVs by vehicle type across scenarios in financial year 2040



⁴⁷ See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/csiro-ev-forecast-report.pdf for more details.

EV charging behaviours

The method and frequency of BEV charging will impact the daily load profile of NEM consumers. Charging is likely to be influenced by the availability and type of public and private charging infrastructure, tariff structures, energy management systems, the driver's routine, and charging preferences in weekdays versus weekends and in different seasons.

AEMO incorporates four fixed charging profiles that capture alternative charging patterns of consumers, considering the level of availability of these charging influences:

- Convenience charging – vehicles assumed to have no incentive to charge at specific times and/or no access to alternative charging facilities other than at the place of residence.
- 'Smart' daytime charging – vehicles incentivised to charge during the day through fixed time-of-use tariff structures, with available associated infrastructure to enable charging at this time.
- 'Smart' night-time charging – vehicles incentivised to charge overnight through fixed time-of-use tariff structures, with available associated infrastructure to enable charging at this time.
- Highway fast-charging – vehicles require a fast-charging service while in transit.

These fixed charging profiles are provided in the IASR Assumptions Book.

Over time, it is expected that EV charging is moving from following fixed daily patterns to be optimised around the availability of generation from variable renewable energy sources. As result, AEMO also models three dynamic charging behaviours:

- Coordinated charging – vehicle charging (when connected to appropriate infrastructure) is assumed to be optimised by third party agent (retailer/aggregator) to occur when demand otherwise is low (typically associated with high PV generation).
- Vehicle to Grid (V2G) – vehicles assumed to have associated infrastructure that enables electricity retailers or aggregators to utilise vehicle battery capacity to charge from and discharge to the grid at times that best services the needs of the electricity grid.
- Vehicle to Home (V2H) – vehicles assumed to have associated infrastructure at a place of residence and are self-incentivised to utilise excess electricity within the vehicle's battery with associated DER to export directly to the home at times that best services the needs of the household.

By way of example, Table 8 shows the assumed proportion of EV charging profiles for residential consumers, used to estimate the impact on maximum and minimum electricity demands for each scenario. It shows the assumed evolution of consumer adoption of 'smarter' charging profiles and the influence of digitalisation and increased consumer incentives/tariffs to change to more efficient charging behaviours.

Table 8 Assumed proportions of BEV charging profiles applied to total BEVs

	Convenience (%)	Smart daytime (%)	Smart nighttime (%)	Highway fast-charging (%)	Co-ordinated (%)	V2G (%)	V2H (%)
2030-31							
Slow Change	80.7	3.9	9.6	5.4	0.0	0.2	0.2
Steady Progress	73.4	4.7	12.1	8.4	0.6	0.4	0.4
Net Zero 2050	73.4	4.7	12.1	8.4	0.6	0.4	0.4
Step Change	67.5	4.1	12.8	12.3	2.0	0.7	0.7

	Convenience (%)	Smart daytime (%)	Smart nighttime (%)	Highway fast-charging (%)	Co-ordinated (%)	V2G (%)	V2H (%)
Hydrogen Superpower	63.1	5.8	12.5	14.4	2.5	0.9	0.9
2040-41							
Slow Change	67.1	6.7	15.9	5.2	0.0	2.5	2.5
Steady Progress	60.1	5.0	12.4	5.7	10.1	3.4	3.4
Net Zero 2050	55.4	4.8	13.2	6.6	10.3	4.8	4.8
Step Change	45.3	3.1	9.8	8.4	17.6	7.9	7.9
Hydrogen Superpower	38.1	3.7	10.4	9.5	19.3	9.5	9.5
2049-50							
Slow Change	57.7	9.3	18.8	5.0	0.0	4.6	4.6
Steady Progress	49.0	2.5	8.6	5.0	22.8	6.1	6.1
Net Zero 2050	43.7	2.4	8.8	5.0	22.6	8.8	8.8
Step Change	30.8	0.0	0.0	5.0	35.7	14.3	14.3
Hydrogen Superpower	21.9	0.0	0.0	5.0	38.6	17.3	17.3

Charge profile preferences are forecast to change over time. Early adopters of EVs are assumed to predominantly charge at times aligned with the convenience charge profile, as evidenced currently. The increasing electrification of the transport sector is expected to lead to greater charging infrastructure development and tariff change, providing consumers with greater choice to charge their vehicles in ways that are increasingly flexible, lowering user costs, while minimising grid cost and impact. As a result, AEMO anticipates growth over time in charging behaviour aligned to times of low overall demand, such as when distributed PV generation is high. As shown in the table above, the Step Change scenario demonstrates strong digitalisation trends influencing consumer behaviours, with increased shifts away from convenience based charging towards smarter more dynamic methods of charging.

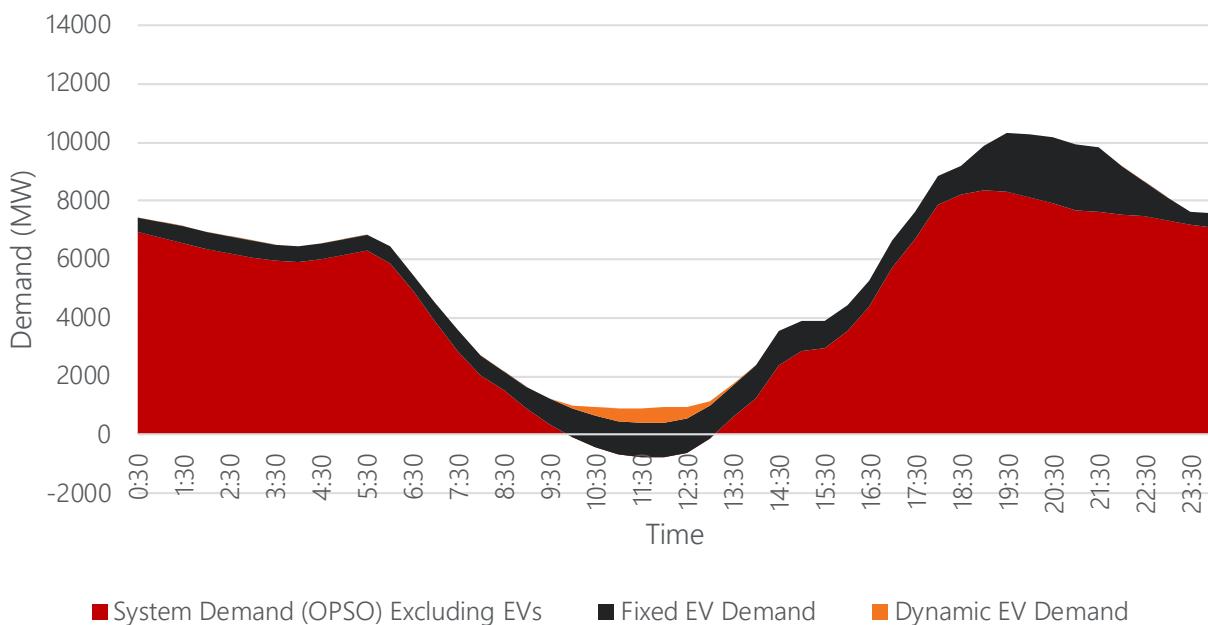
The resulting load traces developed for each scenario published with the 2021 ESOO will incorporate the vehicle charge profiles that are not coordinated (that is, excluding co-ordinated, V2H and V2G profiles). The IASR Assumptions Book also provides example daily charge patterns for each scenario for these same charging profiles.

Vehicles will remain modes of transportation first and foremost, and a key challenge (as the sector transforms) will be the enablement of data-driven decision-making that attempts to maintain vehicle availability for travel when required, while avoiding unnecessary costs to consumers associated with charging. Without this, charging load may put more stress on the power system than may be necessary with energy management innovation incorporated into these future vehicles and charging infrastructure.

Figure 12 below shows examples of projected contribution to demand from BEV charging. It demonstrates the importance of dynamic charging forms, such as coordinated charging, and infrastructure required to enable them, as they will lower the potential impact to the electricity system peak demands and increase the level of electricity demand at trough periods.

The figure shows fixed charging behaviour on aggregate contributes to the daily peak, while the dynamic charging shifts the electricity charging of BEVs to earlier times to utilise higher PV generation during the day. Under these conditions, a proportion of EVs are assumed to be sufficiently incentivised to charge in a coordinated manner to flatten the electricity demand profile, reducing maximum demand and increasing minimum demand (relative to if BEV charging was uncoordinated).

Figure 12 Weekday fixed and dynamic BEV demand by vehicle type charge profile assumed for the Net Zero 2050 scenario in January 2040 for New South Wales



Note: Dynamic EV Demand refers to the co-ordinated and V2G/V2H profiles, while Fixed EV Demand refers to the combined load from all other remaining charging profiles that are static and independent of prevailing market conditions.

3.3.6 Distributed energy resources

Input vintage	• Updated forecast finalised in May 2021.
Source	• CSIRO • Green Energy Markets
Updates since Draft IASR	All forecasts have been updated through consultancies, and have addressed issues with PV being under-forecast in 2020. Draft distributed PV, battery storage uptake, and VPP aggregation were presented to the FRG in March 2021, followed by a two-week consultation period before being finalised.

DER describes consumer-owned devices that, as individual units, can generate or store electricity or have the 'smarts' to actively manage energy demand. This includes small-scale embedded generation such as distributed PV systems (including PVNSG), battery storage, and EVs. To establish the 2021 DER forecasts, AEMO engaged CSIRO and Green Energy Markets (GEM) to prepare independent forecasts of this important component. With two forecasts, using two independent models but aligned to the same assumptions and scenario narratives, AEMO considers that the accuracy of the forecasts are improved over a single view. The forecasts were then consulted on through FRG meetings.

Table 9 below describes the source of the forecasts that were used in each scenario. Stakeholders should consider this when considering each consultant report on the forecasts, detailed in Table 56.

Table 9 DER consultant scenario mapping

	Slow Change	Steady Progress	Net Zero 2050	Step Change	Hydrogen Superpower
Consultant forecast used for distributed PV and battery uptake	CSIRO Slow Growth	Average of CSIRO and GEM Current Trajectory	Average of CSIRO and GEM Net Zero	GEM Sustainable Growth	GEM Export Superpower

Note: the consultant reports refer to the Steady Progress scenario as "Current Trajectory", the Step Change scenario as "Sustainable Growth", and Hydrogen Superpower as "Export Superpower".

AEMO includes both consultant forecasts based on stakeholder feedback and to explore a level of dispersion across the scenario collection to capture the long term uncertainty of DER uptake. The Steady Progress and Net Zero 2050 scenarios adopted an averaging approach of the consultants' forecasts, as these were both considered to be each consultants' best estimates, consistent with the scenario narratives. The Slow Change, Step Change and Hydrogen Superpower scenarios thereby explore the possible range of DER investments considering each scenario's narrative and purpose, and capture material dispersion between the trajectories. Averaging consultant forecasts for these scenarios would not be appropriate as this would narrow the range and imply false improved long term accuracy for the trajectories.

The IASR Assumptions Book contains AEMO's latest DER forecasts, representing the aggregation of the forecasts provided by the consultants in 2021. At a high level, the DER forecasts across the scenarios are described in Table 10. The Steady Progress and Net Zero 2050 scenario projections are the same through to 2031 and then diverge to reflect differences in ongoing rates of decarbonisation beyond that point.

Table 10 Mapping of DER settings and assumptions to proposed scenarios

	Slow Change	Steady Progress	Net Zero 2050	Step Change	Hydrogen Superpower
Distributed PV uptake	Moderate, but elevated in the short term	Moderate	Moderate	High	High
Battery uptake	Low	Moderate	Moderate	High	High
Battery aggregation as VPP	Low	Moderate	Moderate	High	High
BEV Uptake	Low	Moderate	Moderate	High	Moderate/High
BEV infrastructure	Low	Moderate	Moderate	Moderate/High	Moderate/High
Level of coordinated BEV charging	Low	Moderate	Moderate	High	Moderate/High
Fuel cell EVs	Low	Low	Moderate	Moderate	High

Distributed PV

Current distributed PV installed capacity estimates are from the CER, with DER Register data now becoming available as a supplement. PVNSG installed capacity estimates are provided by the Australian Photovoltaic Institute (APVI), in the first instance, then supplemented by the CER and DER Register.

Distributed PV normalised generation half-hourly profiles are provided by Solcast⁴⁸. PVNSG normalised generation half-hourly profiles are generated by AEMO using satellite solar irradiance data provided by

⁴⁸ Rooftop PV normalised generation half-hourly profiles prior to 2007 were provided by the University of Melbourne in collaboration with AEMO.

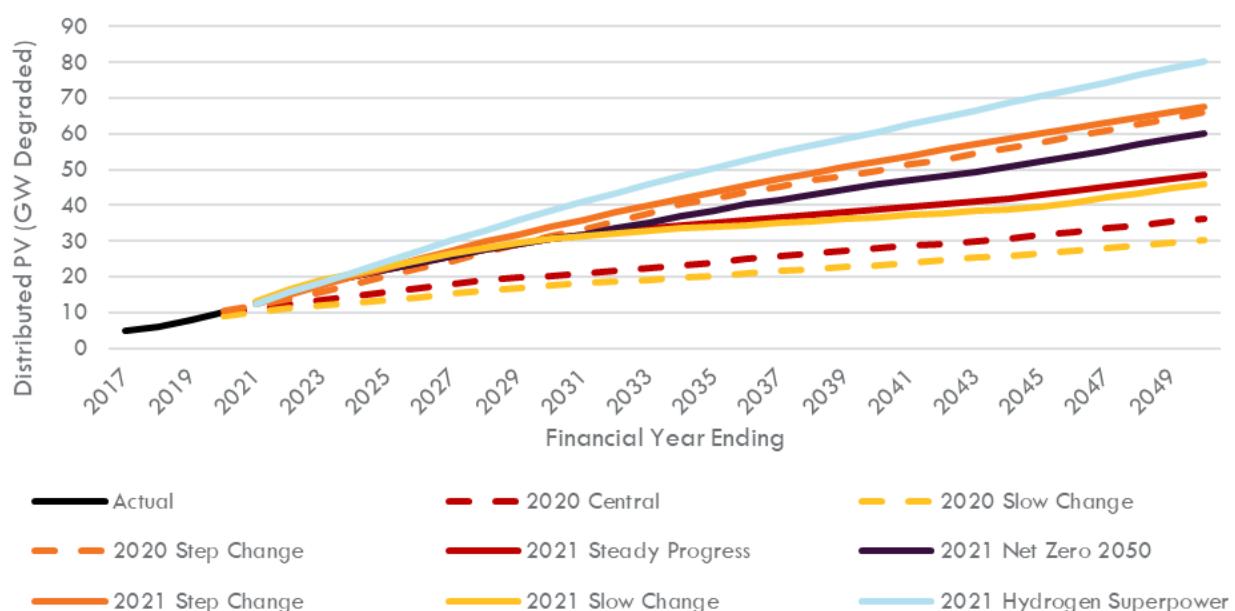
Solcast. The solar irradiance data is a key input into the System Advisory Model⁴⁹ from the National Renewable Energy Laboratory to construct generation profiles.

The uptake of distributed PV systems, including residential rooftop and commercial systems, is forecast to continue to grow strongly. The total capacity of distributed PV systems in the NEM at May 2021 is approximately 14.1 GW⁵⁰.

Figure 13 shows the uptake forecasts across the scenarios according to the scenario mapping in Table 10. Additional information on these forecasts is available in the CSIRO⁵¹ and GEM⁵² reports (see Table 56). The 2021 forecasts are noticeably higher than the 2020 forecasts across all scenarios in the short to medium term. This is largely due to observations of strong uptake of PV despite the downturn in the economy which was anticipated last year during the initial phases of the COVID-19 pandemic, with both CSIRO and GEM revising their forecasts upwards this year. Both consultants consider that the observed strong uptake will persist, at least in the short term. This is supported by data from the CER that indicates that record levels of installations continue to be observed, with over 1.5 GW of small and mid-scale systems installed so far this year. Further, they project yearly growth to increase steadily.

Details on both CSIRO and GEM's revised approach and outlook can be found in the reports referenced above.

Figure 13 NEM distributed PV installed capacity (degraded)



AEMO assumes a rebound of energy consumption equal to 20% of the energy generated by the PV systems as lower future bills may change consumption behaviour or trigger investments in equipment that uses more electricity. This assumption is made largely from anecdotal evidence of a limited sample of consumer data currently available. AEMO will continue to analyse data to validate this assumption in future years.

⁴⁹ For more on the SAM model, see <https://sam.nrel.gov/>.

⁵⁰ Installed capacity estimate as at 7 May 2021 for rooftop solar PV and March 2021 for PVNSG.

⁵¹ See https://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2021/CSIRO-DER-Forecast-Report.

⁵² See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/green-energy-markets-der-forecast-report.pdf?la=en.

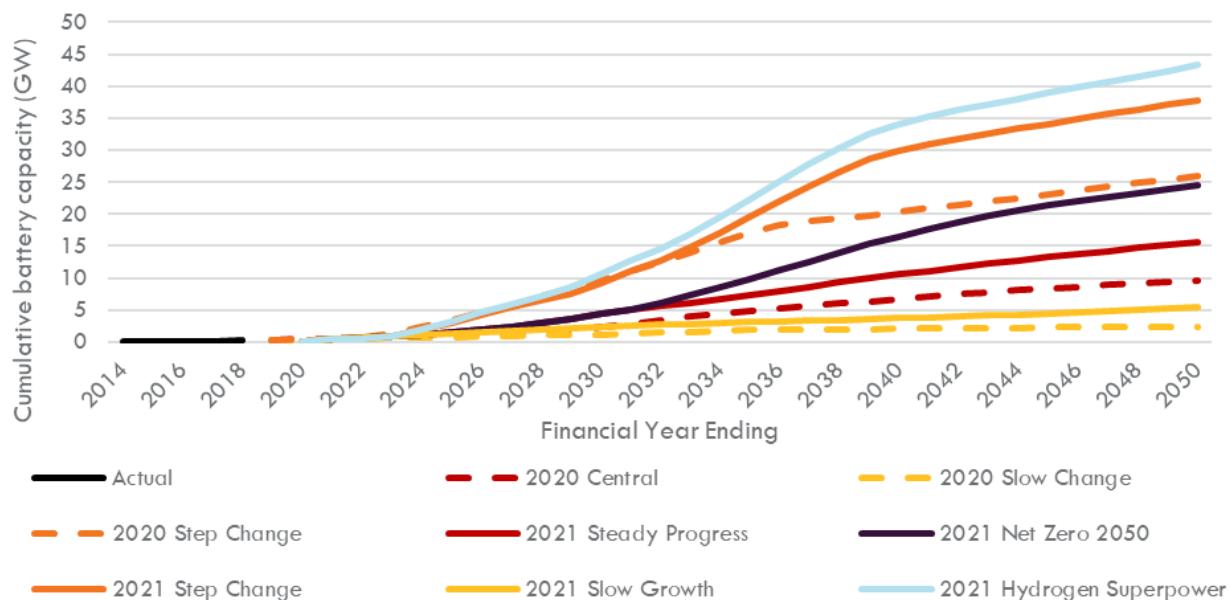
Battery storage uptake

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

- The storage capacity (in kilowatt hours [kWh]), and charge/discharge power (in kilowatts [kW]) of batteries installed.
- The relative penetration of various tariffs and associated battery charge/discharge operation modes⁵³.
- The size and degree of coupling of any complementary PV system and the energy consumption of the household or business.

Figure 14 shows the total forecast installed capacity of customer battery systems across the NEM for all scenarios. The increase in the 2021 forecasts compared to the 2020 forecasts is largely driven by the higher distributed PV forecasts (with greater distributed PV penetration driving a positive externality on the value, and therefore uptake, of battery installations). Additional information on these forecasts, including assumptions on key factors listed above, is available in the CSIRO and GEM reports.

Figure 14 Behind-the-meter battery forecasts for the NEM



Battery storage profiles and virtual power plants

A VPP broadly refers to an aggregation of DER, coordinated using software and communications technology to deliver services that have traditionally been performed by a conventional power plant. In Australia, grid-connected VPPs are focused on coordinating distributed PV systems, battery storage, and EVs. AEMO is collaborating across the industry to establish VPP demonstrations to identify the role VPPs could have in providing reliability, security, and grid services.

While VPPs in the NEM are currently on a small scale, VPP trials are demonstrating the value to the grid and participating consumers of continued coordinated deployment.

AEMO models a projected level of aggregation among distributed storage systems which would operate to meet system peaks (rather than household drivers), effectively acting as a VPP (assumptions are provided in Figure 15). The schedulable component of the aggregated batteries (the VPP) would be operated in the

⁵³ See Appendix A3.2.2 of the *Electricity Demand Forecasting Methodology Information Paper* for more information on assumed battery operating types.

market models in the same way as large-scale batteries. These batteries are assumed to operate with perfect foresight and optimise charge and discharge to minimise system cost. If the supply-demand balance is tight, this will mean batteries are operated to offset as much unserved energy as possible.

Battery systems installed by homeowners and not aggregated would be assumed to behave to minimise grid costs for that household, which may impact the charging and discharging behaviours of these assets. As such, this much more passive behaviour may not optimally discharge to meet market signals, reducing the system benefits relative to VPPs. An example of the type of profile that AEMO has used to model the default charging behaviour is shown in Figure 16, although the exact VPP operating behaviour will be influenced dynamically through the needs of the power system on a daily basis.

Household and utility-scale batteries are currently modelled with a 2:1 energy to power ratio only, and 90% and 80% round-trip efficiency respectively. This means that, from fully charged, the battery could provide two hours of supply if discharging at full capacity.

Figure 15 Aggregation trajectories for VPP forecasts

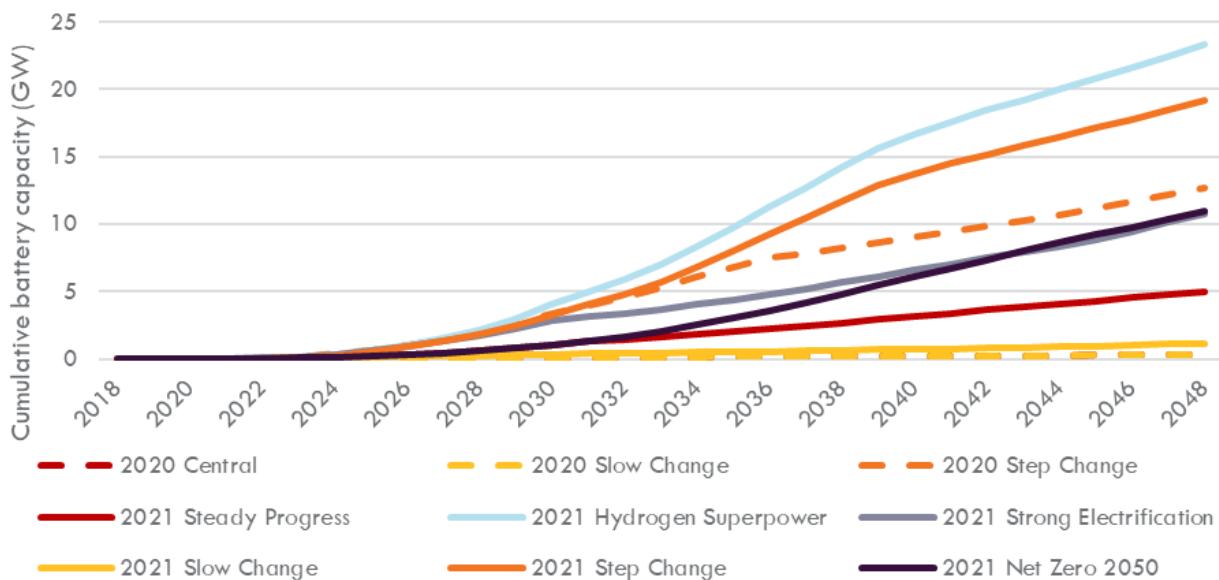
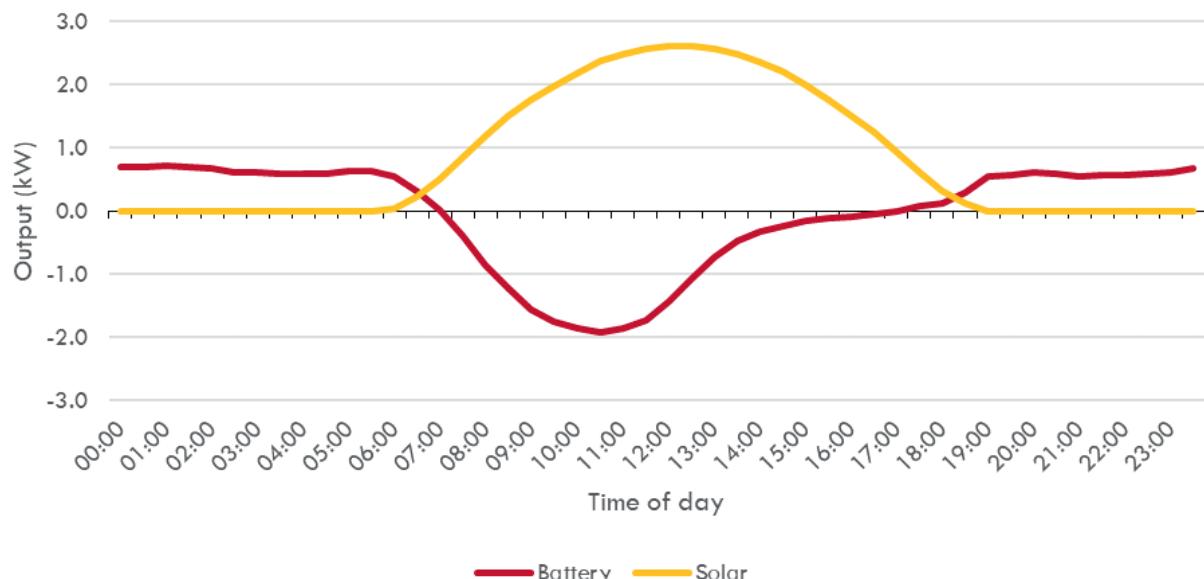


Figure 16 shows the typical charge and discharge behaviours of non-aggregated batteries, demonstrating the average operation expected of households which operate to minimise their energy costs.

Figure 16 Example average normalised non-aggregated battery daily charge/discharge profile for New South Wales in summer (February) based on 5 kW Solar and 3.8 kW battery



3.3.7 Economic and population forecasts

Input vintage	<ul style="list-style-type: none"> Updated forecast finalised in April 2021.
Source	<ul style="list-style-type: none"> BIS Oxford Economics ABS Population Series
Updates since Draft IASR	Economic forecasts have been updated since the Draft IASR through a consultancy, the draft forecasts were presented to the FRG in February 2021, followed by a 2-week consultation period prior to finalising.

In 2021, AEMO engaged BIS Oxford Economics to develop updated long-term economic forecasts for each Australian state and territory as a key input to AEMO's demand forecasts.

The pandemic recovery continues to dominate the near-term outlook, with the services sector leading the rebound in economic activity following a steep decline in 2020. Despite the first domestic recession in over 30 years, a suite of fiscal and monetary supports contributed to the Australian economy outperforming other developed countries in financial year ending (FY) 2020. This, combined with the successful public health response which allowed the easing of state restrictions⁵⁴, resulted in most sectors returning to normal operating conditions. Beyond FY 2022, the construction and manufacturing sectors are expected to reap the benefit of government fiscal stimulus and account for increasing shares of economic activity in the medium term. This trend is forecast to be especially pronounced in Queensland, which outperformed all other major states through the pandemic. In the long term, service-intensive states like Victoria and New South Wales are forecast to benefit as the sectoral composition returns to its structural fundamentals and the services sector continues to gain an increasing share of economic output.

While the vaccine rollout improves the outlook uncertainty compared to last year, international borders are assumed to remain shut for the near term, slowing the opportunity for growth in some industries. It is assumed that the border will re-open gradually as early as FYE 2022 in some scenarios, through travel bubbles and the easing of restrictions. This has already been observed with the recent establishment of a trans-Tasman travel bubble with New Zealand.

⁵⁴ These forecasts were developed prior to the temporary set-back experienced in Australia when the Delta strain spread in a number of states.

Figure 17 shows the forecast economic outcomes for gross state product (GSP) of the aggregated NEM regions, demonstrating the significance of the COVID-19 pandemic and the uncertainty regarding the economic recovery that is captured across the dispersion between scenarios. Figure 18 further provides a breakdown of the relative economic activity of each sub-sector, demonstrating the economic significance of the commercial services sector, and the relative sectoral breakdowns across scenarios in 2040.

Figure 17 NEM aggregated gross state product

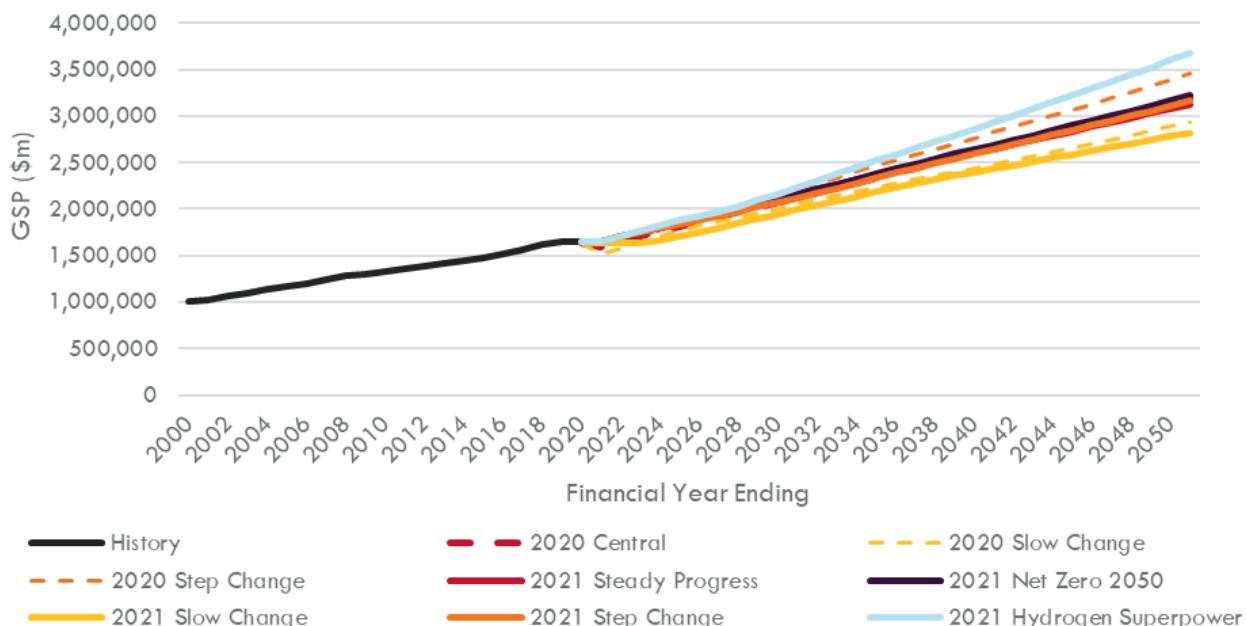
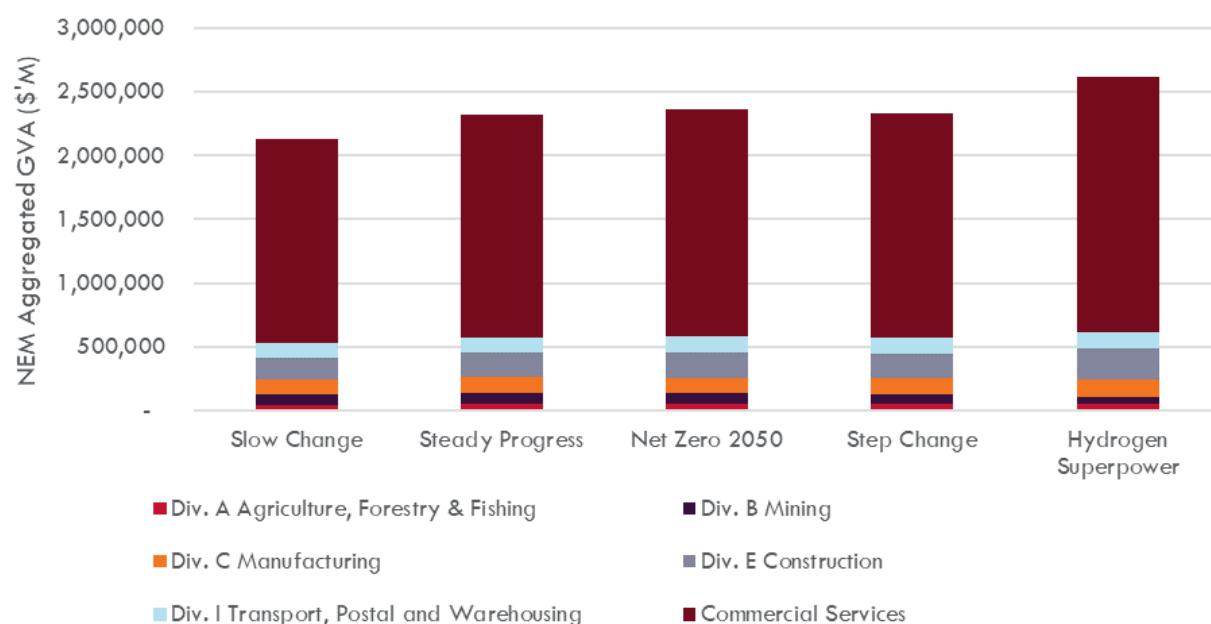


Figure 18 2040 NEM aggregated gross value added (by ANSIC Division), all scenarios



Population growth is also a key driver of Australia's economic growth. BIS Oxford Economics produces its population forecasts using death rates from the Australian Bureau of Statistics (ABS), while total net overseas

migration (NOM) and net interstate migration (NIM) forecasts are developed in-house⁵⁵. The population forecast has been revised down since the last update, driven by lower fertility rate assumptions which reduce the rate of Natural Increase (NI). NOM is expected to return to trend by FYE 2023 following a steady recovery upon the opening of borders (including a backlog of temporary migrants travelling to Australia), although the combination of international border restrictions and the decrease in NI are predicted to have a permanent negative impact on the size of the population.

As the consultant forecasts only three scenarios (low, moderate and high), AEMO has mapped the consultant forecasts to the scenarios, as outlined in Table 11 below.

Table 11 High-level mapping of economic and population settings for proposed scenarios

Scenario	Slow Change	Steady Progress	Net Zero 2050	Step Change	Hydrogen Superpower
Economic growth and population outlook	Low	Moderate	Moderate	Moderate	High

3.3.8 Households and connections forecasts

Input vintage	<ul style="list-style-type: none"> Updated in March 2021.
Source	<ul style="list-style-type: none"> ABS BIS Oxford Economics AEMO meter database Consultant
Updates since Draft IASR	Connections forecasts have been updated since the Draft IASR through a consultancy, the draft forecasts were presented to the FRG in March 2021, followed by a two-week consultation period prior to finalising.

As Australia's population increases, so does the expected number of new households which require electricity connections. AEMO's forecast of the increase in residential electricity consumption is mainly driven by electricity connections growth. A key difference in the short term from the 2020 forecasts was that AEMO's economic consultants, BIS Oxford Economics previously forecast an assumed downturn in construction from the 2021 financial year, due to the stop in overseas migration and international student arrivals into Australia, and general economic uncertainty associated with the COVID-19 pandemic. However, the housing construction industry remained relatively strong in 2020 through to 2021⁵⁶.

In the long term, a key difference that gives a higher forecast for the current Net Zero 2050, Steady Progress and Step Change scenarios compared to the 2020 Central scenario is that BIS Oxford Economics also provided housing stock forecasts associated with its economic forecasts. The net impact by 2051 is approximately 500,000 more connections than the 2020 Central forecast. In contrast, the 2020 forecasts utilised ABS household forecasts and not housing stock forecasts, which are higher due to no occupancy assumptions (and also are more comparable to AEMO's electricity connections).

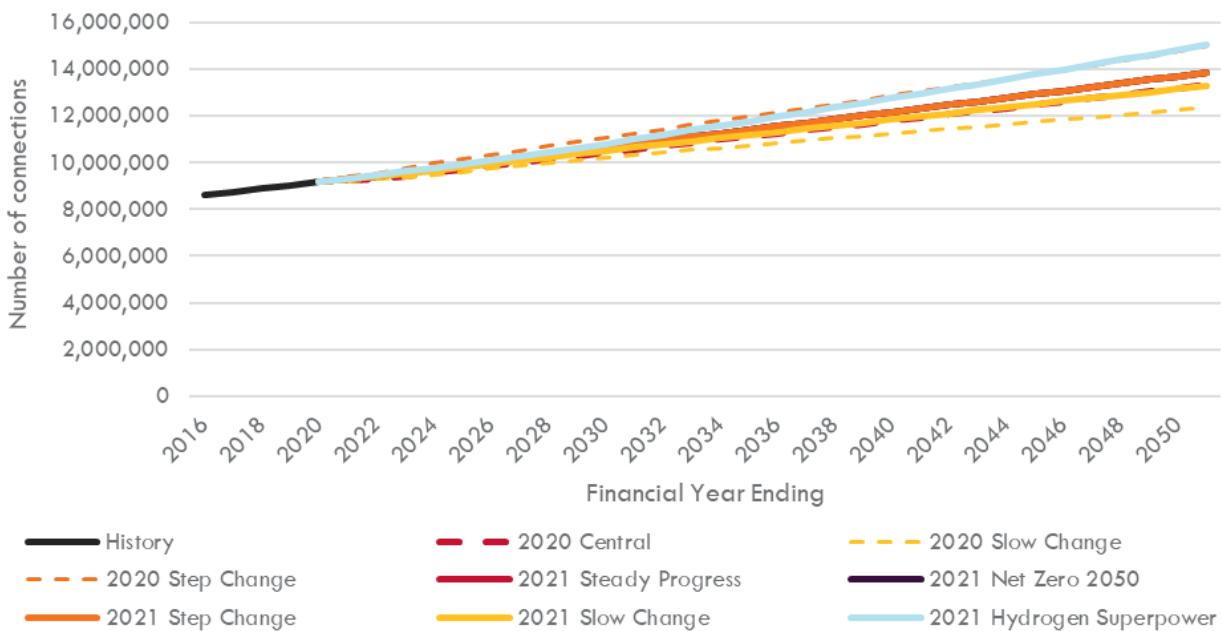
The other 2021 scenarios show a lower dispersion between scenarios due to utilising the BIS Oxford Economics forecasts directly whereas in 2020 AEMO applied a dispersion based on relative construction sector activity to the different scenarios.

⁵⁵ The core demographic assumptions that underpin BIS Oxford's population forecast (such as fertility rate, births and deaths) are consistent with the Federal Government's Centre for Population, at <https://population.gov.au/>. A comparison of BIS Oxford's population forecast and assumptions against the Centre for Population's 'Population Statement' can be found in the 2021 *Macroeconomic Projections Report*, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/bis-oxford-economics-macroeconomic-projections.pdf?la=en.

⁵⁶ Building Approvals, Australia, April 2021 Release, at <https://www.abs.gov.au/statistics/industry/building-and-construction/building-approvals-australia/latest-release>.

Figure 19 shows the connections forecast that is applied to the 2021 scenarios.

Figure 19 2021 NEM residential connections actual and forecast, 2015-16 to 2050-51, all scenarios



3.3.9 Large industrial loads

Input vintage	<ul style="list-style-type: none"> Updated in May 2021
Source	<ul style="list-style-type: none"> Interviews/Surveys Economic Outlook Media search/announcements
Updates since Draft IASR	Updated based on new survey data provided by large customers. The scenario differences have been adjusted to reflect finalised scenarios.

AEMO segments and forecasts LILs separately to small and medium commercial enterprises, due to both their significance in the overall scale of energy consumption, and the individual business circumstances that may not be appropriately captured in broader econometric models.

AEMO currently sources information regarding LILs from:

- Surveys and interviews of the largest consumers, considering the economic outlook based on the advice provided to AEMO by BIS Oxford Economics.
- AEMO's standing data requests from distribution network service providers (DNSPs) regarding prospective and newly connecting loads.
- Media searches and company announcements.

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

AEMO's 2021 LIL forecasts will be available in detail in from AEMO's forecasting portal⁵⁷, by selecting the 'Business' category and 'Large Industrial Loads' from the sub-category menu, once the 2021 ESOI is published.

In AEMO's forecast of existing industrial loads there is little new industrial load development captured across the three scenarios presented, as informed by survey and interview responses. There is, however, material downside risk of industrial load closures should economic conditions deteriorate for individual loads. AEMO's Slow Change scenario provides the lower estimate for existing industrial loads with a net reduction of 25 TWh by 2050 from closures.

Liquified natural gas

Queensland's LNG industry is a material contributor of existing industrial electricity loads, consuming approximately 5% of AEMO's total business consumption category. The international LNG market faces an uncertain future. Global demand for liquid fuels shifts as each country determines how it will achieve its own decarbonisation commitments, with some commentators predicting ongoing strong growth through until 2050 and others predicting a notable decrease⁵⁸. For the NEM's LNG exports facilities in Queensland, AEMO considers that market conditions are unlikely to be conducive to any major new infrastructure to increase export capacity – and the existing LNG export facilities already operate at high utilisation factors. AEMO therefore considers that the upper range of reasonable forecasts for LNG operations is for operations to continue at current high utilisation levels.

The LNG forecasts estimate the expected electricity consumption of the operations of coal seam gas (CSG) fields operating in the NEM by considering surveyed data provided by the LNG consortia, as per other LILs. This data considers the anticipated operating range of CSG facilities over the short term, between three and five years ahead.

AEMO extends the LNG consortia forecasts across the scenario collection by assessing long-term global trends assumed for each scenario, given the relationships that exist between various sectors domestically and internationally that may consume gas.

Figure 20 below demonstrates the forecast range across AEMO's collection. Given the uncertainty that exists, particularly for fossil fuels such as LNG in scenarios with stronger decarbonisation objectives, AEMO applies a range appropriate to the scenario narratives, with the spread reflecting uncertainties⁵⁹ applying to international gas consumption depending on efforts and approaches to minimise carbon emissions.

The Net Zero 2050 and Steady Progress scenarios reflect an unchanged international outlook where countries continue to consume LNG, with steady demand from Queensland LNG facilities. The Slow Change scenario also has continued international LNG consumption, but weaker economic conditions soften demand.

While the Hydrogen Superpower scenario reflects a future with strong global action on carbon emissions, it is assumed that hydrogen technology experiences substantial cost reductions and the adoption of hydrogen expands rapidly, both nationally and internationally. AEMO considers that this emerging fuel becomes a viable alternative to LNG in this scenario, favoured particularly by most trading partners given the lower emissions intensity of the fuel, lowering Australia's long-term LNG exports in this scenario. While the strong electrification sensitivity assumes breakthroughs in hydrogen costs do not occur domestically, the overriding emissions reduction ambition naturally impacts LNG export opportunities, as trading partners put greater

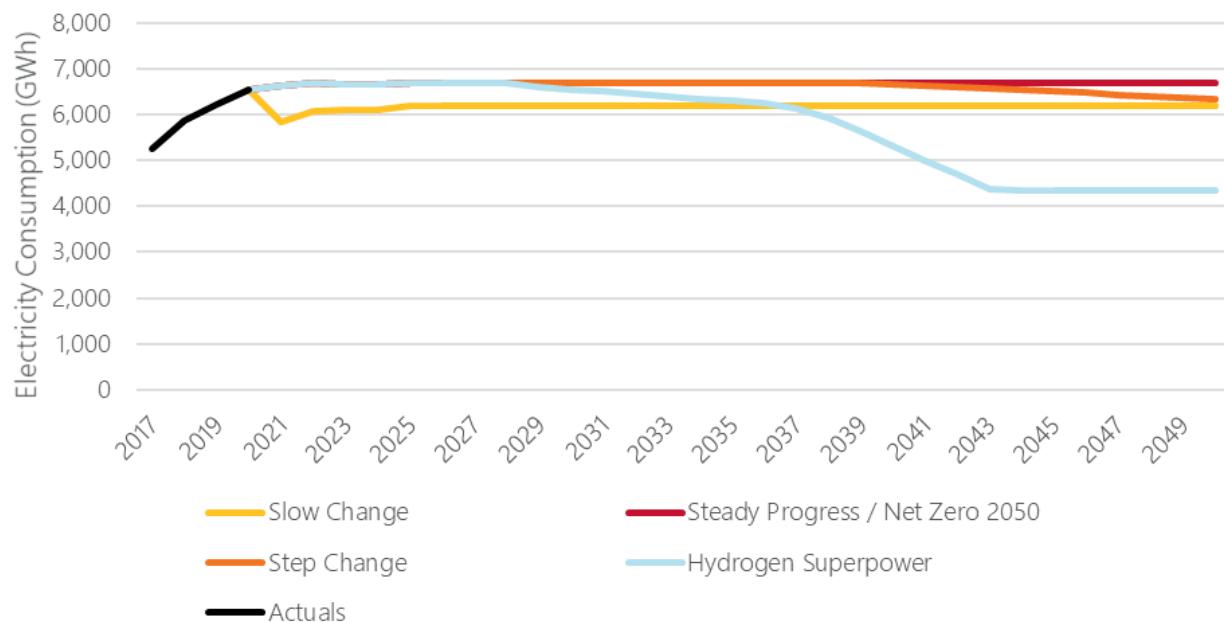
⁵⁷ AEMO's electricity consumption forecasts are available at <http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational>.

⁵⁸ The International Energy Agency outlined an uncertain future for LNG, See International Energy Agency (2021), *Net Zero by 2050: A roadmap for the Energy Sector*, at <https://iea.blob.core.windows.net/assets/0716bb9a-6138-4918-8023-cb24caa47794/NetZeroby2050-ARoadmapfortheGlobalEnergySector.pdf>.

⁵⁹ AEMO has considered a range of independent forecasts in applying this range, with varying views for the commodity between growth and significant retraction. AEMO has considered recent public documentation from IEA (at <https://www.iea.org/reports/net-zero-by-2050>), IPCC (at <https://www.ipcc.ch/sr15/chapter/chapter-2/>), ExxonMobil (at <https://corporate.exxonmobil.com/Energy-and-innovation/Outlook-for-Energy/Outlook-for-Energy-A-perspective-to-2040#ExxonMobilsupportstheParisAgreement>), BP (at <https://www.bp.com/en/global/corporate/energy-economics/energy-outlook/energy-outlook-downloads.html>), McKinsey (at https://www.mckinsey.com/~media/mckinsey/industries/oil_and_gas/our_insights/global_gas_outlook_to_2050/global-gas-outlook-2050-executive-summary.pdf), and Shell (at <https://www.shell.com/energy-and-innovation/natural-gas/liquefied-natural-gas-Ing/Ing-outlook-2021.html#iframe=L3dIYmFwcHMvTE5HX091dGxvb2svMjAyMS8>).

emphasis on other decarbonisation pillars (such as energy efficiency and fuel switching away from fossil fuels) to decarbonise.

Figure 20 LNG forecast electricity consumption, by scenario



3.3.10 Energy efficiency forecast

Input vintage	<ul style="list-style-type: none"> Updated in March 2021 In June 2021, CSIRO's multi-sector modelling guided the utilisation of the energy efficiency pillar of decarbonisation across scenarios, enabling improved mapping of forecasts to scenarios
Source	<ul style="list-style-type: none"> Strategy Policy Research CSIRO/ClimateWorks
Updates since Draft IASR	Energy efficiency forecasts have been updated through consultancy. The draft methodology, input assumptions and prototype forecast presented at the Energy Efficiency Workshop in March 2021, and draft forecasts were presented to FRG in April 2021, followed by a two-week consultation period prior to finalising.

In 2021, AEMO engaged Strategy Policy Research (SPR) to develop energy efficiency forecasts for all NEM regions and the South West Interconnected System (SWIS) in Western Australia. Demand drivers including economic, population, housing, and connections growth settings for each scenario combine with the varying levels of policy ambition (informed by multi-sectoral modelling) to form unique energy efficiency forecasts for each scenario⁶⁰.

The federal and state governments have developed measures to mandate or promote energy efficiency uptake across the economy. AEMO considers the impact of these measures, listed in Section 3.1, on forecast electricity consumption. Generally, Step Change and Hydrogen Superpower are considered the high energy efficiency policy ambition scenarios in the multi-sectoral modelling, with stronger assumptions around the

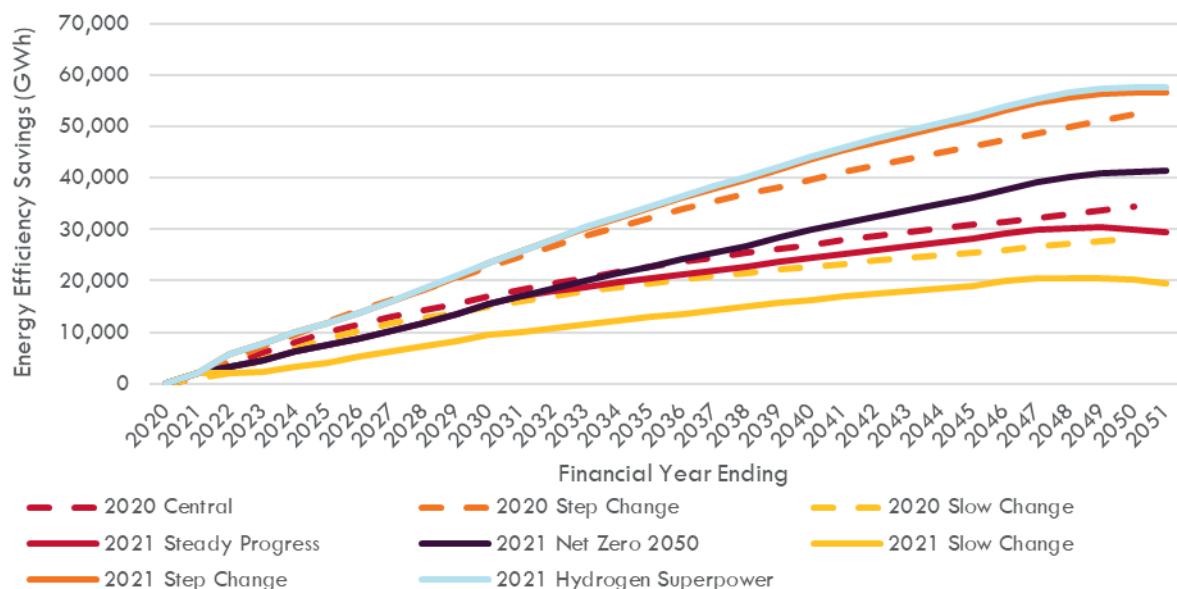
⁶⁰ AEMO removes the future savings from activities that took place prior to the base year of the forecasts. For more information, see the *Electricity Demand Forecasting Methodology Information Paper*, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-demand-forecasting-methodology/final-stage/electricity-demand-forecasting-methodology.pdf?la=en.

extent and uptake of policy measures. To emulate this, new ‘hypothetical’ policy measures were assumed in these scenarios, in addition to the existing measures.

SPR undertook a review of the potential for double counting across policy measures, non-realisation of headline savings of policies, and non-additionality, and made adjustments to the forecast savings⁶¹. SPR also considered the impact of market-led energy efficiency changes, or autonomous energy efficiency improvement (AEEI) that would likely occur in the market, without policy intervention. SPR used estimates of AEEI to calibrate historical consumption data with estimates of historical savings from policy measures, and the same calibration rate was applied during the forecasting period, to moderate the impact of policy savings. Due to these adjustments, SPR recommended to AEMO that no further discounts be applied to the forecasts; AEMO has adopted this recommendation.

Figure 21 shows the total energy efficiency applied to electricity consumption across the modelled scenarios.

Figure 21 Forecast energy efficiency savings, 2020-21 to 2050-51



The 2021 forecasts show a greater degree of spread compared to the 2020 forecasts. In the case of the 2021 Slow Change and Steady Progress scenarios, the adjustments by SPR – as described above, to account for the potential for double-counting, non-realisation of savings, additionality, and consideration of AEEI – lowered the estimated energy efficiency savings, for the E3 program and NCC in particular. State-based schemes also resulted in fuel switching from gas to electricity, effectively reducing estimated energy efficiency savings for electricity. This is observable for the scenarios with low to moderate levels of policy ambition.

Stronger policy assumptions assumed in the mid-2030s result in more savings in Net Zero 2050 compared to 2020 Central. These assumptions, including the introduction of new ‘hypothetical’ policy measures for Step Change and Hydrogen Superpower, temper the fuel switching effect of state-based schemes, resulting in forecasts that are similar to or above the 2020 Step Change scenario.

By the end of the forecasting period, a drop off in savings growth is observable in all scenarios. Commercial building stock that became operational and delivered energy efficiency savings under earlier NCC versions are deemed to have reached the end of their asset life. More recent NCC versions are not expected to reach the same levels of energy efficiency potential compared to earlier versions, resulting in more incremental savings for newer buildings.

⁶¹ SPR defines additionality as savings that are “additional to those that would have occurred in the absence of the measure or effect”.

3.3.11 Appliance uptake forecast

Input vintage	<ul style="list-style-type: none"> Updated in March 2021.
Source	<ul style="list-style-type: none"> Department of Energy and Environment Energy 2015 Residential Baseline Study for Australia 2000 – 2030, (RBS, 2015) available at www.energyrating.com.au. State and Federal energy departments Multi-sectoral modelling (see Section 3.3.4) Economic forecast (see Section 3.3.7)
Updates since Draft IASR	Forecasts have been updated based on new data sources from the Department of Industry, Science, Energy and Resources (DISER) internal register of appliance sales trends, and through updated household income forecasts from BIS Oxford Economics.

Electricity consumption forecasts consider policies and programs that induce fuel switching behaviour (between electricity and natural gas) through the energy efficiency forecasts and the residential sector's forecast of appliance growth.

AEMO used appliance data from the former Australian Government Department of the Environment and Energy (now DISER) 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. Energy services here is a measure based on the number of appliances per category across the NEM, their usage hours, and their capacity and size (Refer to Appendix A5 of AEMO's *Electricity Demand Forecasting Methodology*⁶² for details on the methodology used).

AEMO includes dispersion across the scenarios by applying a per capita Household Disposable Income (HDI) index to the scenarios, relative to the per capita HDI to the moderate economic scenario (also detailed in Appendix A5 of AEMO's *Electricity Demand Forecasting Methodology*).

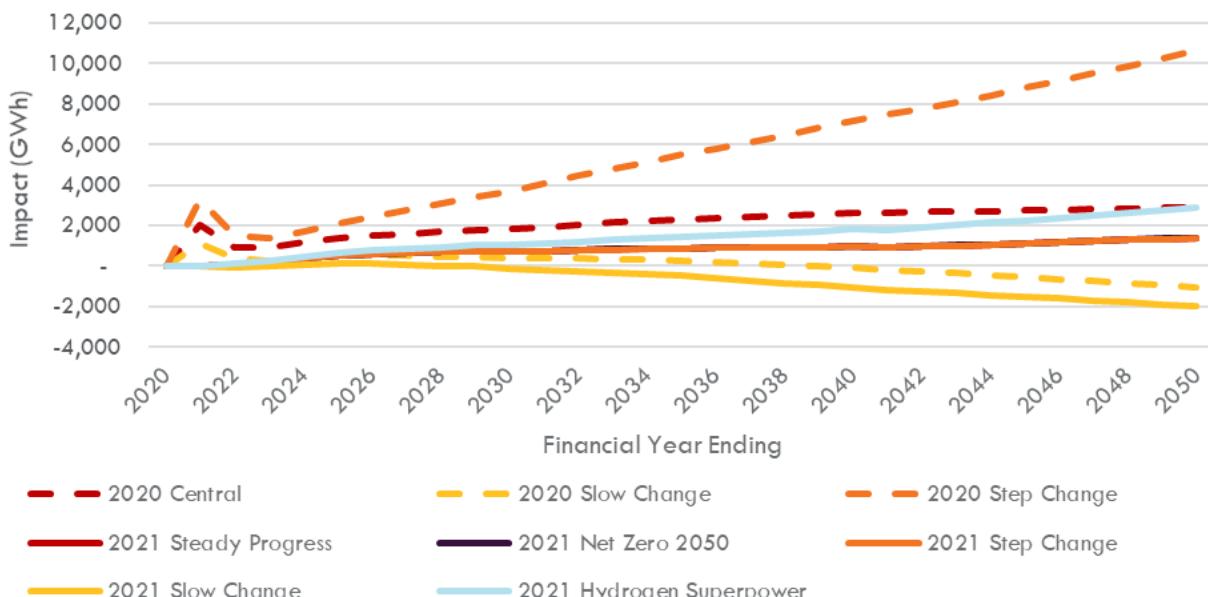
Figure 22 shows the appliance uptake trajectory for the residential sector (excluding fuel switching from gas to electric devices that is considered separately in electrification) in the 2021 scenarios.

In the previous year's forecast, the first two years had higher predicted appliance usage, in part due to the modelled impact of COVID-19 leading to greater "work from home" energy consumption. Beyond this point, a forecast return to near pre-COVID-19 mobility levels was forecast, reducing appliance usage in all scenarios. However, in the 2021 forecasts, this has been removed due to better understanding of COVID-19 impacts and observations that lockdown measures were less severe than anticipated on consumption patterns. Fuel switching impacts are also removed from the 2021 index, as that component is captured in the multi-sectoral modelling electrification (see Section 3.3.4).

The net result is a lower appliance uptake forecast in 2021 relative to the forecast made in 2020, due to a combination of these drivers.

⁶² At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/electricity-demand-forecasting-methodology/final-stage/electricity-demand-forecasting-methodology.pdf?la=en.

Figure 22 Appliance uptake – change in current usage, relative to base year (2020) consumption for the residential sector



3.3.12 Electricity price indices

Input vintage	<ul style="list-style-type: none"> Updated in March 2021.
Source	<ul style="list-style-type: none"> Australian Energy Market Commission (AEMC) annual <i>Residential Electricity Price Trends</i> report, 2020 forecasts available at https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2020 AEMO internal GSOO wholesale price forecasts Transmission costs from the 2020 ISP's optimal development path
Updates since Draft IASR	Retail price trends have been updated with the latest AEMC 2020 report and internal modelling to provide estimated of wholesale price forecasts and transmission costs associated with the 2020 ISP.

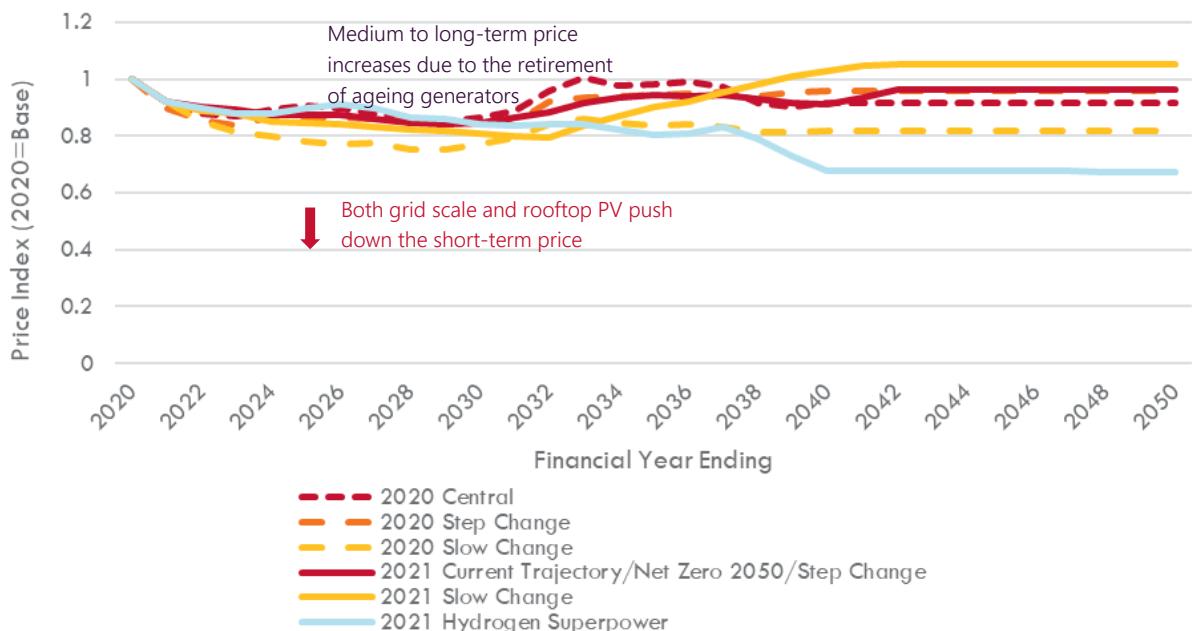
Electricity prices are assumed to influence consumption through short-term behavioural changes (such as how electricity devices are used or energy consumption is managed), and longer-term structural changes (such as decisions to invest in DER).

Figure 23 shows the retail price index assumed in 2021 for the Steady Progress, Slow Change, and Hydrogen Superpower scenarios⁶³. These were formed from bottom-up projections of the various components of retail prices. The retail price structure follows the Australian Energy Market Commission (AEMC) 2020 *Residential Electricity Price Trends* report, and the wholesale price forecasts were informed by analysis derived from AEMO's 2021 GSOO.

Table 12 shows the high level mapping of the various price components used, and their incorporation into the 2021 scenarios. Components were mapped based on the relationship between the 2021 scenarios and the relevant settings of the 2021 GSOO and 2020 ISP scenarios.

⁶³ The Net Zero 2050 and Step Change scenarios use the Steady progress scenarios.

Figure 23 Residential retail price index, NEM (connections weighted)



* Price weighted by the number of households.

Table 12 High-level mapping of price input settings for proposed scenarios

Scenario	Slow Change	Steady Progress	Net Zero 2050	Step Change	Hydrogen Superpower
Wholesale component	GSOO (2021) Slow Change	GSOO (2021) Central	GSOO (2021) Central	GSOO (2021) Central	GSOO (2021) Hydrogen
Transmission costs	ISP (2020) Slow Change	ISP (2020) Central	ISP (2020) Central	ISP (2020) Central	ISP (2020) Step Change
Distribution costs	AEMC (2020) to FYE2023 then constant				
Environmental costs	AEMC (2020) to FYE2023 then decline to zero by FYE2030	AEMC (2020) to FYE2023 then decline to zero by FYE2030	AEMC (2020) to FYE2023 then decline to zero by FYE2030	AEMC (2020) to FYE2023 then decline to zero by FYE2030	AEMC (2020) to FYE2023 then decline to zero by FYE2030
Retail component	AEMC (2020)				

Consumption forecasts consider the price elasticity of demand (that is, the percentage change in demand for a 1% change in price). For residential loads, the price response is influenced by the appliance type. Baseload appliances (such as refrigerators, washing machines, ovens/microwaves, and lighting) are assumed to be price inelastic, and therefore have a price elasticity of zero. Weather-sensitive appliances (such as heating and cooling appliances) on the other hand have a price elasticity of demand of -0.1 across all scenarios.

Similarly, for business mass market loads, price elasticity of demand assumptions is applied in the forecast, but with an increased spread across scenarios as businesses are expected to respond to price more readily than residential consumers. A price elasticity of demand of -0.1 is applied to the Steady Progress, Net Zero 2050, and Step Change scenarios, -0.05 is applied to the Slow Change, and -0.15 is applied to the Hydrogen Superpower scenario.

Table 13 below provides the price elasticities of demand adopted across the scenario collection. Negative values indicate a reduction in consumption from a price increase and an increase from a price decrease.

Table 13 Price elasticities of demand for various appliances and sectors.

Scenario	Slow Change	Steady Progress	Net Zero 2050	Step Change	Hydrogen Superpower
Residential: Baseload appliances	0	0	0	0	0
Residential: weather-sensitive appliances	-0.1	-0.1	-0.1	-0.1	-0.1
Business: all load components	-0.05	-0.1	-0.1	-0.1	-0.15

3.3.13 Demand side participation

Input vintage	<ul style="list-style-type: none"> Starting points updated June 2021, target levels unchanged from ISP 2020. Forecast in June 2021.
Source	Historical meter data analysis and information submitted to the DSP Information portal in April 2021.
Updates since Draft IASR	Forecasts have been updated based on the application of the DSP methodology. Draft forecasts were presented for discussion to the FRG in May 2021, and likely Demand Response Service Providers have been contacted to validate demand response estimates.

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

AEMO estimates the current level of DSP using information provided by registered participants in the NEM through AEMO's DSP Information portal (DSP IP), supplemented by historical customer meter data. DSP responses are estimated for various price triggers and AEMO assumes the 50th percentile of observed historical responses is a reliable, central estimate of the likely response when the various price triggers are reached, as documented in AEMO's *Demand Side Participation Forecast Methodology*⁶⁴.

For the ESOO, AEMO uses existing and committed DSP only, representing the current level discussed above with adjustments for committed changes to DSP as reported to AEMO through the DSP IP, or through policy targets with supporting legislation implemented. The DSP forecast for the 2021 ESOO accordingly includes an estimated impact of the Wholesale Demand Response (WDR) mechanism.

For long-term planning studies like the ISP, the quantity of DSP is grown to meet a target level by the end of the outlook period. The target level is defined as the magnitude of DSP relative to maximum demand and linearly interpolated between the beginning and ends of the outlook period. It is based on a review of international literature and reports of demand response potential (primarily in the United States⁶⁵ and Europe⁶⁶) which indicated that the adopted (high) level of 8.5% of operational maximum demand is a reasonable upper estimate for growth in DSP. This growth will cater for a wide range of growth drivers, both technology-driven and from policy schemes (such as WDR).

⁶⁴ At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/demand-side-participation/final/demand-side-participation-forecast-methodology.pdf.

⁶⁵ See FERC's "A National Assessment of Demand Response Potential" (at https://www.ferc.gov/sites/default/files/2020-05/06-09-demand-response_1.pdf) validated against recent DSP uptake statuses across the United States (from <https://www.ferc.gov/industries-data/electric/power-sales-and-markets/demand-response/reports-demand-response-and>).

⁶⁶ See <https://www.sia-partners.com/en/news-and-publications/from-our-experts/demand-response-study-its-potential-europe>.

The final settings for the 2021 IASR scenarios are provided in Table 14, driven by the following considerations:

- The Step Change and Hydrogen Superpower⁶⁷ scenarios are both assumed to have high growth in DSP. These scenarios are expected to have significant growth in VRE resources, which is typically linked with increasing the capability of adjusting demand to meet the variable nature of supply.
- The Net Zero 2050 and Steady Progress scenarios are both assumed to have moderate growth in DSP, reflecting the pursuit of cost-effective ways to meet or reduce peak demand.
- The Slow Change scenario has the lowest assumed growth in DSP (maintaining the current penetration into the future) due to the potential impact of low gas prices on price volatility.
- For Tasmania, which is not capacity constrained and therefore less incentivised to deploy DSP solutions, the assumed growth in DSP is halved relative to the mainland regions.
- The NSW Peak Demand Reduction Scheme (PDRS) is varied between the scenarios to reflect the uncertainty of the actual implementation. It will in some cases deliver stronger savings than the targets set above. The impact on DSP considers that part of the PDRS target will be delivered by energy efficiency and battery storage, which is accounted for separately in AEMO's forecast components. Accordingly, the growth in DSP is scaled down to match.

Table 14 Mapping of DSP settings to scenarios

Scenario	Step Change	Hydrogen Superpower	Net Zero 2050	Steady Progress	Slow Change
DSP growth target overall – mainland regions	High growth to reach 8.5% of peak demand by 2050	High growth to reach 8.5% of peak demand by 2050	Moderate growth to reach 4.25% of peak demand by 2050	Moderate growth to reach 4.25% of peak demand by 2050	No change from current levels of DSP
DSP growth target overall – Tasmania	High growth to reach 4.25% of peak demand by 2050	High growth to reach 4.25% of peak demand by 2050	Moderate growth to reach 2.125% of peak demand by 2050	Moderate growth to reach 2.125% of peak demand by 2050	No change from current levels of DSP
NSW PDRS	Starting 2022-23 with target growing to 10% of peak demand by 2029-30, then minor growth to 15% by 2039-40 then stays flat. Summer only.	Starting 2022-23 with target growing to 10% of peak demand by 2029-30 and then stays flat. Summer only.	Delayed implementation, starting 2028-29 with target growing to 10% of peak demand by 2035-36 and then stays flat. Summer only.	Not assumed implemented	Not assumed implemented

Note: The Strong Electrification sensitivity will apply the same targets as the Step Change scenario.

3.3.14 Fuel switching and hydrogen production

Input vintage	• Forecast finalised in June 2021.
Source	• CSIRO and ClimateWorks Australia
Updates since Draft IASR	New section outlines the modelling of fuel switching to hydrogen from the multi-sector modelling. Draft forecasts were presented to FRG in April 2021, and final forecasts in June 2021.

⁶⁷ Note that the DSP does not include the flexibility provided by electrolyzers, which is modelled separately.

AEMO's scenario collection allows for the development of hydrogen production technologies, but with this potential development still relatively immature, high uncertainty exists affecting the pace of deployment, scale of total production, and location of future hydrogen facilities.

Across AEMO's Net Zero 2050, Step Change, and Hydrogen Superpower scenarios, this uncertainty is considered, with scenarios ranging from very low forecast development through to high export potential of the new commodity. In other scenarios, and the Strong Electrification sensitivity, hydrogen consumption is limited to use for heavy transport. In the Steady Progress and Slow Change scenarios, the hydrogen production is assumed to be from steam-methane reforming (SMR) facilities – therefore the energy consumption does not directly impact the NEM.

Hydrogen demand is projected by the multi-sectoral modelling based on domestic applications for fuel switching, growth of new industry and hydrogen exports. The modelled demand shows growth in all applications at varying rates. The domestic hydrogen consumption forecast considers potential users of hydrogen within the residential, commercial and industrial sectors, as well as the transport sector. With blending into the domestic gas pipeline system, hydrogen is likely to be consumed by the residential sector initially, with larger consumption potential by industrial consumers in the longer term as a substitution with existing emissions-intensive fuels. In the transport sector, hydrogen sees some uptake as a replacement of oil. More information is available in CSIRO's *Multi-sector Energy Modelling Report* (see Table 56).

Australia's Technology Investment Roadmap⁶⁸ has identified that energy export is of strategic importance to Australia and hydrogen is one of the priority low emissions technologies. Australia's National Hydrogen Strategy⁶⁹ recognises that a strong domestic sector will be required to successfully compete internationally. The emergence of NEM-connected hydrogen exports is only considered in the Hydrogen Superpower scenario.

Total demand

Figure 24 shows the assumed scale of annual domestic hydrogen demand in the NEM regions under each relevant scenario and sensitivity, informed by the multi-sectoral modelling and through stakeholder collaboration. In the scenarios without hydrogen exports, the transport sector is the main consumer of hydrogen in the early years. In the Step Change scenario, industry becomes the largest consumer in the late 2040s and in the Net Zero 2050 scenario the industrial consumption grows to approximately equal the transport demand by the end of the modelling horizon.

While consulting on the levels of fuel switching, stakeholder feedback encouraged AEMO to reconsider the impact of fuel switching in the Hydrogen Superpower scenario; specifically, regarding the potential to repurpose domestic distribution pipelines instead of expansion of new electricity distribution.

Considering both the relative gain in energy efficiency from electrical appliances and the potential for cost savings in distribution (a cost which is not considered in the multi-sectoral modelling), there could be a system-wide cost benefit to fuel switching to hydrogen for residential heating and cooking in the Hydrogen Superpower scenario, even before considering seasonal implications associated with electrifying residential heating load.

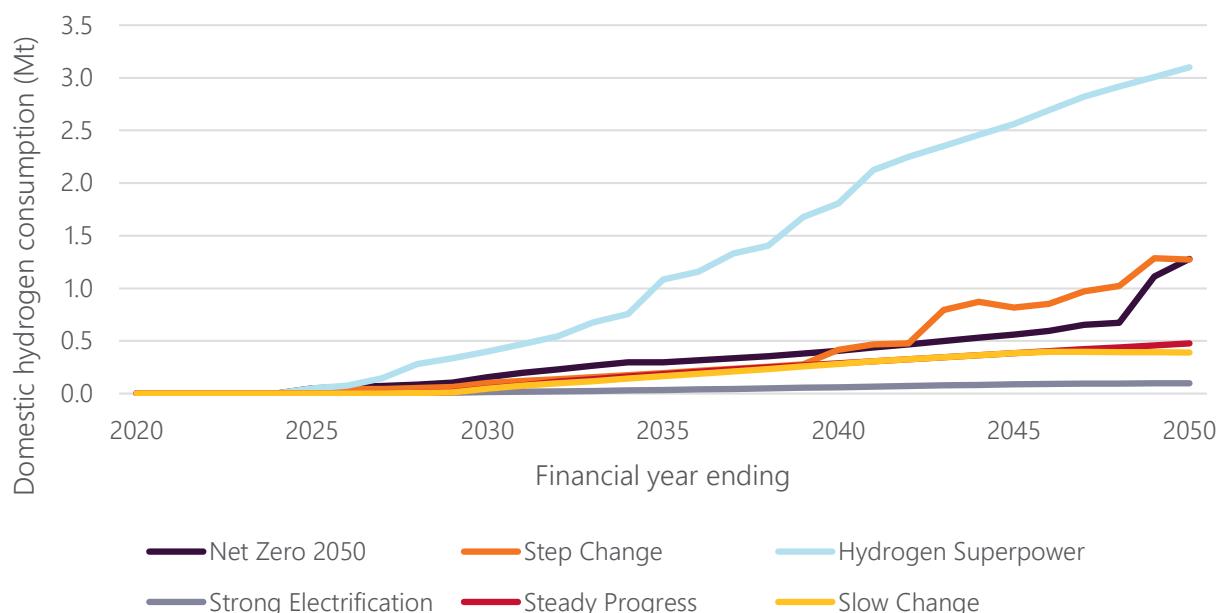
Accordingly, AEMO revised up the fuel switching allocation in this scenario (above that which is reported in the CSIRO report). New houses would not benefit from any sunk costs associated with an existing gas connection, so these loads are assumed to remain entirely electrified. However, existing houses would start to switch to using hydrogen⁷⁰ instead of electricity from 2025, the time when the cost of hydrogen has been determined by the multi-sector model to be competitive enough to see some residential uptake.

⁶⁸ See <https://www.industry.gov.au/sites/default/files/September%202020/document/first-low-emissions-technology-statement-2020.pdf>.

⁶⁹ See <https://www.industry.gov.au/sites/default/files/2019-11/australias-national-hydrogen-strategy.pdf>.

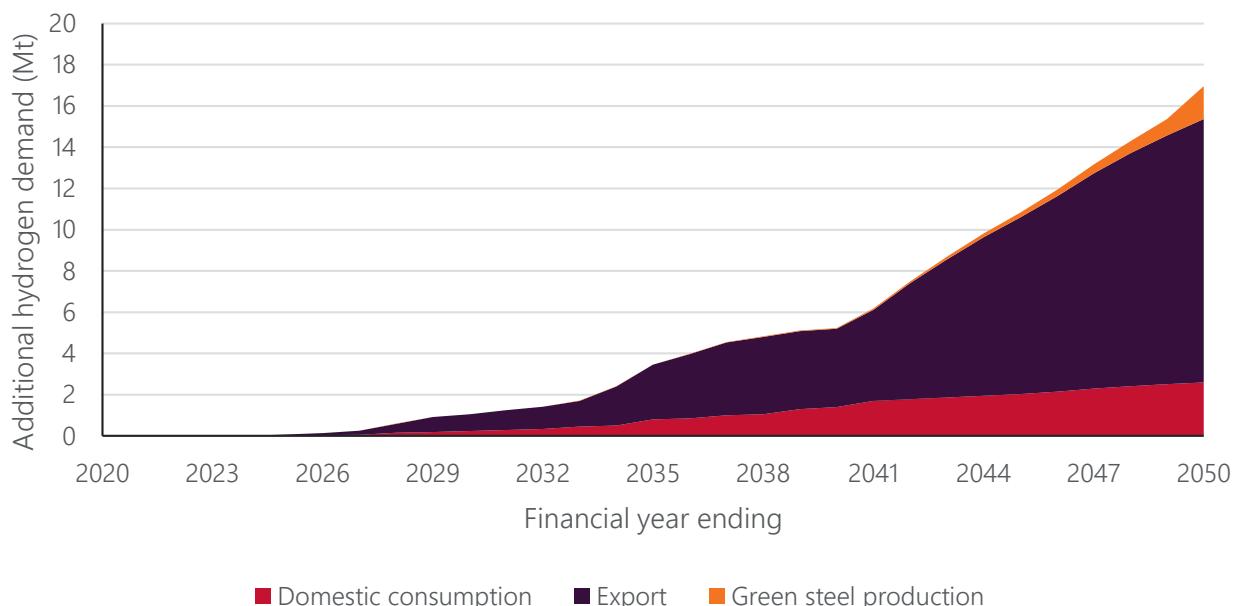
⁷⁰ Hydrogen, or a blended gas-hydrogen mix depending on developments in the gas distribution system and the location of domestic-facing electrolyzers.

Figure 24 Domestic hydrogen consumption in NEM-connected states and territories



While the domestic demand is important, it is substantially smaller than the potential export volumes considered in the Hydrogen Superpower scenario, shown in Figure 25. The Hydrogen Superpower scenario assumes the growth of a major hydrogen export industry, informed by stakeholder consultation and review of national and international publications. With cost breakthroughs in hydrogen production, other manufacturing developments utilising hydrogen fuels were identified as additional potential growth industries, particularly green steel manufacturing.

Figure 25 Total NEM-connected hydrogen consumption for the Hydrogen Superpower scenario



Hydrogen production technologies

There are three primary technology options to produce hydrogen:

- **Electrolysis** – uses electricity to split water molecules into hydrogen and oxygen. If this electricity is sourced from renewable generation it can create “green hydrogen”.
- **Steam methane reforming (SMR)** – reacts methane (natural gas) with steam under pressure to produce hydrogen and carbon dioxide. Carbon capture and storage (CCS) can also be utilised to partially mitigate carbon emissions from this process.
- **Coal gasification** – reacts pulverised coal with oxygen and steam to produce hydrogen and carbon dioxide. Different quality coal can result in different processes and chemical compositions. CCS can also be utilised to partially mitigate carbon emissions from this process.

There are three electrolyser technology options:

- Alkaline – presently more mature technology and lower cost, but limited flexibility.
- Proton Exchange Membrane (PEM) – newer technology, which is substantially more flexible to variable loads and more suitable for modular large applications, but less mature than alkaline. At present, most hydrogen projects that are being developed are employing PEM electrolysis.
- Solid Oxide Electrolysis Cell (SOEC) – newest technology that operates at high temperature and shows substantial promise in terms of efficiency; however, it is still early in its development and not yet being produced, or ready to be produced, in mass quantities.

For the purposes of modelling, AEMO has assumed PEM electrolysis to be the only hydrogen production technology for grid-connected electrolyzers, reflecting the current technology development trends. This is broadly consistent with the multi-sectoral modelling results. In accordance with stakeholder feedback and cost optimisation for hydrogen production, all electrolyzers are considered to be grid-connected.

The reported hydrogen production/consumption quantities are restricted to demand within NEM-connected states and territories, and any export which may be produced from these regions.

Hydrogen production from new SMR is present across all scenarios, but the electricity demand associated with this process is minimal and is not explicitly considered in the electricity consumption modelling; any production from SMR is subtracted from the total electrolyser hydrogen production requirement.

PEM characteristics

Assumptions around key PEM characteristics are outlined in the following section.

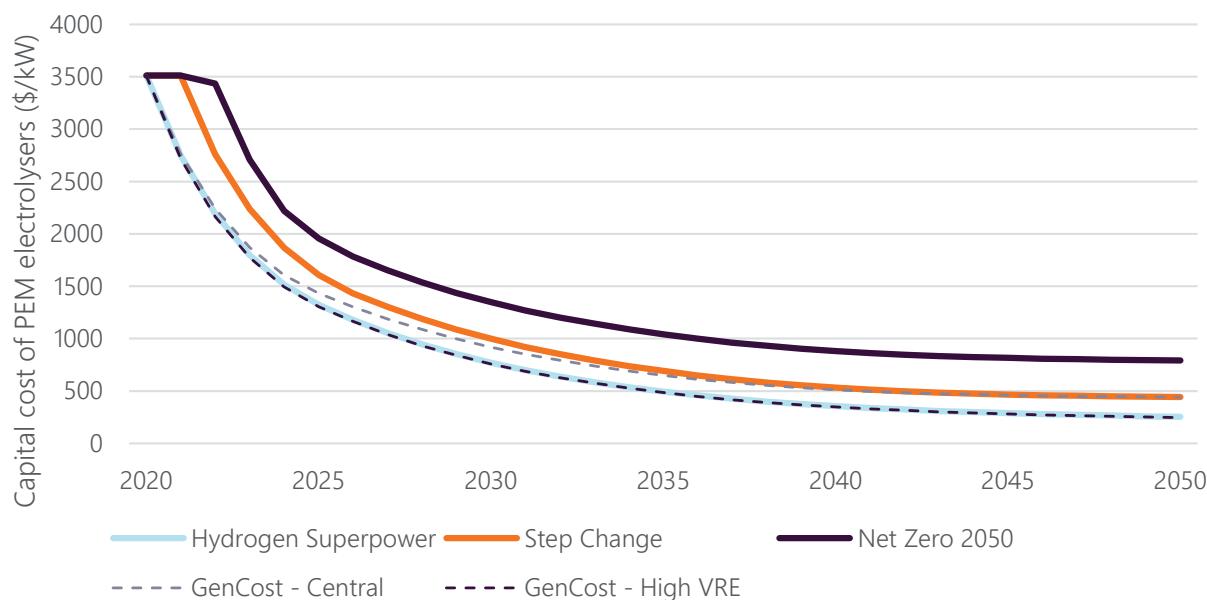
Capital costs

The CSIRO GenCost 2020-21 report contains estimates for the current capital cost of a PEM electrolyser, at \$3,510/kW. By 2036, the cost of PEM electrolyzers is projected to be less than \$1,000/kW in all scenarios.

The cost trajectory was based on the projections in GenCost 2020-21, with the Hydrogen Superpower scenario assumptions aligned with GenCost High VRE scenario assumptions, yet had some further variance applied in the multi-sectoral modelling to reflect the uncertainty of uptake in this technology. The resulting cost projections to be used in AEMO’s ISP are shown in Figure 26.

It is worth noting that the electrolyser capital cost is only one of the drivers for hydrogen adoption. The cost of electricity, the cost of the demand side technology, the availability of the hydrogen, and potential emissions targets all strongly influence the adoption as well.

Figure 26 Capital cost projections assumed for PEM electrolyzers

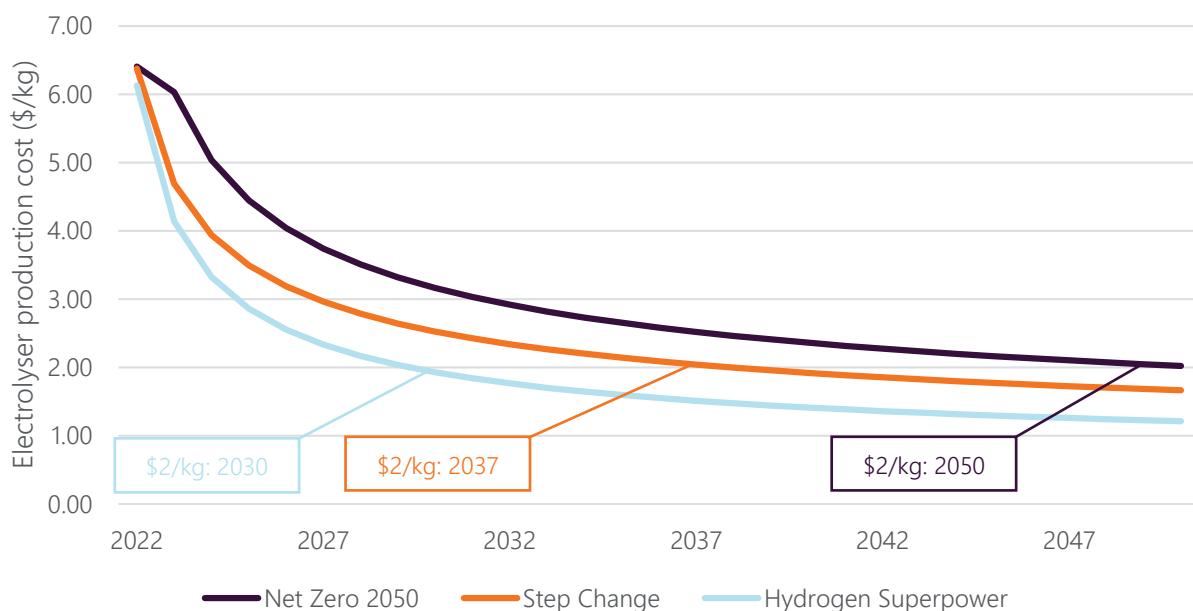


Total hydrogen production costs

Figure 27 shows the projected hydrogen production costs produced from the multi-sectoral model. These costs take into account the capital cost reductions of PEM electrolyzers assumed as result of targeted research and development programs, as well as the cost of energy needed to supply the load. It is important to note that it is assumed electrolyzers will operate flexibly to avoid operation during high price periods, and will prefer to operate at times when electricity prices are equal to, or slightly lower than, the levelised cost of energy for VRE (particularly solar technologies).

Each scenario is forecast to achieve the stated Technology Roadmap goal of \$2/kg (~\$14/gigajoule [GJ]), but on very different timelines. Greatest and fastest hydrogen production learning (and therefore cost reductions) is assumed in the Hydrogen Superpower scenario; relatively low hydrogen costs in this scenario are also assumed to spur a new “green steel” industry.

Figure 27 Projected PEM electrolyser production cost across the scenarios

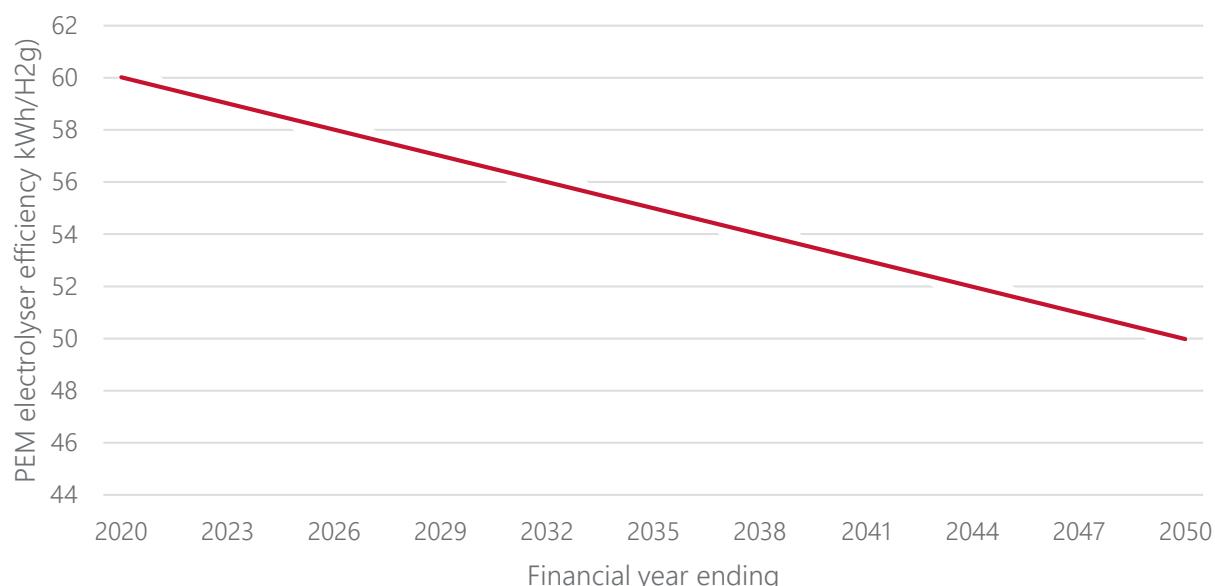


Flexibility

The actual electrolyser itself can be ramped up and down rapidly, potentially even providing fast frequency response similar to electrochemical batteries. AEMO models PEM electrolyzers as fully flexible, although there is an associated baseload component (as described below). The degree of actual flexibility offered in the market will depend strongly on the commercial arrangements in relation to the plant and its contracts for supply of hydrogen, relative to the effectiveness of the markets in the NEM and the opportunities to efficiently arbitrage between contract arrangements and the NEM.

The efficiency of the electrolyser is projected to improve over time, as shown in Figure 28⁷¹.

Figure 28 Efficiency projections for PEM electrolyzers



Modularity

Much like PV and batteries, hydrogen electrolyzers are highly modular and can be scaled up fairly linearly. The modules are assumed to be available in 1 MW increments.

Baseload/auxiliary load of the electrolyser

While the electrolyser stack is fully flexible, an electrolysis plant has a range of components which respond at different rates. Such components include dryers, compressors/pumps, and cooling. Stakeholder consultation suggested the baseload demand consumed by the electrolyser at 10% of total demand, even when the electrolyser is not producing hydrogen.

The best available information that could be sourced from an operating unit comes from Energiepark Mainz⁷² and shows the operating characteristics of a 4 MW PEM electrolyser plant comprised of three modular electrolyzers. The baseload reported is 175 kW (~4.5%).

The scale of baseload auxiliaries is uncertain with regards to the impact that a growing capacity may bring. Discussions with equipment suppliers, international research organisations, and stakeholders indicate that this load may reduce to around 2% with increased scale.

⁷¹ Based on Aurecon, 2020-21 AEMO Costs and Technical Parameter Review for the initial cost and CSIRO, National Hydrogen Roadmap (2018), for projected improvement rate.

⁷² Kopp, M., Coleman, D., Stiller, C., Scheffer, K., Aichinger, J., Scheppat, B. et al. (2017), "Energiepark Mainz: Technical and economic analysis of the worldwide largest Power-to-Gas plant with PEM electrolysis", International Journal of Hydrogen Energy, Vol. 42, Issue 52.

In the absence of better information, AEMO assumes a baseload of 4.5% for domestic-focused electrolyzers that are expected to be more modular, and at smaller scale. Export-focused electrolyzers (in the Hydrogen Superpower scenario) are expected to be developed at larger scale; a baseload/auxiliary rate of 2% is applied to these facilities.

In the Hydrogen Superpower scenario there is substantial export of hydrogen (see Figure 25). Ammonia, liquefaction, other hydrocarbons, and metal hydrides are each different methods for transporting hydrogen for export. For the 2022 ISP, AEMO only considers conversion to ammonia, as this is considered the cheapest, most effective, and most dominant method of export at present. The ammonia plant⁷³ is considered inflexible and will be modelled as an additional baseload to the electrolyzers targeted for hydrogen export. The actual efficiency of those plant is projected to improve over time as shown in the IASR Assumptions Book at a rate similar to the electrolyser gain in efficiency. The result of this is approximately equal to an additional 4.5% of baseload demand on the export electrolyzers.

The Hydrogen Superpower scenario also features “green steel” production using the direct reduction of iron (DRI) process. This is assumed to be export driven and will be coupled with export hydrogen production centres, reflecting similar siting choices of existing steel works being based in locations with ready access to energy, rather than being directly sited with iron ore mines.

The multi-sector modelling forecast the scale of green steel production in the Hydrogen Superpower scenario, growing to around 50 million tonnes (Mt)⁷⁴ of steel production by 2050, or equal to 48 TWh of additional electricity consumption, in addition to the increased demand for hydrogen. This electricity demand from the electric arc furnaces associated with green steel production will be modelled as an additional baseload to the export-focused electrolyzers. The electricity required to produce this scale of production is provided in the IASR Assumptions Book.

For reliability assessments such as the ESOO, it is assumed that domestic electrolyser loads are sufficiently flexible to adjust load up or down within technical limits, if required, to vary supply as a response to prevailing generation and market conditions. In reliability assessments, export-facing hydrogen facilities (including ammonia and green-steel facilities) are not considered. This is equivalent to these facilities being active forms of demand response as required to minimise any potential unserved energy risk.

AEMO’s methodology for identifying potential locations of export electrolyser loads, as outlined in the *ISP Methodology*, co-optimises the development of export facilities, renewable energy generation resources, and electricity infrastructure at least cost. The ESOO therefore ignores the potential for export facilities to impact the reliability assessment in this scenario, given the lack of spatial awareness by the time of ESOO publication. This is equivalent to expecting that export hydrogen facilities operate to provide demand response ahead of any unserved energy affecting consumers.

Storage

Hydrogen production needs to be sufficient to meet the demand determined by the CSIRO and ClimateWorks multi-sectoral modelling. The modelling approach allows for optimisation of electrolyser operations across a one-month period, allowing for a few days of offline production, assumed to be managed by storage.

For domestic hydrogen use, the distribution pipelines will provide some level of inherent storage through linepack. Residential natural gas demand is known to be strongly seasonal in nature. For the purpose of modelling the residential consumption of hydrogen, it is assumed that hydrogen storage will be used to help manage the seasonal demand profile and the monthly production requirement will remain relatively flat. This provides a contrast to the Strong Electrification sensitivity where the seasonal heating impact on the

⁷³ The capital cost of building and operational cost of these plants need not be considered in the modelling efforts. Since the ammonia facilities are assumed to operate as a flat load, and the demand is fixed before this ammonia plants would be considered, their capacity factor is not subject to the optimisation in the electricity expansion model and their cost does not have impact on the outcome of the supply modelling.

⁷⁴ This value is approximately half the opportunity identified here: https://www.energy-transition-hub.org/files/resource/attachment/zero_emissions_metals.pdf.

electricity system could be significant. Without assuming hydrogen storage (or deep electricity storage), seasonality of heating demand would impact the power system in a similar manner irrespective of whether fuel switching directly to electrification, or to hydrogen produced by NEM-connected electrolyzers.

3.4 Existing generator and storage assumptions

3.4.1 Generator and storage data

Input vintage	July 2021 Generation Information update
Source	Participant survey responses
Updates since Draft IASR	Updated quarterly, Final IASR reflects most recent release.

AEMO's Generation Information page⁷⁵ publishes data on existing, committed, and anticipated generators and storage projects (size, location, capacities, seasonal ratings, auxiliary loads, full commercial use dates and expected closure years), and non-confidential information provided to AEMO on the pipeline of future potential projects. This information is updated quarterly, with the most recently available information adopted for each of AEMO's publications (and clearly identified in each publication).

The resource availability for existing, committed and anticipated VRE generation is modelled using half-hourly generation profiles as described in Section 3.6.2.

3.4.2 Technical and cost parameters (existing generators and storages)

Input vintage	July 2021 Generation Information update, plus various other sources from 2018-19 onwards, as outlined below.
Source	Various, see below
Updates since draft IASR	Minor updates to reflect final Aurecon assumptions, operating and maintenance assumptions for coal revised based on engagement with power station owners. Other minor updates based on stakeholder feedback.

AEMO has sourced the operating and cost parameters of existing generators and storages from several different sources, including AEMO internal studies⁷⁶. They include:

- AEMO's Generation Information page.
- GHD, *2018-19 AEMO Costs and Technical Parameter Review*.
- Aurecon, *2020-21 Cost and Technical Parameter Review*.
- AEP Eical, *2020 Assessment of Ageing Coal-Fired Generation Reliability*.
- Generator surveys.
- CER, *Electricity sector emissions and generation 2019-20*.

The specific parameters obtained from each of these sources are summarised in Table 15 below.

⁷⁵ Data on existing and committed generators is given in each regional spreadsheet on the Generation Information page, at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

⁷⁶ Consultant reports and data books from GHD, Aurecon and AEP Eical are available at <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines>.

Table 15 Sources 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% POE Summer, Typical Summer and Winter) • Auxiliary loads • Commissioning and retirement dates
GHD 2018-19 Costs and Technical Parameters Review (primarily for existing generators)	<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 2020-21 Cost and Technical Parameter Review (primarily for new entrant generators)	<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"> • Forced outage rates • Refinements to fixed and variable operating and maintenance costs for coal-fired generation
AEP Electrical 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 for coal-fired generation (using the 90th percentile of non-zero ramp rates bid into the market by each units). • Minimum and maximum capacity factors
CER, Electricity sector emissions and generation 2019-20	<ul style="list-style-type: none"> • Scope 1 Emissions factors

The assumptions on the parameters documented in this table are contained in the IASR Assumptions Book.

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.

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

Minimum stable levels for existing generators are based on AEMO internal analysis of historical generation and operational experience. Minimum stable levels for new entrant generators are sourced from Aurecon (see Table 56). In the time-sequential models, minimum stable levels are applied for baseload and mid-merit generators and, for some units, minimum loads are enforced. However, in the capacity outlook models, minimum load levels are applied instead of minimum stable levels and to some baseload generators only, to manage computational complexity.

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 IASR Assumptions Book 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 curves⁷⁷.
- Unit commitment optimisation and minimum stable levels if the model granularity warrants the additional complexity. For hourly or half-hourly modelling purposes, these optimisation limits are inappropriate for many peaking plants, as this may restrict modelled dispatch in the models that is not representative of real-time operation capabilities in sub-half-hourly dispatch periods.

Further details on the implementation of these technical limitations can be found in AEMO's *ISP Methodology*⁷⁸.

3.4.3 Forced outage rates

Input vintage	June 2021
Source	Generator surveys and AEP Eical 2020
Updates since Draft IASR	Forced outage rates are updated at least annually, as part of AEMO's ESOO data collection process. The latest projections were presented at the June 2021 FRG.

Forced outage rate collection process

Forced outage rates are a critical input for AEMO's reliability assessments and for modelling the capability of dispatchable generation capacity more generally. For the 2021 ESOO, AEMO collected information from all generators on the timing, duration, and severity of unplanned forced outages, via its annual survey process. This includes information on historical outages, and (for selected participants) outage projections across the 10-year forecast period.

This data was used to calculate the probability of full and partial forced outages in accordance with the *ESOO and Reliability Forecasting Methodology*⁷⁹. Station-level forced outage rate projections are applied when statistically stable and where implementation can preserve participant confidentiality. For some generator technology types, like peaking plants and hydro, technology aggregates are applied to individual stations to smooth the impact of outlying years. In published models where applied rates are visible, only technology aggregates are applied to preserve participant confidentiality.

Where participants have provided outage rate projections, AEMO adopts these provided these projections have been sufficiently evidenced. AEMO also commissioned AEP Eical⁸⁰ in 2020 to provide forward-looking outage values for coal-fired generators, to complement participant-provided projections.

For a limited number of generators where a forward-looking projection was not provided or where outage projections were not sufficiently substantiated with explanations or evidence, AEMO has supplemented or replaced these forecasts with those provided by AEP Eical. In these instances, AEMO consulted individually with the relevant participant to ensure any use of AEP Eical forecasts was made transparently with participant

⁷⁷ This is provided by Aurecon and GHD's technical generator capability reports (see Table 56), or analysis of historical information from both the Gas Bulletin Board and AEMO's Market Management System data if necessary.

⁷⁸ At <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-ispl/2022-integrated-system-plan-ispl/ispl-methodology>.

⁷⁹ At <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines>.

⁸⁰ Under supporting material, at <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines>.

acknowledgement. To protect the confidentiality of responses, AEMO is not able to list who provided forward-looking projections and who did not.

In aggregate, the forecasts applied capture a combination of improvements and deteriorations in outage performance across the generation fleet.

For ISP purposes, the forced outage rate assumptions are held constant past the first 10 years. Although reliability may degrade as plant ages and nears retirement, any accuracy of this trend beyond 10 years is difficult to implement, particularly when timing of generation withdrawal may be dynamic. It is a level of complexity that AEMO does not consider warranted, as it is not expected to introduce a material difference to ISP outcomes.

Long duration unplanned outages

As described in the *ESOO and Reliability Forecast Methodology*, AEMO has removed outages with a duration longer than five months (long duration outages) from historical outage data from 2010-11 to 2020-21, prior to calculation of the Expected Forced Outage Rate. For the ESOO, AEMO uses an extended historical period of all available data (in this case 11 years) to determine the (unplanned) long duration outage rates for each region and technology class⁸¹. This is done to avoid overestimation of outage rates for an individual station, and to instead consider the likelihood of long duration outages in a longer-term context across a technology class.

For reliability assessments, these long duration outages, which typically have a much lower probability of occurring) are applied in addition to the more regular forced outage rate assumptions. The long duration outages used in 2021 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 16 below. These models use large numbers of simulations that allow full representation of the long duration outages, including some iterations that may not have any long duration outages at all. These have been updated with the most recent year's history for use in 2021-22 publications. The Mean Time to Repair (MTTR) assumptions are a direct reflection of observed long duration events as per AEMO's definition over the last 11 years.

The ISP uses a different application for long duration outages. In reserve calculations (which are a part of the capacity outlook modelling approach, see Section 2.4.3 of the ISP Methodology) the seasonal ratings of generators are derated by the equivalent forced outage rate (EFOR). For this purpose, the EFOR will exclude the contribution from long duration outages; this is because the comparable impact of low probability transmission outage rates is not able to be included⁸². Excluding the impact of long duration outages in the determination of firm capacity ensures there is no systematic bias for generation or transmission when assessing the value of alternative options for addressing reliability. Exclusion of long duration outages in the reserve calculation is not expected to materially impact outcomes in the ISP given the coarseness of that calculation. Reliability of the optimal development path is further tested in time-sequential models as part of the validation process.

The capacity of generation that is able to be dispatched in the capacity outlook model is the seasonal capacity, derated by the EFOR. For this purpose, the contribution from long duration outages will be included in the EFOR (noting they are only applied to existing generators so should not introduce any bias in model selection of new generation, storage or transmission infrastructure). Similarly, in subsequent time-sequential modelling, the long duration outage rates will be included in the standard full forced outage rate to test reliability of the development path. Long duration outages are not able to be separately modelled, as is done in the ESOO, due to a reduced number of modelling simulations which could create instability in modelling outcomes.

⁸¹ Any planned outages are excluded from this analysis. Reserve outages are not considered in the unplanned outage dataset.

⁸² Transmission outage rates are not included in the ISP as they have low probability and the modelling in the ISP is not generally using a sufficiently large number of simulations to ensure that results are sufficiently converged. See Section 3.10.10 for further detail.

Table 16 2021 long duration outage assumptions

Technology	Long duration outage rate (%)	MTTR (hours)*
Brown coal	0.59	5,290
Black coal (New South Wales)	0.76	5,568
Black coal (Queensland)	0.21	4,656
All coal average	0.53	5,330
Open cycle gas turbine (OCGT)	0.80	5,580

*MTTR = Mean time to repair: this parameter sets the average duration (in hours) of generator outages.

Forced outage rate trajectories

The first year forced outage rates assumed in the 2021 ESOO are based on participant-provided information and projections for each technology, as shown in Table 17 below. Relative to the values used in the 2020 ESOO, the rates for 2021-22 have increased, consistent with the participant-provided station level projections and often also, recent performance.

Table 17 Forced outage assumptions (excluding long duration outages) for 2021-22 year

Generator aggregation	Full forced outage rate – 2021 ESOO (%)	Full forced outage rate – 2020 ESOO (%)	Change since 2020 ESOO (%)	Partial forced outage rate (%)	Partial derating (% pf capacity)	MTTR – Full outage (hours)	MTTR – Partial outage (hours)
Brown coal	6.19	5.51	+0.68	7.63	20.41	100	9
Black coal (Queensland)	4.11	3.02	+1.09	13.24	22.22	102	41
Black coal (New South Wales)	8.46	5.02	+3.44	31.05	18.33	174	46
OCGT	3.74	2.42	+1.32	2.21	4.20	22	19
Small peaking plant*	6.82	4.57	+2.25	0.21	23.20	75	13
Hydro	2.62	2.52	+0.10	0.01	36.18	49	48
Steam Turbine & closed cycle gas turbine (CCGT)	2.29	4.21	-1.92	2.60	7.05	54	40

* 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 forced outage rate⁸³ of all technology aggregates are shown in Figure 29 and Figure 30, with and without the effect of long duration outages. The annual effective forced outage rate is affected by changes to assumed reliability and retirements of generators over the horizon. To protect the confidentiality of the individual station-level information used, forced outage trajectories are provided for the first 10 years of the horizon for technology aggregates only⁸⁴.

⁸³ Where effective full forced outage rate = Full forced outage + partial outage rate x average partial derating.

⁸⁴ Beyond 2030, the number of stations in each aggregation diminishes, and as such the presentation of aggregated information would reveal individual station-level trajectories.

The ISP does not apply station-specific outage rate projections, instead using technology aggregate projections based on expected closure years until 2030, remaining constant beyond that point as the impact of outage rate deterioration is generally offset by the retirement of older stations.

More information on treatment of outage rates across AEMO's modelling is provided in the *ISP Methodology*⁸⁵.

Figure 29 Effective full forced outage rate projections for coal-fired generation technologies

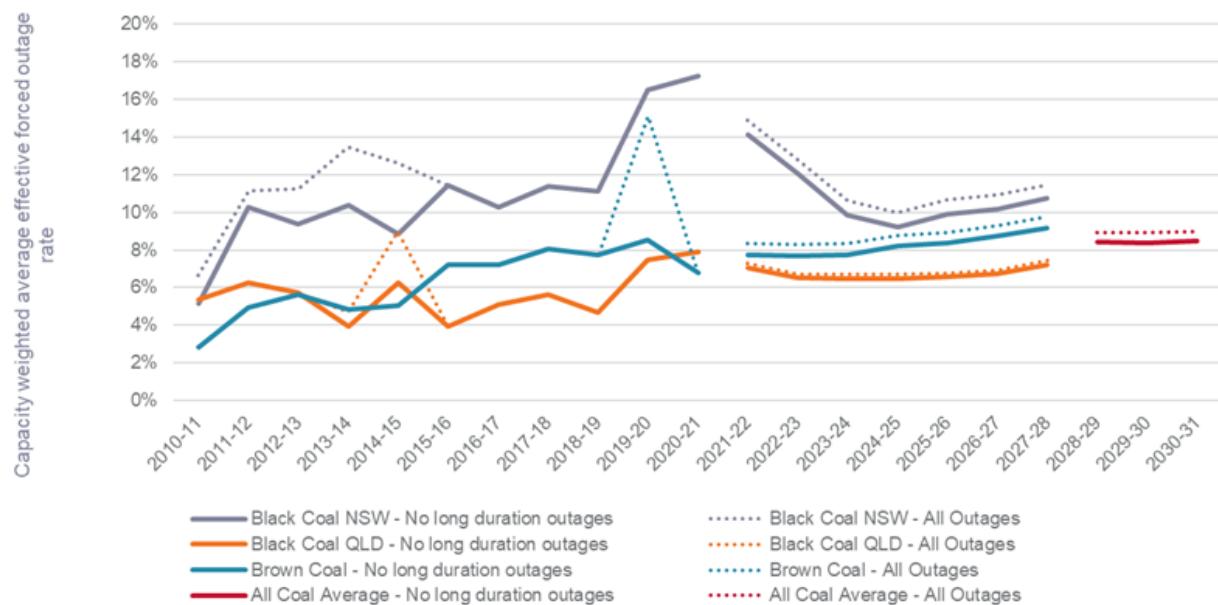
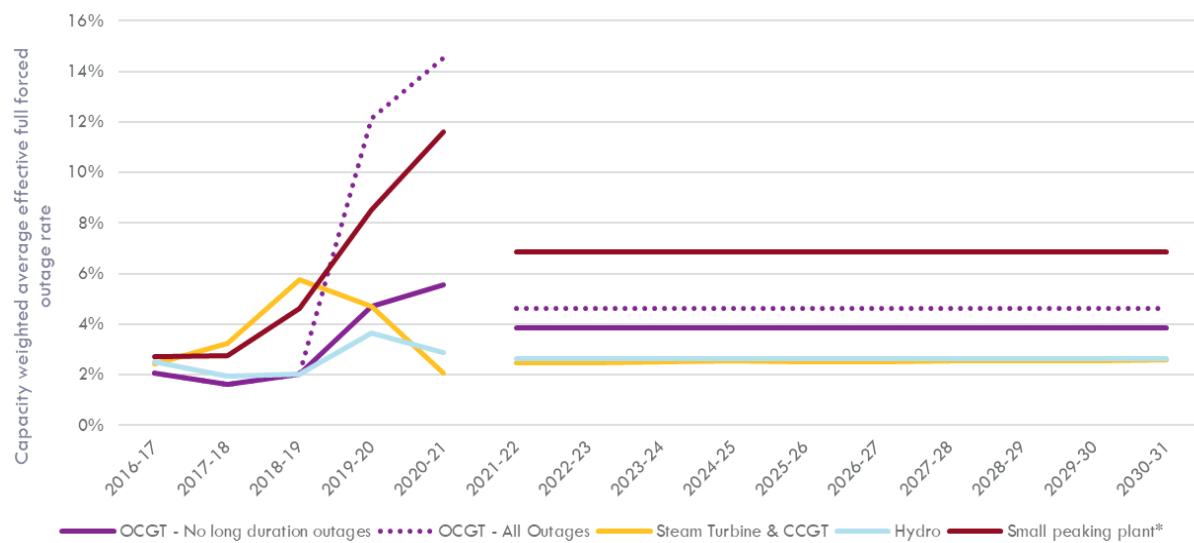


Figure 30 Effective full forced outage rate projections for other generation technologies



The IASR Assumptions Book provides the detailed information on the forced outage rate parameters of each technology over time.

⁸⁵ At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2021/isp-methodology/draft/draft-isp-methodology.pdf?la=en.

New entrant generation outage assumptions

The 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 generation.

3.4.4 Generator retirements

Input vintage	<ul style="list-style-type: none">• Retirement costs unchanged since 2020 ISP.• Retirement dates updated from July 2021 Generation Information page.
Source	<ul style="list-style-type: none">• Generation Information page• GHD 2018
Updates since Draft IASR	Expected closure years and closure dates have been updated to reflect the most recent data collection. AEMO engaged with generator participants but no further information on retirement costs was able to be provided.

For existing generators, AEMO applies expected closure years provided by participants through AEMO's Generation Information⁸⁶ page, with allowable adjustments to these as described in the *ISP Methodology* (for example, generators can be retired earlier based on profitability assessments). In contrast, registered closure dates, are applied consistently across all scenarios.

For reference, a "closure date" has the meaning specified in NER clause 2.10.1(c1) which specifies the date a generator will cease to supply electricity in the market, while an "expected closure year" is the year in which a generator expects to cease to supply electricity (as per NER clause 2.2.1(e)(2A)).

As such, AEMO's approach recognises the increased accuracy of closure date submissions, thereby locking these dates in across all analysis, rather than contemplating alternative economic-triggered closure timing.

Unlike the 2020 ISP, AEMO will not consider refurbishment opportunities to extend the life of coal plant across all scenarios. Considering the scale of investment required to refurbish the plant to extend the useful life of the asset, and the uncertainty that exists as to the impact of new developments that may encroach on the role that each unit may provide to generate energy, AEMO considers that it is unlikely that life extensions of these deteriorating assets will eventuate, even in a Slow Change scenario.

Retirement costs by generation technology have been provided by GHD and are presented in the IASR Assumptions Book. Retirement costs incorporate the cost of decommissioning, demolition, and site rehabilitation and repatriation, excluding battery storage technologies where disposal cost data is not known.

3.4.5 Hydro modelling

Input vintage	Updated based on new historical data provided by hydro operators in early 2021.
Source	Inflows – hydro operators, considering insights from the Electricity Sector Climate Information (ESCI) project ⁸⁷ .
Updates since Draft IASR	Updated with new information provided by hydro operators. Updates to the climate change impacts on hydro inflows were presented to the FRG in May 2021.

⁸⁶ At <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

⁸⁷ ESCI information available at <https://www.climatechangeaustralia.gov.au/en/projects/esci/>.

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

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

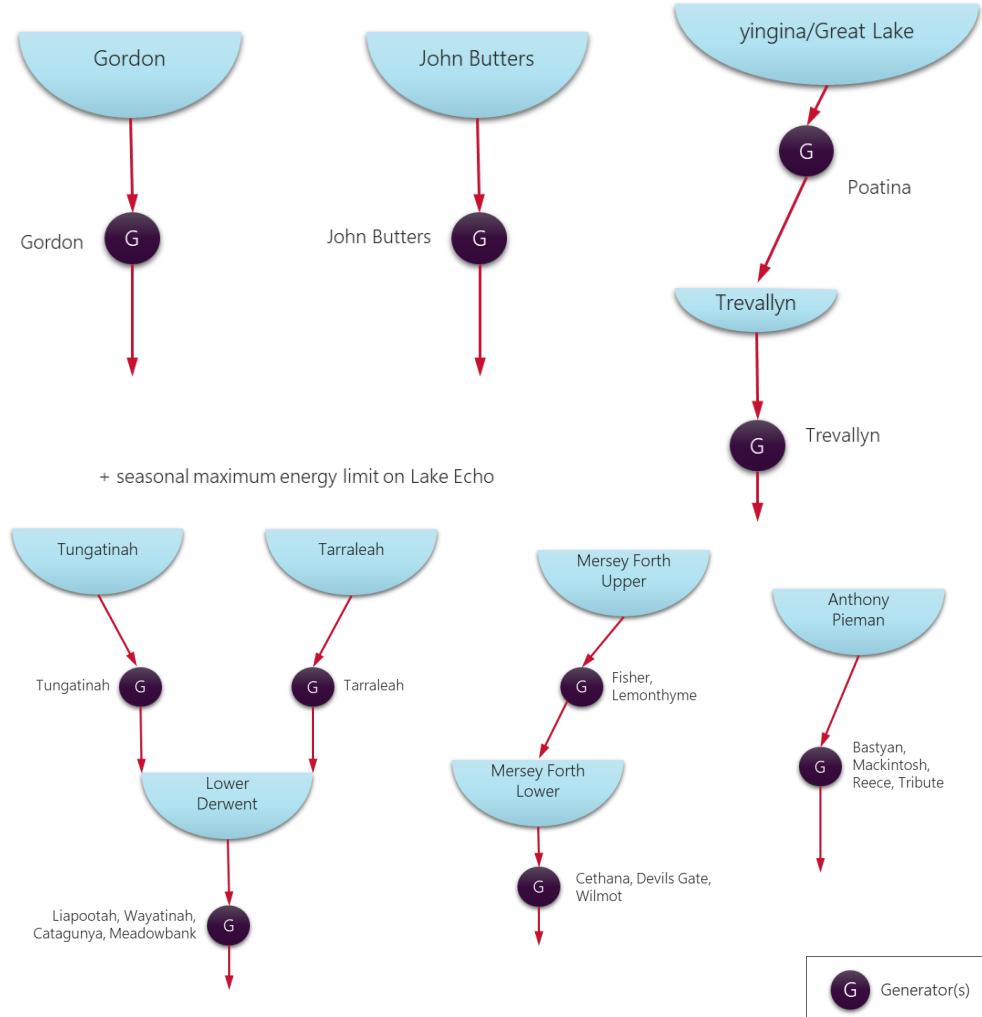
Table 18 identifies how schemes or power stations are allocated across these storages and provides assumptions on the energy in storage available. Energy inflow data for each Tasmanian hydro water storage is determined from historical daily yield information provided by Hydro Tasmania.

Table 18 Storage energy (in GWh) of the three types of generation in Tasmania

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

AEMO's approach to modelling the existing Tasmanian hydro schemes relies on a 10-pond⁸⁸ topology designed to capture different levels of flexibility associated with the different types of storage outlined above (Figure 31).

Figure 31 Hydro Tasmania scheme topology



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

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

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

The latest information on the monthly storage inflows used in market modelling studies can be found in the IASR Assumptions Book.

⁸⁸ The capacity outlook model may aggregate long-term storages together to reduce simulation time.

Figure 32 presents a representation of the topology currently modelled for the Snowy scheme.

Figure 32 Snowy Hydro scheme topology

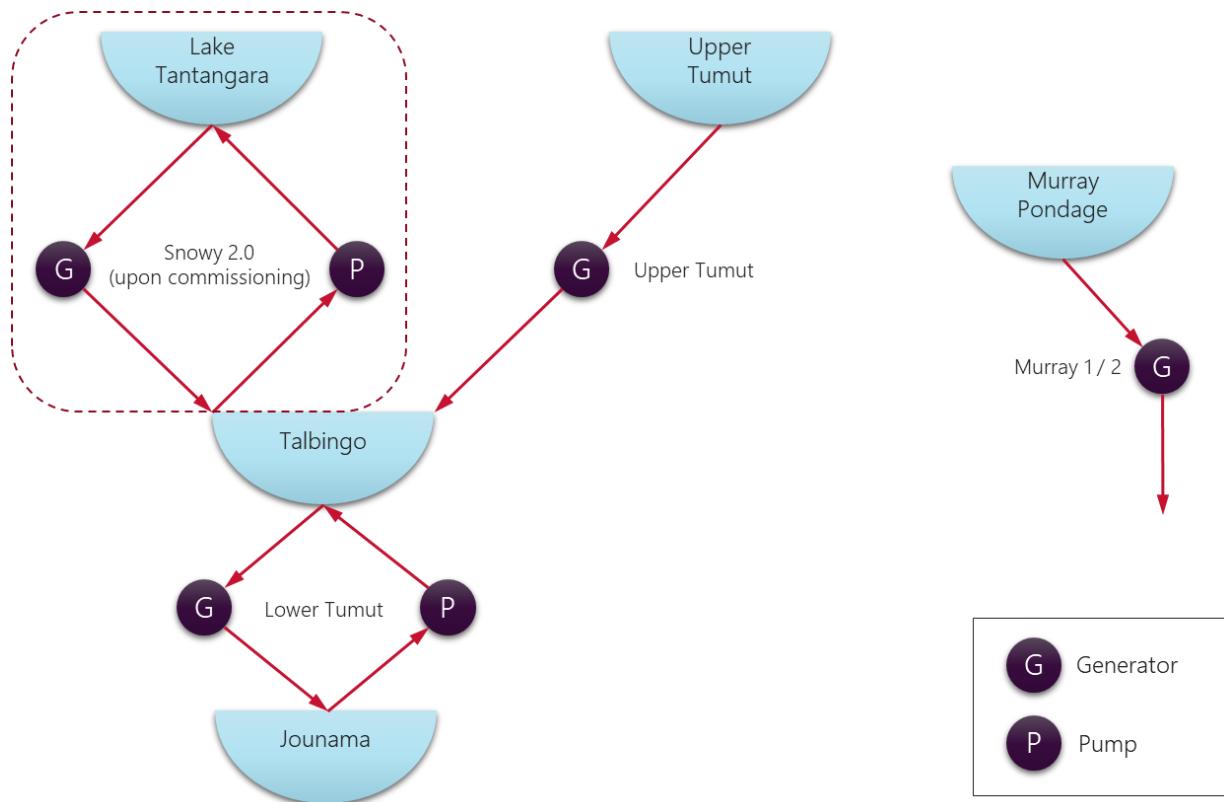
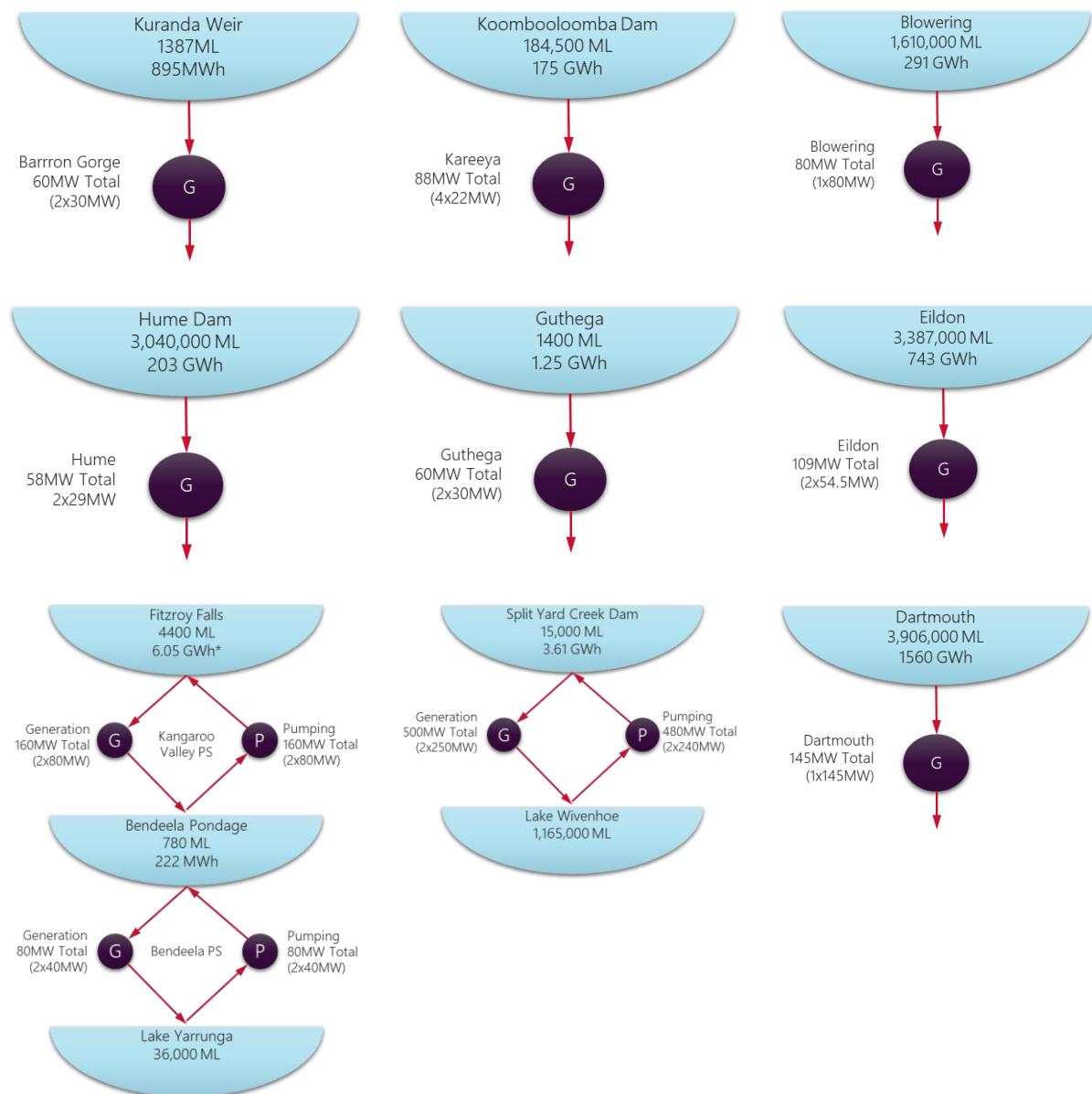


Figure 33 provides graphical representations of the other hydrological models used in the market simulations, as well as the registered capacity of the adjoining generating units⁸⁹.

Figure 33 Other power station hydro models



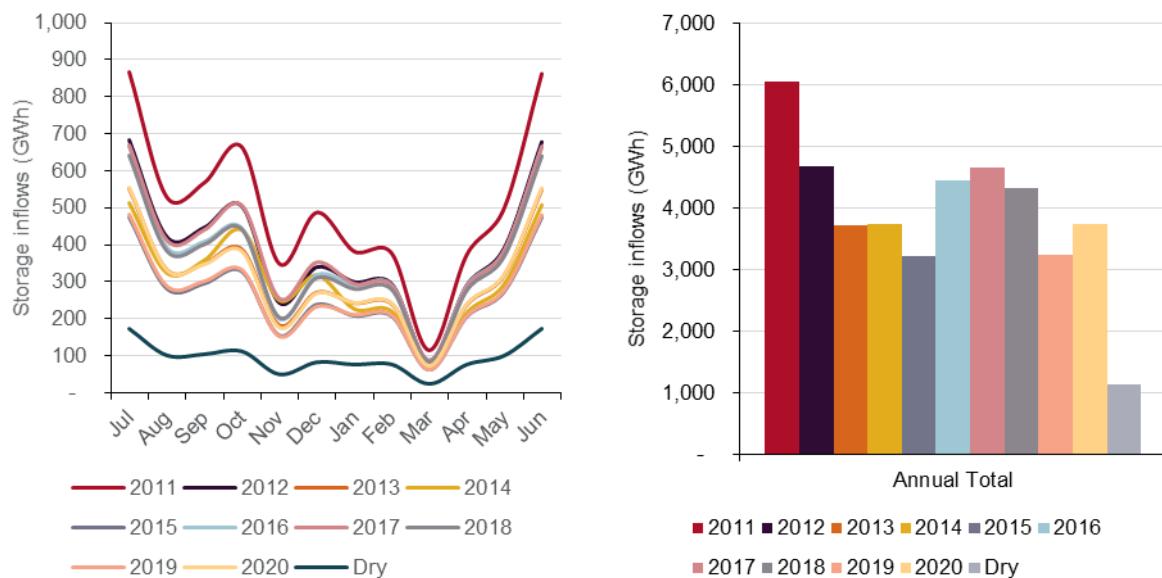
Note. Origin Energy has proposed an expansion of the Shoalhaven pumped hydro scheme, increasing the storage capacity of the project. As this project is not yet committed, the representation provided reflects the existing capacity only.

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

⁸⁹ Storage capacities are defined in megalitres (ML).

The IASR Assumptions Book provides the annual and seasonal variation in hydro inflows for key hydro schemes. An example of this is shown in Figure 34 below, for Snowy Hydro.

Figure 34 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 Government⁹⁰.

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 19 for the Steady Progress and Net Zero 2050 scenarios, as an example. Other scenario hydro climate factors are available in the IASR Assumptions Book.

Table 19 Median hydro climate factors, Steady Progress and Net Zero 2050 scenarios

Region	2020-21	2030-31	2040-41	2050-51
North Queensland	0%	0%	0%	0%
South Queensland, New South Wales, Victoria, and South Australia	-2.3%	-5.8%	-6.1%	-6.7%
Tasmania	-0.8%	-2.0%	-1.7%	-1.5%

⁹⁰ See <https://www.climatechangeinaustralia.gov.au/en/projects/esci/>.

3.5 New entrant generator assumptions

3.5.1 New entrant generation projects included in different publications

Input vintage	July 2021 Generation Information update
Source	Participant survey responses
Updates since Draft IASR	Updated quarterly, IASR reflects most recent release.

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

For reliability assessment purposes, AEMO assumes that Committed projects are sufficiently advanced to be confident they will be in the system on time to help maintain system reliability if needed, but that the same level of confidence cannot be applied to Anticipated projects. Therefore, Anticipated projects are excluded from ESOO assessments of reliability.

For ISP purposes, both Committed and Anticipated projects are assumed to proceed on time 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.

AEMO's modelling will therefore include projects based on their classification in the Generation Information page:

- For the ESOO:
 - Committed⁹¹ or
 - Committed* – projects under construction and well advanced to becoming committed⁹².
- For the ISP and GSOO, the categories above, as well as Anticipated projects⁹³.

Committed projects are considered to become operational on dates provided by the participants.

Committed* projects are assumed to commence operation after the end of the next financial year (1 July 2023), reflecting uncertainty in the commissioning of these projects. Further details are available in the *Reliability Forecasting Methodology Final Report*⁹⁴.

Anticipated projects are defined in a manner consistent with the AER's Cost Benefit Analysis Guidelines and the RIT-T instrument as being a project that "is in the process of meeting at least three of the five criteria for a committed project"⁹⁵. AEMO's process for assessing whether a project is Anticipated is outlined in the *ISP Methodology*. Anticipated projects are assumed to commence operation after the end of the next financial year (1 July 2023), consistent with the approach applied to Committed* projects.

This IASR applies the Generation Information July 2021 release. A summary of existing, committed, anticipated projects included in that release is provided in Figure 35 and Table 20 below.

⁹¹ Committed projects meet all five of AEMO's commitment criteria (relating to site, components, planning, finance, and date). For details, see <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

⁹² In AEMO's Generation Information page these projects are called Committed* or Com*. Further detail is provided in the Background section of AEMO's Generation Information page.

⁹³ Anticipated projects demonstrate progress towards three of five of AEMO's commitment criteria, in accordance with the AER's Forecasting Best Practice Guidelines and RIT-T guidelines.

⁹⁴ See Section 5.3 at <https://www.aemo.com.au/-/media/Files/Stakeholder-Consultation/Consultations/NEM-Consultations/2019/Reliability-Forecasting-Methodology/Reliability-Forecasting-Methodology-Final-Report.pdf>.

⁹⁵ See Table 15 at <https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%202025%20August%202020.pdf>.

Figure 35 Generation and storage projects in July 2021 Generation Information page

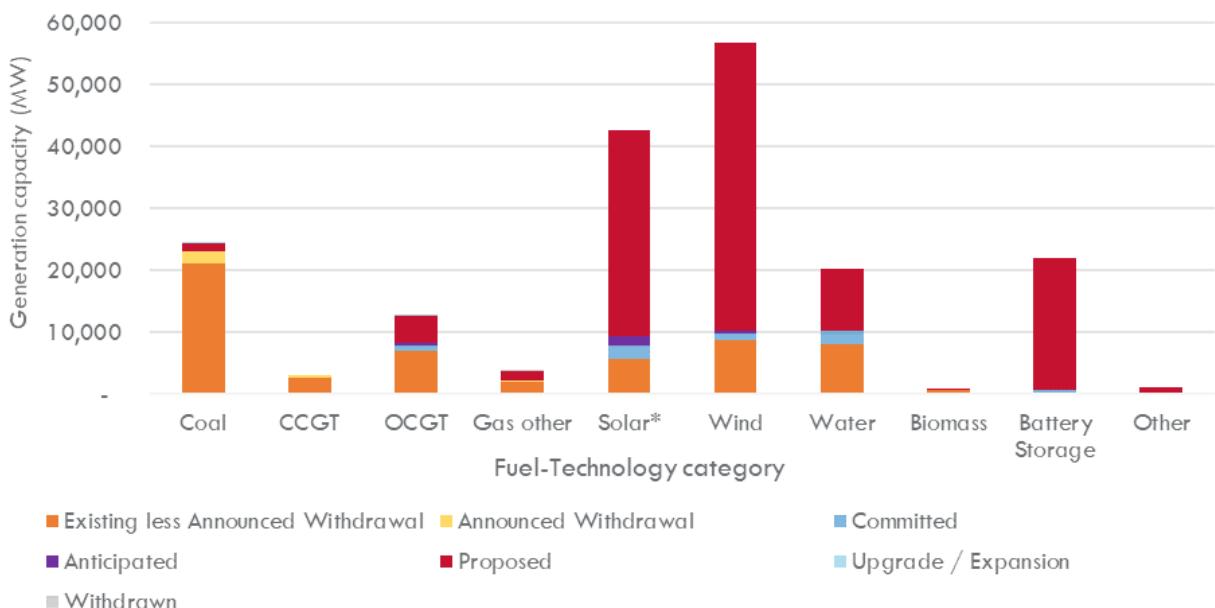


Table 20 Generation and storage projects in July 2021 Generation Information page

	Coal	CCGT	OCGT	Gas other	Solar	Wind	Water	Biomass	Battery Storage	Other	Total
Existing	23,201	2,985	7,013	2,170	5,730	8,815	7,992	617	261	202	58,986
Announced withdrawal	2,000	388	-	240	-	-	-	-	-	-	2,628
Existing less announced withdrawal	21,201	2,597	7,013	1,930	5,730	8,815	7,992	617	261	202	56,358
Upgrade / expansion	90	-	15	-	-	-	-	-	-	-	105
Committed	-	-	904	-	2,087	1,101	2,290	-	489	24	6,895
Anticipated	-	-	316	-	1,489	368	-	-	18	-	2,191
Proposed	1,141	-	4,433	1,532	33,459	46,517	9,936	41	21,263	887	119,210
Withdrawn	-	-	34	240	-	-	-	-	-	-	274

Given the constantly changing information relating to the status of new generation and storage projects and the time taken to undertake major modelling exercises, AEMO's analysis cannot always reflect the current view on committed and anticipated projects. Rather, AEMO's modelling will use the most current view available and published on the Generation Information page at the time modelling commences, incorporating material updates where possible. Each publication will note what version of the Generation Information was used in the assessment.

The resource availability of new entrant VRE generation is modelled using half-hourly generation profiles as described in Section 3.6.2.

3.5.2 Candidate technology options

Input vintage	Updated through 2020-21 GenCost 2020-21 process, which was finalised in June 2021.
Source	<ul style="list-style-type: none"> • CSIRO: <i>GenCost 2020-21 Final report</i> • Aurecon: <i>2020-21 Costs and Technical Parameters Review</i> • GHD: <i>2018-19 Costs and Technical Parameters Review</i>
Updates since Draft IASR	No updates in the list of technologies considered, but additional consideration of offshore wind. Please refer to the <i>IASR Consultation Summary Report</i> ⁹⁶ (and below) for an explanation of AEMO's consideration of feedback received in relation to candidate technology options.

For the 2022 ISP's capacity outlook modelling, a filtered list of technologies – selected from those provided by Aurecon and CSIRO (GenCost) – are considered, based on technology maturity, resource availability, energy policy settings, and the capacity outlook models' ability to distinguish between technologies. Table 21 below presents the filtered list of technologies that are included in the 2021-22 forecasting publications.

Table 21 List of candidate generation and storage technology options

List of technologies to be available in the 2022 ISP	Commentary
Advanced ultra supercritical PC – black coal with CCS	–
Advanced ultra supercritical PC – black coal without CCS	Given the market need for flexible plant to firm low-cost renewable generation, new coal-fired generation would be highly unlikely in any scenario with emissions abatement objectives, particularly given the long-life nature of any new coal investment.
CCGT – with CCS	–
CCGT – without CCS	–
OCGT – without CCS, Small unit size	–
OCGT – without CCS, Large unit size	Larger OCGT added based on stakeholder feedback from the 2020 ISP.
OCGT – hydrogen, based on larger size units	Operating characteristics are considered to be similar to OCGT. Used only in the Hydrogen Superpower scenario, and only available from 2030, considering fuel availability and technology development barriers, as well as feedback from stakeholders.
Battery storage	AEMO includes storage sizes from 1-8 hours in its models. No geographical or geological limits will apply to available battery capacity given its small land footprint.
Solar PV – single axis tracking	–
Solar thermal central receiver with storage (8hr)	–
Wind – onshore	–
Wind – offshore	Candidate offshore wind zones (OWZs) have been added to the 2021 IASR, considering announced projects and stakeholder feedback. More information is available within Section 3.9.
Biomass – electricity only	–
Pumped hydro energy storage (PHES)	AEMO includes variants of PHES, ranging from 8 to 24 hours of storage.

⁹⁶ At <https://aemo.com.au/en/newsroom/news-updates/draft-2021-inputs-assumptions-and-scenarios-report-released>.

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

- New brown coal generation (with or without CCS) has been excluded given no such projects are publicly announced in the NEM and there are lower cost dispatchable alternatives that offer greater system flexibility. Given Victoria's existing public policy regarding net zero emissions, new brown coal generation would present an internal inconsistency with that policy requirement. Investment risks for new brown coal developments are therefore assumed too high to be considered as a commercially viable development option.
- Reciprocating internal combustion engines – reciprocating engines are not modelled due to their high capex relative to open cycle gas turbines (OCGTs). Their benefits are not well captured within long-term models, and the differences are not considered material for long-term planning.
- Nuclear generation – nuclear generation is excluded, as currently Section 140A of the *Environment Protection and Biodiversity Conservation Act 1999*⁹⁷ 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 any REZ, nor have they been successfully commercialised in Australia. There may be targeted applications of geothermal technologies suitable for the NEM, but they are currently not included in ISP modelling.
- Solar PV fixed flat plate (FFP) and dual-axis tracking (DAT) technologies – AEMO acknowledges that the best solar configuration may vary for each individual project. Given current cost assumptions, single-axis tracking (SAT) generally presents a greater value solution in AEMO's capacity outlook models. Presently, announced SAT projects also provide more proposed capacity than DAT and FFP projects, and almost all recent project commitments for large-scale projects are SAT⁹⁸. Given this preference, the relative cost advantage, and the relatively small difference in expected generation profiles of each technology, AEMO models all future solar developments with a SAT configuration.
- Tidal/wave technologies – this is not sufficiently advanced or economic to be included in the modelling.
- Hybrid technologies are not explicitly considered; however, 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 Technology build costs

Input vintage	Updated through 2020-21 GenCost process, which was finalised in June 2021.
Source	<ul style="list-style-type: none">• CSIRO: <i>GenCost 2020-21 Final report</i>• Aurecon: <i>2020-21 Costs and Technical Parameters Review</i>• Entura: <i>2018 Pumped Hydro Cost Modelling</i>• Hydro Tasmania information on Cethana project
Updates since Draft IASR	Updated to reflect final projections from Aurecon and CSIRO, which includes revisions based on stakeholder feedback.

Capital cost trajectories

Generator capital cost trajectories are informed by the GenCost publication, an annual publication of electricity generation technology cost projects conducted jointly through a CSIRO/AEMO partnership. To support this forecast, Aurecon determined the current cost of each generation technology.

The GenCost projections utilise CSIRO's GALLM model, which provide build cost forecasts that are a function of global and local technology deployment. The build cost projections are given for three GenCost scenarios

⁹⁷ Australian Government, Environment Protection and Biodiversity Conservation Act 1999, at <https://www.legislation.gov.au/Details/C2012C00248>.

⁹⁸ Based on July 2021 Generation Information, at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information>.

("High VRE", "Central" and "Diverse Technology"). These scenarios are described in greater detail in CSIRO's GenCost Final report⁹⁹, and AEMO maps the IASR scenarios to the GenCost scenarios, as shown in Table 22 below.

As CSIRO's High VRE scenario is linked with strong decarbonisation ambitions and high levels of VRE development globally, it has been applied to the Step Change and Hydrogen Superpower scenarios. CSIRO's Central scenario does not significantly expand renewable targets and has a more muted decarbonisation ambition, and has therefore been applied in the Slow Change, Steady Progress and the Net Zero 2050 scenarios.

Table 22 Mapping AEMO scenario themes to the GenCost scenarios

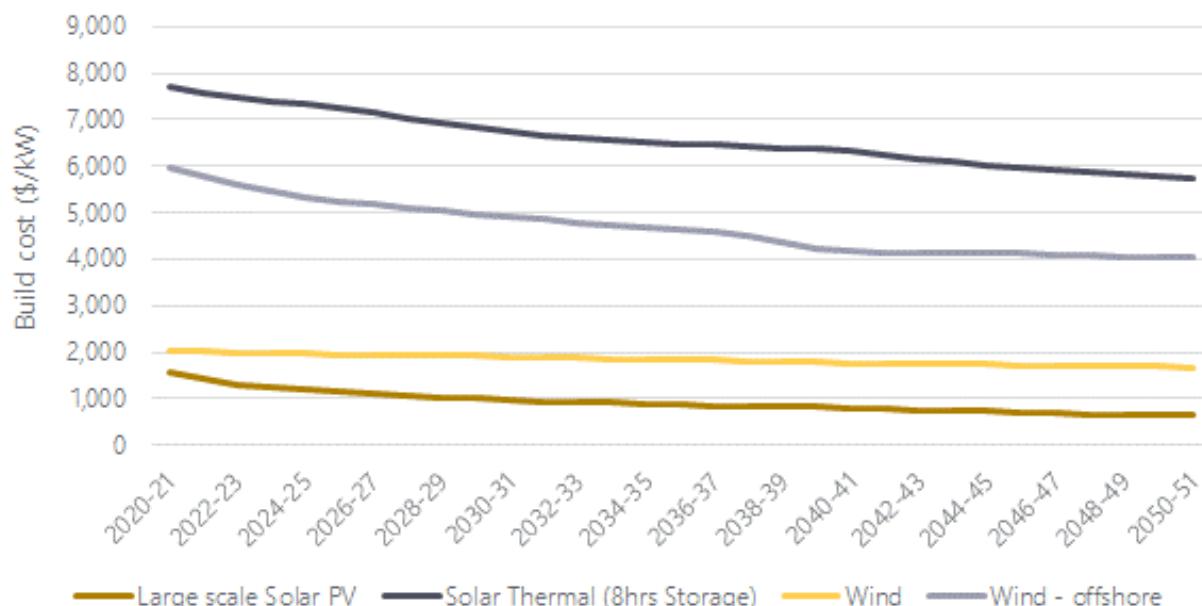
AEMO scenario	GenCost scenario
Slow Change	Central
Steady Progress	Central
Net Zero 2050	Central
Step Change	High VRE
Hydrogen Superpower	High VRE*

* The Hydrogen Superpower scenario assumes accelerated capital cost reductions for large-scale solar PV compared to the High VRE GenCost scenario, as a key enabler of hydrogen expansion for export.

* The Strong Electrification sensitivity maintains the large-scale solar PV capital costs from the GenCost High VRE scenario, precluding the development of a hydrogen export industry within the NEM.

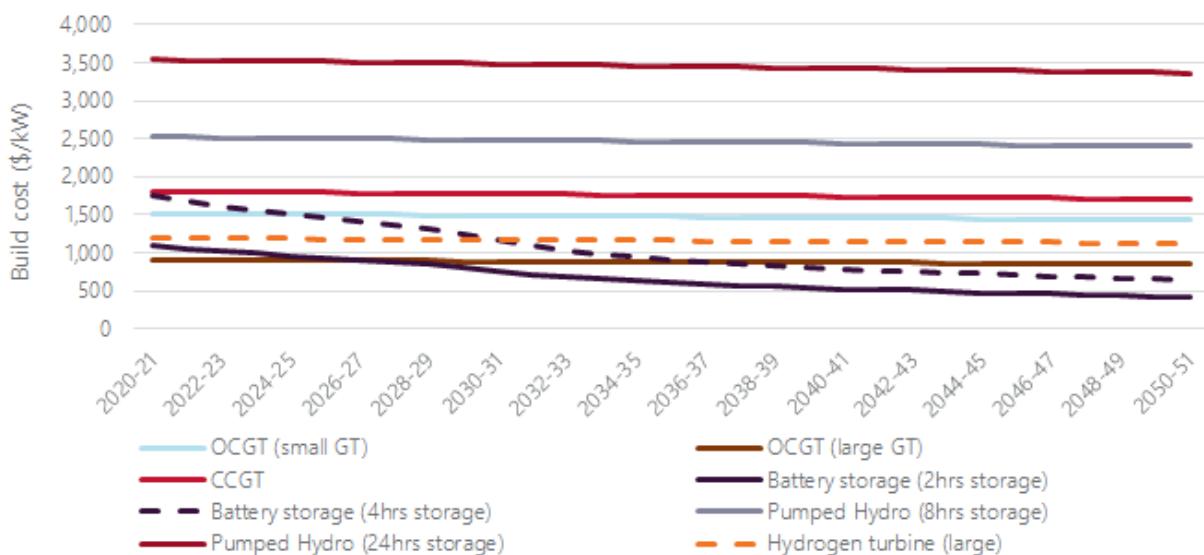
Figure 36 and Figure 37 present GenCost central build costs projections for selected technologies if constructed in Melbourne, excluding connection costs, for example. These costs will be applied to the Slow Change, Steady Progress, and Net Zero 2050 scenarios. Cost projections for each scenario are available in the IASR Assumptions Book.

Figure 36 Central build cost trajectories forecast, scenarios, wind and solar



⁹⁹ At https://www.csiro.au/-/media/EF/Files/GenCost2020-21_FinalReport.pdf.

Figure 37 Central build cost trajectories forecast, gas, and selected storage



Note: A premium has been applied to the costs of hydrogen gas turbines that is equivalent to the capital cost premium of hydrogen reciprocating engines compared to gas reciprocating engines in CSIRO's GenCost outputs.

Wind build costs, site quality deterioration, and efficiency improvements

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

A transformation of CSIRO's cost inputs is therefore required to reflect this increased efficiency trend in AEMO's models. The capital cost of wind technology is adjusted down to effectively mirror the \$/MWh cost reductions from turbine efficiency improvements. AEMO considers this a reasonable approach (applying cost reductions and maintaining static renewable energy profiles), given the development of renewable technologies such as wind is targeted largely to provide energy, rather than peak capacity, and therefore accurate representation of the cost per unit of energy is more appropriate than per unit of capacity. This approach provides an appropriate balance of supply modelling complexity and accuracy.

Locational cost factors

Input vintage	July 2021 – Updated for the 2021 IASR following consultation on the Draft 2021 IASR
Source	<ul style="list-style-type: none"> GHD: 2018-19 Costs and Technical Parameters Review Aurecon: 2020-21 Costs and Technical Parameters Review AEMO revisions
Update process	Updated based on stakeholder feedback provided on the Draft 2021 IASR.
Consultation process	Inputs revised in response to consultation.

Developing new generation can be a labour- and resource-intensive process. Access to specialised labour and appropriate infrastructure to deliver and install components to site can have a sizable impact on the total cost of delivering a project. Access to ports, roads, and rail, regional labour cost differences, and localised environmental/geological/social drivers, all contribute to locational variances of technologies.

The 2020 ISP incorporated three cost groupings – low, medium, and high – mapped across the NEM regions to summarise locational multiplicative scalars that should apply between developments of equivalent technology type but across different locations. These locational scalars take into account access to ports, roads and rail, and regional labour costs, but ignore localised environmental/geological/social drivers which require site-by-site assessments and are difficult to predict pre-feasibility. They also exclude cost premiums

that may arise if multiple projects are simultaneously competing for scarce resources across the construction supply chain.

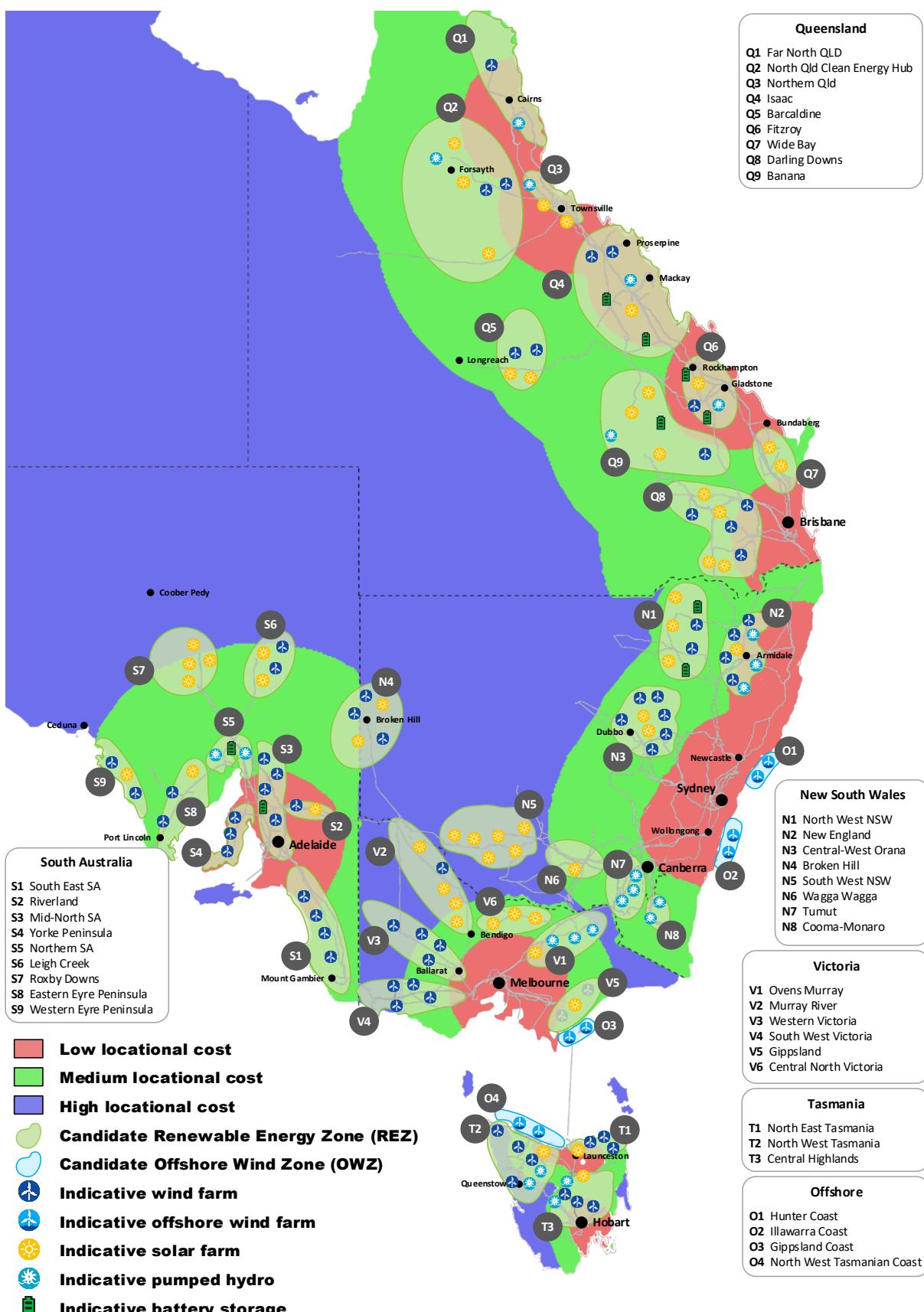
Based on feedback provided on the Draft 2021 IASR, AEMO has revised these scalars such that the lowest cost zone in each region has an equivalent cost factor, removing significant disparity between regions which stakeholders indicated was not reflective of recent experience.

Although the regional factors have been normalised, the differences between locations within regions has been retained to reflect the impact of proximity to major infrastructure and workers. These are presented in Figure 38, with the location of REZs overlaid.

To calculate the capital costs of technologies developed in different locations, the locational cost factors provide a multiplicative scalar to the respective generation development costs. These scalars are derived from regional development cost weightings by cost component, provided in Table 23, and technology cost component breakdowns, which are presented in Table 24.

The IASR Assumptions Book provides additional details of these cost factors, including the resulting technology, regional cost adjustment factors.

Figure 38 Locational cost map



[†] The New South Wales Government is in the early stages of planning for two new REZs in the Hunter-Central Coast and Illawarra regions of New South Wales, as set out under the *New South Wales Electricity Infrastructure Act 2020*. These REZs are not modelled because they are not yet geographically defined.

Table 23 NEM locational cost factors

Region	Grouping	Equipment costs	Fuel connection costs	Cost of land and development	Installation costs	O&M costs
Victoria	Low	1	1	1	1	1
	Medium	1.03	1.03	1	1.03	1.03
	High	1.05	1.05	1	1.05	1.05
Queensland	Low	1	1	1	1	1
	Medium	1.05	1.1	1	1.15	1.12
	High	1.1	1.21	1	1.31	1.25
New South Wales	Low	1	1	1	1	1
	Medium	1.05	1.07	1	1.1	1.08
	High	1.1	1.16	1	1.2	1.17
South Australia	Low	1	1	1	1	1
	Medium	1.05	1.1	1	1.15	1.12
	High	1.1	1.2	1	1.29	1.24
Tasmania	Low	1	1	1	1	1
	Medium	1.05	1.07	1	1.1	1.09
	High	1.1	1.14	1	1.21	1.17

Table 24 Technology cost breakdown ratios

Technology	Equipment costs	Fuel connection costs	Cost of land and development	Installation costs
Black Coal (advanced ultra supercritical PC)	33%	2%	16%	49%
Black Coal (advanced ultra supercritical PC) with CCS	33%	1%	16%	49%
OCGT (small GT)	60%	6%	8%	26%
OCGT (large GT)	58%	10%	7%	25%
Hydrogen GTs	58%	10%	7%	25%
CCGT	62%	3%	8%	27%
CCGT with CCS	63%	2%	8%	27%
Biomass	33%	0%	17%	50%
Battery storage (1hr storage)	76%	0%	9%	16%
Battery storage (2hrs storage)	77%	0%	7%	16%

Technology	Equipment costs	Fuel connection costs	Cost of land and development	Installation costs
Battery storage (4hrs storage)	79%	0%	4%	16%
Battery Storage (8hrs storage)	81%	0%	2%	17%
Large scale Solar PV	57%	0%	6%	38%
Solar Thermal (8hrs Storage)	72%	0%	4%	24%
Wind	66%	0%	6%	28%
Wind - Offshore	69%	0%	2%	29%

3.5.4 Technical and other cost parameters (new entrants)

Input vintage	Updated through 2020-21 GenCost process, which was finalised in June 2021.
Source	<ul style="list-style-type: none"> Aurecon: 2020-21 Costs and Technical Parameters Review GHD: 2018-19 Costs and Technical Parameters Review Hydro Tasmania information on Cethana project
Updates since Draft IASR	Updated to reflect final projections from Aurecon and CSIRO, which includes revisions based on stakeholder feedback. Tasmanian pumped hydro costs have been refined using data provided by Hydro Tasmania.

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

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

These parameters are updated annually to reflect the current trends and estimates of future cost and performance data of new technologies, and are published in the IASR Assumptions Book and in the supporting material from Aurecon. For 2021-22 modelling, AEMO has updated these parameters where they have been provided by Aurecon, or through the GenCost process more generally. AEMO has also engaged with Hydro Tasmania to source specific inputs for the Cethana project which has been identified as the preferred pumped hydro project in Tasmania¹⁰⁰.

For new entrant technologies, the technical life of each asset is enforced, such that new builds may retire within the forecasting horizon according to the technical life assumptions of each installed technology, leading to greenfield replacement of new developments in the ISP. While replacements are not greenfield in nature typically, technology improvements often mean that much of the original engineering footprint of a

¹⁰⁰ See <https://www.hydro.com.au/news/media-releases/2020/12/15/lake-cethana-selected-as-first-pumped-hydro-project>.

project may require redevelopment. Brownfield replacement costs therefore may require site-by-site assessments, and this data is not available to provide a more bespoke approach.

The technical life assumed for new wind and solar projects has been able to be validated through inspection of the July 2021 Generation Information dataset. On average, committed VRE projects have submitted a technical life (reflecting the time between commissioning date and the expected closure year) of 27 years for solar generation projects and 28 years for wind generation projects, reasonably aligned with AEMO's assumptions of 30 years for both technologies.

3.5.5 Storage modelling

Input vintage	Updated through 2020-21 GenCost process, which was finalised in June 2021, and augmented with additional data provided by Hydro Tasmania in June 2021.
Source	<ul style="list-style-type: none">• Aurecon: <i>2020-21 Costs and Technical Parameters Review</i>• CSIRO: <i>GenCost 2020-21 Final report</i>• Entura: <i>2018 Pumped Hydro Cost Modelling</i>• Hydro Tasmania information on Cethana project
Updates since Draft IASR	Updated to reflect final assumptions from Aurecon, which includes revisions based on stakeholder feedback. The pumped hydro options have been consolidated to reflect proposed projects and improve alignment with the New South Wales Electricity Infrastructure Roadmap and Queensland governments plans for PHES in south-east Queensland.

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

Storage developments are limited by the sub-regional build limits presented in the IASR Assumptions Book. For pumped hydro technologies, these limits are informed by sub-regional limits within the 2018 Entura report¹⁰¹, modified where appropriate to reflect the latest generator development announcements, while still observing sub-regional limits. This ensures that the sub-regional limits at least provide sufficient capability to reflect announced projects such as the Borumba Dam Pumped Hydro in southern Queensland¹⁰².

AEMO has added the Cethana project in Tasmania (see Section 3.5.4) as a specific option, and deducted this project from the capacity available in Tasmania in the Entura report.

Exact storage locations are identified considering the storage needs of REZ 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.

Pumped hydro energy storage (PHES)

AEMO includes PHES options equivalent to eight, 24, and 48 hours of energy in storage across the NEM and supplemented by the 20-hour Cethana project in Tasmania. Six and 12 hours PHES options have been consolidated into an eight-hour option to be aligned with the New South Wales Infrastructure roadmap and to reflect likely future PHES developments across the NEM. This portfolio of candidates complements deep storage initiatives (such as Snowy 2.0), and existing traditional hydro schemes.

Build costs and locational costs for these pumped hydro storage sizes consider estimates from Entura, and feedback received during the 2020 ISP development (leading to a 50% increase to pumped hydro cost estimates).

¹⁰¹ 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.

¹⁰² See https://www.epw.qld.gov.au/_data/assets/pdf_file/0019/17218/borumba-dam-pumped-hydro.pdf.

AEMO will apply the same cost assumptions for pumped hydro costs in the 2022 ISP, but represented at a sub-regional level to be consistent with the capacity outlook model configuration, with the exception of the Cethana project which uses the midpoint of the cost range estimated by Hydro Tasmania of \$1.8m/MW.

As with all technologies, future costs are influenced by forecast technology cost improvements. For PHES, AEMO has applied the forecast capital cost reduction of PHES projects in the *2020-21 GenCost Final Report*. These are provided in detail in the IASR Assumptions Book.

For clarification, the capital costs assumed for PHES projects only apply to future uncommitted PHES projects. For example, these do not apply to the Snowy 2.0 project, which is considered a committed project and included in all scenarios.

As with other new entrant technologies, sub-regional locational cost factors have been applied to PHES options. However these cost factors distinguish between sub-regions (see Section 3.10.1 for details of the ISP sub-regions) based on their natural resource and cost advantages, rather than on workforce and installation logistics grounds. These values are also sourced from the same Entura report.

Tasmania, for example, has been assumed to have materially lower development costs for PHES than the mainland, for most PHES options. As shown in Table 25, Tasmanian PHES facilities are at least approximately 25% lower cost than Victorian alternatives, and the cost advantages of pumped hydro in Tasmania increases for deeper storage sizes. These factors apply only to generic Tasmania PHES projects, as a specific cost is assumed for the Cethana project.

The cost inputs provided by Hydro Tasmania for Cethana are comparable to the generic cost assumptions that were proposed in the Draft IASR and are maintained in this IASR. This further supports the view that the 50% uplift in PHES costs that were applied during the 2020 ISP and retained for this IASR provides a better reflection of PHES costs once projects progress to the detailed design stage.

Table 25 Pumped hydro energy storage locational cost factors

ISP Sub-region	PHES: 8hrs	PHES: 24hrs	PHES: 48hrs
CNQ	1.01	0.88	0.86
GG	N/A	N/A	N/A
SQ	1.11	0.96	0.88
NNSW	0.88	0.82	0.62
CNSW	1.02	1.08	1.12
SSNW	1.04	1.00	0.91
SNW	N/A	N/A	N/A
VIC	1.00	1.00	1.00
SA	1.35	1.67	N/A
TAS	0.75	0.62	0.46

PHES build limits

AEMO applies sub-regional build limits for pumped hydro expansion candidates to reflect the sub-regional configuration of the capacity outlook models. Limits are based on sub-regional estimates detailed by Entura. AEMO has adjusted the limits to consider proposed projects across NEM regions while maintaining Entura's sub-regional breakdown. In the capacity outlook models, sub-regional build limits are split into storage depth

(8-hr¹⁰³, 24-hr, 48-hr). The time-sequential phase of the ISP modelling allocates pumped hydro to specific locations within the sub-region while observing these limits, taking into account the location of developer or government interest.

The pumped hydro sub-regional limits are shown in Table 26.

Table 26 Pumped hydro sub-regional limits

ISP sub-region	PHES: 8hrs	PHES: 24hrs	PHES: 48hrs
CNQ	2,250	3,000	200
GG	N/A	N/A	N/A
SQ	1,350	1,000	300
NNSW	1,125	500	500
CNSW	1,750	167	83
SNSW	2,500	583	167
SNW	N/A	N/A	N/A
VIC	2,700	700	400
SA	1,526	452	0
TAS	1,625	1,200	371

[†] Total value excludes the contribution of the proposed Snowy 2.0 project

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

- New South Wales pump hydro limits are based on 24 energy projects shortlisted for potential development as part of the New South Wales Government Pumped Hydro Roadmap¹⁰⁴.
- South Australian PHES limits have been adjusted to reflect Generation Information submissions, applying the project size ratios as specified in the Entura report.
- Tasmanian PHES storage limits have been informed by underlying analysis of the detailed project information within the Entura report, provided by contributors to the Entura report (but not published). This data avoids misinterpretation of projects that may not be mutually exclusive and is aligned reasonably with Tasmanian PHES Generation Information submissions.
- Queensland PHES storage limits have been adjusted to reflect the publicly announced Borumba Dam Pumped Hydro¹⁰⁵ feasibility study being undertaken by Powerlink with funding support from the Queensland Government, and information provided by the Queensland Government on North Queensland Pumped Hydro developments.

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.

¹⁰³ The 8-hour PHES limits are an aggregation of 6-hour and 12-hour PHES options, weighted by the energy in storage.

¹⁰⁴ New South Wales Government. Pumped Hydro Roadmap, at <https://energy.nsw.gov.au/renewables/clean-energy-initiatives/hydro-energy-and-storage#-pumped-hydro-roadmap->.

¹⁰⁵ See https://www.epw.qld.gov.au/_data/assets/pdf_file/0019/17218/borumba-dam-pumped-hydro.pdf.

Assumptions for battery storages of 1-hour, 2-hour, 4-hour, and 8-hour duration depths are based on data provided by Aurecon. Battery round-trip efficiency is assumed to be 84%, 84%, 85%, and 83% respectively for 1-hour, 2-hour, 4-hour, and 8-hour duration depths. Battery storage degradation, which Aurecon indicates is 2.2% annually, is not able to be modelled explicitly due to computational complexity (particularly in capacity outlook models). To account for this degradation, AEMO reduces the storage capacity of all battery storage by 19% which is an estimate of the average storage capacity over the battery life.

In the Draft 2021 IASR, AEMO outlined a proposed approach for the replacement of the battery component after 10 years. This assumption has been removed based on stakeholder consultation feedback and further review of recent battery storage developments, which indicate that 20-year lifetimes are being offered, albeit with higher warranty costs. These additional warranty costs have been included as an additional fixed operating cost.

AEMO does not have appropriate data sets for battery disposal costs, and therefore these costs are not considered. This may underestimate the full life-cycle cost of the technology. In replacing retired technologies AEMO assumes a greenfield development, which may overstate the effective cost of replacement. In the absence of better data sets, AEMO considers it reasonable that these two factors balance out the total life-cycle costs; no additional stakeholder feedback was received disputing (or supporting) this assumption.

Solar thermal technology

AEMO models solar thermal as a solar thermal central receiver with an 8-hour storage size. AEMO's capacity outlook modelling treats the storage component as a controllable storage object, rather than applying a static storage discharge trace.

3.6 Fuel and renewable resource assumptions

3.6.1 Fuel prices

Gas prices

Input vintage	July 2021 – Minor updates from forecast provided in Draft IASR.
Source	Lewis Grey Advisory
Updates since Draft IASR	Explicit consideration of a Low Gas Price sensitivity (with gas price lower than originally proposed in Draft IASR) to reflect Stakeholder feedback on Draft IASR and gas price workshop in April 2021.

AEMO sourced natural gas price forecasts from consultant Lewis Grey Advisory (LGA). These gas prices were updated and finalised for the 2021 GSOO report.

Gas price forecasts are derived from a game theory model that simulates competitive pricing outcomes suitable to understand contract pricing¹⁰⁶. Gas production costs, reserves, infrastructure, and pipelines are fundamental inputs into this model that also considers international natural gas prices, oil prices, and measures of the domestic economy. This methodology was consulted at FRG meeting 35 in September 2020¹⁰⁷, and at a subsequent stakeholder gas price workshop in April 2021.

Four forecasts were provided, based on assumptions about international pricing, Australian infrastructure, cost of producing gas from existing and upcoming petroleum fields, and the local level of competition. No

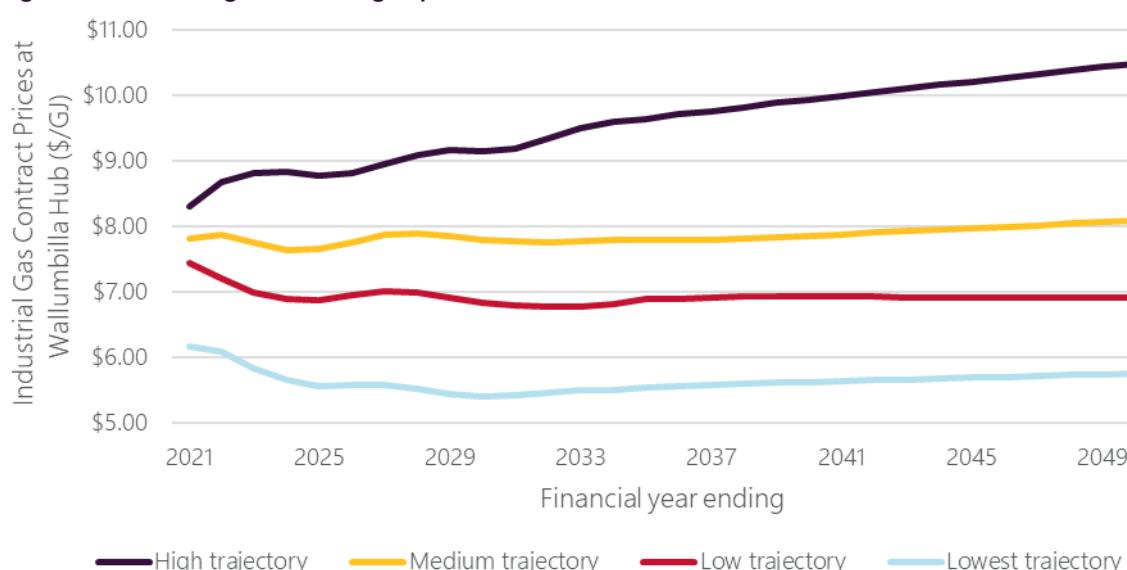
¹⁰⁶ The price projections do not attempt to model the full variance of the spot market. The spot market can sometimes experience pricing at very high levels when there is little uncontracted gas available and sometimes at very low levels, even below breakeven, when there is a surplus of uncontracted gas available.

¹⁰⁷ AEMO, FRG minutes and meeting packs, at <https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg>.

explicit reservation policy was considered. Based on stakeholder views that gas prices could be lower than assumed across LGA's projections, AEMO reduced the lowest of the LGA forecasts by a further \$1.00/GJ to produce the Low Gas Price sensitivity, incorporating increased competition in the domestic gas market in addition to opening new gas fields and pipelines, and a further reduction in production costs considering stakeholder feedback on these estimates. These alternative settings provide a Low Gas Price sensitivity that is approximately \$1.50-2.50/GJ lower than LGA's medium price trajectory, as shown in Figure 39 which compares industrial prices at Wallumbilla.

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

Figure 39 Average industrial gas price forecast at Wallumbilla



The gas price trajectories are mapped to the scenarios outlined in this 2021 IASR as shown in Table 27 below. These price mappings are selected because:

- The Net Zero 2050 and Steady Progress scenarios both assume a middle cost trajectory. Gas consumption continues to play an important role in both business and residential consumption for much of the forecast horizon. Gas developments continue in a similar trajectory to today, at least to 2040, supported by affordable capital costs and the existing supply/demand balance continues. The global demand for LNG remains strong, particularly in the Asian markets, and Australia domestic gas prices continue to be influenced by the international prices.
- CSIRO and ClimateWorks' multi-sectoral modelling of the decarbonisation targets has projected a substantial reduction in the demand for natural gas in the Hydrogen Superpower scenario, Step Change scenario, and Strong Electrification sensitivity. This reduction in demand will reduce pressure on gas supply and allow for utilisation of the lower cost reserves and resources without as great a need to access higher production cost gas. However, the ongoing need to invest to replace depleting fields means that even in this situation, prices driven by oversupply are not considered sustainable.
- The Slow Change scenario sees ongoing weaker economic conditions than the other scenarios, and continued use of natural gas. The gas price modelling for the high trajectory considered fewer competitors and fewer energy options contributing to tighter supply-demand balance and increasing prices.

- The Low Gas Price sensitivity considers a lower bound on plausible gas prices. This sensitivity assumes much increased supply and pipeline infrastructure, higher competition, lowest production costs and would be consistent with a future where gas producers were able to find substantial savings that were passed on to the customers. It is informed by LGA modelling, but has been subsequently adjusted further downwards to reflect feedback from stakeholders.

Table 27 Mapping of the gas prices trajectories to the proposed scenarios

Scenario	Gas price scenario to apply
Slow Change	High Trajectory
Steady Progress	Medium Trajectory
Net Zero 2050	Medium Trajectory
Step Change	Low Trajectory
Hydrogen Superpower	Low Trajectory
Strong Electrification	Low Trajectory
(Low Gas Price Sensitivity)	<i>Lowest Trajectory</i>

Table 28 identifies cost components that apply for different gas consumer types, as incorporated by LGA's forecast approach.

Table 28 Cost drivers for different consumer types

Gas consumer type	Cost uplift description	Cost uplift (\$/GJ)
Industrial	Transport costs to the relevant gas transmission node, reflective of a high load factor customer	-
Residential and commercial	Transport costs to the relevant gas transmission node, reflective of a low load factor customer Storage/balancing charges	Varies from approximately \$1.20/GJ (in Queensland across all scenarios), to as high as \$2.76/GJ (in Tasmania in the high cost trajectory). The greater availability of regional gas, the more stable and lower the residential and commercial uplift. Across all regions and all years, the simple average uplift ranged from \$1.99/GJ in the high cost trajectory down to \$1.69/GJ in the low trajectory.
GPG	Transport costs to the relevant gas transmission node, reflective of a high load factor customer (CCGT) or a low load factor customer (OCGT) Storage/balancing charges (OCGT)	Peaking gas plant receive a cost uplift of approximately \$0.50/GJ above mid-merit CCGT plant.

Coal prices

Input vintage	April 2021
Source	Wood Mackenzie
Updates since Draft IASR	Based on 2021 Draft IASR consultation feedback, revisions were made to coal prices for some New South Wales power stations.

AEMO engaged external consultant Wood Mackenzie to provide updated coal price forecasts. The coal price forecasts were based on information regarding coal procurement arrangements and the marketability of coal for export (driving export-parity pricing in some cases). These forecasts are shown in Figure 40 and Figure 41, and are provided in greater detail for all scenarios in the accompanying IASR Assumptions Book and Wood Mackenzie Coal Prices report¹⁰⁸.

Figure 40 Coal price forecast for existing coal-fired power stations – central trajectory

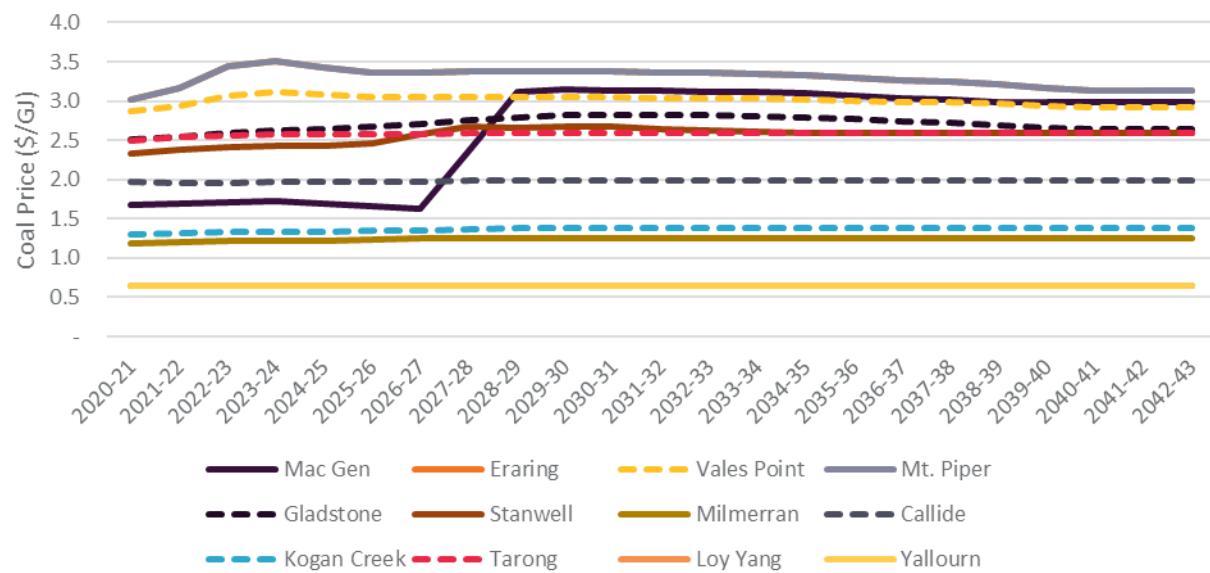
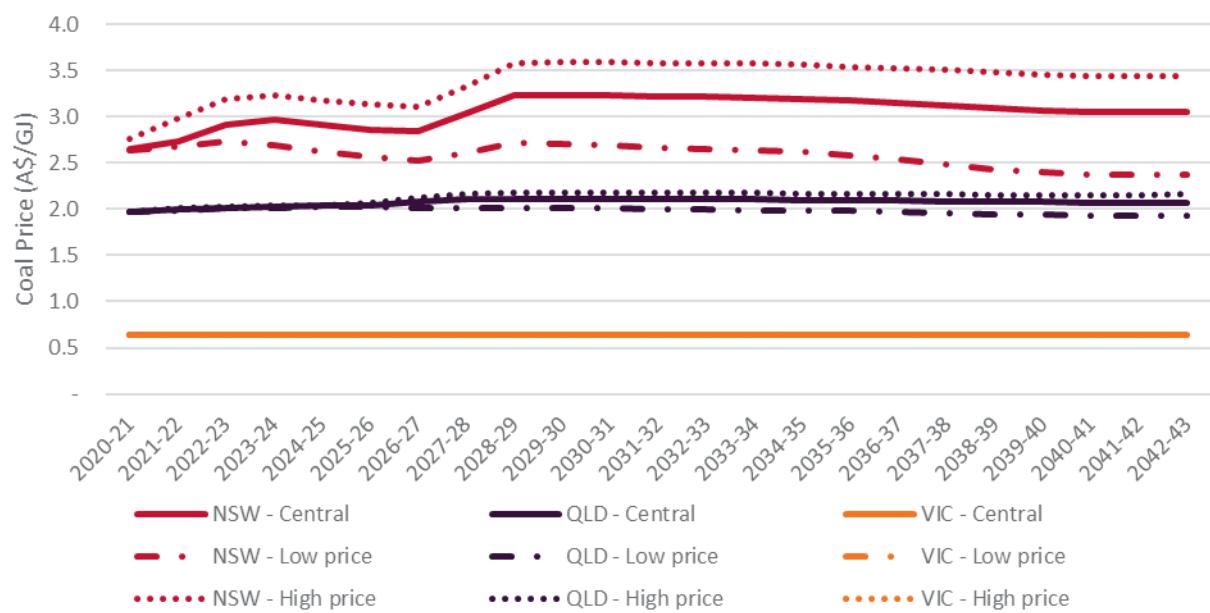


Figure 41 Region-averaged coal price forecast for existing coal-fired power stations – all trajectories



Three coal price trajectories were developed (Central, Low price, and High price) to align with plausible global coal demand with varying renewable energy uptake and global temperature pathways. The mapping of the prices to the scenarios is shown in Table 29.

¹⁰⁸ At <https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isps/2022-integrated-system-plan-isps/current-inputs-assumptions-and-scenarios>.

Table 29 Mapping of the coal prices to the new scenarios

Scenario	Coal price trajectory to apply
Slow Change	High Price
Steady progress	Central
Net Zero 2050	Central
Step Change	Low price
Hydrogen Superpower	Low price

Hydrogen prices

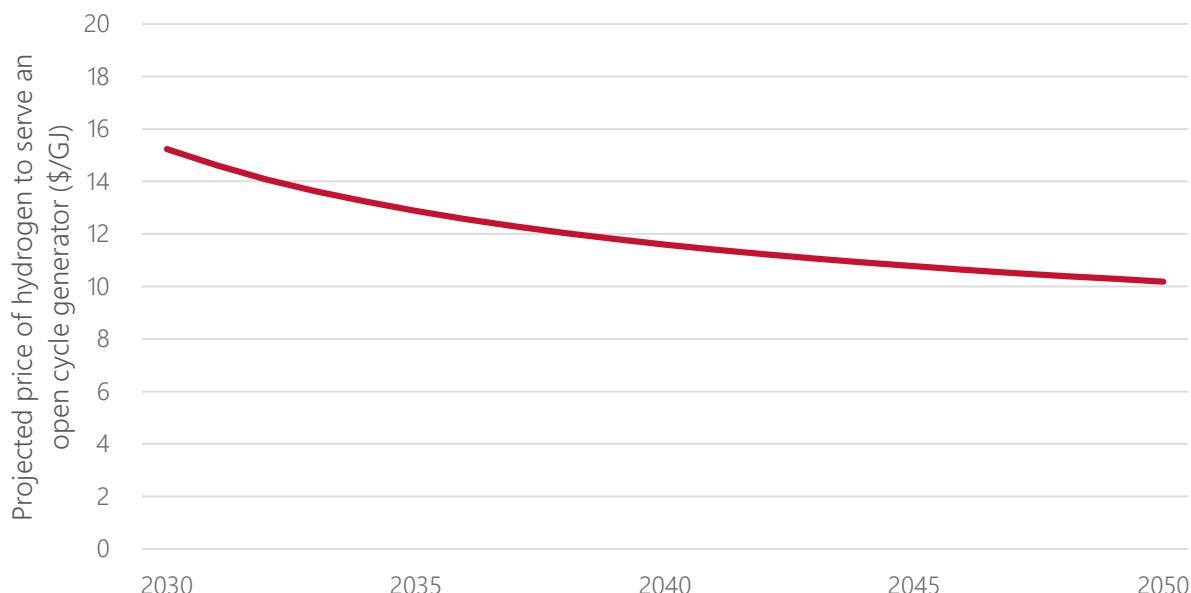
Input vintage	July 2021
Source	• CSIRO and ClimateWorks Australia
Updates since Draft IASR	New section produced to allow for the potential use of hydrogen in electricity generation in the Hydrogen Superpower scenario.

Increased availability of hydrogen in the Hydrogen Superpower scenario may enable its use in power generation as an alternative to peaking gas.

In the ISP's Hydrogen Superpower scenario, hydrogen-fuelled gas turbines are assumed to be able to purchase hydrogen fuel that was bound for export markets. Hydrogen for generation will not compete with other domestic markets, and therefore will be locationally limited to those export ports that are developed in the scenario.

Figure 42 shows the assumed hydrogen price available to GPG in the Hydrogen Superpower scenario.

Figure 42 Assumed hydrogen price for GPGs in Hydrogen Superpower scenario



This price reflects the cost of production as well as margins to reflect contract returns, guarantee of supply and transportation costs. This increment was determined by the average GPG vs industrial price uplift from

the lower cost trajectories for GPG from natural gas and applied to the hydrogen cost curve for Hydrogen Superpower shown in Figure 27. To provide direct comparison, the assumed production cost of hydrogen in 2030 is approximately \$13.50/GJ (\$1.93/kg). This is consistent with the \$2/kg price target stated in the Technology Roadmap.

Biomass and liquid fuel prices

Input vintage	Unchanged from 2020 ISP.
Source	<ul style="list-style-type: none"> Biomass prices – AEMO assumption Liquid fuel prices – ACIL Allen 2014
Updates since Draft IASR	No updates

The price trajectory for liquid fuels (>\$30/GJ) has been sourced from ACIL Allen¹⁰⁹.

AEMO has not updated its assumed biomass prices of \$0.55/GJ, and recognises that GenCost 2020-21 applied a price range from \$0.50/GJ to \$2.00/GJ, broadly consistent with AEMO's assumption¹¹⁰.

3.6.2 Renewable resources

Input vintage	Updated for 2021 ESOO in July 2021.
Source	<ul style="list-style-type: none"> CSIRO reanalysis Solcast irradiance and PV output analysis BoM AEMO SCADA data
Updates since Draft IASR	Updated to include the 2020-21 reference year, updates to REZ boundaries, change in reanalysis provider to CSIRO, and the inclusion of additional offshore wind locations based on stakeholder feedback.

Renewable resource quality and other weather variables are key inputs in the process of producing generation profiles for solar and wind generators. This data is obtained from several sources, including:

- Wind speed (at a hub height of 150m), solar irradiance, and other relevant reanalysis data from CSIRO¹¹¹.
- Solar irradiance reanalysis data from Solcast.
- Temperature and ground-level wind speed data from the BoM.
- Historical generation and weather measurements from SCADA data provided by participants.

Since the Draft IASR, AEMO has changed data providers for wind speed reanalysis, now using CSIRO to provide this data, as well as several other variables of importance such as solar irradiance and air temperature. While there may be changes in weather trends at individual sites due to differences in the underlying climate models, this change in data providers has had a minimal impact on the relative resource quality across the NEM.

Resource quality data and other weather inputs are updated annually to include the most recent reference years used in the modelling. AEMO uses resource to power models to estimate VRE generator output as a

¹⁰⁹ ACIL Allen, Fuel and Technology Cost Review, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/ntndp/2014/data-sources/fuel_and_technology_cost_review_acil_allen.pdf.

¹¹⁰ A wide range of bioenergy technologies exist, with different technology cost profiles and fuel cost profiles. AEMO assumes a single biomass technology for the purposes of the ISP.

¹¹¹ CSIRO reanalysis data uses the Conformal Cubic Atmospheric Model (CCAM) to downscale climate and weather data from ERA-5 reanalyses to a 12 km grid across Australia and a temporal resolution of 30-minute timesteps. More information on CCAM is available at <https://www.csiro.au/en/research/natural-environment/atmosphere/ccam>.

function of meteorological inputs. Wind output modelling, for example, uses an empirical machine learning model to estimate generator output as a function of wind speed and temperature, capturing the impacts of high wind and high temperature events observed in historical data. Participant information on generator capabilities during summer peak demand temperatures are overlayed on top of these resource to power models. Further detail on how AEMO estimates half-hourly renewable generation profiles for existing, committed and anticipated VRE generators is provided in the *ESOO and Reliability Forecasting Methodology* document¹¹².

For new entrant VRE generators, AEMO represents wind resource quality in each REZ in two tranches representing high and medium quality sites, based on an assessment of all available wind datapoints within each REZ. AEMO represents solar quality based on an assessment of solar resource at a selection of existing connection points within each REZ. This process is described in further detail in the *ISP Methodology*¹¹³. Indicative capacity factors for each REZ and technology are provided in the IASR Assumptions Book.

3.7 Financial parameters

3.7.1 Discount rate

Input vintage	Finalised in July 2021
Source	Synergies Economic Consulting
Updates since Draft IASR	Updated in response to feedback on the draft IASR, consulted on with AEMO's ISP Consumer Panel, TNSPs, the AER, and the Clean Energy Finance Corporation.

The AER's Cost Benefit Analysis Guidelines state that the discount rate in the ISP is "required to be appropriate for the analysis of private enterprise investment in the electricity sector across the NEM".

In the Draft IASR, AEMO proposed a real, pre-tax discount rate of 4.8%, but received feedback from several stakeholders that this value was inappropriate. In response to this feedback, AEMO engaged Synergies Economic Consulting to provide appropriate discount rate assumptions for use in the ISP.

The discount rate recommended by Synergies is a weighted-average cost of capital (WACC) based estimate reflecting an average investor view about required return on investments in the NEM. The recommended discount rates include both a central estimate, as well as a lower bound based on recent regulated WACC determinations for transmission¹¹⁴ and distribution businesses¹¹⁵ and an upper bound based on a more risk-sensitive view about required returns on private investments in the NEM.

Further details of the discount rates and the assumptions that underpin the values can be found in the Synergies report¹¹⁶. The values that will be applied in the ISP are shown in Table 30. The lower and upper bound values are used in sensitivity analysis.

¹¹² 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>.

¹¹³ At https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2021/isp-methodology/draft/draft-isp-methodology.pdf?la=en.

¹¹⁴ AER Draft determination, June 2021, at <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausnet-services-determination-2022-27> (Transmission).

¹¹⁵ AER Final determinations, April 2021, at <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/united-energy-determination-2021-26>, <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/powercor-determination-2021-26>, <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/jemena-determination-2021-26>, <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/citipower-determination-2021-26>, <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausnet-services-determination-2021-26> (Distribution).

¹¹⁶ At <https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios>.

The central estimate of the discount rate is higher than the original rate proposed in AEMO's Draft IASR, but lower than the 7% which has been typically applied by Australian policy-makers when undertaking cost-benefit analysis for infrastructure projects. Synergies notes that the default 7% assumption has become entrenched since around 1989, but also that it is reasonable to assume that it reflects higher government bond rates from the late 20th century compared to current rates and projections.

In contrast, the National Australia Bank (NAB) report on the WACC for new entrant generation that was conducted to support the development of the New South Wales Electricity Infrastructure Roadmap estimated values between 2.81% and 3.41%¹¹⁷, based on a survey of investors. AEMO's rate sits above this assessment, however is intended to represent investments over the course of the ISP horizon, whereas the NAB report is based on an assessment of current conditions.

Considering the expert guidance provided on discount rates to adopt for the ISP, and taking into consideration stakeholder feedback, AEMO considers that two adjustments are appropriate for the ISP from the Synergies recommendation:

- Rounding the Synergies estimates to provide a slightly broader range of values.
- Including a higher discount rate sensitivity, which applies a value of 10%, in line with suggested sensitivity analysis from the ISP Consumer Panel. This fourth value will be considered in the sensitivity analysis in the same way as the other two will, in determining the resilience and robustness of the ISP's optimal development path to this key variable.

Table 30 Pre-tax real discount rates applied in the ISP

	Central Estimate	Lower Bound	Upper Bound	Highest Value
Synergies recommendation	5.6%	2.2%	7.3%	-
AEMO adopted values	5.5%	2.0%	7.5%	10%

3.7.2 Value of customer reliability

Input vintage	December 2019
Source	AER: 2019 Values of Customer Reliability Review
Updates since Draft IASR	Updated to a customer-weighted average based on stakeholder feedback to the Draft 2021 IASR

A Value of Customer Reliability ([VCR], usually expressed in dollars per kilowatt-hour) reflects the value different types of consumers place on having reliable electricity supply. VCRs are used in cost-benefit analysis to quantify market benefits arising from changes in involuntary load shedding when comparing investment options.

In accordance with the AER's Cost Benefit Analysis Guidelines, AEMO is required to use the AER's most recent VCRs at the time of publishing the ISP Timetable. The AER released its final report on its review of VCRs in December 2019¹¹⁸, which represents the most recent calculation as of October 2020 when the ISP Timetable was published¹¹⁹.

¹¹⁷ See Table 1.1 at <https://energy.nsw.gov.au/sites/default/files/2020-11/NSW%20Electricity%20Infrastructure%20Roadmap%20-%20WACC%20Report.pdf>.

¹¹⁸ AER values of customer reliability: Final report on VCR values, December 2019, at <https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf>.

¹¹⁹ At <https://www.aemo.com.au/-/media/files/major-publications/isp/2022/2022-ispt-timetable.pdf>.

Based on stakeholder feedback on VCR in the Draft 2021 IASR, AEMO will use customer load weighted state VCRs provided in the AER's report, which are set out in Table 31 below. Customer load weighted state VCRs are adopted as they reflect the VCRs of the customer composition on the network as per the guidance provided in AER's VCR report.

Table 31 AER Values of distribution and transmission customer load weighted VCR by state

	New South Wales	Victoria	Queensland	South Australia	Tasmania
VCR (\$/MWh)	43,526	42,586	41,366	44,673	33,234

3.8 Climate change factors

The changing climate has an impact on a number of aspects of the power system, from consumer demand response to changing temperature conditions, to generation and network availability impacts. The impact of reduced precipitation on dam inflows is described in Section 1.1.5. The following sections describe other impacts considered in AEMO modelling.

3.8.1 Temperature change impacts

Input vintage	Accessed Jan-2019 (CMIP5)
Source	BoM, CSIRO, http://www.climatechangeinaustralia.gov.au/esci/
Updates since Draft IASR	Updated since the Draft IASR based on updated climate data, presented to the May 2021 FRG.

AEMO incorporates climate change temperature change factors in its demand forecasts and transmission variable thermal line ratings. 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 Australia¹²⁰. For more information on this, see Appendix A.2.3 of the Electricity Demand Forecasting Methodology¹²¹. The same data and considerations are also applied to relevant variable transmission thermal ratings in Victoria.

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. Warming over the medium term is largely locked in from historical emissions and does not vary substantially between scenarios to 2050. Where the physical impacts associated with the RCP's referenced in the scenario narrative are not available, results are scaled between available RCP's (often just 4.5 and 8.5) to reflect the likely outcome.

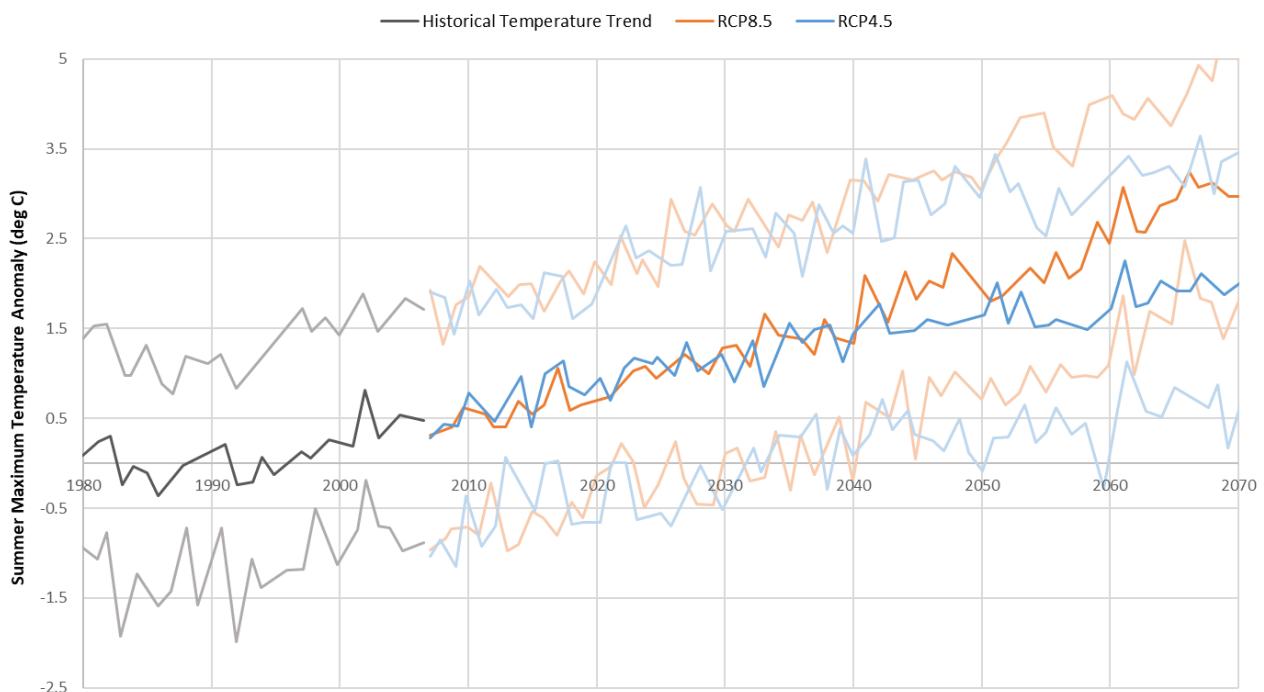
Figure 43 shows the change to summer maximum temperature anomaly ranges expected for Southern Australia under two atmospheric greenhouse gas concentrations relevant to the scenario definitions (RCP4.5 - RCP8.5)¹²². For example, RCP4.5 is assumed in AEMO's Steady Progress and Net Zero 2050 scenarios. For more detail on the scenario definitions, see Section 2.1. Where the physical impacts associated with the RCP's referenced in the scenario narrative are not available, results are scaled to reflect the likely outcome. 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.

¹²⁰ At <https://www.climatechangeinaustralia.gov.au/en/climate-projections/explore-data/data-download/station-data-download/>.

¹²¹ 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?la=en&hash=C8FB4B327EE1F7B0E4EDD6284E735842.

¹²² Data sourced from www.climatechangeinaustralia.com.au.

Figure 43 Southern Australia summer maximum temperature anomaly



3.8.2 Bushfire hazard change impacts

Input vintage	July 2021
Source	BoM, CSIRO, ESCI (see ClimatechangeinAustralia.gov.au)
Update process	Subject to the infrequent provision of appropriately tailored climate science.
Consultation process	Was presented at the May 2021 FRG.

AEMO incorporates bushfire hazard change impacts in its transmission line failure rates as reported in Section 3.10.10. In consultation with BoM and CSIRO, AEMO deploys projections taken from the ESCI bushfire case study¹²³ that demonstrate an increasing frequency of high-risk bushfire weather days. These projections are applied to relevant (bushfire-related) transmission line failure rates within reliability assessments including the ESOO reliability forecast.

One of the key metrics for bushfire weather is the Forest Fire Danger Index (FFDI), which recognises the combination of rainfall, humidity, temperature, and wind that corresponds with fire hazard, as used by fire agencies. For transmission outages which are correlated with FFDI, the mean trajectory from these projections will be applied. The confidence interval (CI) and mean projection for the count of days over FFDI thresholds are shown below in Figure 44.

A transmission climate factor has been developed for the two Victoria – New South Wales lines identified as being predominantly impacted by bushfires. These two transmission lines represent those most affected by major bushfire events in 2009, 2019 and 2020. The factor summarises the increasing frequency of transmission bushfire interactions in the region, as a function of increasing FFDI over threshold frequency.

¹²³ See <https://www.climatechangeinaustralia.gov.au/en/projects/esci/>.

The factor represents the rolling mean of the projections, baselined for 2015 (the centre of the period AEMO uses for modelling weather), and suggests that average bushfire weather risk (expressed as count of days with an FFDI > 50) will be approximately 20% higher by 2030-31, as shown in Figure 45.

The factor will be applied only to the two Victoria – New South Wales transmission lines identified as being impacted by bushfires, such that:

$$\text{Forecast Outage Rate } \{\text{year}\} = \text{Historical Outage Rate} * (1 + \text{climate factor } \{\text{year}\}).$$

See Section 3.10.10 for more details on these outage rates.

Figure 44 FFDI over threshold projections for Shepparton

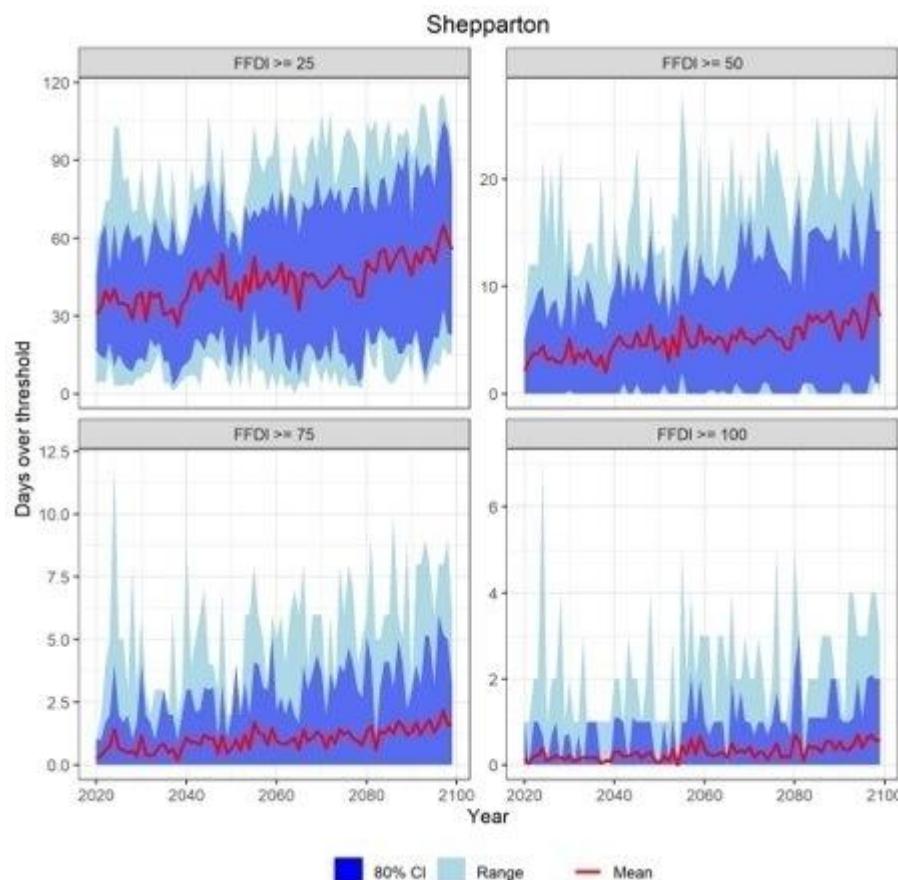
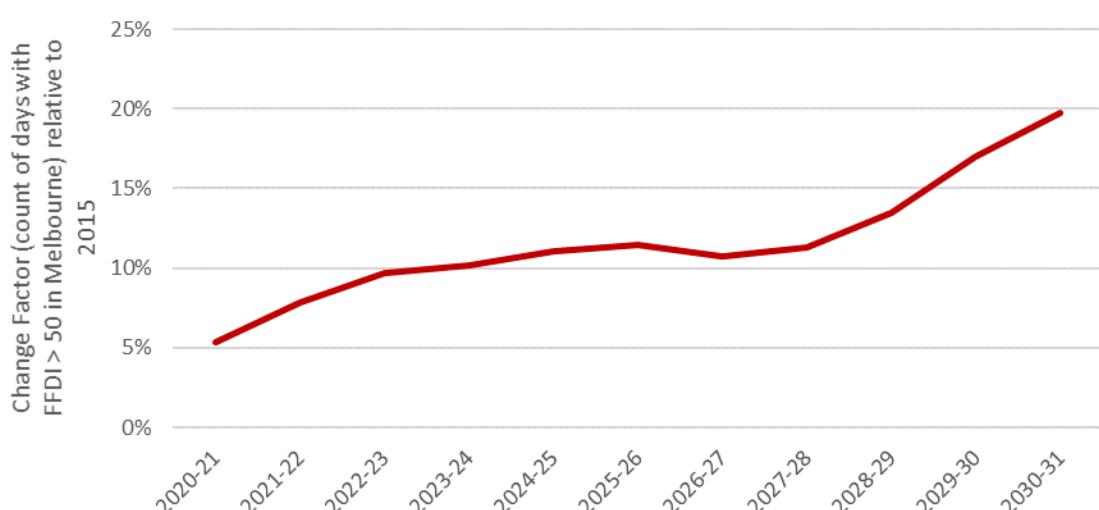


Figure 45 Transmission climate factor for Victoria (relative to 2015 baseline)



3.9 Renewable energy zones

REZs are areas in the NEM where clusters of large-scale renewable energy can be efficiently developed, promoting economies of scale in high-resource areas, and capturing important benefits from geographic and technological diversity in renewable resources. An efficiently located REZ can be identified by considering a range of factors, primarily:

- Quality of 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.
- The 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.

AEMO modelling also considers the benefits of connecting renewable generation in areas of the network not defined as REZs. For these areas, resource limits, generator capacity factors and network limits are outlined in the IASR Assumptions Book. This process ensures the 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 potentially lesser quality resources in areas with spare network capacity.

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). REZ candidates have been continuously updated and refined through the 2020 ISP and 2021 IASR consultation process. This section describes the following parameters for candidate REZs:

- Geographic boundaries.
- Resource limits.
- Transmission limits.
- Connection costs.

3.9.1 REZ geographic boundaries

Input vintage	July 2021
Source	AEMO – based on 2018 DNV-GL report, ISP workshops, consultation with TNPs and jurisdictions, and written feedback to the 2018 ISP, 2020 ISP and Draft 2021 IASR.
Updates since Draft IASR	In response to feedback to the Draft IASR, the following revisions have been made: <ul style="list-style-type: none">• Four offshore wind zones (OWZs) were added – Hunter Coast, Illawarra Coast, Gippsland Coast, and North West Tasmanian Coast.• The boundary of the Gippsland REZ (Victoria) was revised to accommodate the Gippsland Coast OWZ.

REZ candidates are based on geographic areas that represent where new renewable energy generation can be grouped to best utilise resources. These were initially developed through consultation to the 2018 ISP, the 2020 ISP, and the 2021 IASR.

Geographic Information Systems (GIS) data

GIS data defining the candidate REZ boundaries is available on the 2022 ISP website¹²⁴.

¹²⁴ At <https://www.aemo.com.au/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios>.

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 46).
- As the REZ polygons are approximate in nature, they should not be used to determine whether a project is within or outside of a candidate REZ.

Candidate REZ identification

Ten development criteria were used to identify candidate REZs:

- Wind resource – a measure of high wind speeds (above 6 m/s).
- Solar resource – a measure of high solar irradiation (above 1,600 kW/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 the development criteria together with feedback received throughout the Draft IASR consultation, 35 candidate REZs are modelled. In addition to these REZs, four OWZs are modelled – broadly based on publicly available information on offshore wind projects.

Offshore wind development

The ISP considers options for offshore wind development via OWZs. Table 32 outlines the OWZs considered in the ISP.

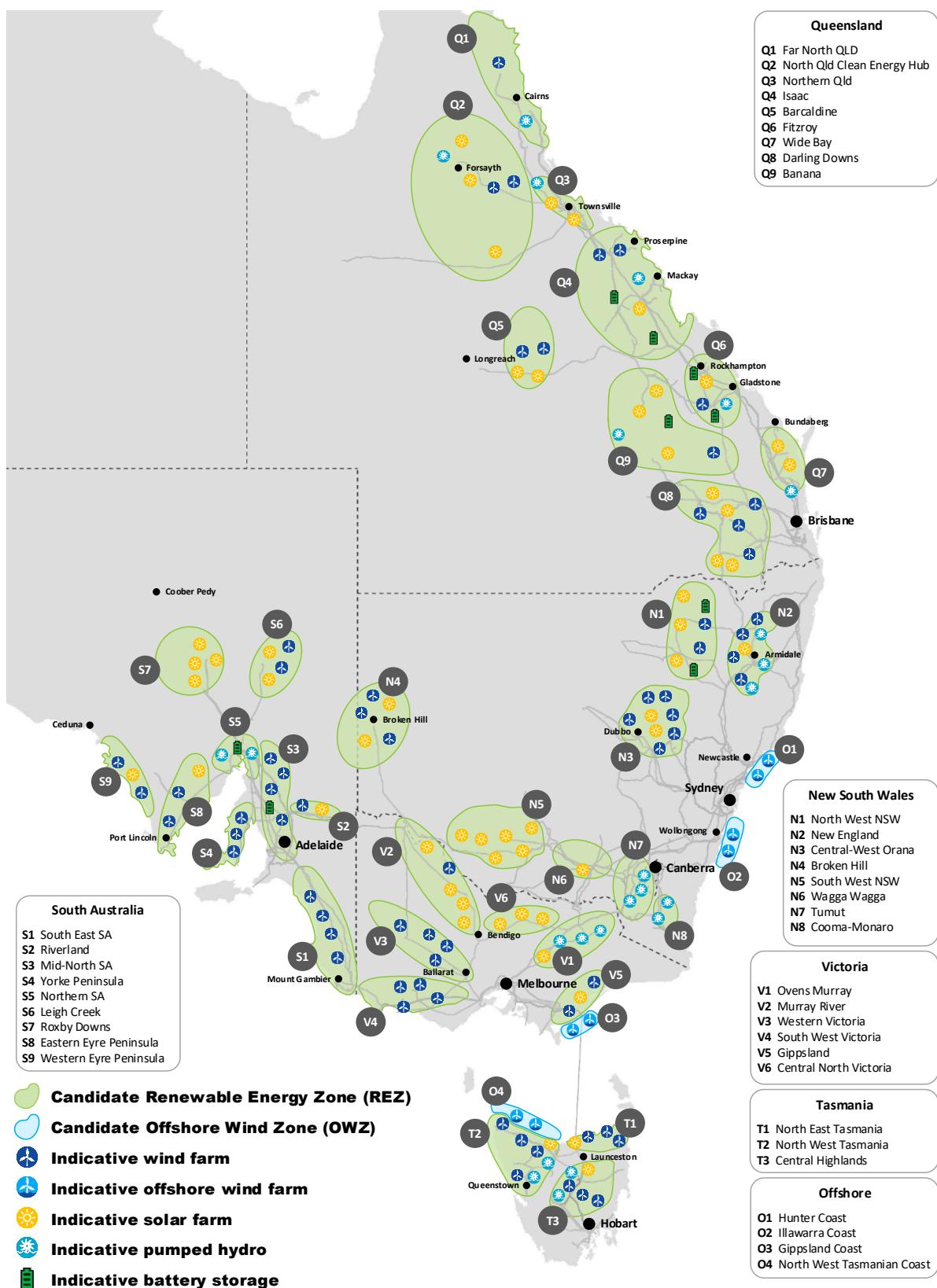
Table 32 Offshore wind zones (OWZs)

ID	OWZ Name	Region	Connection Point
O1	Hunter Coast	NSW	Eraring 500 kV
O2	Illawarra Coast	NSW	Dapto 330 kV
O3	Gippsland Coast	VIC	Loy Yang 500 kV
O4	North West Tasmanian Coast	TAS	Burnie 220 kV

Candidate REZ geographic boundaries

Figure 46 shows the geographic locations of REZ and OWZ 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 46 Renewable Energy Zone map



[†] The New South Wales Government is in the early stages of planning for two new REZs in the Hunter-Central Coast and Illawarra regions of New South Wales, as set out under the *New South Wales Electricity Infrastructure Act 2020*. These REZs are not modelled because they are not yet geographically defined.

[‡] The Queensland Government has identified three Queensland REZs, which encompass these REZs. Northern QREZ includes Q1, Q2, Q3, Q4 and Q5; Central QREZ includes Q6, Q7 and Q9; Southern QREZ includes Q8.

3.9.2 REZ resource limits

Input vintage	July 2021.
Source	AEMO. Resource limits were derived by AEMO based on 2018 DNV-GL report, ISP workshops, consultation with TNSPs and jurisdictions, and written feedback to the 2018 ISP, 2020 ISP and Draft 2021 IASR.
Updates since Draft IASR	Updated available resource limits to account for committed generation as of July 2021.

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.

Wind generation limits

Maximum REZ wind generation resource limits have initially been calculated based on a DNV-GL¹²⁵ 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).
- An assumption that only 20% of this land area will be able to be utilised for wind generation, considering competing land and social limitations.

Resource limits were adjusted for the 2021 IASR 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 REZ¹²⁶ (see Section 3.5.1 for more information on classification of generation projects). Updated resource limits are shown in Figure 47. The resource limits are further detailed in the IASR Assumptions Book.

Offshore wind resource limits

OWZs were added in response to feedback on the Draft IASR. These zones are broadly located based on public information on offshore wind projects. Because the zones are highly conceptual, a notional 10,000 MW resource limit is applied to each OWZ.

Solar PV plus solar thermal 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.

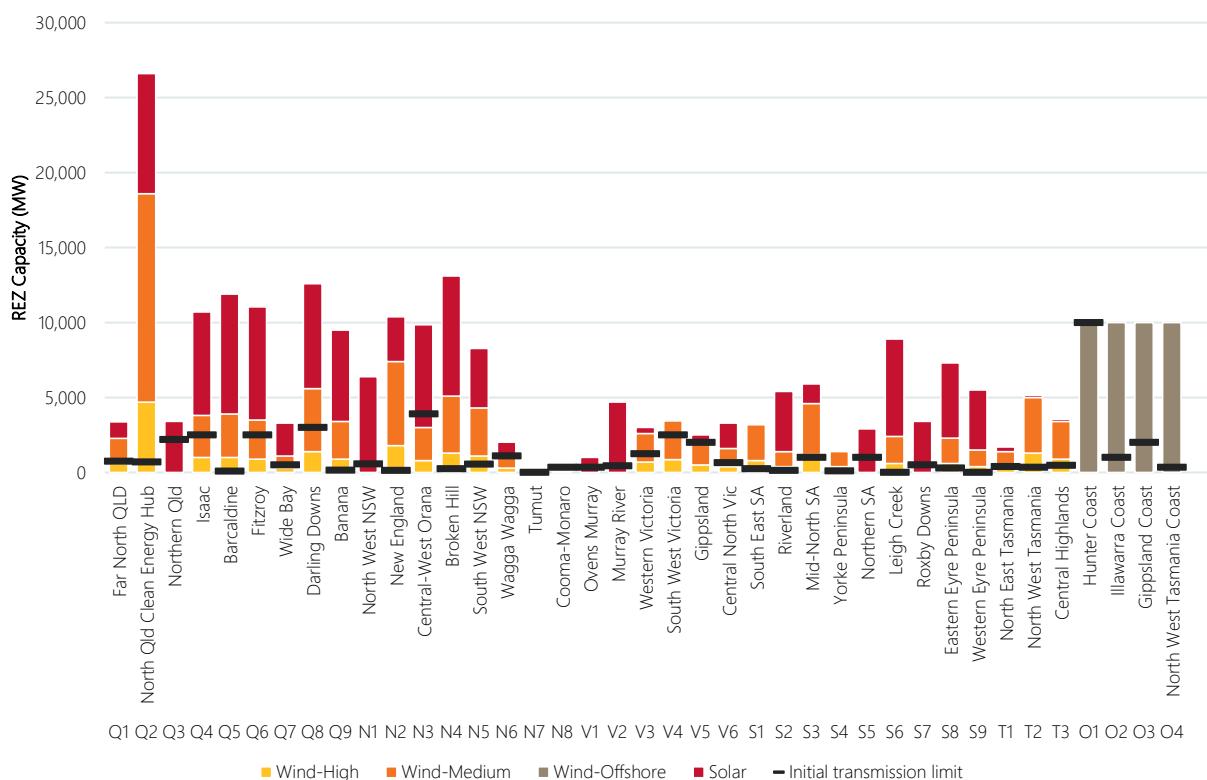
2021 IASR resource limits have been updated to include input from TNSPs, changes to REZ geographic boundaries, increased connection interest, and also now are presented on a total resource basis (not headroom available). Refer to *ISP Methodology* for more details around how resource limits and transmission

¹²⁵ 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

¹²⁶ AEMO. Committed 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>.

limits are jointly considered in the modelling. Updated resource limits are shown in Figure 47. The latest updates to the committed and anticipated generation within each REZ are accounted for within the market modelling by summation of generation in each REZ and subtracting this from the total resource limit. The resource limits are further detailed in the IASR Assumptions Book.

Figure 47 REZ resource and transmission limits



Note: The offshore wind resource limit is notional – it is not based on an assessment of resource availability. This setting is not expected to influence the selection of an optimal development path.

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

Land use reviews indicate that expansions of REZs are likely to become constrained by social license factors, as opposed to purely on land availability. Some REZs, perhaps, more than others.

To assess the outcomes if REZ resource limits are allowed to increase, but still take into account the likely increase in land costs or difficulties in obtaining land, AEMO applies an additional land use penalty factor of \$0.25 million/MW to all new VRE build costs in REZs if generation is required above the assumed REZ resource limit, as described in the *ISP Methodology*¹²⁷. The penalty factor was derived based on aligning historical observations with ISP modelling, and was consulted on during the IASR consultation phases. By using the REZ land-use penalty factor, AEMO can model increases in land costs, reflecting more complicated arrangements required for planning approvals and engagement with community and traditional owners as more renewable generation goes into a REZ. This same land-use penalty factor is applied to VRE built outside candidate REZ to reflect fewer economies of scale in absence of co-ordinated planning.

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.

¹²⁷ AEMO. *ISP Methodology*, at <https://aemo.com.au/en/consultations/current-and-closed-consultations/isp-methodology>.

Figure 47 shows an overview of the REZ resource limits, as well as the respective REZ transmission limits. The REZ transmission limits are further discussed in Section 3.9.3, and detailed in the IASR Assumptions Book.

Social license

AEMO recognises the critical nature of obtaining social license and bringing the community along during the development process of these projects. Social license for projects cannot be taken for granted and will vary from project to project. It will be a result of the quality of engagement by project developers with communities.

The ISP is an economic options assessment. It can therefore only take social license impact into account at a high level, for example by attributing different development costs for projects as a result of the expected complexity of obtaining social license for a project. It expects that community impacts are fully understood and mitigated during the existing planning and approval processes for transmission developments. Existing TNSPs and the newly formed state government bodies are best positioned to conduct the essential work on the ground with communities regarding the impacts and community acceptance of these projects.

The ISP assumes these institutions use best practice approaches of working with communities and obtain the social license for the projects identified in the ISP. The modelling therefore implicitly assumes:

- The community will accept large-scale solar and wind developments.
- The community will accept transmission build to facilitate these developments with appropriate mitigations, including some undergrounding in areas which will not meet statutory planning standards for overhead such as in high-density urban areas.
- Noting challenges that may arise with social license, communities may prefer investment in distributed PV or off-shore investment instead of large-scale onshore developments.

3.9.3 REZ transmission limits and network augmentations

Input vintage	July 2021
Source	AEMO internal – Based on the 2021 Transmission Cost Report and feedback to the ISP Methodology.
Updates since Draft IASR	<ul style="list-style-type: none">• REZ expansion costs for Hydrogen Superpower scenario are now based on the 2021 Transmission Cost Report.• Based on feedback to the ISP Methodology, REZ transmission limits are provided rather than generation hosting capacity – this allows the ISP model to determine an efficient level of network congestion within each REZ.

Network studies were undertaken to identify REZ transmission limits of the existing network. The 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. See Section 3.10.5 for additional information on flow path augmentations.
- 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.

Based on feedback to the *ISP Methodology* consultation, REZ transmission limits have been updated since the Draft IASR to reflect total transmission limits rather than surplus hosting capacity (see Figure 47). See Section 2.3.4 of the *ISP Methodology*¹²⁸ for information on how REZ transmission limits are developed.

¹²⁸ At <https://aemo.com.au/en/consultations/current-and-closed-consultations/isp-methodology>.

Current REZ transmission limits and augmentation options for all the REZs are shown in the IASR Assumptions Book. Notably, these REZ network augmentations options represent the starting point of the ISP analysis. As the ISP modelling progresses, these options are refined and improved upon. New options may be added as outcomes from the various stages of the model are evaluated and inputs refined. This iterative process is described in Section 1 and Section 4 of the *ISP Methodology*.

Detail relating to the cost of these augmentations is available in the *2021 Transmission Cost Report*¹²⁹.

REZ transmission limits include the capacity added through the delivery of committed and anticipated transmission projects (see Section 3.10.4). For example:

- The Central-West Orana REZ Transmission Link is an anticipated REZ network augmentation that increases network capacity in the Central West Orana REZ.
- The Western Victoria Transmission Network Project is an anticipated REZ network augmentation that increases network capacity in the Western Victoria REZ.
- Project EnergyConnect is an anticipated flow path augmentation that increases network capacity in the South West NSW, Murray River and Riverland REZs.

Group constraints

The transmission network is a highly meshed system, and the flow of electricity is influenced by generation and system services across multiple locations. Within AEMO's capacity outlook model, simplifications are needed to the power system representation 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 included that combine the generation from more than one REZ to reflect network limits that apply to multiple areas of the power system. The IASR Assumptions Book shows the group constraints that apply in the capacity outlook model. These were developed by considering the limits observed from power system analysis, and in consultation with TNSPs.

Modifiers due to flow path augmentations

If flow path augmentation options traverse a REZ, the increase in network capacity delivered by the option is reflected in the REZ transmission limits. Revised transmission expansion costs are then applied to the REZ to consider the network upgrades required for further capacity.

Assessment of all new or augmented flow path augmentation options therefore includes re-assessment of transmission limits and expansion costs for impacted REZ.

3.9.4 Connection costs and REZ expansion costs

Input vintage	July 2021
Source	AEMO internal – Based on the Transmission Cost Database and TNSP data.
Updates since Draft IASR	Costs are revised based on the 2021 Transmission Cost Report consultation.

When the capacity outlook model chooses to build new generation, a cost is incurred for generator connection cost and REZ expansion cost:

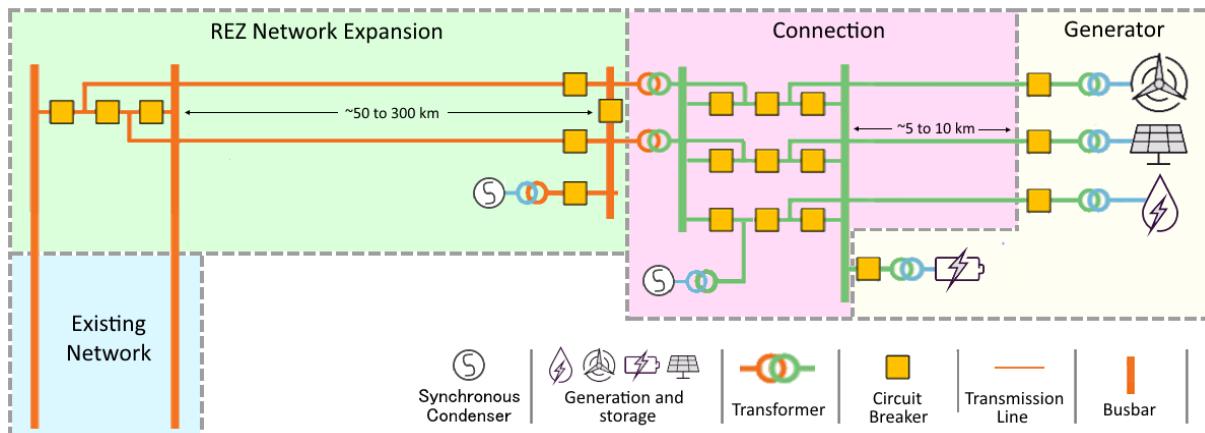
- REZ expansion costs reflect the network required to connect renewable generation in areas where clusters of large-scale renewable energy can be developed using economies of scale.

¹²⁹ At <https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan>.

- Connection costs refer to the cost of connecting a generator to the high-voltage network within a REZ. This cost varies depending on the proximity to transmission assets, which is assumed to vary based on technology.

An example of how these costs are allocated in relation to overall costs is shown in Figure 48.

Figure 48 Connection cost allocation



The *2021 Transmission Cost Report*¹³⁰ details the assumption and data behind these costs. A comparison of connection costs associated with REZs is detailed in the IASR Assumptions Book. These costs are presented alongside other REZ-based expansion costs in Figure 49.

The proximity of the generation to the transmission network is assumed to vary depending on the generator technology. Due to resource location, wind, solar, and pumped hydro projects will often be located 5-10 km from the existing network. The connection cost of battery storage is lower than other storage and generation options because battery storage has more flexibility in its location and can leverage the connection assets used in connecting VRE. For technologies that do not vary based on REZ design, regional-based connection costs are defined based on the expected connection voltage in each region, and presented in Table 33.

Table 33 Regional-based connection costs (\$/kW)

Region	CCGT	OCGT or reciprocating engines	Black coal (supercritical PC)	Biomass	Battery storage (2hrs storage)	Battery storage (4hrs storage)
Queensland	103.33	103.33	103.33	103.33	96.67	96.67
New South Wales	80.00	80.00	80.00	80.00	72.50	72.50
Victoria	75.00	108.00	-	108.00	100.00	100.00
South Australia	103.33	103.33	-	103.33	96.67	96.67
Tasmania	108.00	108.00	-	108.00	100.00	100.00

Notes:

- CCS technology is not expected to change the connection cost of coal-fired generation.
- Pumped hydro connection costs are included in the capital costs provided by Entura.
- Offshore wind connection costs are included in the capital costs provided by Aurecon.

¹³⁰ At <https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan>.

System strength remediation as part of REZ network expansion

System strength remediation costs have been estimated from the system strength remediation requirements assessed in the 2020 ISP studies¹³¹, and costing detailed in the *2021 Transmission Cost Report*¹³². The provision of synchronous condensers is used as the basis for costing system strength remediation, but AEMO notes that a variety of new technologies and approaches for remediating system strength issues are emerging. AEMO's approach therefore represents an approximate upper bound of these costs.

REZs that are already at system strength limits, but have available network capacity, include system strength remediation costs of \$106/kW within the generator connection cost (see Section 5.2 of the *2021 Transmission Cost Report*¹³³). REZs that have surplus system strength, but are likely to reach system strength limits as the network needs to expand, include the same remediation cost (\$106/kW) in the REZ expansion component rather than the connection cost. This delineation of applying system strength costs as a part of the REZ expansion cost versus the generator connection cost is done for modelling purposes and is not intended to influence decisions regarding the scope of actionable projects.

AEMO's incorporation of system strength costs do not consider which party will ultimately pay for system strength remediation (TNSP or generation proponent). The costs have been modelled in this way to ensure system strength remediation costs are appropriately captured.

AEMO notes that there is a proposal for rule changes under consideration currently⁵¹ to the existing system strength framework, to be effective from late in 2022. AEMO does not consider that the currently proposed changes will materially change the ODP or outcomes in terms of REZ and VRE development, but rather that they will support the timing and staging of that development:

- The introduction of a second standard (for efficient level of voltage waveform stability) will have more impact in terms of the timing of supporting infrastructure during REZ development, than ultimate outcomes for the ODP. It is intended to enable an efficient level of investment for system strength based on ISP projections of future inverter-based resources (IBR), so such investments occur in a timely manner.
- As such, it would not be expected to materially impact the overall ODP; rather, it would provide enabling infrastructure to support development of VRE in alignment with ISP projections and ISP timing.

However, once the rule changes are finalised later in 2021, AEMO will further consider any potential impacts and if needed, consider these when finalising the 2022 ISP in 2022.

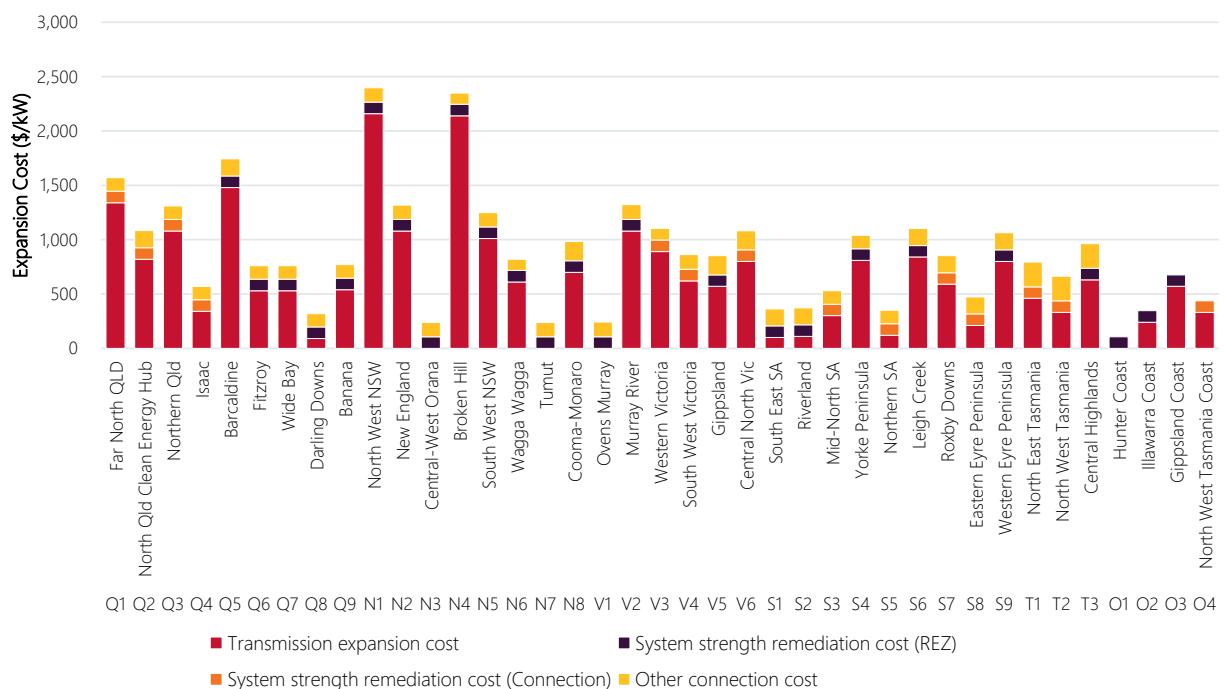
A comparison of costs associated with REZs is shown in Figure 49, and is detailed in the IASR Assumptions Book.

¹³¹ Based on available fault level calculations. AEMO 2020 ISP Appendix 5 REZ scorecards, at <https://www.aemo.com.au/-/media/files/major-publications/isp/2020/appendix--5.pdf?la=en>.

¹³² At <https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan>.

¹³³ At <https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan>.

Figure 49 Summary of REZ-based expansion costs



REZ expansion costs under the Hydrogen Superpower scenario

For the Hydrogen Superpower scenario, hydrogen export ports will present new and significant load centres that are distant from existing load centres, requiring different network upgrades to service them (see Figure 55). This scenario will therefore apply alternative REZ expansion cost assumptions to take this into account.

To allow optimal determination of REZ expansion to supply hydrogen export facilities, REZ expansion costs in this scenario are based on the distance from the REZ to a nearby port (see Section 3.12.1). Based on costs in the *2021 Transmission Cost Report*¹³⁴, REZ expansion to ports is assumed to be \$1,608/MW/km. This cost is based on the REZ expansion cost determined for the 500 kV option for the Q9 Banana REZ (see Section 4.3.9 of the *2021 Transmission Cost Report*¹³⁵).

3.10 Network modelling

This section describes inputs and assumptions relating to the transmission network. The inputs and assumptions are grouped into the following categories:

- **ISP sub-regions** – the power system is modelled in different ways depending on the analysis being performed. A 10-sub-region structure is applied to improve the granularity of optimisations that were previously assessed across five regions.
- **Existing network capacity** – this section summarises the existing capacity of the transmission network.
- **Committed transmission projects** – these projects are included in all scenarios. Once a project meets five commitment criteria, the projects are classified as committed and will be modelled in all scenarios.

¹³⁴ At <https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan>.

¹³⁵ At <https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan>.

- **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** – flow paths are the portion of the transmission network used to transport significant amounts of electricity across the backbone of the interconnected network to load centres. This section includes flow path upgrades that are not committed or anticipated and will be assessed in the ISP.
- **Transmission augmentation costs** – the costs of transmission augmentation options and the building blocks used to estimate new augmentations as the need may arise.
- **Non-network options** – AEMO considers potential non-network options alongside network solutions to develop an efficient power system strategy.
- **Inter-regional loss flow equations** – these equations are used to reflect the energy lost when transferring energy between regions.
- **Network losses and marginal loss factors (MLFs)** – these values are used to reflect network losses and the marginal pricing impact of bids from a connection point to the regional reference node.
- **Transmission line failure rates** – forced outage rates of inter-regional transmission elements are critical inputs for AEMO's reliability assessments.

3.10.1 ISP sub-regions

Input vintage	December 2020 – based on 2020 ISP with additional sub-regions added to enable better modelling of projects where AEMO triggered preparatory activities.
Source	AEMO internal
Updates since Draft IASR	None – stakeholders supported the structure proposed in the Draft IASR.

Depending on the purpose and the stage of the modelling, AEMO represents the network topology and reference nodes in different ways. The network can be represented as either a regional or sub-regional topology:

- In the regional topology, each of the five NEM regions is represented by a single reference node. In this topology, all regional loads are placed at the 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.

The following table lists all the regions and the sub-regions to be used in AEMO studies (and their corresponding reference nodes). The nodes in **bold** are those used as reference nodes in the regional topology.

Table 34 NEM regions, ISP sub-regions, reference nodes and REZs

NEM region	ISP sub-region	Reference node	REZs
Queensland	Central and North Queensland (CNQ)	Ross 275 kilovolts (kV)	Q1, Q2, Q3, Q4, Q5 and Q6
	Gladstone Grid (GG)	Calliope River 275 kV	-
	Southern Queensland (SQ)	South Pine 275 kV	Q7, Q8 and Q9
New South Wales	Northern New South Wales (NNSW)	Armidale 330 kV	N1 and N2
	Central New South Wales (CNSW)	Wellington 330 kV	N3
	South NSW (SNSW)	Canberra 330 kV	N4, N5, N6, N7 and N8
	Sydney, Newcastle, Wollongong (SNW)	Sydney West 330 kV	-
Victoria	Victoria (VIC)	Thomastown 66 kV	V1, V2, V3, V4, V5 and V6
South Australia	South Australia (SA)	Torrens Island 66 kV	S1, S2, S3, S4, S5, S6, S7, S8 and S9
Tasmania	Tasmania (TAS)	Georgetown 220 kV	T1, T2 and T3

*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.

Capacity outlook model representation

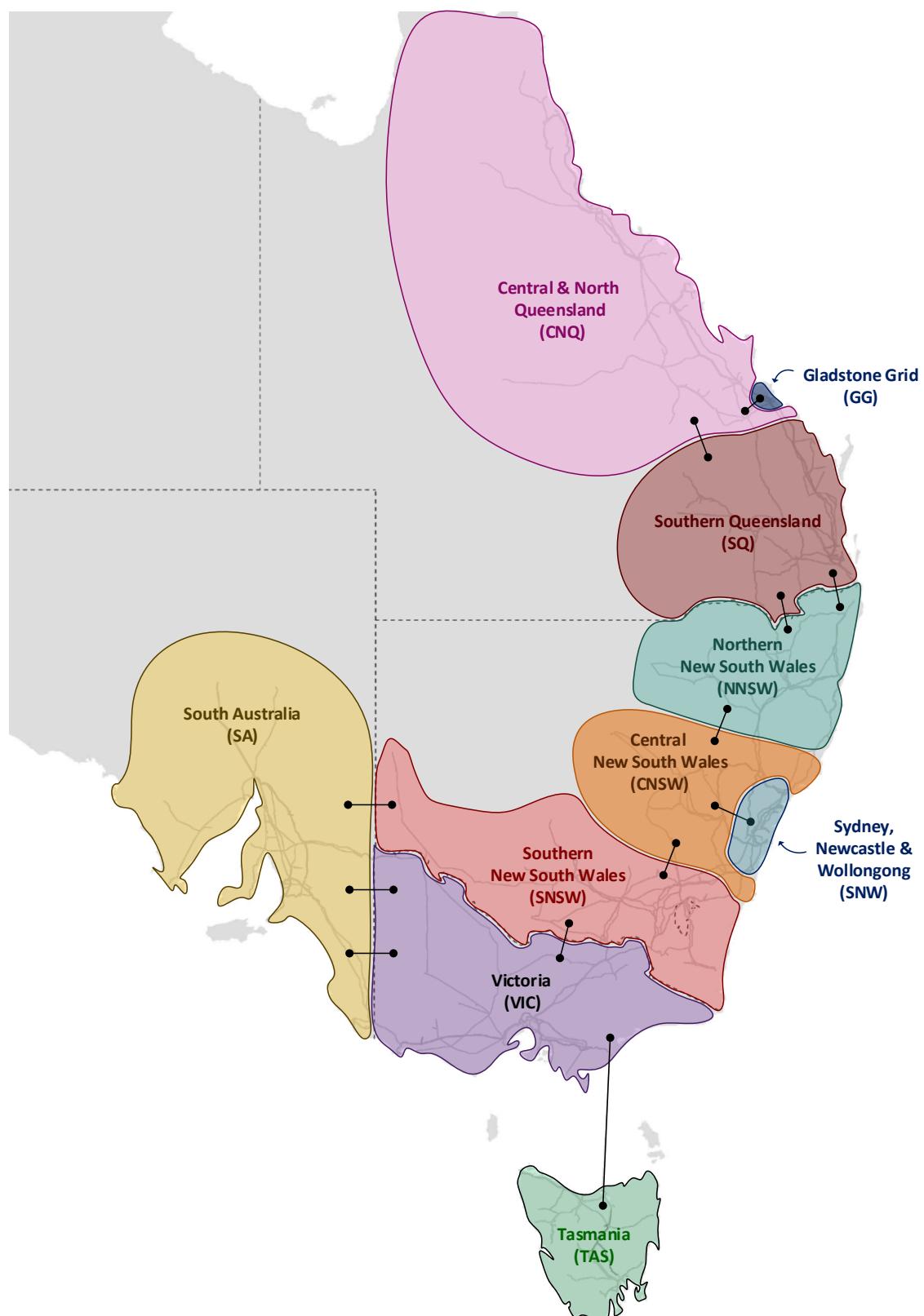
For the purposes of ISP modelling, AEMO expands the capacity outlook modelling from a five-state regional model to a 10-area sub-regional model. This provides more granular information on key intra-regional transmission limitations and augmentations which are not well approximated by REZ limits alone.

There is a trade-off when adding zones to this model. While additional zones provide more information, they increase the computational complexity of the PLEXOS model.

The sub-regional structure enables better information for projects that were actionable or where AEMO triggered preparatory activities in the 2020 ISP.

The sub-regional representation is presented and described in Figure 50 and Table 35.

Figure 50 ISP sub-regional model



Note: The “Southern Queensland” sub-region is used for modelling purposes and is distinct from the “Southern QREZ” zone identified by the Queensland Government (see <https://www.epw.qld.gov.au/about/initiatives/renewable-energy-zone>).

Table 35 Flow path representation between sub-regions

Flow Path	Notional direction of power flow
CNQ – 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 (2 circuits) Teebar Creek – Wurdong (1 circuit) Callide A – Gladstone South 132 kV (2 circuits)
SQ – CNQ	Woolooga – Teebar Creek 275 kV (1 circuit) Woolooga – Gin Gin 275 kV (2 circuits) Halys – Calvale 275 kV (2 circuits)
NNSW – SQ (Queensland – New South Wales interconnector, or Queensland – New South Wales interconnector [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 (2 circuits) 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)
VIC – SNSW	Murray – Upper Tumut 330 kV (1 circuit) Murray – Lower Tumut 330 kV (1 circuit) Wodonga – Jindera 330 kV (1 circuit) Red Cliffs – Buronga 220 kV line (circuit) 132 kV bus tie at Guthega (1 circuit which is normally open)

Flow Path	Notional direction of power flow
SNSW – SA	Buronga – Bundey 330 kV (2 circuits)
VIC – SA (Heywood)	Heywood – South East 275 kV (2 circuits)
VIC – SA (Murraylink)	Red Cliffs – Monash HVDC cable
TAS – VIC	George Town – Loy Yang HVDC cable

Representation of load and generation within each of the sub-regions is presented in the table below. Sub-regional loads are to be represented at the sub-regional reference node. The reference node for each sub-region is located close to the sub-region's major load centre.

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

Sub-region	Reference Node	Load and generation representation
Gladstone grid (GG)	Calliope River 275 kV	All load and generation at Calliope River, Boyne Island, Larcom Creek, Raglan, Wurdong, Gin and Teebar Creek substations.
Central/North Queensland (CNQ)	Ross 275 kV	All load and generation including and north of Calvale, Calliope River and Wurdong substations, except load and generation in GG sub-region.
Southern Queensland (SQ)	South Pine 275 kV	All Queensland load and generation except load and generation in CNQ sub-region.
Northern New South Wales (NNSW)	Armidale 330 kV	Within NSW, all load and generation including and north of Tamworth substation.
Central New South Wales (CNSW)	Wellington 330 kV	Within NSW, all load and generation including and west of Wallerawang and Wollar substations. Load and generation at Bayswater, Liddell, and Muswellbrook substations. Load and generation at Bannaby, Avon and Dapto substations.
South NSW (SNSW)	Canberra 330 kV	Within NSW, all load and generation including and south of Gullen Range, Marulan, and Kangaroo Valley substations. All load and generation in South West NSW.
Sydney, Newcastle, and Wollongong (SNW)	Sydney West 330 kV	All NSW region load and generation except CNSW and SNSW sub-region load and generation.
Victoria (VIC)	Thomastown 66 kV	All load and generation within Victoria
South Australia (SA)	Torrens Island 66 kV	All load and generation within South Australia
Tasmania (TAS)	Georgetown 220 kV	All load and generation within Tasmania

Detailed time-sequential model representation

The time-sequential models used in the ISP and ESOO use a regional topology. The NEM transmission network is represented using detailed transmission constraint equations, similar in form to what is used in the NEM Dispatch Engine (NEMDE), as developed for future different development pathways up to 2050 instead of current operational constraints in the live NEM.

These constraints:

- Consider the NEM's future 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 future 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 future changing power system conditions and outages.
- Are modified to cater for different development pathways and scenarios assessed in an ISP.

3.10.2 Existing transmission capability

Input vintage	July 2021.
Source	AEMO internal supplemented by advice from TNSPs via joint planning.
Updates since Draft IASR	Updated following consultation on the <i>Draft 2021 Transmission Cost Report</i> . Transfer limits have been split into three system conditions that align with the approach to modelling generation capacity. Historical transfer performance was reviewed, and power flow studies undertaken by AEMO and TNSPs.

Transfer capability across the transmission network is determined by thermal capacity, voltage stability, transient stability, small signal stability, and system strength. Transfer capability 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 sub-regions are represented at the time of "Summer Peak", "Summer Typical", and "Winter Reference" in the importing sub-region.

These notional transfer limits are presented in the table below. Interconnector transfer capabilities are a subset of this information and are listed in the IASR Assumptions Book. The forward direction of flow is typically in the north or west direction and is consistent with the flow path name.

Table 37 Notional transfer capabilities between sub-regions

Flow path (forward power flow direction)	Forward direction capability (MW)			Reverse direction capability (MW)		
	Summer Peak	Typical Summer	Winter Reference	Summer Peak	Typical Summer	Winter Reference
CNQ – GG ^a	700	700	1,050	750	750	1,100
SQ – CNQ	700	700	1,000	2,100	2,100	2,100
NNSW – SQ ("QNI") ^b	685	745	745	1,205	1,165	1,170
NNSW – SQ ("Terranora")	0	50	50	130	150	200
CNSW – NNSW	910	910	910	930	930	1,025
CNSW – SNW	7,525 (6,125 ^c)	7,525 (6,125 ^c)	7,625 (6,225) ^d	6,125 ^d	6,125 ^d	6,125 ^d
SNSW – CNSW	2,700	2,700	2,950	2,320	2,320	2,590
VIC – SNSW ^e	870	1,000	1,000	400	400	400
SNSW – SA	800	800	800	800	800	800
VIC – SA ("Heywood") ^f	650	650	650	650	650	650

Flow path (forward power flow direction)	Forward direction capability (MW)			Reverse direction capability (MW)		
	Summer Peak	Typical Summer	Winter Reference	Summer Peak	Typical Summer	Winter Reference
SNSW – SA & VIC – SA combined	1,300	1,300	1,300	1,450	1,450	1,450
VIC – SA (Murraylink)	220	220	220	100	200	200
TAS – VIC	478	478	478	478	478	478

Note: Forward and reverse directions are as referred in the first column of this table.

- A. CNQ-GG limits are heavily influenced by the amount of generation in northern and central Queensland, particularly at Gladstone. The provided transfer limit is a representation with typical generation output from Stanwell and Calvale and reduced generation at Gladstone. This limit will be further reviewed with hourly simulation results.
- B. QNI Minor is a committed project and is included in the transfer capability.
- C. The CNSW to SNW transfer limit is reduced to 6,125 MW in the absence of Eraring or Vales Point generation.
- D. Power is not expected to frequently flow from SNW to CNSW since the major load centre is SNW. For DLT modelling, a transfer limit of 6,125 MW is assumed for this limit, and will be reviewed if it becomes material.
- E. VNI Minor is a committed project and is included in the transfer capability.
- F. The Heywood interconnector currently operates at 600 MW forward capability and 550 MW reverse capability. AEMO and ElectraNet are working to release the transfer capability to its designed capability of 650 MW in both directions.

3.10.3 Committed transmission projects

Input vintage	July 2021
Source	AER and TNSPs – AER’s approval of Contingent Project Application and advice from TNSPs on the status of projects meeting the 5 commitment criteria.
Updates since Draft IASR	<ul style="list-style-type: none"> • New South Wales components of VNI Minor transitioned from “anticipated” to “committed”. • VNI System Integrity Protection Scheme transitioned from “anticipated” to “committed”.

AEMO applies the definition of committed projects from the AER’s RIT-T instrument¹³⁶, as required by the CBA Guidelines.¹³⁷

Specifically, a committed transmission project must meet all the following criteria:

- The proponent has obtained all required planning consents, construction approvals and licenses, 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.

The following projects are classified as committed transmission projects. Some projects currently categorised as anticipated (see Section 3.10.4) may become committed before the next IASR. AEMO will use reasonable endeavours to incorporate any changes to committed transmission projects in its forecasting and planning activities for 2021-22, time permitting.

¹³⁶ AER, *Regulatory investment test for transmission*, at <https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20Investment%20test%20for%20transmission%20-%202025%20August%202020.pdf>.

¹³⁷ AER Cost Benefit Analysis guidelines, at <https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%202025%20August%202020.pdf>.

Table 38 Committed transmission projects

Project	Description	Expected in service date
QNI Minor (Queensland – New South Wales interconnector)	The committed upgrade involves: <ul style="list-style-type: none"> Uprating of following transmission lines from the existing design operating temperature of 85°C to 120°C. Liddell–Tamworth 330 kV line. Liddell–Muswellbrook 330 kV line. Muswellbrook–Tamworth 330 kV line. Installation of shunt capacitor banks at Armidale, Dumaresq, and Tamworth substations. Installation of dynamic reactive plant at Tamworth and Dumaresq. 	Commissioning and inter-network testing are planned to commence in January 2022 and conclude in June 2022. AEMO assumes full capacity will be available from 1 July 2022.
South Australia system strength remediation	This project includes installation of: <ul style="list-style-type: none"> Two high inertia synchronous condensers at Davenport 275 kV substation. Two high inertia synchronous condensers at Robertstown 275 kV substation. Each of the four synchronous condensers provide 575 MVA nominal fault current and 1,100 MWs of inertia.	Synchronous condensers energised and commissioned in 2021.
VNI System Integrity Protection Scheme † (Non-network solution)	Allow to increase import capability from New South Wales to Victoria of the VIC-NSW interconnector (VNI) during November to March each year. This involves procurement of 250 MW System Integrity Protection Scheme (SIPS) in Victoria to rapidly respond by injecting power after a contingency event on VNI.	Service date: Summer 2021-2022
VNI Minor ‡	The committed upgrade involves: <ul style="list-style-type: none"> Upgrade South Morang–Dederang 330 kV line; An additional new 500/330 kV transformer at South Morang; and Power flow controllers on Upper Tumut-Yass and Upper Tumut–Canberra 330 kV lines. 	Service date: Late 2022 To allow time for inter-network testing, AEMO will model this augmentation at full capacity from September 2023.

[†] AEMO. Victorian Annual Planning Report, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2020/2020-vapr.pdf?la=en.

[‡] In November 2020, AEMO published an ISP feedback notice confirming that the VNI Minor project meets the identified need and remains aligned with the optimal development path set out in the 2020 ISP. The notice is available at <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/integrated-system-plan-feedback-loop-notices>.

Note: Some committed transmission projects are not included in this list because they are unlikely to impact AEMO's modelling.

3.10.4 Anticipated transmission projects

Input vintage	July 2021
Source	AER and TNSPs – AER's approval of Contingent Project Application and advice from TNSPs on the status of projects meeting the commitment criteria.
Updates since Draft IASR	<ul style="list-style-type: none"> NSW components of VNI Minor transitioned from "anticipated" to "committed". VNI System Integrity Protection Scheme transitioned from "anticipated" to "committed". Project EnergyConnect confirmed as "anticipated" following the AER's approval of ElectraNet and TransGrid's contingent project applications.

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 RIT-T instrument to determine anticipated projects. These projects must be in the process of meeting three out of the five committed project criteria (as described in Section 3.10.3). Such projects could be network or non-network augmentations and could be regulated or non-regulated assets.

Some degree of judgement is required in assessing whether a project is “in the process of meeting three out of the five committed project criteria”. For regulated projects, AEMO typically considers projects to be anticipated following the AER’s approval of a contingent project application for the full project¹³⁸ – at this stage funding is confirmed and other criteria are typically well advanced. Other projects are individually assessed by AEMO using information from the local TNSP, state government, and any relevant proponents.

In the NEM, transmission is typically a regulated asset, and for a new transmission project to be approved, the relevant TNSP is required to go through the RIT-T, administered by the AER. Information on the stages of the RIT-T can be found on the AER website¹³⁹.

The *Reliability Forecasting Methodology*¹⁴⁰ 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.

Table 39 outlines the projects that are currently classified as anticipated transmission projects. AEMO may incorporate additional anticipated projects if they become anticipated during the development of the ISP. These projects generally have funding arrangements, but have some outstanding steps before they advance to committed (such as environmental and land planning approvals, land acquisition, finalisation of contracts for supply and construction of major components).

Table 39 Anticipated network projects

Project name	Project description	Timing
Western Victoria Transmission Network Project	<p>Stage 1 augmentation includes:</p> <p>The installation of wind monitoring equipment and the upgrade of station limiting transmission plant on the:</p> <ul style="list-style-type: none"> • Red Cliffs–Wemen 220 kV line. • Wemen–Kerang 220 kV line. • Kerang–Bendigo 220 kV line. • Moorabool–Terang 220 kV line. • Ballarat–Terang 220 kV line. <p>Stage 2 augmentation includes:</p> <ul style="list-style-type: none"> • A new terminal station at north of Ballarat. • A new 500 kV double-circuit transmission line from Sydenham to the new terminal station north of Ballarat. • A new 220 kV double-circuit transmission line from the new terminal station North of Ballarat to Bulgana (via Waubra). • 2 x 500/220 kV transformers at the new terminal station north of Ballarat. • Cut-in the existing Ballarat–Bendigo 220 kV line at the new terminal station north of Ballarat. • Moving the Waubra Terminal Station connection from the existing Ballarat–Ararat 220 kV line to one of the new terminal stations north of Ballarat–Bulgana 220 kV lines. • Cut-in the existing Moorabool–Ballarat No. 2 220 kV line at Elaine Terminal Station. <p>Stage 3 augmentation includes:</p> <ul style="list-style-type: none"> • Completion of inter-network testing. 	<p>Stage 1 completed in 2021.</p> <p>Stage 2 complete by October 2025.</p> <p>Stage 3 complete by July 2026</p>

¹³⁸ AEMO will also consider a project to be anticipated following approval of an alternative funding mechanism for the full project in accordance with state legislation that disapplies funding approval processes under the NER.

¹³⁹ At <https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable>.

¹⁴⁰ 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>.

Project name	Project description	Timing
Project EnergyConnect †	<p>Project EnergyConnect is a new double-circuit 330 kV transmission line between Wagga Wagga in New South Wales and Robertstown in South Australia via Buronga. This is planned to be completed in two stages.</p> <p>Stage 1:</p> <ul style="list-style-type: none"> • A new Robertstown to Bunley 275 kV double circuit line strung one circuit initially. • A new Bunley to Buronga 330 kV double circuit line strung one circuit initially. • A new Buronga to Red Cliffs 20 kV double circuit line strung one circuit only. • A new 330/275 kV substation and a transformer at Bunley. • A new 330/220 kV substation, a 330/220 kV transformer and a 330 kV phase shifting transformer at Buronga. • Static and dynamic reactive plant at Bunley and Buronga. <p>Stage 2:</p> <ul style="list-style-type: none"> • Second 275 kV circuit strung on the Robertstown–Bunley 275 kV double circuit line. • Second 330 kV circuit strung on the Bunley–Buronga 330 kV double circuit line. • A new 330 kV double-circuit line from Wagga Wagga to Dinawan to Buronga. • Two additional new 330/275 kV transformers at Bunley. • A new 330 kV switching station at Dinawan. • Additional new 330 kV phase shifting transformers at Buronga. • Additional new 330/220 kV transformer at Buronga. • Turning the existing 275 kV line between Para and Robertstown into Tungkillo. • Static and dynamic reactive plant at Bunley, Robertstown, Buronga, Dinawan. • A special protection scheme to detect and manage the loss of either of the AC interconnectors connecting to South Australia. 	<p>Service date: Stage 1 - Mid-2023 Stage 2 – Mid 2024</p> <p>To allow time for inter-network testing, AEMO will model this augmentation at full capacity from July 2025.</p>
Northern QREZ Stage 1 ‡	<p>The first stage of development proposed for the Far North QLD REZ is the Northern QREZ Stage 1 project. This augmentation is progressing as a funded network augmentation. The design includes establishing a third 275 kV connection into Woree by November 2023.</p> <p>The scope of work includes:</p> <ul style="list-style-type: none"> • Conversion of one side of the coastal 132 kV double-circuit transmission line to permanently operate at 275 kV. • Construction of a 275 kV bay at Ross Substation. • Installation of a 275/132 kV transformer at Tully Substation. • Installation of a 275 kV bus at Woree Substation with an associated line reactor. 	November 2023.
Central West Orana REZ Transmission Link	New transmission lines connecting to 500 kV and 330 kV network in vicinity of the Orana REZ indicative location.	Shovel ready by the end of 2022.

† Project EnergyConnect was approved by the AER on 31 May 2021 (see <https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/transgrid-and-electranet---project-energyconnect-contingent-project>).

‡ Powerlink. *Developing the Northern Queensland Renewable Energy Zone*, at <https://www.powerlink.com.au/sites/default/files/2021-06/Powerlink%20Queensland%20-%20Consultation%20Paper%20-%20Developing%20the%20Northern%20Queensland%20Renewable%20Energy%20Zone.pdf>.

3.10.5 Flow path augmentation options

Input vintage	July 2021
Source	<p>AEMO, supported by TNSPs via joint planning and other stakeholders via feedback to the Draft IASR and <i>Draft 2021 Transmission Cost Report</i>.</p> <p>Projects with preparatory activities were provided by Powerlink and TransGrid. AEMO estimated the cost of TransGrid's preparatory activities projects because TransGrid consider their cost estimate to be confidential.</p>
Updates since Draft IASR	<ul style="list-style-type: none"> • Augmentation options were consulted on via the Draft IASR and <i>2021 Transmission Cost Report</i>. • Project EnergyConnect was removed as an option after it advanced to the "anticipated project" status. • Minor variations on other flow path augmentations are included in the <i>2021 Transmission Cost Report</i>.

Flow paths are a feature of power system networks, representing the main transmission pathways over which bulk energy is shipped. They are the portion of the transmission network used to transport significant amounts of electricity across the backbone of the network to load centres. Flow paths change as new interconnection is developed, or as a result of shifting large amounts of generation into new areas (such as in the case of major REZ development).

Flow path augmentation options represent new network and non-network options to increase the transfer capability between ISP sub-regions. Each option is a candidate to be built during capacity expansion modelling¹⁴¹. 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 3.9.3.

AEMO identified flow path augmentation options across ISP sub-regions to connect REZs and pumped hydro storage. Credible options include the following technologies:

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

The options presented in this section were sourced from the previous ISP consultations, AEMO's engagement with stakeholders, Transmission Annual Planning Reports (TAPRs), the 2020 ISP, and the Draft IASR consultation.

Notably, these flow path augmentation options represent the starting point of the ISP analysis. As the ISP modelling progresses, these options are refined and improved upon. New options may be added as outcomes from the various stages of the model are evaluated and inputs refined. This iterative process is described in Section 1 and Section 4 of the *ISP Methodology*.

Augmentation options

The augmentation options have been modified to suit the sub-regional representation of the capacity outlook model (described in Section 3.10.1). This means some of the interconnector augmentation options used in the 2020 ISP are now separated into multiple components. This is particularly relevant for the Queensland – New South Wales interconnector (QNI).

The flow path augmentation options are aligned with the modelled network topology (see 3.10.1) and increase the transfer between sub-regions. These augmentation options are categorised as follows:

- **Gladstone Grid (GG) Reinforcement** – an option to increase transfer capacity between the Central/North Queensland (CNQ) and Gladstone sub-regions for which AEMO triggered preparatory activities in the 2020 ISP. Powerlink has provided a report that describes this option in detail¹⁴².
- **Central to Southern Queensland** – options to increase transfer capacity between the CNQ and Southern Queensland (SQ) sub-regions, including the Central to Southern Queensland Transmission Link for which AEMO triggered preparatory activities in the 2020 ISP. Powerlink has provided a report that describes this option in detail¹⁴³.
- **Northern New South Wales (NNSW) – Southern Queensland** – options to increase the transfer capability between NNSW and SQ. This includes components of the QNI Medium and Large project for

¹⁴¹ See AEMO Market Methodology Report for further details, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Market-Modelling-Methodology-Paper.pdf.

¹⁴² Powerlink. Preparatory Activities – Gladstone Grid Reinforcement, available at <https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan>.

¹⁴³ Powerlink. Preparatory Activities – CQ-SQ Transmission Link, available at <https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan>.

which AEMO triggered preparatory activities in the 2020 ISP. Powerlink has provided a report that describes the Queensland components of this option in detail¹⁴⁴.

- **Central New South Wales – Northern New South Wales** – options to increase the transfer capability between CNSW and NNSW. This includes components of the QNI Medium and Large project for which AEMO triggered preparatory activities in the 2020 ISP.
- **Central New South Wales – Sydney, Newcastle, and Wollongong** – options to reinforce supply to Sydney, Newcastle and Wollongong load centres following retirement of coal power generators in New South Wales. This includes the Reinforcing Sydney, Newcastle, and Wollongong Supply project for which AEMO triggered preparatory activities in the 2020 ISP.
- **South New South Wales (SNSW) – Central New South Wales** – options to increase the transfer capability between SNSW and CNSW. Options include the currently proposed HumeLink¹⁴⁵ project.
- **Victoria – South New South Wales** – options to increase the transfer capability between Victoria and SNSW. This includes augmentation options considered as part of the Victoria – New South Wales Interconnector West¹⁴⁶.
- **Tasmania – Victoria** – options to increase transfer capability between Tasmania and Victoria. Options include Project MarinusLink¹⁴⁷, the proposed new interconnector would increase the transfer capability between Tasmania and Victoria.

The different corridors associated with these options are illustrated in Figure 51 and described in more detail in the *2021 Transmission Cost Report* and the IASR Assumptions Book.

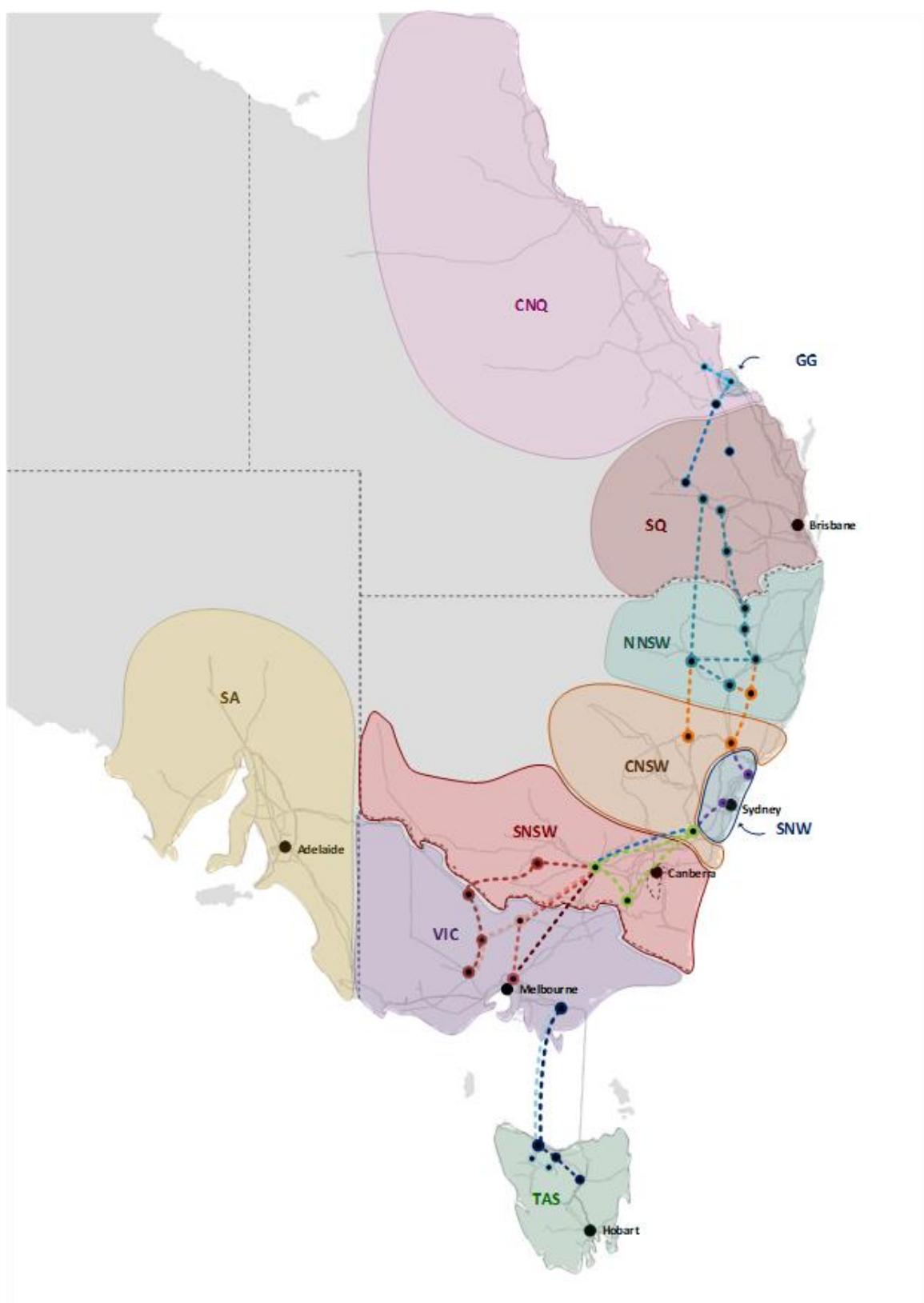
¹⁴⁴ Powerlink. Preparatory Activities – QNI Medium and Large, at <https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan>.

¹⁴⁵ TransGrid. *HumeLink*, at <https://www.transgrid.com.au/humelink>.

¹⁴⁶ AEMO. *VNI West*, at <https://aemo.com.au/en/initiatives/major-programs/victoria-to-new-south-wales-interconnector-west-regulatory-investment-test-for-transmission>.

¹⁴⁷ TasNetworks. *Marinus Link*, at <https://www.marinuslink.com.au/>.

Figure 51 Flow path augmentation options



Augmentation capability

Notional transfer capability for each of the options is determined from power flow studies, which were undertaken by AEMO and TNSPs. AEMO has undertaken due diligence on transfer limits provided by TNSPs for options which were part of preparatory activities or RIT-Ts in progress.

For capacity outlook modelling, notional transfer limits between the sub-regions are represented at the time of peak demand, summer typical, and winter reference in the importing sub-region. In most cases, by taking into account demand, dispatch of existing generation, location and dispatch of new generation, and seasonal ratings, the notional transfer capability increase is a good representation of the overall increase in transfer capability for other system conditions. In time-sequential modelling, separate constraint equations are used to identify complex network limit equations. If necessary, notional transfer limits may be reviewed during the modelling period in an iterative approach to ensure the physical limitations of the power system are adequately represented.

Expected service dates

Expected service dates for projects identified as actionable in the 2020 ISP have been sourced from TNSPs. For all other augmentations, expected lead times represent the likely minimum time for service from the date of publication of the Final 2022 ISP. The lead time includes regulatory justification, AER approval, relevant community engagement and planning approvals, procurement, construction, commissioning, and inter-network testing.

Service dates are listed in the IASR Assumptions Book and in the *2021 Transmission Cost Report*¹⁴⁸. Each augmentation option in the 2021 Assumptions Book is considered to be a 'standalone' option. Where options are built subsequent to a previous option (that is, if there is a pre-requisite upgrade), it is explicitly stated.

3.10.6 Transmission augmentation costs

Input vintage	July 2021
Source	<ul style="list-style-type: none">• TNSPs provided information for actionable projects and preparatory activities.• AEMO estimated the cost of other projects using the Transmission Cost Database.
Updates since Draft IASR	Updated for the 2021 IASR following consultation on the Draft IASR and <i>Draft 2021 Transmission Cost Report</i> . Three webinars and a four-week written consultation were held. Responses to the consultation are listed in the <i>IASR Consultation Summary Report</i> ¹⁴⁹ .

Following feedback from stakeholders on the transmission costs assumed for the 2020 ISP, AEMO implemented an initiative to improve the accuracy and transparency of costs used for the 2022 ISP. A new *2021 Transmission Cost Report*¹⁵⁰ is published alongside this IASR, and covers the following:

- Methodology used for transmission cost estimation, including:
 - Description of cost estimate stages.
 - Transmission Cost Database.
 - Process for review of TNSP estimates.
- Design, capacity and cost estimates for each augmentation option.
- Generator connection costs.

¹⁴⁸ At <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios>.

¹⁴⁹ At <https://aemo.com.au/en/newsroom/news-updates/draft-2021-inputs-assumptions-and-scenarios-report-released>.

¹⁵⁰ At <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios>.

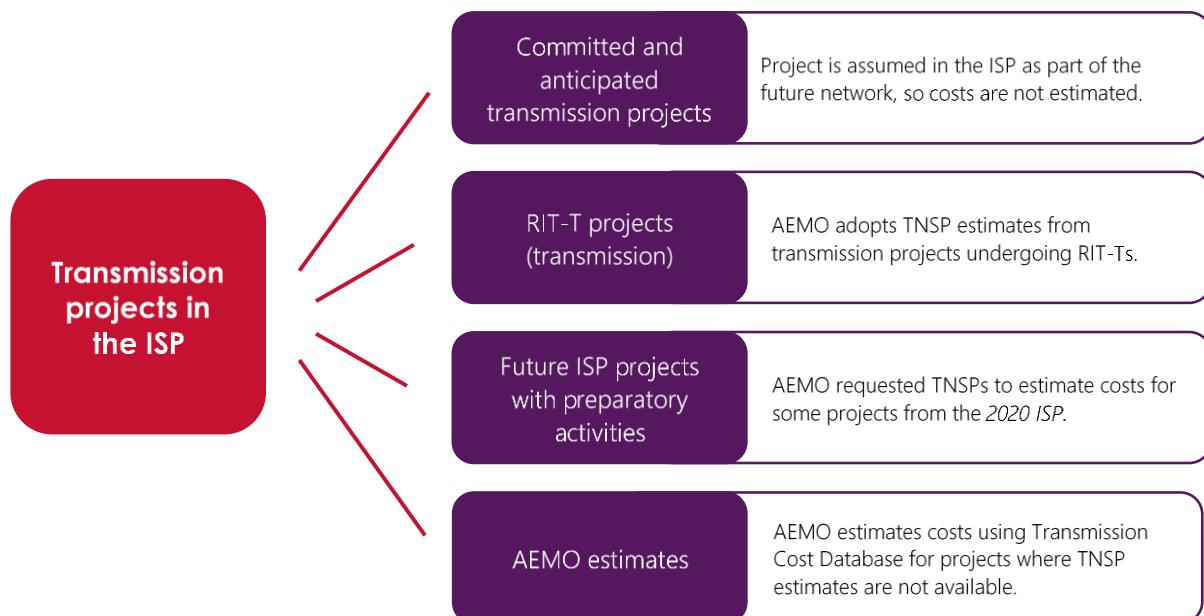
A summary of consultation on the *Draft 2021 Transmission Cost Report* is available in the *IASR Consultation Summary Report*¹⁵¹.

Source of transmission cost estimates

As part of the RIT-T process, TNSPs progress the design of proposed projects in collaboration with AEMO and develop cost estimates. As a project progresses further through the RIT-T stages, and the level of design increases, the accuracy of the cost estimate is also expected to improve.

AEMO's approach to incorporating cost estimates in the ISP is illustrated in Figure 52 below, and described in more detail in the *2021 Transmission Cost Report*.

Figure 52 AEMO's approach to incorporating transmission projects in the ISP



Cost estimation standardisation

A new Transmission Cost Database was developed by GHD as an expert independent consultant, for use by AEMO in developing cost estimates. It comprises a Cost and Risk Databook, and a cost estimation tool, and has been published to improve transparency on the estimation process and data. The approach used in the database is to incorporate known and unknown risk allowances in cost estimates from the earliest stage, so that the expected project cost used in the ISP modelling is more reflective of the final costs seen once the project is implemented.

While AEMO has adopted the Association for Advancement of Cost Estimation (AACE) International¹⁵² standard for the ISP to improve alignment and consistency of cost estimation for transmission projects, this standard is not currently a requirement for TNSPs. TNSPs each have a unique project cost estimation process that has evolved through the development of their respective transmission project portfolios.

For this reason, AEMO has engaged with each TNSP to establish a process to ensure cost estimates are aligned across all projects in AEMO's ISP modelling. This includes reviewing the TNSP estimates and cross-checking with results from the Transmission Cost Database.

¹⁵¹ At <https://aemo.com.au/en/newsroom/news-updates/draft-2021-inputs-assumptions-and-scenarios-report-released>.

¹⁵² AACE International, *The Association for Advancement of Cost Estimation*, at <https://web.aacei.org>.

Where sufficient information has not been provided to AEMO, or where missing or insufficient allowance has been made for cost components or risk, AEMO may add an additional allowance to the TNSP cost. Where this has been required, information on the adjustment is provided in the *2021 Transmission Cost Report*¹⁵³.

Design, capacity and cost estimates

The *2021 Transmission Cost Report*¹⁵⁴ includes a summary table for each transmission augmentation option. The following information is presented for each augmentation option:

- A description of the option.
- The expected increase in transfer capacity.
- The project cost, including the class of the estimate and associated accuracy.
- An overview of characteristics which are key cost drivers.

The following table summarises the costs for network projects that were actionable or where AEMO triggered preparatory activities in the 2020 ISP. More information on the cost estimation, classification system, and other project costs is included in the *2021 Transmission Cost Report*.

Table 40 Transmission costs for previously actionable and preparatory activities projects

Project	Forward/reverse capacity (MW)	Cost (\$ million)	Class	Source
Central to Southern QLD	900 / 900	476	Class 5	Powerlink
HumeLink	2,200 / 2,200	3,315	Unknown †	TransGrid
Marinus Link (stage 1)	750 / 750	2,270	Class 4	TasNetworks
Marinus Link (stage 2)	750 / 750	1,210	Class 4	TasNetworks
New England	1,800 ‡	2,009	Class 5b	AEMO #
North West NSW	1,660 ‡	3,584	Class 5b	AEMO #
QNI Large (Pre-requisite: QNI Medium)	550 / 800	384	Class 5b (QLD works) Class 5b (NSW works)	Powerlink and AEMO ‡
QNI Medium	910 / 1,080	1,253	Class 5b (QLD works) Class 5b (NSW works)	Powerlink and AEMO ‡
Reinforcing Gladstone Supply	550 / 500	408	Class 5	Powerlink
Reinforcing Sydney Supply (North)	5,000 / 5,000	880	Class 5b	AEMO #
Reinforcing Sydney Supply (South)	4,500 / 4,500	2,256	Class 5b	AEMO #

¹⁵³ At <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-ispl/2022-integrated-system-plan-ispl/current-inputs-assumptions-and-scenarios>.

¹⁵⁴ At <https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-ispl/2022-integrated-system-plan-ispl/current-inputs-assumptions-and-scenarios>.

Project	Forward/reverse capacity (MW)	Cost (\$ million)	Class	Source
VNI West (Kerang route)	1,930 / 1,800	4,076	Unknown †	AEMO and TransGrid
VNI West (Shepparton route)	1,930 / 1,800	2,711	Unknown †	AEMO and TransGrid

[†] Estimates for costs for HumeLink and the NSW works on VNI West are included using TransGrid's estimates. As the information provided did not allow AEMO to transparently confirm these classifications, the accuracy and class of the estimates are stated as 'unknown' in this report.

[‡] REZ network limits are designed to export power from a REZ, so transfer limits are only provided in one direction.

[#] AEMO requested that TransGrid provide information on these options through preparatory activities as per clause 5.22.6(c) in NER. Although TransGrid provided AEMO with the required scope and cost estimates, the cost estimates were provided on a confidential basis. The ISP regulatory framework is designed to be transparent and consultative for all stakeholders, and AEMO does not consider it appropriate to use confidential transmission costs in the ISP. Accordingly, AEMO has developed independent cost estimates using the Transmission Cost Database and the project scopes provided by TransGrid.

3.10.7 Non-network options

Input vintage	July 2021
Source	AEMO – informed by submissions to previous consultations.
Updates since Draft IASR	None.

Non-network options are defined in the NER (Chapter 10, glossary) as a means by which an identified need can be fully or partly addressed other than by a network option. 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.

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.

As per item 27 (Table 13) of the AER CBA guidelines¹⁵⁵, 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 step one of its process for selecting development options.

The *2021 Transmission Cost Report* includes several non-network options. AEMO sought input on non-network options in the draft IASR consultation and in the transmission cost consultation. AEMO welcomes stakeholders to recommend non-network options for inclusion in the ISP, but also considers that opportunities can be provided at the time of the RIT-T, when there is more certainty on the optimal timing and identified need.

¹⁵⁵ At <https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%202025%20August%202020.pdf>.

3.10.8 Inter-regional loss flow equations, marginal loss factor (MLF) equations and loss proportioning factors

Input vintage	July 2021
Source	AEMO. Initial MLFs, loss equations and proportioning factors are based on the March 2021 <i>Regions and Marginal Loss Factors</i> report. Loss equations and proportioning factors are varied based on flow path augmentations, as outlined in the <i>ISP Methodology</i> .
Updates since Draft IASR	Updated to align with the March 2021 <i>Regions and Marginal Loss Factors</i> draft report.

This section describes the inter-regional loss flow equations, interconnector MLF equations, and interconnector loss proportioning factors for use in studies such as the ISP and ESOO. While the sub-regional model does split some regions into smaller sub-regions, inter-regional losses will continue to be modelled across regional boundaries – consistent with the design of the NEM.

Inter-regional loss equations and inter-regional loss factor equations

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 flow equations are presented in the interconnector loss parameters tab of the IASR Assumptions Book and are sourced from the March 2021 *Regions and Marginal Loss Factors* report¹⁵⁶.

Inter-regional loss factor equations describe the variation in loss factor at one regional reference node (RRN) with respect to an adjacent Regional Reference Node (RRN). These equations are necessary to cater for the large variations in loss factors that may occur between RRNs as a result of different power flow patterns. This is important in minimising the distortion of economic dispatch of generating units. Inter-regional loss factor equations can be found on the Interconnector loss parameters tab of the IASR Assumptions Book.

Interconnector loss proportioning factors

In both NEMDE and AEMO's market models, the total inter-regional losses on each interconnector in each period are apportioned to the connected regions based on specified proportioning factors. Any allocated losses to a region effectively increment the load that needs to be met within that region. Other than interconnector losses, other transmission losses and all distribution losses are already included in the demand forecast.

Loss proportion factors are out an outcome of applying the methodology described in AEMO's *Forward-Looking Transmission Loss Factors*¹⁵⁷. Loss proportion factors are updated every financial year with the publication of AEMO's *Regions and Marginal Loss Factors* report¹⁵⁸. Inter-regional loss flow equations are presented in the Interconnector loss parameters tab of the IASR Assumptions Book.

¹⁵⁶ At <https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries>.

¹⁵⁷ At <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries>.

¹⁵⁸ At <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries>.

3.10.9 Network losses – marginal loss factors

Input vintage	July 2021
Source	March 2021 <i>Regions and Marginal Loss Factors</i> report
Updates since Draft IASR	Updated to reflect the March 2021 <i>Regions and Marginal Loss Factors</i> report, and revisions to Snowy 2.0's shadow generator in response to stakeholder feedback.

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. In the NEM, transmission network losses are represented through MLFs.

MLFs are used to adjust the price of electricity in a NEM region (or sub-region), relative to the RRN, in a calculation that aims to recognise the difference between a generator's output and the energy that is actually delivered to consumers. In dispatch and settlement in the NEM, the local price of electricity at a connection point is equal to the regional price multiplied by the MLF. A renewable generator's revenue is directly scaled by its MLF, through both electricity market transactions and any revenue derived from large-scale renewable generation certificates (LGCs) created if accredited under the LRET.

MLFs are an outcome of applying the methodology described in AEMO's *Forward-Looking Transmission Loss Factors*. MLFs are updated every financial year with the publication of AEMO's *Regions and Marginal Loss Factors* report. AEMO updates the MLFs to reflect the latest available version of this report. Where a committed or anticipated generator does not have an MLF calculated in the *Forward-Looking Transmission Loss Factors* report, a 'shadow' generator is used. This is a generator which is located electrically close to the generator in question and, where possible, is the same technology. This same concept is applied to generic new entrant generators.

AEMO assesses MLF robustness as a part of the methodology used to validate generator investments and REZ designs. AEMO does not intend to update individual generator MLFs throughout the modelling horizon because they are unlikely to materially affect the outcome of assessing development paths, and the estimated cost of undertaking the analysis is disproportionate given the level of uncertainty regarding future outcomes.

See the MLF tab in the IASR Assumptions Book for values.

3.10.10 Transmission line failure rates

Input vintage	June 2021
Source	AEMO Network Outage Schedule and other AEMO sources.
Updates since Draft IASR	Updated to reflect latest outage data

Similar to generators, forced outage rates of inter-regional transmission elements are critical inputs for AEMO's reliability assessments. Information is collected on the timing, duration, and severity of the transmission outages to inform transmission forced outage rate forecasts. Consistent with the NER definition of unserved energy (USE), AEMO only models the impact of single credible contingencies and reclassifications on key transmission lines that materially contribute to inter-regional transfer capability.

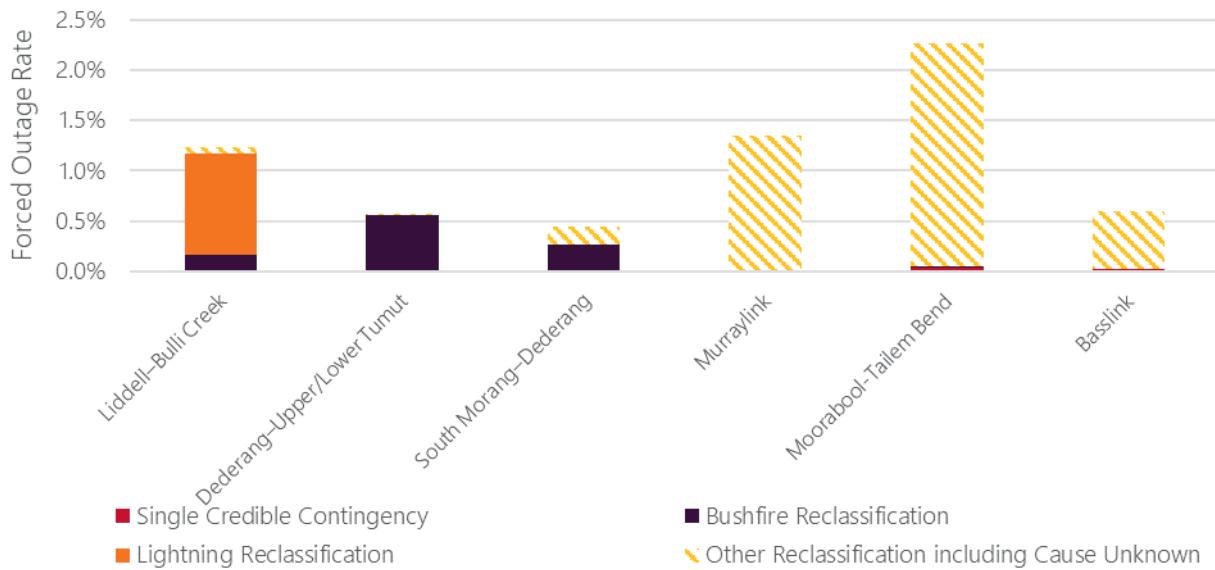
Many noteworthy transmission incidents involve multiple contingencies or non-credible contingencies that are specifically excluded from the definition and calculation of unserved energy in the ESOO.

Six lines are chosen for implementation that represent material single credible contingencies or reclassifications. These lines include major interconnectors, and the lines that connect those interconnectors to stronger meshed elements of the regional grids. When events occur on these selected lines, interconnector

limits vary. Additionally, the lines chosen have a sufficiently high historically observed outage rate to justify inclusion in modelling.

All transmission outage rates are derived for implementation using the outage rates observed in the 12 years of available outage history, noting that data before this point is unavailable. The outages considered in deriving these rates comprise single credible contingencies and reclassification events. The historic rate of these outages is shown by category in Figure 53.

Figure 53 Observed outage event rate (2009-21) by category



In response to feedback received in consultation, AEMO will implement outage rates calculated from events caused by bushfire reclassification, lightning reclassification, and single credible contingencies only. Other reclassifications, which tend to be longer in duration, will be excluded in 2021 until further consultation can be undertaken to better include stakeholder perspectives on which outages should be considered in calculations.

When the outage is triggered in reliability forecast simulations, AEMO will apply a set of constraints consistent with those used operationally during single credible contingency events for each line. These constraints will reduce the transfer limits on the affected lines, and may constrain generator output in some situations. In the case of Basslink and Murraylink, both of which are single circuit, these constraints may reduce the transfer limit to zero; in other cases the limit will remain non-zero.

Where relevant, AEMO implements these transmission outage rates using time-varying rates based on meteorological parameters, such as bushfire weather¹⁵⁹. Input meteorological trends will follow climate change projections consistent with the scenario specification. The use of meteorological variables ensures that forced outages are simulated consistent with the reference year, with regard for coincident power system impacts.

For the 2021 ESOO, only the South Morang – Dederang line and Dederang to Upper and Lower Tumut lines are noted to be predominantly impacted by bushfire reclassification, and will therefore be implemented as a function of bushfire weather (FFDI). See Section 3.8.2 for more details on how the climate projections will impact these outage rates.

The following table shows the inputs used in the 2021 ESOO.

¹⁵⁹ With regards to a possible decline in the likelihood of re-occurrence of bushfires due to any fire mitigation practices, the transmission outage rate observed over time would decline correspondingly, and would therefore be captured within AEMO's methodology for considering the likelihood of a transmission forced outage rate.

Table 41 Transmission line outage rates

Line	Implementation	2020 FOR	2021 FOR
Liddell – Bulli Creek	Annual rate	NA	1.17%
Dederang – Upper/Lower Tumut	Rgress against weather	NA	0.56%
South Morang – Dederang	Rgress against weather	0.53%	0.26%
Murraylink	Annual rate	NA	0%
Moorabool – Tailem Bend	Annual rate	2.64%	0.05%
Basslink	Annual rate	0.07%	0.02%

FOR = forced outage rate

Due to small sample sizes, all lines will use the average Mean Time to Repair, as observed in the outage history, of seven hours.

As discussed in Section 3.4.3, transmission outages are not included in the ISP modelling given their low probability and the relatively small number of simulations which are undertaken compared to the reliability assessments in the ESOO. The impact of major transmission outages may be tested through additional resilience studies.

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. This includes the continued availability of system services to be able to restore the power system to a secure operating state within 30 minutes following a contingency event. As such, planning studies focus not only on energy and reliability, but also on system services and system security.

New generation and transmission investments may change the scale and location of required services. A changing mix of technologies from synchronous units and new IBR developments create both key challenges and key opportunities for planning the future power system. This is especially so for voltage-related system services such as reactive reserve levels, voltage control, and system strength, which are localised and impacted by changes in local area infrastructure.

The following sections describe the security services AEMO incorporates into its planning assessments.

3.11.1 Power system security services

Input vintage	July 2021
Source	AEMO internal – updated through IASR and <i>ISP Methodology</i> consultation and to remain consistent with the latest power system security information published (including the <i>Engineering Framework</i> , ESOO and TNSP operating advice).
Updates since Draft IASR	<ul style="list-style-type: none"> • Added table to summarise unit commitment assumptions across all regions. • Updated to clarify unit commitment assumptions up to 2025, and that ongoing studies may refine these requirements. • Updated regional tables to include advanced battery energy storage system (BESS) capabilities currently being trialled. • South Australia regional table updated to reflect current system following the commissioning of synchronous condensers. • Tasmania unit commitment requirements updated to include environmental water flow requirements for hydro units.

To operate the power system in a secure and reliable manner, a number of power system security services are required. AEMO's *Power System Requirements* document¹⁶⁰ describes the services in more detail, and the capabilities of various technologies to supply these services.

Some power system requirements may not be monitored across time periods when forecasting economic market dispatch. Therefore, AEMO post-processes market modelling outcomes to assess the capability of the future power system with respect to:

- **System strength** – including fault current and short-circuit ratio.
- **Frequency control** – including inertia, fast frequency control and frequency control ancillary services (i.e. primary and secondary frequency response).
- **Non-credible contingencies** – including the trip of double-circuit interconnectors.

Planning assumptions are applied when developing the ISP, given the uncertainty regarding the future operation of synchronous generating units, emerging technology, and new innovations that enable IBR to provide sought-after system services, demand levels, regulatory change, operational measures, and other emerging security issues.

In terms of unit commitment requirements in each region, an existing set of minimum synchronous unit requirements will initially be modelled by ensuring an appropriate number of units are constrained on at all times. This requirement is then largely removed from 2025 onwards (details are provided in the following sections). This does not reflect that AEMO considers unit commitment will not be required after 2025, but rather that unit commitment is not assumed to be the only solution to deliver these services after 2025. The existing system strength, inertia, and market 2025 frameworks¹⁶¹ are intended to allow for the efficient delivery of these system services through contracting and capital investment.

As the system evolves, and once detailed models are available, comprehensive studies will be required to improve the accuracy of operating requirements and limits advice. Outputs from these ongoing studies, including reviews such as the *Engineering Framework*¹⁶², may be incorporated when available.

Table 42 summarises assumptions for the required unit commitment of large synchronous generating units (e.g. coal or gas-fired generators). These assumptions are further detailed in the following sections.

¹⁶⁰ At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power-system-requirements.pdf?la=en.

¹⁶¹ ESB. Post 2025 Electricity Market Design, at <https://esb-post2025-market-design.aemc.gov.au/>.

¹⁶² AEMO. Engineering Framework, at <https://aemo.com.au/initiatives/major-programs/engineering-framework>.

Table 42 Summary of assumed unit commitment requirements

Region	Condition	Large synchronous generating unit requirement †
New South Wales	Now	≥ 7
	From 2025-26	≥ 0
Queensland	Now	≥ 11
	From 2025-26	≥ 0
South Australia	Now ‡	≥ 2
	After Project EnergyConnect	≥ 0
Tasmania*	Now	≥ 3
	After Marinus Link (if progressed)	≥ 3
Victoria	Now	≥ 5
	From 2025-26	≥ 0

† Numbers shown are high-level planning assumptions only, not operational advice. Comprehensive studies with detailed models will be required closer to these time periods and as the power system evolves.

‡ Synchronous condensers are currently being commissioned in South Australia. Prior to their commissioning, 4 large synchronous generating units are assumed to be required online. 2 large synchronous generating units are assumed to be required online after commissioning is complete.

*These are based on environmental water flow requirements for hydro units.

The tables in the following sections highlight the source of power system services now and into the future for each region. The following notation is used in the tables:

- **Orange outline** indicates the expected primary service provider for the service.
- **Green shading** indicates the services can be provided by the corresponding source.
- **Shaded green** indicating low or partial levels of service can be provided.
- **Numbers** are used to indicate an approximate unit requirement (when multiple sources are required).

New South Wales

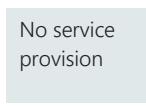
Because the New South Wales power system has multiple large AC interconnectors to other regions, the likelihood of electrical islanding is low. For this reason, it is assumed that inertia and frequency control services can be transferred to New South Wales through the AC interconnectors.

The following table outlines the planning assumptions for the current New South Wales power system.

Table 43 Planning assumptions for the current New South Wales power system

Power System Requirement	Number of required synchronous generating units			IBR	HVDC Inter-connection	AC inter-connection		Synchronous condensers	Demand side response	Distributed PV
	Gas	Coal	Hydro (incl PHES)			Directlink	QNI			
Bulk Energy										
Energy Balance										
Operating Reserve-ramping										
Inertial response and RoCoF										
Primary Frequency Control										
Secondary Frequency Control										
Fast voltage control										
Slow voltage control										
System Strength	≥ 7							Note †		

Notation:



† Generation proponents are already installing synchronous condensers to meet localised system strength needs.

If the number of synchronous generating units online reduces (either for station retirements or operational changes, including mothballing, seasonal operation, or reducing units online), the system strength services currently being provided by those synchronous generating units needs to be replaced by other sources. Proposals to increase interconnection to New South Wales will further reduce the likelihood of requiring local services under islanding conditions.

The following table outlines the planning assumptions for the future New South Wales power system (from 2025-26 onward).

Table 44 Planning assumptions for the future New South Wales power system

Power System Requirement	Number of required synchronous generating units			IBR	HVDC inter-connection	AC inter-connection			Synchronous condensers	Demand side response	Distributed PV	BESS
	Gas	Coal	Hydro (incl. PHES)			Directlink	QNI	VNI				
Bulk Energy												
Energy Balance												
Operating Reserve-ramping												
Inertial response and RoCoF				In trial stage					Note †			In trial stage
Primary Frequency Control												
Secondary Frequency Control												
Fast voltage control												
Slow voltage control												
System Strength												In trial stage

Notation:

Primary service provider	Service provider	Partial service provider	No service provision
--------------------------	------------------	--------------------------	----------------------

† Even though AC interconnectors assist in resolving local inertia requirements, NEM regions cannot all rely on other regions for inertia at the same time. Fitting high inertia flywheels to new synchronous condensers may be able to efficiently maintain the NEM-wide inertia need.

Queensland

Queensland currently has a number of large coal power stations which provide the essential power system requirements. With IBR (utility-scale and DER) increasingly supplying the energy needed, the reliance on thermal synchronous generation for energy and capacity will reduce. AEMO expects this will lead to changes in the commercial operation of the thermal power stations, including decommitments and partial availability of synchronous generating units. The power system services that the synchronous generating units provide will need to be sourced elsewhere if replaced in daily dispatch by cheap energy from IBR to the point where units are decommitted. If too many units are offline in a particular area, system strength issues may begin to arise. Further, when the QNI is at risk of tripping (for example, during maintenance or if a double-circuit trip is declared a credible contingency) local inertia requirements will become increasingly important.

The following table outlines the planning assumptions for the current Queensland power system.

Table 45 Planning assumptions for the current Queensland power system

Power System Requirement	Number of required synchronous generating units			IBR	HVDC inter-connection	AC inter-connection	Demand side response	Distributed PV
	Gas	Coal †	Hydro (incl. PHES)		Directlink			
Bulk Energy								
Energy Balance		≥ 2						
Operating Reserve-ramping		≥ 2						
Inertial response and RoCoF		≥ 2						
Primary Frequency Control		≥ 1						
Secondary Frequency Control		≥ 4						
Fast voltage control								
Slow voltage control								
System Strength	≥ 11							

Notation:

Primary service provider	Service provider	Partial service provider	No service provision
--------------------------	------------------	--------------------------	----------------------

† On the assumption that if a non-credible separation were to become unmanageable without intervention (for example, result in high RoCoF), interconnector constraints or unit commitment, like used for South Australia, may be implemented. System strength requirements are the current dominant requirement. Other requirements are only first pass assumptions based on local contingency sizes and generation capabilities.

If an additional New South Wales to Queensland interconnector is delivered, local inertia requirements are likely to no longer be required in the event of one of the AC interconnectors being out of service. That said, NEM regions cannot all rely on other regions for inertia at the same time, so fitting high-inertia flywheels to new synchronous condensers may be appropriate.

The following table outlines the planning assumptions for the future Queensland power system (from 2025-26 onward).

Table 46 Planning assumptions for the future Queensland power system

Power System Requirement	Number of required synchronous generating units			IBR	HVDC interconnection	AC interconnection	Synchronous condensers	Demand side response	Distributed PV	BESS
	Gas	Coal	Hydro (incl. PHES)		Directlink	QNI				
Bulk Energy										
Energy Balance										
Operating Reserve-ramping										
Inertial response and RoCoF				In trial stage			Note †			In trial stage
Primary Frequency Control										
Secondary Frequency Control										
Fast voltage control										
Slow voltage control										
System Strength										In trial stage

Notation:

- Primary service provider
- Service provider
- Partial service provider
- No service provision

† Even though a second AC interconnector would assist in resolving local inertia requirements, NEM regions cannot all rely on other regions for inertia at the same time. Fitting high inertia flywheels to new synchronous condensers may be able to efficiently maintain the NEM-wide inertia need.

South Australia

The South Australian power system does not currently have any synchronous hydroelectric or coal-fired generators, so currently, a minimum number of GPG units are required online at all times in order to meet all service requirements. For planning studies, this operational requirement is modelled with constraint equations that reflect the impact on the economic dispatch.

ElectraNet is currently in the process of commissioning synchronous condensers (see Section 3.10.3), which are expected to reduce the need for synchronous generation to remain online to approximately two units – noting that during outages, or under certain operational conditions, the need may be higher. To ensure that following a non-credible contingency of the Heywood interconnector¹⁶³ the South Australia region is still able to operate in a secure manner, there will likely be remaining requirements only able to be met by synchronous units until a second AC interconnector is in place.

¹⁶³ A “non-credible” separation event has occurred approximately once every two to three years since NEM start. With Project Energy Connect, the separation risk would be reduced.

Consistent with ElectraNet's economic evaluation¹⁶⁴ that was used to justify the synchronous condensers, AEMO assumes that two large generating units will be required to remain online following the commissioning of synchronous condensers, and that this requirement is removed following the commissioning of Project EnergyConnect (see Section 3.10.4).

The following table outlines the planning assumptions for the current South Australian power system (after the commissioning of four large synchronous condensers).

Table 47 Planning assumptions for the current South Australia power system

Power System Requirement	Number of required Synchronous generating units (Gas)	IBR	HVDC interconnection (Murraylink)	AC interconnection (Heywood)	Synchronous condensers	Demand side response	Distributed PV	BESS
Bulk Energy								
Energy Balance	≥ 2							
Operating Reserve-ramping	≥ 2							
Inertial response and RoCoF					Note †			Note ‡
Primary Frequency Control	≥ 1							
Secondary Frequency Control	≥ 2							
Fast voltage control								
Slow voltage control								
System Strength								

Notation:

- Primary service provider
- Service provider
- Partial service provider
- No service provision

† RoCoF risk is currently managed with a 3 Hz/s RoCoF constraint on the Heywood interconnector.

‡ Fast Frequency Response is currently utilised to reduce synchronous inertia requirements

With Project EnergyConnect and the four large ElectraNet synchronous condensers in place, for the ISP modelling, AEMO assumes there is no longer a minimum requirement for synchronous generating units to always remain online, even when considering a non-credible trip of one of the AC interconnectors.

The following table outlines the planning assumptions for the future South Australian power system after Project EnergyConnect is commissioned.

¹⁶⁴ ElectraNet. Addressing the system strength gap in SA – Economic evaluation report (see section 5.1), at <https://www.aer.gov.au/system/files/ElectraNet%20-%20System%20Strength%20Economic%20Evaluation%20Report%20-%202018%20February%202018.PDF>.

Table 48 Planning assumptions for the future South Australia power system

Power System Requirement	Number of required Synchronous generating units	IBR	HVDC inter-connection	AC inter-connection		Synchronous condensers	Demand side response	DPV	BESS
				Murraylink	VIC-SA				
Bulk Energy									
Energy Balance									
Operating Reserve-ramping									
Inertial response and RoCoF		In trial stage							In trial stage
Primary Frequency Control									
Secondary Frequency Control									
Fast voltage control									
Slow voltage control									
System Strength									In trial stage

Notation:

Primary service provider

Service provider

Partial service provider

No service provision

Tasmania

Tasmania's generation has historically been predominantly hydro-based, and Tasmania has historically relied on this synchronous generation to provide the bulk of Tasmania's needs for power system services, when generating.

A key requirement in Tasmania is services to cater for the credible trip of the Basslink interconnector, as with this single contingency Tasmania continues to be exposed to islanding.

As more IBR connects to the system, hydroelectric units may be needed to be placed into synchronous condenser mode in order to continue to supply voltage control, inertia, and system strength services.

Due to the large number of small distributed hydroelectric generators, Tasmania does not have a strict minimum number of units required to be online, but instead has a large number of combinations that can be utilised. No manual constraints are applied within market modelling to achieve this because operation of synchronous condensers when needed does not materially influence the energy market outcomes.

The following table outlines the planning assumptions for the current Tasmania power system.

Table 49 Planning assumptions for the current Tasmania power system

Power System Requirement	Synchronous generating units		IBR	HVDC interconnection	Synchronous condensers ‡	Demand side response	Distributed PV
	Gas	Hydro		Basslink			
Bulk Energy							
Energy Balance		≥ 2					
Operating Reserve-ramping		≥ 2					
Inertial response and RoCoF							
Primary Frequency Control		≥ 1					
Secondary Frequency Control		≥ 2		Note †			
Fast voltage control							
Slow voltage control							
System Strength							

Notation:

- Primary service provider
- Service provider
- Partial service provider
- No service provision

† Noting Basslink has a Frequency Controller that enables transfer of FCAS.

‡ A number of hydro generating units can be placed into synchronous condenser mode in the Tasmanian region.

If completed, the proposed Marinus Link project (see Section 3.10.5) will relax the reliance on hydro generation for all the services. Services are predominantly expected to be met with hydro generation (generating, pumping, or synchronous condenser mode), or via one of the HVDC links.

The following table outlines the planning assumptions for the future Tasmania power system (if Marinus Link is commissioned). If Marinus Link does not proceed, or is delayed, AEMO assumes the existing requirements in Tasmania will continue.

Table 50 Planning assumptions for the future Tasmania power system, if Marinus Link proceeds

Power System Requirement	Synchronous generating units		IBR	HVDC inter-connection		Synchronous condensers	Demand side response	Distributed PV	BESS
	Gas	Hydro (incl. PHES)		Basslink	Project Marinus				
Bulk Energy									
Energy Balance									
Operating Reserve-ramping									
Inertial response and RoCoF			In trial stage						In trial stage
Primary Frequency Control		≥ 1							
Secondary Frequency Control									
Fast voltage control									
Slow voltage control									
System Strength									In trial stage

Notation:

Primary service provider	Service provider	Partial service provider	No service provision
--------------------------	------------------	--------------------------	----------------------

Victoria

Due to the Victorian region already having two AC interconnectors, the likelihood of islanding is low, resulting in the ability for inertia and frequency control services to be met by the interconnectors.

As IBR penetration increases, the number of large coal units online is reducing and encroaching on the system strength limits. Within the market modelling there are not any manual constraints to enforce provision of these system services as the required plant is dispatched for the energy market outcomes.

In future years as coal retires, system strength shortfalls may be declared to ensure delivery of the service.

The following table outlines the planning assumptions for the current Victoria power system.

Table 51 Planning assumptions for the current Victoria power system

Power System Requirement	Synchronous generating units			IBR	HVDC inter-connection		AC inter-connection		Synchronous condensers	Demand side response	Distributed PV	BESS
	Gas	Coal	Hydro		Murray Link	Basslink	VIC-SA	VNI				
Bulk Energy												
Energy Balance												
Operating Reserve-ramping												
Inertial response and RoCoF												
Primary Frequency Control												
Secondary Frequency Control												
Fast voltage control												
Slow voltage control												
System Strength		≥ 5								Note †		

Notation:

Primary service provider

Service provider

Partial service provider

No service provision

† Generation proponents are already installing synchronous condensers to meet localised system strength needs.

As coal-fired generation retires, the system strength services currently being provided will need to be replaced by other sources including synchronous condensers or from additional pumped hydro generation. Any increase in interconnection to Victoria will even further reduce the likelihood of requiring local services under islanding conditions.

The following table outlines the planning assumptions for the future Victorian power system (from 2025-26 onward).

Table 52 Planning assumptions for the future Victoria power system



Note: Marinus Link and VNI West are augmentation options in the ISP. While their development would change the assumed power system needs in Victoria, the timing and/or need for these augmentations will be evaluated by the ISP.

3.11.2 System strength

Input vintage	December 2020
Source	AEMO – 2020 System Strength and Inertia Report
Updates since Draft IASR	References to the published 2020 System Strength and Inertia Report added. No change to requirement numbers previously published in the Draft IASR.

Key areas of system strength (discussed in AEMO's white paper *System Strength Explained*¹⁶⁵) include steady state voltage management, voltage dips, fault ride-through, power quality, and operation of protection. The increasing integration of IBR across the NEM has implications for the engineering design of the future power

¹⁶⁵ At <https://aemo.com.au/-/media/files/electricity/nem/system-strength-explained.pdf>.

system. Under the current system strength framework, generators will need to offset their impact on system strength, and TNSPs will need to ensure a basic level of fault current across their networks.

AEMO's incorporation of system strength costs (see the *2021 Transmission Cost Report*¹⁶⁶) does not consider which party will ultimately pay for system strength remediation (TNSP or generation proponent). The costs have been modelled in this way to ensure system strength remediation costs (assumed to be \$106/kW – see Section 3.9.4) are appropriately captured. AEMO notes that there is a rule change underway¹⁶⁷ which makes changes to the existing system strength framework. AEMO intends to model system strength requirements against the current framework, and will use reasonable endeavours to incorporate any transitional arrangements that apply to the 2022 ISP.

Fault level requirements

AEMO is required to determine the fault level requirements across the NEM and identify whether a fault level shortfall is likely to exist now or in the future. The *System Strength Requirements Methodology*¹⁶⁸ defines the process AEMO must apply to determine the system strength requirement at each node. Updates are made to the requirements periodically and published on AEMO's website¹⁶⁹.

Shortfall declarations are not an outcome of the ISP process, but are an outcome from the separate annual *System Strength and Inertia Report* which may draw from ISP projections. Table 53 lists the current fault level nodes and requirements. AEMO will use reasonable endeavours to use updated fault level requirements if they change.

Table 53 Minimum three phase fault levels for 2020

Region	Fault level node	2020 minimum three phase fault level (MVA)	
		Pre-contingency	Post-contingency
New South Wales	Armidale 330 kV	3,300	2,800
	Darlington Point 330 kV	1,500	600
	Newcastle 330 kV	8,150	7,100
	Sydney West 330 kV	8,450	8,050
	Wellington 330 kV	2,900	1,800
Queensland	Greenbank 275 kV	4,350	3,750
	Gin Gin 275 kV	2,800	2,250
	Lilyvale 132 kV	1,400	1,150
	Ross 275 kV	1,350	1,175
	Western Downs 275 kV	4,000	2,550

¹⁶⁶ At <https://aemo.com.au/consultations/current-and-closed-consultations/transmission-costs-for-the-2022-integrated-system-plan>.

¹⁶⁷ AEMC, *Efficient Management of System Strength on the Power System*, available at <https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system>.

¹⁶⁸ See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/%E2%80%8C_System_Strength_Requirements_Methodology_PUBLISHED.pdf.

¹⁶⁹ See <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability>.

Region	Fault level node	2020 minimum three phase fault level (MVA)	
		Pre-contingency	Post-contingency
South Australia	Davenport 275 kV	2,400	1,800
	Para 275 kV	2,250	2,000
	Robertstown 275 kV	2,550	2,000
Tasmania	Burnie 110 kV	850	560
	George Town 220 kV	1,450	1,450
	Risdon 110 kV	1,330	1,330
	Waddamana 220 kV	1,400	1,400
Victoria	Dederang 220 kV	3,500	3,300
	Hazelwood 500 kV	7,700	7,150
	Moorabool 220 kV	4,600	4,050
	Red Cliffs 220 kV	1,700	1,000
	Thomastown 220 kV	4,700	4,500

3.11.3 Inertia

Input vintage	December 2020
Source	AEMO – 2020 System Strength and Inertia Report
Updates since Draft IASR	References to the published 2020 System Strength and Inertia Report added. No change to the inertia requirements that were published in the Draft IASR.

Maintaining an appropriate level of synchronous inertia, or its equivalent, is crucial for ensuring overall power system security. AEMO is required under the NER to calculate (in accordance with the published methodology) and publish the satisfactory and secure requirements for synchronous inertia for each NEM region when it is islanded. These are outlined in AEMO's *Inertia Requirements Methodology* and individual updates found on AEMOs website¹⁷⁰. Shortfall declarations are not an outcome of the ISP process, but are an outcome from the separate annual *System Strength and Inertia Report*.

The following table lists the current inertia requirements for the NEM. AEMO will use reasonable endeavours to use updated inertia requirements if they change.

¹⁷⁰ At <https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability>.

Table 54 Inertia requirements for 2020

Region	2020 inertia requirements	
	Secure (MWs)	Minimum (MWs)
Queensland	14,800	11,900
Victoria	13,900	9,500
New South Wales	12,500	10,000
South Australia	Combination of synchronous inertia and fast frequency response	4,400
Tasmania	3,800	3,200

3.11.4 Other system security settings

Input vintage	July 2021
Source	AEMO Internal and TNSP limits advice.
Updates since Draft IASR	AEMO draws on the latest information from TNSP limits advice and the corresponding constraint equation information in AEMOs market management system.

In NEMDE, a series of network constraint equations control dispatch solutions to ensure that intra-regional network limitations are accounted for. The time-sequential model used in reliability assessments and long-term planning studies contains a subset of the NEMDE network constraint equations to achieve the same purpose. This subset of network constraint equations reflects power system operation within security limits. 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 anticipated and committed transmission and generation projects on the network is implemented as modifications to the network constraint equations that control flow. The methodology for formulating these constraints is in AEMO's Constraint Formulation Guidelines¹⁷¹.

¹⁷¹ At <https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource>.

3.12 Hydrogen infrastructure

Input vintage	July 2021
Source	<ul style="list-style-type: none"> AEMO engaged with stakeholders in a Hydrogen Workshop in September 2020 to assist in defining the hydrogen assumptions for the Hydrogen Superpower scenario. CSIRO/ClimateWorks multi-sector modelling.
Updates since Draft IASR	Hydrogen price assumptions updated to align with assumptions in the multi-sectoral modelling conducted by CSIRO and ClimateWorks. FRG September 2020, FRG May 2021, and FRG June 2021.

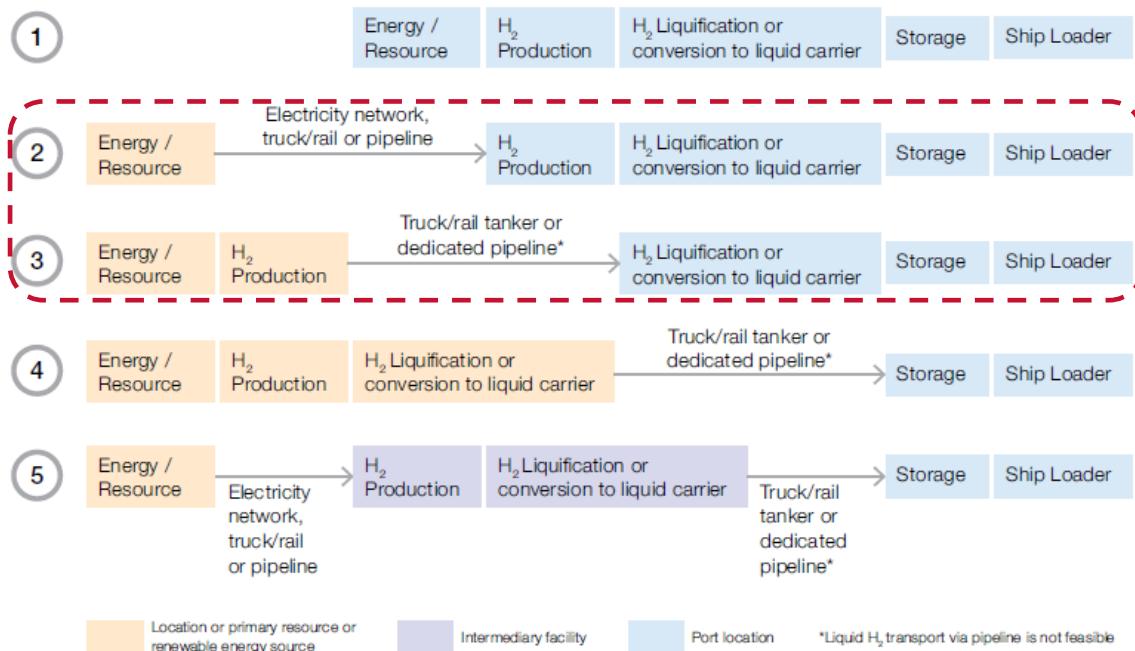
This section outlines key inputs and assumptions related to infrastructure needs of relevance to the Hydrogen Superpower scenario, where potential for development of hydrogen GPG and export production locations are explored within ISP modelling.

Hydrogen consumption and production assumed across scenarios is discussed in Section 3.3.14.

3.12.1 Hydrogen infrastructure needs

ARUP's Australian Hydrogen Hubs report to the COAG Energy Council identified the potential hydrogen export pathways¹⁷² in Figure 54. A hydrogen export pathway describes the supply chain from the energy source to the export location and includes the method and form of energy transport; the location of the electrolyzers; and the location of the hydrogen liquefaction or conversion facilities. Figure 54 highlights those that are applied in AEMO's current forecasting and planning approach.

Figure 54 Hydrogen export pathways



Source: Arup, 2019, Australian Hydrogen Hubs Study

In the 2022 ISP Hydrogen Superpower scenario, AEMO will consider infrastructure developments that are designed around the principles of pathway 2, which transports the energy for hydrogen production via electrical transmission lines. For export purposes, pathway 2 in Figure 54 has limited inherent storage, since

¹⁷² At <http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/nhs-australian-hydrogen-hubs-study-report-2019.pdf>.

the hydrogen is generated close to the port, with minimal pipeline needed. AEMO therefore assumes that sufficient on-site/local storage is included in the hydrogen production facilities near hydrogen export ports. Pathway 3 may be explored in future ISPs.

Electrolyser location

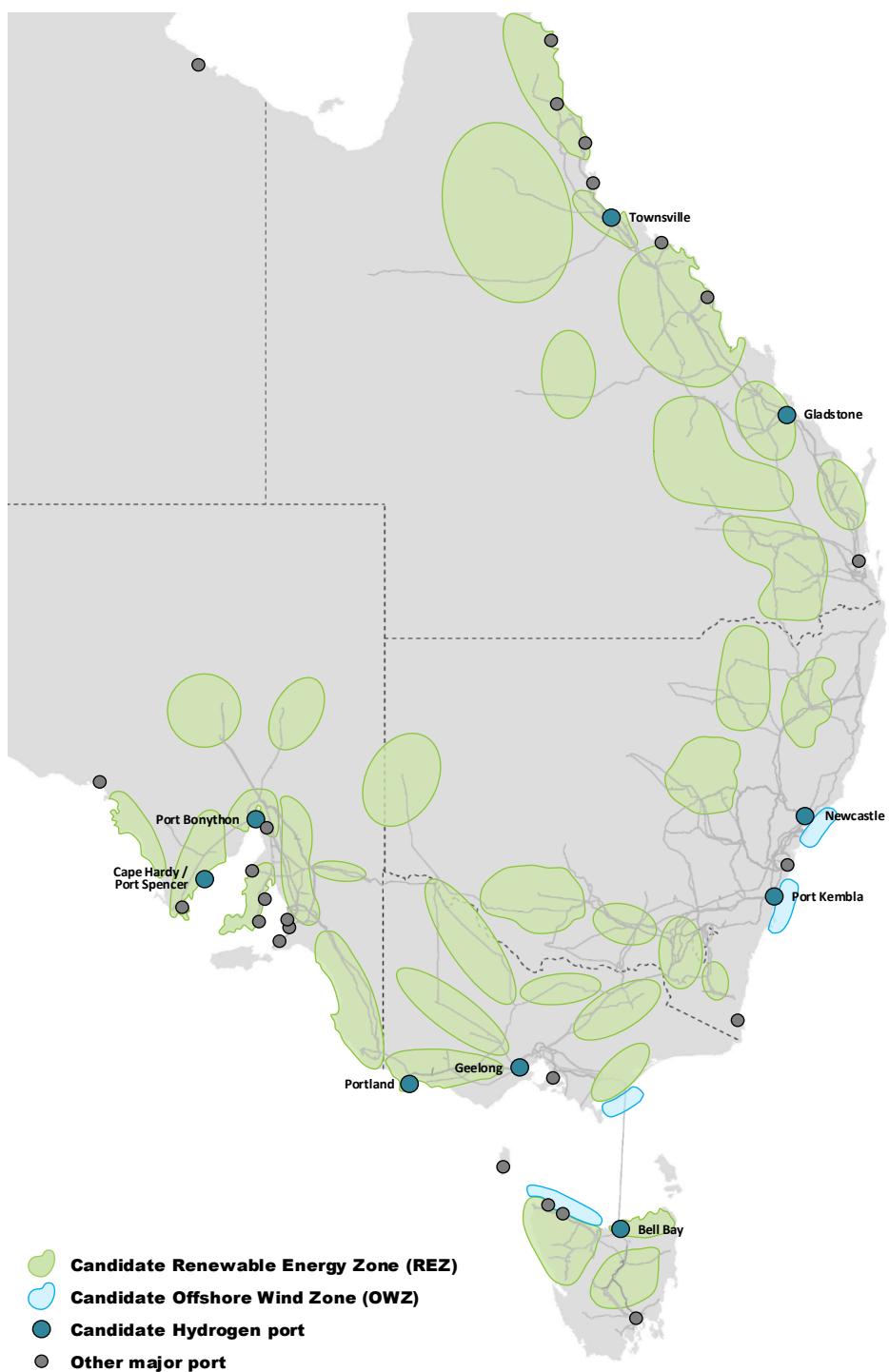
Hydrogen export ports were selected from 30 hydrogen hubs identified in ARUP's Australian Hydrogen Hubs report to the COAG Energy Council¹⁷³. The following table outlines nine candidate hydrogen export ports (shown geographically in Figure 55) that provides a geographic spread with access to REZ and port infrastructure. These nine candidate ports will be considered as options in the Hydrogen Superpower scenario ISP modelling.

Table 55 Candidate hydrogen export ports

NEM region	Potential port location
New South Wales	Newcastle, Port Kembla
Queensland	Gladstone, Townsville
South Australia	Port Bonython, Cape Hardy/Port Spencer
Tasmania	Bell Bay
Victoria	Geelong, Portland

¹⁷³ At <http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/nhs-australian-hydrogen-hubs-study-report-2019.pdf>.

Figure 55 Candidate hydrogen export ports



Water supply

For the 2022 ISP, water availability is not assumed to be a significant limitation to siting options since all sites are assumed to be coastal, and is not a costed component of electrolyser operation. Some export ports may require desalination or further analysis in subsequent work to validate the availability of water resources.

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A2. Supporting material

In addition to the IASR Assumptions Book and Consultation Report, Table 56 documents additional information related to AEMO's inputs and assumptions.

Table 56 Additional information and data sources

Organisation	Document/source	Influencing	Link
ACIL Allen	2014 Fuel and Technology Cost Review	Generation costs and technical performance	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/ntndp/2014/data-sources/fuel_and_technology_cost_review_report_acil_allen.pdf
AEMO	Generation Information	Generation availability	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information
AEMO	Transmission Cost Database	Transmission costs	https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios
AEMO	Transmission Cost Database Output Files	Transmission costs	https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios
AEMO	2021 Transmission Cost Report	Transmission costs	https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios
AEMO	2020 GSOO Stakeholder Surveys and gas supply input data	Gas demand, supply and production	https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2020/2020-gsoo-supply-input-data-files.zip?la=en
AEP Elical	2020 Assessment of Ageing Coal-Fired Generation Reliability	Generation technical performance	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/aep-eical-assessment-of-ageing-coal-fired-generation-reliability.pdf?la=en
Aurecon	2020-21 Cost and Technical Parameter Review	Generation costs and technical performance	Report: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/Aurecon-Cost-and-Technical-Parameters-Review-2020.pdf Workbook: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/Aurecon-Cost-and-Technical-Parameters-Review-2020-workbook.xlsb
BIS Oxford Economics	2021 Macroeconomic Projections Report: Final	Electricity demand forecasts	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/bis-oxford-economics-macroeconomic-projections.pdf?la=en
CSIRO	GenCost 2020-21 Final Report	Generation costs	https://www.csiro.au/-/media/EF/Files/GenCost2020-21_Final_Report.pdf ; https://data.csiro.au/collections/collection_Cicsiro:44228v2/Dltrue

Organisation	Document/source	Influencing	Link
CSIRO	Projections for small-scale embedded technologies	Electricity demand forecasts	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/csiro-der-forecast-report.pdf?la=en
CSIRO	Electric Vehicle Projections 2021	Electricity demand forecasts	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/csiro-ev-forecast-report.pdf
CSIRO	Multi-sector energy modelling	Carbon budgets and electricity demand forecasts	https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-ispl/2022-integrated-system-plan-ispl/current-inputs-assumptions-and-scenarios
Entura	Pumped Hydro cost modelling	Generation availability	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Report-Pumped-Hydro-Cost-Modelling.pdf
GHD	2018-19 AEMO Costs and Technical Parameter Review	Generation costs and technical performance	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/9110715-rep-a-cost-and-technical-parameter-review---rev-4-final.pdf?la=en&hash=AFEFC07973CE5E2244A0FC0FF8773AA8
GHD	2018-19 AEMO Costs and Technical Parameter Review - databook	Generation costs and technical performance	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/ghd-aemo-revised---2018-19-costs_and_technical_parameter.xlsb?la=en&hash=B4BE15FE1B665E5B63F691E22A6916FB
GHD	Transmission Cost Database – User Manual	Transmission costs	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2021/transmission-costs-for-2022-ispl/transmission-cost-database-user-manual.pdf?la=en
GHD	Transmission Cost Database – GHD Report	Transmission costs	https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2021/transmission-costs-for-2022-ispl/transmission-cost-database-ghd-report.pdf?la=en
Green Energy Markets	Projections for DER – solar PV and stationary energy battery systems	Electricity demand forecasts	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/green-energy-markets-der-forecast-report.pdf?la=en
Lewis Grey Advisory	Lewis Grey Advisory Fuel Prices	Fuel prices	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/gas-price-projections-for-the-2021-gsoo-public-final-13-12-20.pdf?la=en
MBB Group	Transmission Cost Database Phase 1 Report	Transmission costs	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/Transmission-Cost-Database-Phase-1-Report.pdf
Powerlink Queensland	Preparatory Activities – CSQ Transmission Link	Transmission costs	https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-ispl/2022-integrated-system-plan-ispl/current-inputs-assumptions-and-scenarios
Powerlink Queensland	Preparatory Activities – Gladstone Grid Reinforcement	Transmission costs	https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-ispl/2022-integrated-system-plan-ispl/current-inputs-assumptions-and-scenarios
Powerlink Queensland	Preparatory Activities – QNI Medium and Large	Transmission costs	https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-ispl/2022-integrated-system-plan-ispl/current-inputs-assumptions-and-scenarios

Organisation	Document/source	Influencing	Link
Strategy Policy Research	Strategy Policy Research: Energy Efficiency Forecasts 2021 – Final Report	Electricity demand forecasts	https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-ispl/2022-integrated-system-plan-ispl/current-inputs-assumptions-and-scenarios
Synergies Economic Consulting	Discount rates for use in cost benefit analysis of AEMO's 2022 ISP	Discount rate	https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-ispl/2022-integrated-system-plan-ispl/current-inputs-assumptions-and-scenarios
Wood Mackenzie	Wood Mackenzie Coal Prices	Fuel prices	https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-ispl/2022-integrated-system-plan-ispl/current-inputs-assumptions-and-scenarios