2020 Inputs, Assumptions and Scenarios Report

August 2020

For use in the 2020 Electricity Statement of Opportunities for the National Electricity Market, and 2021 Gas Statement of Opportunities for eastern and south-eastern Australia.

Important notice

PURPOSE

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) in 2020.

This publication has been prepared by AEMO using information available at 1 July 2020. Information made available after this date may have been included in this publication where practical.

DISCLAIMER

AEMO has made every reasonable effort to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances. This publication does not include all of the information that an investor, participant or potential participant in the National Electricity Market might require, and does not amount to a recommendation of any investment.

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VERSION CONTROL

Version	Release date	Changes
1	27/8/2020	Initial release
2	31/8/2020	Clarifications to footnote Table 11 and caption Figure 27

Executive summary

AEMO delivers a range of forecasting and planning publications for the National Electricity Market (NEM), including the NEM Electricity Statement of Opportunities (ESOO), the Gas Statement of Opportunities (GSOO), and the Integrated System Plan (ISP). This Inputs, Assumptions and Scenarios Report (IASR) contains descriptions of the 2020 scenarios, inputs, and assumptions which have been used in the 2020 ESOO and are proposed for use in other AEMO NEM forecasting and planning publications in 2020-21, unless otherwise stated in those publications.

2020 NEM forecasting and planning consultation

The inputs and assumptions presented in this report have benefited from extensive stakeholder consultation. AEMO published its 2020 Forecasting inputs and assumptions consultation paper in December 2019, inviting written submissions by February 2020. AEMO received and published 20 submissions from industry, academia and individuals and has considered this feedback in refining the inputs and assumptions documented in this IASR[1].

AEMO endeavours to source input data and assumptions from the most recent and accurate sources of information reasonably available. This inevitably means some inputs need to be refreshed after the formal consultation process has completed. To validate these updated inputs, AEMO solicits stakeholder feedback at workshops and forums, including the Forecasting Reference Group (FRG), as outlined in its Interim Reliability Forecast Guidelines.

Scenario development is performed every two years, in accordance with the development of the ISP. For this 2020 IASR, AEMO has continued to apply the themes of the five core scenarios developed in 2019, although refinements to policy settings and/or the magnitude of individual drivers have been applied in some cases.

2019-2020 forecasting and planning scenarios

The use of scenario planning is an effective approach to manage investment and business risks when planning in a highly uncertain environment, particularly through disruptive transitions. Defining and applying scenarios is a critical aspect of forecasting, providing the information needed to assess 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.

The five scenarios currently in use for AEMO's forecasting and planning purposes provide a suitably wide range of possible industry outcomes, differing with respect to the growth in grid-scale renewable generation resources, the uptake of distributed energy resources, and the level and breadth of decarbonisation policies (see Figure 1):

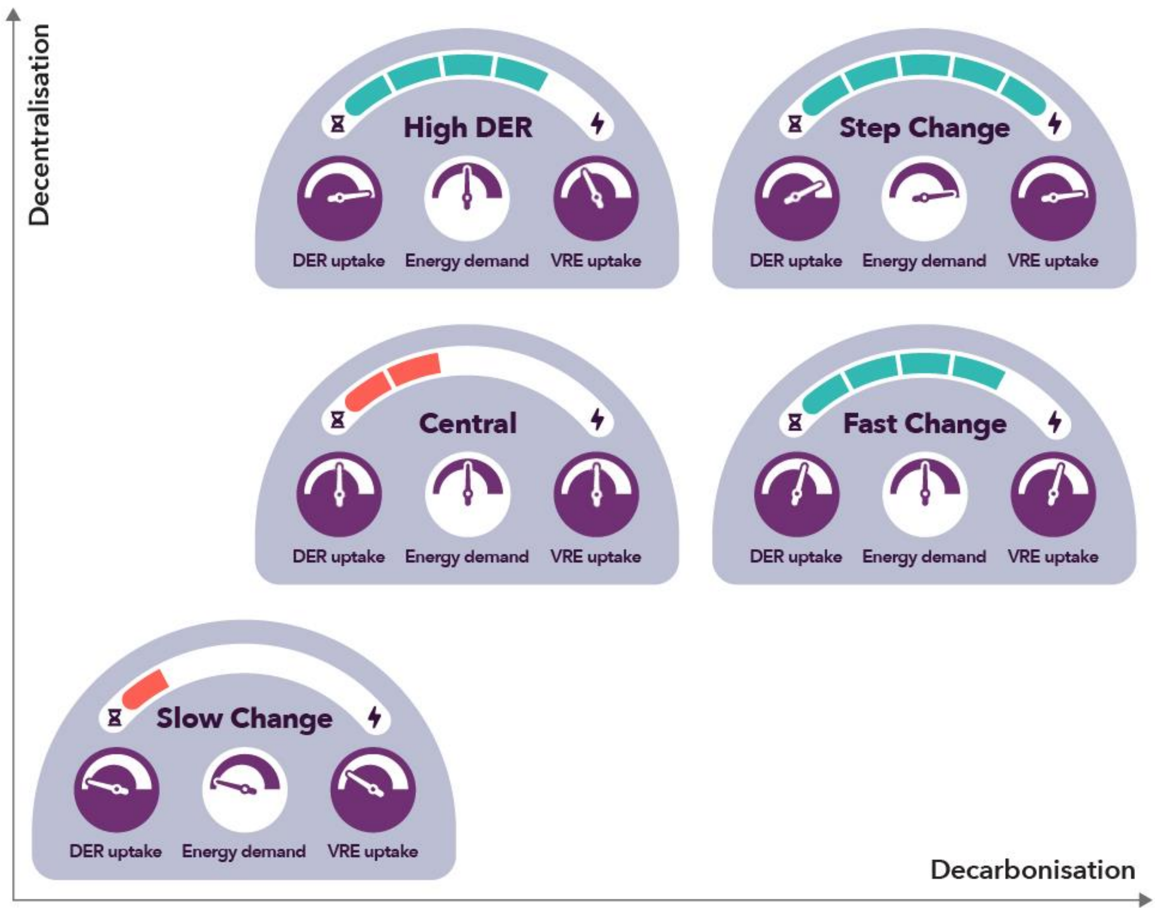
- The ***Central scenario*** reflects the **current transition of the energy industry** under current policy settings and technology trajectories, where the transition from fossil fuels to renewable generation is generally led by market forces and supported by current federal and state government policies[2].

[1] For consultation paper and submissions, see https://aemo.com.au/consultations/current-and-closed-consultations/2020-planning-and-forecasting-consultation-on-scenarios-inputs-and-assumptions/.

[2] Includes existing Federal emissions reduction policy to reduce Australia's emissions by 26% by 2030 economy wide, state renewable energy targets, pumped hydro initiatives (Snowy 2.0 and Battery of the Nation), and various policies affecting the scale and timing of energy efficiency adoption and DER penetration. Section 2.3 provides more detail.

- The ***Slow Change*** scenario reflects a **general slow-down of the energy transition**. It is characterised by slower advancements in technology and reductions in technology costs, low population growth, and low political, commercial, and consumer motivation to make the upfront investments required for significant emissions reduction.
- The ***High DER*** scenario reflects a more **rapid consumer-led transformation** of the energy sector, relative to the Central scenario. It represents a highly digital world where technology companies increase the pace of innovation in easy-to-use, highly interactive, engaging technologies. This scenario includes reduced costs and increased adoption of distributed energy resources (DER), with automation becoming commonplace, enabling consumers to actively control and manage their energy costs while existing generators experience an accelerated exit. It is also characterised by widespread electrification of the transport sector.
- The ***Fast Change*** scenario reflects a **rapid technology-led transition**, particularly at grid scale, where advancements in large-scale technology improvements and targeted policy support reduce the economic barriers of the energy transition. This includes coordinated national and international action towards achieving emissions reductions, leading to manufacturing advancements, automation, accelerated exit of existing generators, and integration of transport into the energy sector.
- The ***Step Change*** scenario reflects **strong action on climate change** that leads to a step change reduction of greenhouse gas emissions. In this scenario, aggressive global decarbonisation leads to faster **technological improvements**, accelerated exit of existing generators, greater electrification of the transport sector with increased infrastructure developments, energy digitalisation, and **consumer-led innovation**.

Figure 1 Comparative rates of decarbonisation and decentralisation across the five scenarios to be used in AEMO's 2019-20 and 2020-21 forecasting and planning publications



2020 inputs and assumptions

For each of these scenarios, this report describes key inputs and assumptions in relation to:

- Components for forecasting energy consumption, including DER uptake, energy efficiency forecasts and demand side participation (DSP).
- Key policy settings affecting the NEM.
- Technical and economic settings affecting energy supply.
- Existing and new generator assumptions.
- Transmission modelling.
- Renewable energy zones (REZs).
- Gas modelling.

Further information on inputs and assumptions, as well as the methodologies used in AEMO's forecasting and planning publications, can be found in AEMO's scenarios, inputs and assumptions, and forecasting methodologies and guidelines web pages[3].

[3] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines/forecasting-and-planning-guidelines.

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1. Introduction

AEMO produces several publications that inform the decision support function for stakeholders, and are coordinated and integrated in AEMO's modelling to provide its forecasting and planning advice, including:

- **Electricity Statement of Opportunities (ESOO)** – provides operational and economic information about the National Electricity Market (NEM) over a 10-year outlook period, with focus on electricity supply reliability. The ESOO includes a reliability forecast identifying any potential reliability gaps in the coming five years, as defined according to the Retailer Reliability Obligation (RRO)[4]. The final five years of the 10-year ESOO forecast provide an indicative forecast of any future material reliability gaps. It also includes 20-year forecasts of annual consumption, maximum demand and demand side participation (DSP). It is published annually, with updates if required.
- **Gas Statement of Opportunities (GSOO)** – provides AEMO's forecasts of annual gas consumption and maximum gas demand, and uses information from gas producers about reserves and forecast production, to project the supply-demand balance and potential supply gaps over a 20-year outlook period. It is published annually, with updates if required.
- **Integrated System Plan (ISP)** – is a whole-of-system plan that efficiently achieves the power system needs of a transforming energy system in the long-term interests of consumers. It serves the regulatory purpose of identifying actionable and future ISP projects, as well as the broader purposes of informing market participants, investors, policy decision makers and consumers. It provides a transparent, dynamic roadmap over a planning horizon of at least the next two decades, optimising net market benefits while managing the risks associated with change. AEMO published the inaugural ISP for the NEM in 2018, and the first under the actionable ISP rules framework in July 2020. It is published every two years. This 2020 IASR was not applicable for the 2020 ISP, nor will it be applicable for the 2022 ISP, but is relevant for any forecasting and planning publications between ISP years.

Many uncertainties face the energy sector:

- The role of consumers in the energy market is evolving as distributed energy resources (DER), new technological innovations, and customer behaviours change.
- Other industries, such as the transportation sector, are increasingly electrifying their energy supplies and are thus having a direct impact on the energy sector.
- Existing supply sources, particularly thermal generators, are ageing and approaching the end of their technical lives. These resources must be replaced to maintain a reliable and secure power system that meets consumer demand at an affordable cost as well as achieving public policy requirements.

AEMO uses a scenario analysis approach to investigate the direction and magnitude of shifts impacting the energy sector, and the economically efficient level of infrastructure necessary to support the future energy needs of consumers.

This 2020-21 version of the Inputs, Assumptions and Scenarios Report (IASR) outlines the scenarios modelled by AEMO across its forecasting and planning publications. It also describes key inputs and assumptions used in AEMO's modelling (unless otherwise stated in the publication).

It is complemented by AEMO's:

[4] The RRO came into effect on 1 July 2019. For more information, see http://www.coagenergycouncil.gov.au/publications/retailer-reliability-obligation-rules.

- 2020-21 Inputs and Assumptions Workbook[5], which provides detail of all modelling inputs used by AEMO that affect supply and demand of electricity in the NEM, and includes detailed collections of inputs and assumptions used for each of the scenarios.
- Forecasting Approach[6], which outlines a collection of methodologies including AEMO's methods for assessing the reliability forecast and ISP.

1.1 Consultation on key forecasting inputs in 2020

AEMO's 2020-21 forecasting and planning publications utilise the scenarios that were extensively consulted on in preparation of the 2020 ISP. The inputs and assumptions have been updated based on the latest market trends and information. In updating these inputs and assumptions, views have been sought from a broad collection of stakeholders through written submissions, in-person discussions, and Forecasting Reference Group (FRG) meetings.

1.1.1 Regulatory requirements for consultation on inputs and assumptions

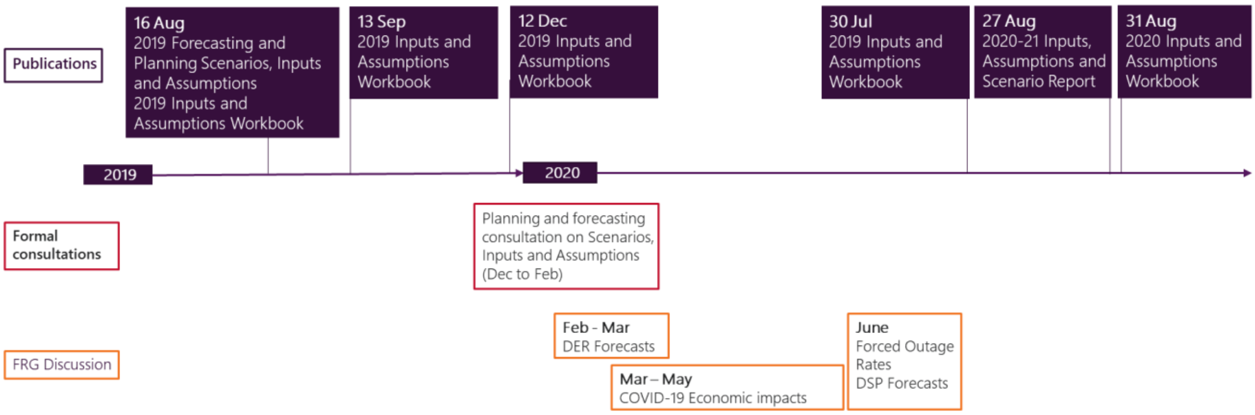
The methodologies, assumptions and inputs that underpin AEMO's forecasting processes must be transparent, disclosed to stakeholders, and developed and prepared in accordance with the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines (FBPG) and the Forecasting Best Practice Consultation Procedures[7].

AEMO established (and consulted on) the Interim reliability forecast guidelines in 2019. These guidelines set out how AEMO updates its inputs for the reliability forecast within the 2020 ESOO. In accordance with the AER's Interim FBPG[8] and the Interim reliability forecast guidelines, AEMO consulted on its key inputs that apply across AEMO's forecasting and planning publications (including, but not limited to those used in developing its reliability forecast). This IASR consultation process is outlined in the following sections.

1.1.2 Key engagement milestones

Figure 2 below shows key engagement milestones[9] of the IASR consultation. The process commenced with the adoption of the Central, Slow Change, and Step Change scenarios from the 2020 ISP, which were published in August 2019 following the ISP stakeholder consultation from February 2019.

Figure 2 Consultation milestones for 2020 inputs and assumptions



[5] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Input-and-Assumptions-workbook.xlsx.

[6] 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.

[7] At https://www.aer.gov.au/retail-markets/retail-guidelines-reviews/retailer-reliability-obligation-interim-forecasting-best-practice-guideline.

[8] The AER published its final Forecasting Best Practice Guidelines on 25 August 2020. The inputs and assumptions in this 2020 IASR have been developed following the principles outlined in the Interim FBPG.

[9] DSP – Demand Side Participation.

AEMO considered stakeholder engagement and standing information requests early in the IASR process, through discussions in the November 2019 FRG meeting.

From December 2019 to February 2020, AEMO ran a formal consultation on key forecasting inputs[10], which included assumptions and data sources. Where it was too early to update the inputs to be used in reliability forecasts, feedback was sought on the appropriateness of the previous year's assumptions and modifications that should be considered for use in 2020 forecasts.

AEMO gratefully acknowledges the valuable contributions from all stakeholders in this process.

AEMO received 21 written submissions in response to the IASR consultation, conducted between December 2019 and February 2020. Appendix A1 summarises the submissions and AEMO's responses to them.

The Interim FBPG recognises that to ensure forecasts are current, whenever data, policies or assumptions change, AEMO should have the flexibility to incorporate these to ensure accurate forecasts. Where inputs have dependencies and need to be updated over time to avoid data latency issues, and consistent with the approach outlined in AEMO's interim Reliability Forecast Guidelines, AEMO used the FRG to present updates and receive feedback on any data or forecast updates that occurred outside of the formal IASR consultation process. Appendix A2 summarises the FRG topics presented and discussed at its monthly meetings. Presentations and minutes of these meetings are accessible from the FRG webpage[11].

1.2 Supplementary material

AEMO has published an Inputs and Assumptions Workbook to provide more detail and complement this report. Table 1 provides links to additional information related to AEMO's forecasting and planning inputs and assumptions that supplements this report.

Table 1 Additional information and data sources

Information source	Website address and link
Generation Information web page	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information
BIS Oxford Economics, 2020 Macroeconomic forecasts	**Primary forecasts:** https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/bis-oxford-economics-macroeconomic-projections.pdf?la=en **COVID-19 update:** https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/bis-oxford-economics-macroeconomic-central-scenario-and-downside-scenario-forecast.pdf?la=en
CSIRO, 2020 projections for small-scale embedded technologies	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/csiro-der-forecast-report.pdf?la=en
Green Energy Markets, 2020 projections for distributed energy resources	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/green-energy-markets-der-forecast-report.pdf?la=en
AEP Elical - Assessment of Ageing Coal-Fired Generation Reliability	http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

10 At https://aemo.com.au/consultations/current-and-closed-consultations/2020-planning-and-forecasting-consultation-on-scenarios-inputs-and-assumptions.

11 At https://aemo.com.au/en/consultations/industry-forums-and-working-groups/list-of-industry-forums-and-working-groups/forecasting-reference-group-frg.

Information source	Website address and link
CSIRO, GenCost 2020	https://publications.csiro.au/publications/#publication/PIcsiro:EP201952/
Core Energy, Delivery wholesale gas price outlook 2020-2050	**Report:** https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/core-energy-delivered-wholesale-gas-price-outlook-2020-2050_report.pdf?la=en&hash=4D53CA4DD239E0A075336D0B572462C7 **Workbook:** https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/core-energy-delivered-wholesale-gas-price-outlook-2020-2050_databook.xlsx?la=en&hash=5260BC9179F0328EB4C26D796980EFF1
Wood Mackenzie, 2019 coal cost projections	**Report:** https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/woodmackenzie_aemo_coal_cost_projections_approach_20190711.pdf?la=en&hash=0CDC58B55D42C01E3B9E81BE0E9D5D7E **Workbook:** https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/woodmackenzie_aemo_delivered_cost_of_coal_20190711.xlsx?la=en&hash=602DB920B69C5CA6E9D3153D7A1B10BA

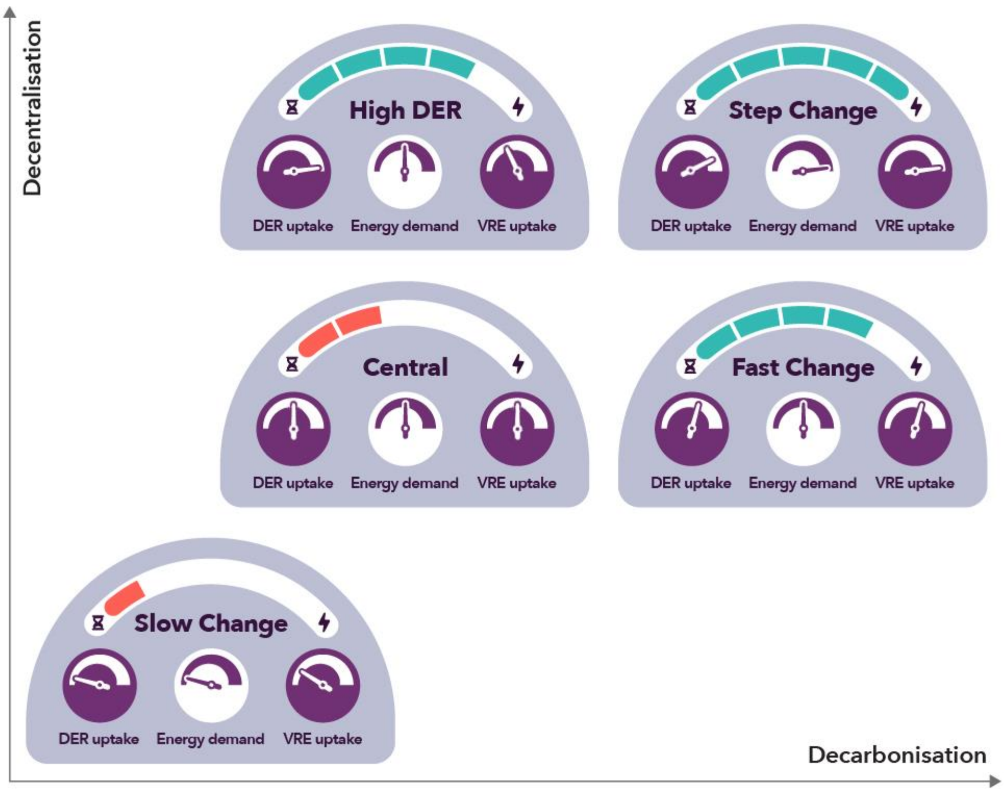
2. Scenarios

2.1 Scenario overview

AEMO assesses future forecasting and planning requirements under a range of credible scenarios over a period sufficiently long to support stakeholders' decision-making in the short, medium, and long term. These scenarios are developed every two years as part of the ISP development process. The current cycle examined the key scenario definitions and drivers in 2019; these will be re-examined and consulted on during 2020-21 for use in 2021-22 forecasting publications.

This 2020 IASR repeats the scenario descriptions for each scenario determined in collaboration with the energy industry in 2019. The scenarios vary broadly with respect to the rate of growth in grid-scale renewable generation resources and the uptake of DER (see Figure 3). Scenarios resulting in stronger decarbonisation and/or stronger decentralisation of the energy industry also include stronger electrification of other sectors, particularly the transport sector.

Figure 3 Comparative rates of decarbonisation and decentralisation across the five scenarios used in AEMO's 2019-20 and 2020-21 forecasting and planning publications



The scenarios provide a breadth of potential futures examining different roles for different elements of the industry. The scenario analysis approach will enable the identification of energy industry developments to support future consumer energy needs efficiently and at lowest cost.

These scenarios investigate:

- Current transition of the energy industry, under current public policies and technology trajectories, such that consumers and investors drive future infrastructure needs **(Central).**
- Slower technology advances, lower consumer interest in directing change, and no direct policy changes beyond existing commitments **(Slow Change)**.
- Consumer-led transformation of the industry, with a much faster pace of innovation and development of DER due to significant embrace from consumers **(High DER).**
- Technology-led transition of the industry, supported by policy to remove any barriers to entry, leading to a faster pace of change and cost reduction affecting large-scale providers of energy, with grid-based solutions being favoured over consumer-driven alternatives **(Fast Change).**
- Strong climate commitments and developments to support the achievement of ambitious decarbonisation objectives, in line with the aim of the Paris Agreement to limit the increase in global average temperatures to well below 2°C, supported by a mixture of technology advancements at the large scale, and consumer-led innovation **(Step Change)**.

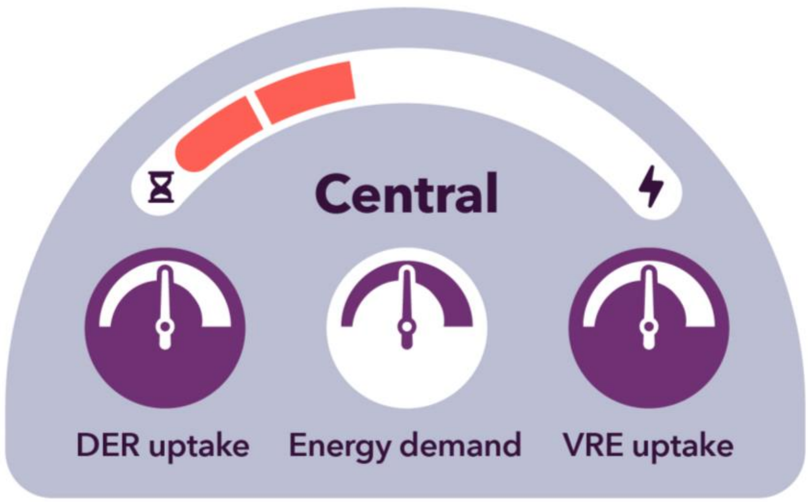
These scenarios, explained in the 2019 forecasting and planning scenario, inputs and assumptions report, are described again in the following sections for completeness.

2.2 Scenario narratives

2.2.1 Central

The Central scenario reflects a future energy system based around current government policies and best estimates of all key drivers.

This scenario represents the **current transition of the energy industry** under current policy settings and technology trajectories, where the transition from fossil fuels to renewable generation is generally led by market forces.



In this scenario:

- Moderate growth in the global economy[12] is in line with current best estimates, with Australia's long-term average growth in line with an economy slowly transitioning from being export-oriented to

[12] The COVID-19 pandemic certainly is having a strong impact on the global economy. "Moderate growth" in this context does not necessarily translate into consistent positive growth, but should be interpreted relative to the other scenarios. More information on the effect of COVID-19 on the inputs and assumptions is provided in Chapter 3.

service-oriented. Emission reduction and energy policy settings are in line with current government policies, with focus at a federal level being on consumer costs and reliability, and regional renewable generation development and consumer investment in DER encouraged at a state level. Sectoral change beyond current policies is driven by commercial decision-making as ageing power stations close.

- Technology improvements – particularly in renewable energy and consumer technologies – are gradual in line with current trends, and adoption trends in new technologies such as consumer energy storage systems (ESS) and electric vehicles (EVs) are relatively slow in the next decade. Technology cost breakthroughs domestically are not expected in the short term, particularly in EVs, because vehicle prices are slow to reduce and vehicle model availability is limited. Cost parity with traditional internal-combustion engine (ICE) vehicles is not expected until about 2030, with a stronger focus on short-range vehicles (with heavier vehicles reaching cost parity approximately 10 years later). A lack of supportive policy and EV infrastructure contributes to this delayed parity with ICEs.
- Broader energy efficiency and DER development (particularly distributed photovoltaic [PV] systems) continues, as consumers seek to invest in devices to lower their energy cost exposure, however there is no significant change to customer tariffs or additional DER incentives.
- In terms of large-scale developments, economic factors (rather than intervention policies) drive industry change. Australia remains on track to meet its current emission reduction commitment to 2030. However, global commitments to climate change and decarbonisation do not lead to strong government-led increases in commitments to meet the Paris Agreement, and as such, coal generation remains in operation until the end of its technical life, and economic closures are not hastened by policy measures. The change affecting the stationary energy sector is evolutionary and gradual.
- In the long term, modest global carbon reduction ambitions lead to higher global and domestic temperatures and more extreme weather conditions, consistent with the IEA's latest World Energy Outlook (2018) projections[13].

Policy settings to apply in the Central scenario

The Central scenario incorporates all government environmental and energy policies where:

a) There is a current policy commitment with clear articulation of when and how it impacts the power system, and

b) Any of the following criteria are met:
   - A commitment has been made in an international agreement.
   - The policy is legislated.
   - There is a regulatory obligation in relation to a policy.
   - The policy has received material funding in a State or Federal government budget.
   - The Council of Australian Governments (COAG) Energy Council, or the COAG Energy Council Senior Committee of Officials (SCO), has advised AEMO to incorporate the policy.

Given the above approach, the Central scenario incorporates the following state and federal government environmental and energy policies and initiatives:

- Australia's target of a 26% reduction in 2005-level emissions by 2030, with the NEM taking a pro rata share.
- Victorian Renewable Energy Target (VRET, 50% by 2030).
- Tasmanian Renewable Energy Target (TRET, 100% by 2022)[14].
- Queensland Renewable Energy Target (QRET, 50% by 2030).

[13] International Energy Agency, World Energy Outlook (2018) examines the forecast energy outcomes considering the impacts of only those policies and measures that are firmly enshrined in legislation as of mid-2018. According to the IEA's "Tracking Clean Energy Progress' tracker, at https://www.iea.org.au/tcep/, "we are far from on track" to hitting the objectives of the Paris Agreement's well below 2°C climate goal.

[14] Note that the proposed extension of the target to 200% by 2040 has not been included in the Central scenario.

- New South Wales Electricity Strategy[15] (including development of the Central-West Orana REZ Transmission Link).
- The Snowy 2.0 energy storage project.
- Current state and federal policies impacting DER and energy efficiency (EE)[16], including:
  - Small Scale Renewable Energy Scheme (SRES) and Large Scale Renewable Energy Target (LRET).
  - Emission Reduction Fund and Victorian Energy Saver Incentive Scheme (additional PV non-scheduled generation [PVNSG] revenue stream via Australian Carbon Credit Units [ACCUs]).
  - Victorian Solar Homes Scheme.
  - South Australia Home Battery Scheme.
  - Australian Capital Territory Next Generation Energy Storage program.

2.2.2 Slow Change

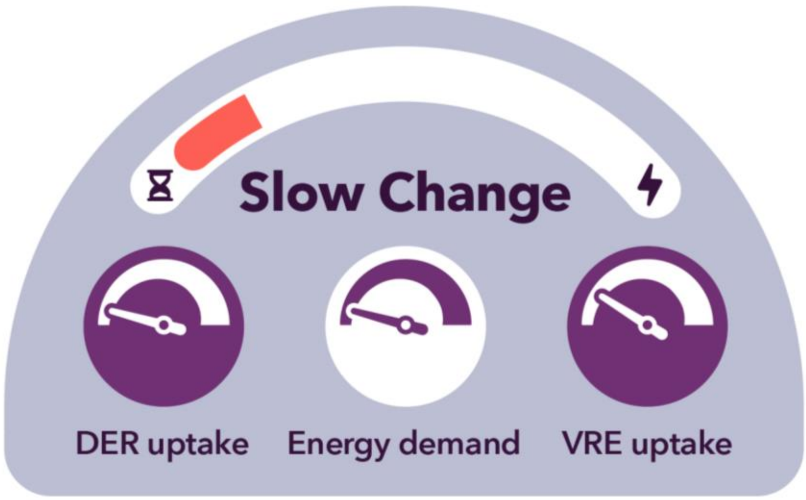
In this scenario, economic conditions are challenging, leading to a slowdown in investment and hence a slowdown in transformation of the industry. Consumers and governments put more emphasis on protecting standards of living than on structural reform to the energy sector and, with less capital available, investors are slow in developing large-scale technology projects to replace existing resources.

This maintains reliance on fossil fuels well into the second half of this century. Support for local industry is high, but slow global conditions lead to challenging times for some industrial sectors.

This scenario reflects **slower technology advancements, lower consumer interest, and fewer direct policy drivers.**

Key differences to the Central scenario include:

- Weaker economic and population growth.
- Slower decarbonisation of stationary energy sector and transport sector, which in turn may result in life extensions of existing generators, if economic.
- Proportionately lower decentralisation.



[15] See https://energy.nsw.gov.au/government-and-regulation/electricity-strategy.

[16] See Section 3.1.4 for a list of EE policies.

The Slow Change scenario reflects a future world with more challenging global and local economic conditions. In this scenario:

- The population growth outlook is slower, lowering broader economic growth and limiting household disposable income growth. Weak economic conditions lead to higher risk of industrial demand closures, while business and residential loads seek to lower consumption to manage bill exposure.
- With less disposable income and fewer policy settings to support DER, investment in distributed PV, batteries, and EVs is lower relative to the Central scenario. Australia does not actively promote local EV deployment.
- Renewable generation investment slows with limited political, commercial, and social support. The generation technology transition is slower, relative to the Central scenario. While innovation in renewable generation is still expected, the rate of transition globally is slower, resulting in slower improvements in renewable generation technology costs.
- Owners of coal generators in particular may choose to extend their asset lives, if economic, rather than invest in new resources.
- In the long term, climate change leads to higher temperatures and more extreme weather conditions. Long-term average rainfall decline also requires more frequent operation of desalination plant.

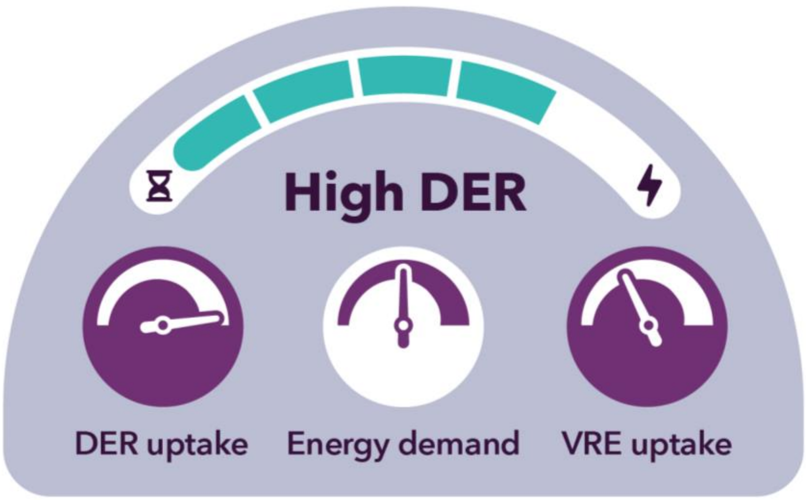
2.2.3 High DER

This scenario represents a highly digital world where technology companies increase the pace of innovation in easy to use, highly interactive and engaging technologies.

This includes reduced costs and increased adoption of solar PV, ESS and EVs, with automation becoming commonplace, enabling consumers to actively control and manage their energy costs, and consumer-led preferences lead to wide-spread electrification of the transport sector.

This scenario reflects **a consumer-led transformation of the energy sector.**

The key difference to the Central scenario is significantly greater decentralisation through higher DER.



In this scenario:

- Community groups recognise that consumers, rather than large commercial or government entities, can play a strong role in the future energy mix, and consumers' actions will assist in broader decarbonisation efforts.

- Controllable home devices lead to a stronger role for at-home energy management, and the scenario has a relatively high share of consumer storage solutions, EVs, and controllable battery systems. Digital communities exist, with technological innovation increasing the ease with which energy solutions can be embraced with improved interoperability and minimal intervention.
- There is a migration away from large-scale generation developments to commercial and residential systems to help achieve decarbonisation targets.

This is a variant on the Central scenario with stronger growth in DER, and therefore has broader settings in line with that scenario.

2.2.4 Fast Change

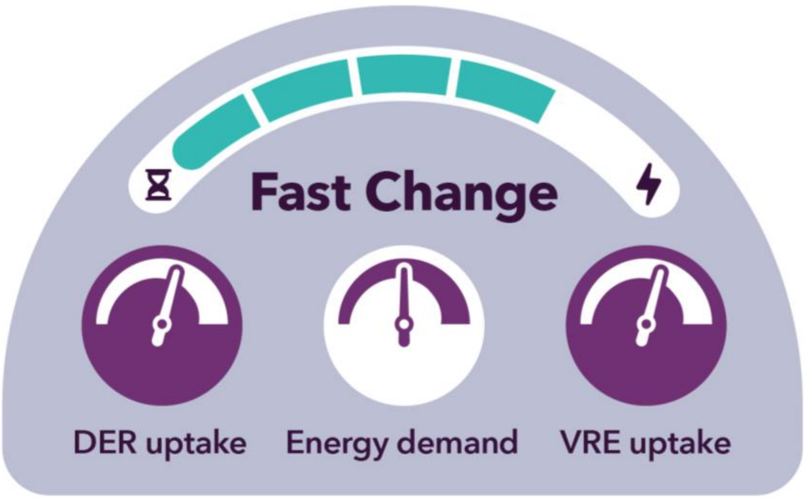
This scenario includes reductions in international economic barriers, leading and delivering technological improvements and manufacturing advancements that will assist in delivering cost reductions to consumers and industry alike.

Greater digitalisation increases consumers' adoption of methods for controlling energy use and integrating transport into the energy sector. These technological improvements and cost reductions remove some of the political and social barriers to addressing climate change, and greater coordinated global emission reduction ambition is achieved.

This scenario reflects **a technology-led transition, particularly at grid scale.**

Key differences to the Central scenario:

- Faster adoption of decarbonised investments.
- Technology innovation and increased DER uptake.
- Greater EV uptake and stronger role for energy storage solutions.



In this scenario:

- Moderate growth in the global economy is in line with current best estimates (same as the Central scenario), with Australia's long-term average growth in line with an economy slowly transitioning from being export-oriented to service-oriented in many parts of the nation.
- Technology innovations lead to cost reductions across large- and small-scale technologies, as global uptake of zero and low emissions technologies is more rapid. This leads to a moderate to high degree of consumer DER penetration, with cost reductions complementing policy support that can catalyse local developments in DER including EVs (such as increased model availability and access to innovative customer tariff structures and charging stations).

- In terms of large-scale developments, strong investment focus is placed on renewable generation to meet decarbonisation goals, and some coal-fired generation retires earlier than currently expected. High uptake of renewable resources nationally results in less need for state policies to try to incentivise development of these resources locally, leading to development in areas across all NEM regions where the resource quality and transmission access is best suited.
- While stronger action on climate change is delivered sooner than in the Central scenario, developments to 2050 do not come quickly enough to limit global temperature rises to 2 degrees Celsius (^{0}C) by 2100.

2.2.5 Step Change

This scenario includes a 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.

Risks associated with climate change are urgently addressed. Domestic and international action rapidly increases to achieve the objectives of the Paris Agreement.

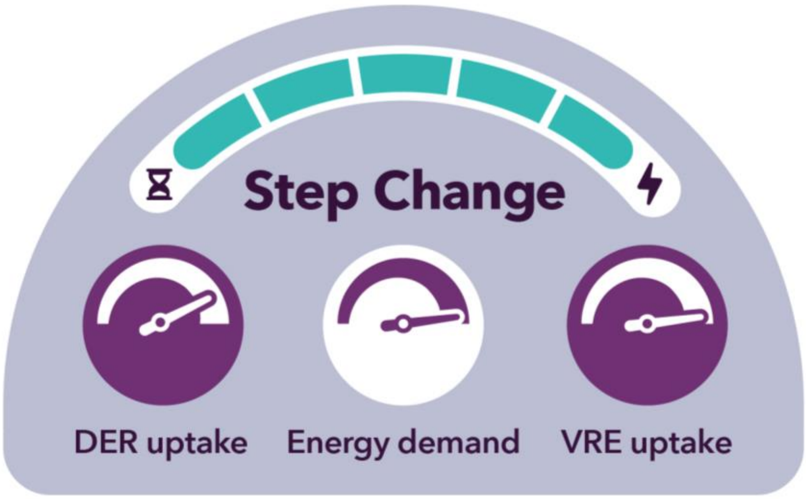
Advancements in digital trends globally increases the role of consumer technologies to manage energy use, and technology improvements and complementary manufacturing and infrastructure developments enables greater adoption of alternative fuelled vehicles, electrifying much of that sector.

Sustainability has a very strong focus, with consumers, developers and government also supporting the need to reduce the collective energy footprint through adoption of greater EE measures.

This scenario reflects **strong direct climate action**, with a step change in approach that focuses on decarbonisation efforts.

Key differences to the Central scenario:

- Higher population and economic growth.
- Most aggressive decarbonisation goals.
- Technology innovation and increased DER uptake.
- Greater EV uptake and stronger role for energy management solutions, as the transportation sector increases its role in decarbonisation, achieving a net-zero emissions sector by 2050, in line with the intent of the stronger climate action across the broad economy.
- Stronger role for EE measures.



In this scenario:

- 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 no more than 2^{0}C, ideally less than 1.5^{0}C.
- Australia benefits from strong population growth and economic activity from increased quality of life, migration, access to renewable resources, and a greater digital economy.
- Technology innovations lead to cost reductions across large- and small-scale technologies as global uptake of zero and low emissions technologies is prolific.
  - Greater innovation in digital trends and technology costs leads to stronger consumer energy management and DER investment, as consumers embrace their role in decarbonisation efforts and move towards digital energy (highly flexible, measurable supply sourced from multiple sites, coordinated effectively in real time through greater digital connectivity and management of 'big data').
  - This leads to a relatively high degree of consumer DER penetration, similar to the High DER scenario (but with a greater population base), and the electricity sector includes electrification of transportation sectors to efficiently achieve decarbonisation goals. The scenario includes strong growth in EVs (and alternative fuelled vehicles) as the transportation sector transforms to zero emissions by 2050. 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.
- In terms of large-scale developments, the scenario will exhibit the fastest rate of technology cost reductions for zero/low emissions technologies. Consistent with a step change, new policies are implemented that drive uptake of renewable generation resources well in excess of current state and federal ambitions to 2030, and the proposed extension of TRET to 200% by 2040.
- Ambitious future EE standards are set for buildings and equipment, resulting in substantial energy savings.
- Global and domestic action on climate change limits global temperature rises to 1.5^{0}C or 2^{0}C by 2100.

2.3 Key scenario parameters

For each scenario, the role of government and public policies can influence the ultimate direction and scale of action affecting the energy sector. These policy settings collectively may influence the infrastructure developed to support the consumption of energy, and each scenario will include a differing degree of policy-driven change.

While the **Central Scenario** includes all current legislated government policies, future possible variations in these policies are incorporated in the other scenarios to be internally consistent with the scenario narratives.

The **Slow Change** scenario does not include the full QRET policy, as the scenario itself considers less overall emission reduction ambition with no coordinated carbon budget. Furthermore, future state governments are assumed to scale back the level of ambition pursued within their own renewable energy development targets. Renewable generation already committed under the current schemes is assumed to still be developed.

The **High DER** scenario closely represents the scenario settings of the Central Scenario, with state governments' various renewable energy development schemes being implemented at the same time as consumers increase demand for DER. The TRET is also assumed to be expanded to 200% by 2040 in this scenario to more fully test the implications and interactions of large-scale variable renewable energy (VRE) development and consumer- and technology-led increases in DER.

The **Fast Change** scenario focuses on greater centralised, large-scale developments located in regions across the NEM that deliver the maximum market benefits to consumers while meeting decarbonisation objectives[17]. In this scenario, high uptake of renewable resources is expected to reduce the relative value for state policies to incentivise local renewable developments, as these developments are likely to develop

[17] State-based renewable energy targets are likely to deliver other benefits and externalities beyond those captured in market benefits.

naturally from the decarbonisation action nationally. As such, state governments opt not to strengthen their renewable generation aspirations, and instead revert to reliance on national objectives tied to decarbonisation goals. This is expected to lead to strong development of renewable energy across all NEM regions where the resource quality and transmission access is best suited.

The **Step Change** scenario has significant national emission abatement ambition and is likely to be supported by strong government policy at both federal and state levels. While the actual mechanisms for achieving this ambition are not defined in the scenario, it is plausible to envisage that current and proposed government policies would continue, supplemented by other incentives. In this instance, the global emission trajectory is likely to be far more binding than any other policy settings and VRE and DER targets are therefore expected to be well exceeded.

Table 2 shows the settings to be applied to each scenario. The model representation of the policies affecting energy supply and dispatch is discussed in the Market Modelling Methodology Paper[18].

Table 2 2020 scenario policy settings

Policy	Slow Change	Central	Fast Change	High DER	Step Change
VRET – 40% by 2025, 50% by 2030	✓	✓	✓	✓	✓✓
TRET – 100% by 2022	✓	✓	✓	✓	✓
TRET – 200% by 2040	×	×	×	✓	✓
QRET – 50% by 2030	×	✓	×	✓	✓✓
Central West Orana REZ Transmission Link	✓	✓	✓	✓	✓
Snowy 2.0	✓	✓	✓	✓	✓
Current DER and EE policies	✓	✓	✓	✓✓	✓✓
26% reduction in emissions by 2030 (NEM)	✓	✓	✓	✓	✓✓
NEM carbon budget to achieve 2050 emissions levels	×	×	✓	×	✓✓

✓ included in the scenario.
× excluded in the scenario.
✓✓included at a minimum, but volume likely to be exceeded based on scenario narrative.

Table 3 consolidates all the key policy settings, demand drivers, technological improvements, investment considerations, and climatic assumptions to be applied for each of the scenarios. Details are in the Inputs and Assumptions Workbook[19].

Table 3 2019-20 scenario dimensions

Scenario	Slow Change	Central	Fast Change	High DER	Step Change
Demand drivers					
Economic growth and population outlook	Slower growth	Central	Central	Central	Higher growth

[18] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Market-Modelling-Methodology-Paper.pdf.

[19]At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Input-and-Assumptions-workbook.xlsx.

Scenario	Slow Change	Central	Fast Change	High DER	Step Change
EE improvement	Low	Moderate	Moderate	Moderate	High
DSP	Low	Moderate	Moderate	Moderate	High
COVID-19 settings					
COVID-19 restrictions	15-18 months	6-9 months	6-9 months	6-9 months	6-9 months
Business	Slow recovery	Moderate recovery	Moderate recovery	Moderate recovery	Quick recovery
Industrial	Closures of at-risk industrial facilities	Limited impact	Limited impact	Limited impact	Limited impact
Maximum demand offset	Lower	Central	Central	Central	Upper
Minimum demand offset	Lower	Central	Central	Central	Upper
DER uptake					
Distributed PV	Low	Central	Central-High	High	High
Battery storage installed capacity	Low	Moderate	Moderate – High	High	High
Battery storage aggregation/ virtual power plant (VPP) deployment by 2050	Existing trials do not successfully demonstrate a strong business case for VPP aggregation. Low role for energy storage aggregators and VPPs.	Moderate role for energy storage aggregators and VPPs.	Existing trials demonstrate a business case for VPP aggregation. High role for energy storage aggregators and VPPs.	Existing trials demonstrate a business case for VPP aggregation. High role for energy storage aggregators and VPPs.	Existing trials demonstrate a business case for VPP aggregation. High role for energy storage aggregators and VPPs, faster than all other scenarios.
EV uptake	Low	Moderate	Moderate-High	Moderate-High	High (Assumes zero emissions transport sector by 2050)
EV charging times	Delayed adoption of infrastructure and tariffs to enable 'better' charging options. No move from time-of-use flex charging to fully coordinated dynamic charging.	Moderate adoption of infrastructure and tariffs to enable 'better' charging options. Some move from time-of-use flex charging to fully coordinated dynamic charging post 2030.	Faster adoption of infrastructure and tariffs to enable 'better' charging options. Some move from time-of-use flex charging to fully coordinated dynamic charging post 2030.	Faster adoption of infrastructure and tariffs to enable 'better' charging options. Significant move from time-of-use flex charging to fully coordinated dynamic charging post 2030.	Faster adoption of infrastructure and tariffs to enable 'better' charging options. Significant move from time-of-use flex charging to fully coordinated dynamic charging post 2030.
Climate change (physical symptoms)					
Representative Concentration Pathway [RCP] (average temperature rise by 2100)[A]	RCP 8.5 (>4.5°C)	RCP 7.0 (3.0 – 4.5°C)	RCP 4.5 (2.5 – 2.7°C)	RCP 7.0 (3.0 – 4.5°C)	RCP 1.9 / 2.6 (1.4 – 1.8°C)

Scenario	Slow Change	Central	Fast Change	High DER	Step Change
Median Hydro inflow reduction by 2050 (mainland)[B]	-18%	-14%	-7%	-14%	-4%
Median Hydro inflow reduction by 2050 (Tasmania)[C]	-9%	-7%	-5%	-7%	-3%
Large-scale renewable build cost trajectories					
Solar PV	Weaker reductions than CSIRO GenCost 2020 Central scenario	CSIRO GenCost 2020 Central scenario	CSIRO GenCost 2020 High VRE scenario	CSIRO GenCost 2020 Central scenario	Stronger reductions than CSIRO GenCost 2020 High VRE scenario
Wind	Weaker reductions than CSIRO GenCost 2020 Central scenario	CSIRO GenCost 2020 Central scenario	CSIRO GenCost 2020 High VRE scenario	CSIRO GenCost 2020 Central scenario	Stronger reductions than CSIRO GenCost 2020 High VRE scenario
Pumped hydro	No variability of PHES costs is applied across scenarios. Pumped hydro costs do not change significantly owing to the high maturity of its plant components and starting costs for pumped hydro have also increased. The lack of scenario dispersion is consistent with the approach within CSIRO GenCost 2020.				
Battery	CSIRO GenCost 2020 Central scenario	CSIRO GenCost 2020 Central scenario	CSIRO GenCost 2020 High VRE scenario	CSIRO GenCost 2020 Central scenario	Stronger than CSIRO GenCost 2020 High VRE scenario
Solar thermal	Weaker reductions than CSIRO GenCost 2020 Central scenario	CSIRO GenCost 2020 Central scenario	CSIRO GenCost 2020 High VRE scenario	CSIRO GenCost 2020 Central scenario	Stronger reductions than CSIRO GenCost 2020 High VRE scenario
Investment and retirement considerations					
Generator retirements	Maintained at least until expected closure year, potentially extended if economic to do so	In line with expected closure years, or earlier if economic to do so	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	In line with expected closure year, or earlier if economic or driven by decarbonisation objectives
Project finance costs	High	Moderate	Moderate	Moderate	Moderate

A. For more information on Representative Concentration Pathways (2.6, 4.5, 6.0, 8.5) see https://www.climatechangeinaustralia.gov.au/en/publications-library/technical-report/ . Additional RCPs (1.9, 3.4, 7.0) are emerging through work by the Intergovernmental Panel on Climate Change (IPCC) sixth assessment due to be published in 2020-21 and are developed on a comparable basis.

B. Hydro reductions consider both rainfall reductions (global climate model [GCM] trajectories for the 'Southern Australia' supercluster in which almost all hydro facilities are located, available from www.climatechangeinaustralia.gov.au. Median projection based on ACCESS1.0, high and low sensitivities on GFDL-ESM2M & NorESM1-M GCMs) and estimates of the effect of reduced rainfall on broader dam inflow reductions (informed by http://www.bom.gov.au/research/projects/vicci/docs/2016/PotterEtAl2016.pdf).

C. Hydro reductions for Tasmania consider a reduced drying expectation, as supported by numerous studies, particularly the Climate Futures for Tasmania dataset.

2.4 Sensitivity analysis

In any scenario analysis, it is important that scenarios be defined to adequately capture the spread of potential future worlds. Fundamentally, scenarios are used to investigate alternative futures, whereas sensitivities are designed to validate the significance of key assumptions within a given future.

AEMO adopts sensitivities in each of its major publications depending on the materiality of the potential risk, uncertainty or variable. For example, the 2020 ESOO has examined the sensitivity of consumption to COVID-19 uncertainties surrounding DER uptake and economic impacts, which may amplify the uncertainty of energy consumption and demand variability. These sensitivities are described in detail in the relevant publications.

AEMO will continue to apply sensitivity analysis where appropriate to strengthen the breadth of analysis provided by the core scenarios described in this report.

3. Inputs and assumptions

The following sections outline the key inputs and assumptions AEMO will adopt in its 2020-21 forecasting and planning publications. For each of these assumptions, the 2020 Inputs and Assumptions Workbook[20] provides additional details.

3.1 Key components for forecasting energy consumption

AEMO updates its projections of energy consumption annually. This is done for electricity as part of the ESOO, and for gas as part of the GSOO. This process includes significant stakeholder consultation with AEMO's 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 forecasts of:
  - Rooftop PV.
  - Customer ESS.
  - EV uptake and charging behaviours.
  - The role of ESS aggregation and virtual power plants (VPPs).
- Economic and population growth drivers.
- EE forecasts.
- Fuel switching.
- Outlook for large industrial loads and liquified natural gas (LNG) exports.

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 Information Paper, although each section commences with a high-level linkage to the forecast components that use the inputs outlined. For gas demand forecasting, the GSOO's demand forecasting methodology[21] also outlines the usage of these key inputs.

3.1.1 Customer distributed energy resources

Forecast component relationships: **Residential sector**

Business sector (Small-medium enterprises and electric vehicles)

Small non-scheduled generation

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. AEMO commissioned CSIRO and Green Energy Markets (GEM) to assist in producing DER forecasts of the anticipated uptake rates and usage behaviours of various DER devices. The two sets of forecasts have been combined to the single set used in

[20] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

[21] At https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2020/gas-demand-forecasting-methodology.pdf?la=en.

AEMO's 2020 scenarios as shown in Table 4. Details of assumptions underpinning each consultant's forecasts are provided in their reports that supplement this IASR.

Table 4 Mapping of consultant trajectories used for DER forecasts

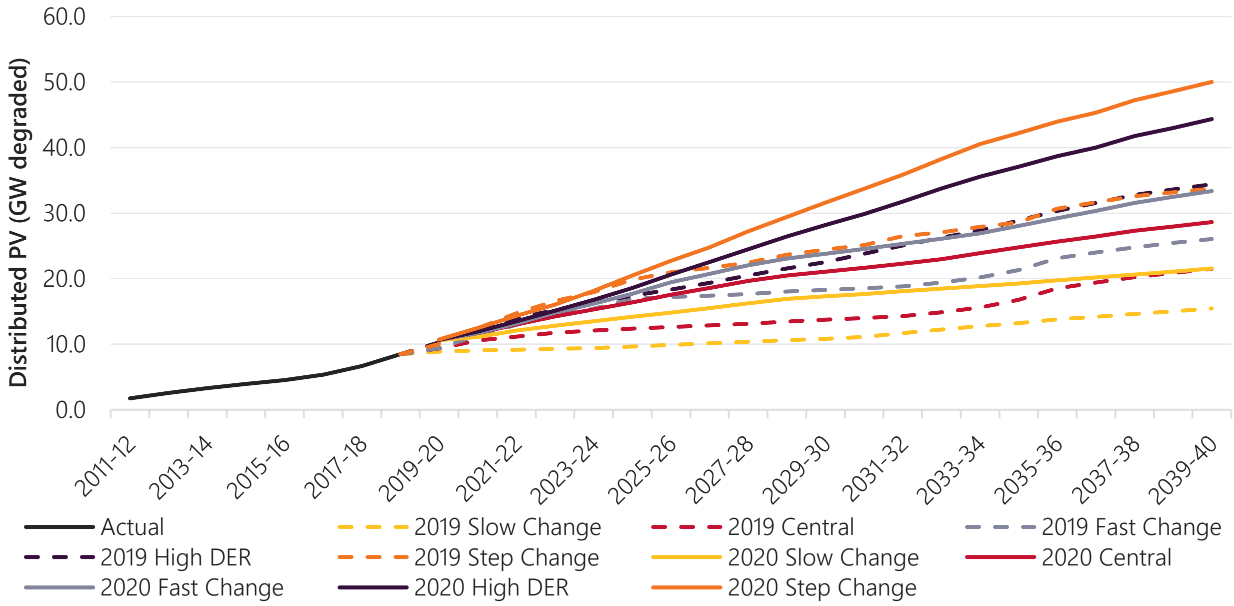
	Slow Change	Central	Fast Change	High DER	Step Change
Distributed PV	CSIRO Slow Change	Average of CSIRO Central and GEM Central	Average of CSIRO Fast Change and GEM Fast Change	GEM High DER	GEM Step Change
Battery	CSIRO Slow Change	Average of CSIRO Central and GEM Central	Average of CSIRO Fast Change and GEM Fast Change	GEM High DER	GEM Step Change
EV[22]	CSIRO Slow Change	CSIRO Central	CSIRO Fast Change	CSIRO High DER	CSIRO Step Change

Distributed PV

Distributed PV systems, including residential rooftop, commercial rooftop, and larger embedded PVNSG[23] systems, have seen very strong growth over 2019 and early 2020, leading to approximately 2.1 gigawatts (GW) of new installations over the 2019 calendar year, and a total capacity of distributed PV systems in the NEM of about 10.7 GW[24].

Figure 4 compares the uptake forecasts across the 2020 scenarios, and with the 2019 ESOO scenario forecast.

Figure 4 NEM distributed PV installed capacity



The 2020 PV forecasts are an upwards revision on the 2019 forecast, driven by a number of influences, including:

- A revision to CSIRO's short-term forecast methodology, in response to recent strong installation rates.

[22] CSIRO was the sole provider of EV forecasting for 2020.

[23] "Rooftop PV" refers to systems of a size less than or equal to 100 kW, and PVNSG refers to systems that are larger than 100 kW.

[24] Installed capacity estimate as at 30 June 2020, unadjusted for degradation.

- Broader inclusion of Victoria's Solar Homes Scheme[25], now applied across all scenarios (previously was in the 2019 Step Change scenario). The net impact in the 2020 Central scenario for Victoria is a higher installed capacity by 4 GW in 2029-30 compared to the 2019 Central scenario.
- Lower PV cost assumptions[26] relative to those assumed in 2019.
- Increased average rooftop PV system sizes., from 5 kilowatts (kW) in 2019, to between 6.6 kW and 8.1 kW across the forecast period.
- Tempered short term growth in distributed PV, assuming a slowing effect from COVID-19.

As forecast previously, the medium to long-term growth in distributed PV naturally slows due to a forecast easing of retail prices and reduced subsidies (such as small-scale technology certificates, or STCs). Conversely, replacement of older systems with new, larger systems contributes to further growth.

Additional information on these forecasts is available in the CSIRO and GEM reports (see Table 1).

Battery systems

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 these changes depends on a number of factors, including:

- The quantity, storage capacity (in kilowatt hours [kWh]), and charge/discharge power (kW) of batteries installed.
- The relative penetration of different tariffs and associated battery charge/discharge operation modes[27].
- The size of any complementary PV system and the energy consumption of the household or business.
- The degree to which battery installations are coupled with PV systems

The number of batteries currently installed in the NEM is subject to some uncertainty. The Clean Energy Regulator (CER) keeps a voluntary register of batteries, which presently indicates just over 23,000 behind-the-meter battery systems are installed in the NEM[28]. However, as registrations are currently voluntary, the dataset is incomplete. AEMO's current work to implement the DER Register[29], along with collaboration with CSIRO in the National Energy Analytics and Research (NEAR) program[30], aims to improve the accuracy of this dataset in future.

Figure 5 shows the total forecast installed capacity of customer battery systems across the NEM for the forecast scenarios, compared with the assumptions applied in 2019. Higher growth is forecast in the medium term, with additional battery uptake forecast due to a greater assumed degree of decoupling of PV and battery systems (supported by increased evidence in historical sales activities), higher tariff assumptions in the medium to long-term, and lower battery system costs.

Additional information on these forecasts is available within the CSIRO and GEM reports (see Table 1).

[25] More information on Victoria's Solar homes program is at https://www.solar.vic.gov.au/.

[26] See Section 3.2.10 of Graham, Paul; Hayward, Jenny; Foster, James; Havas, Lisa. GenCost 2019-20. CSIRO publications repository: CSIRO; 2020, at https://doi.org/10.25919/5eb5ac371d372.

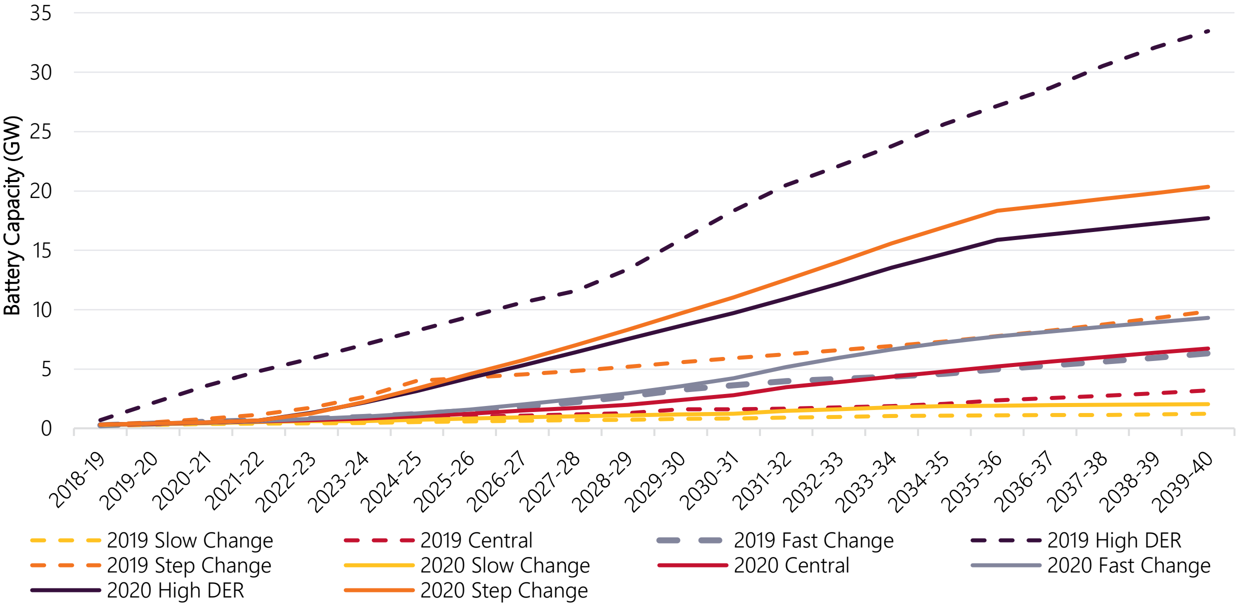
[27] See Appendix A3.2.2 of the Electricity Demand Forecasting Methodology Information Paper for more information on assumed battery operating types.

[28] CER data sourced on 1 July 2020 from http://www.cleanenergyregulator.gov.au/RET/Forms-and-resources/Postcode-data-for-small-scale-installations.

[29] For more information, see https://www.aemo.com.au/Stakeholder-Consultation/Consultations/NEM-Distributed-Energy-Resources-Information-Guidelines-Consultation.

[30] One research area in the NEAR program is to identify batteries that are not captured on CER's database. For more information on the NEAR program, see https://near.csiro.au/.

Figure 5 Behind-the-meter battery forecasts for the NEM



Electric vehicles

EV uptake

Electrification of the transport sector could drive significant growth in electricity consumption in future. Key EV adoption factors include:

- Government policies.
- The levelised cost of electric vehicles (including plug-in hybrids) compared to ICE vehicles.
- Substitutes and alternatives to EVs (such as public transport, rideshare services, and hydrogen fuel cell vehicles).
- Commercial fleet ownership.
- Access to charging infrastructure.
- The availability of different EV models in Australia.

EVs presently are estimated to represent less than 1% of the total vehicle fleet across the NEM. Based on the current level of uptake, and in the absence of any policy incentives, AEMO's Central scenario (as forecast by CSIRO) projects that the uptake of EVs across the NEM will reach only 3%, or half a million vehicles, by 2029-30. Growth is forecast to accelerate in the late 2020s and 2030s, due to assumed access to greater model choice, charging infrastructure, and falling vehicle costs.

Figure 6 shows the projected uptake by vehicle type, with residential vehicles forecast to be the largest EV sector, followed by light commercial vehicles and trucks.

Figure 6 NEM forecast number of EVs by vehicle type, Central scenario, 2017-18 to 2039-40

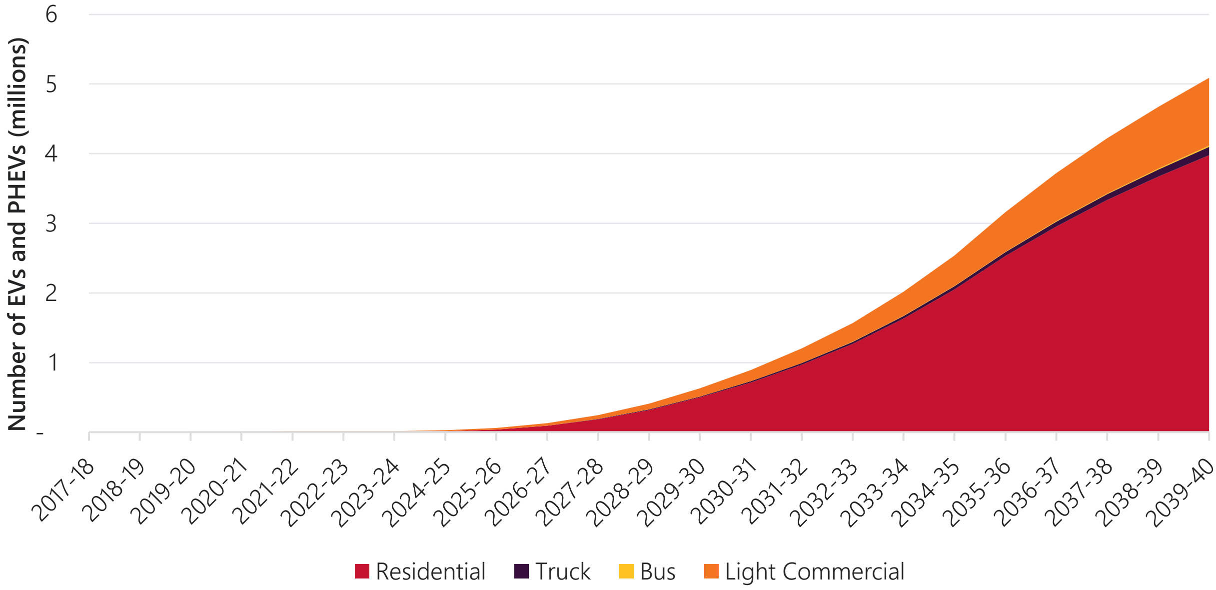
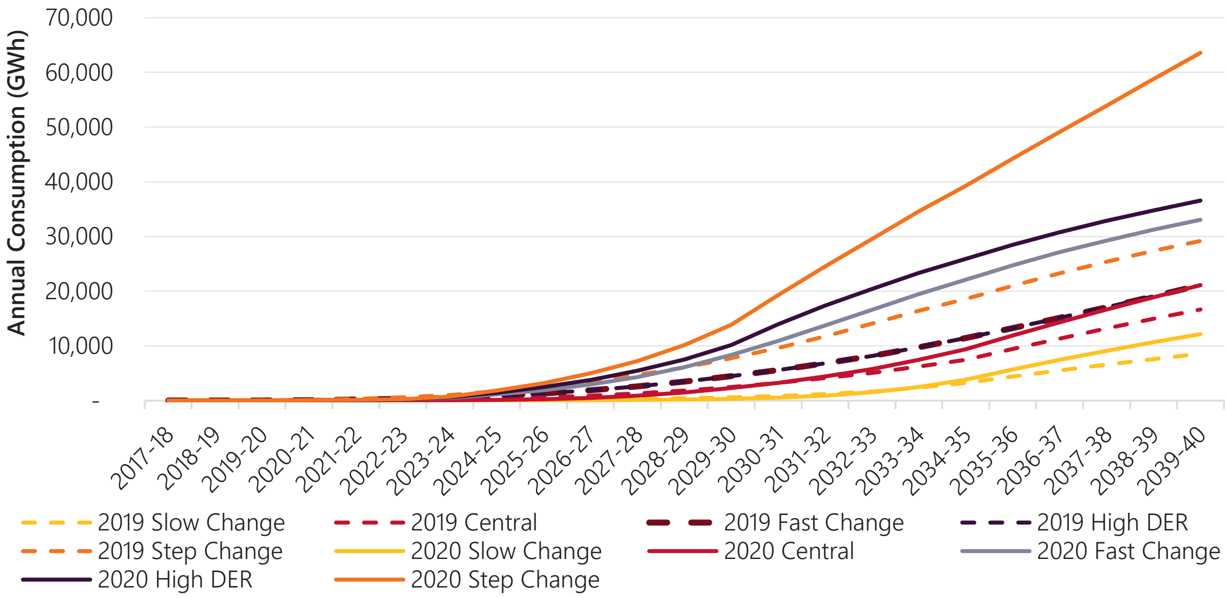


Figure 7 shows the forecast annual consumption attributed to EVs across the NEM in the next 20 years, across all scenarios and compared to the 2019 ESOO.

Figure 7 NEM EV annual consumption forecast, 2017-18 to 2039-40, all scenarios, compared to 2019 ESOO



EV forecast uncertainty and future improvements

The magnitude of transport electrification is highly uncertain, with EVs still in the early stages of adoption. The forecast EV uptake spread is wide across the scenarios. AEMO is working with relevant stakeholders in government, transport and energy sectors to increase coordination and understanding between sectors. Initially this should focus on developing a common approach to forecasting – developing datasets, sources, and assumptions that are key for EV adoption and charging factors – which should help reduce the uncertainty that emerging transport electrification provides for forecasting and planning engineers.

EV charging behaviours

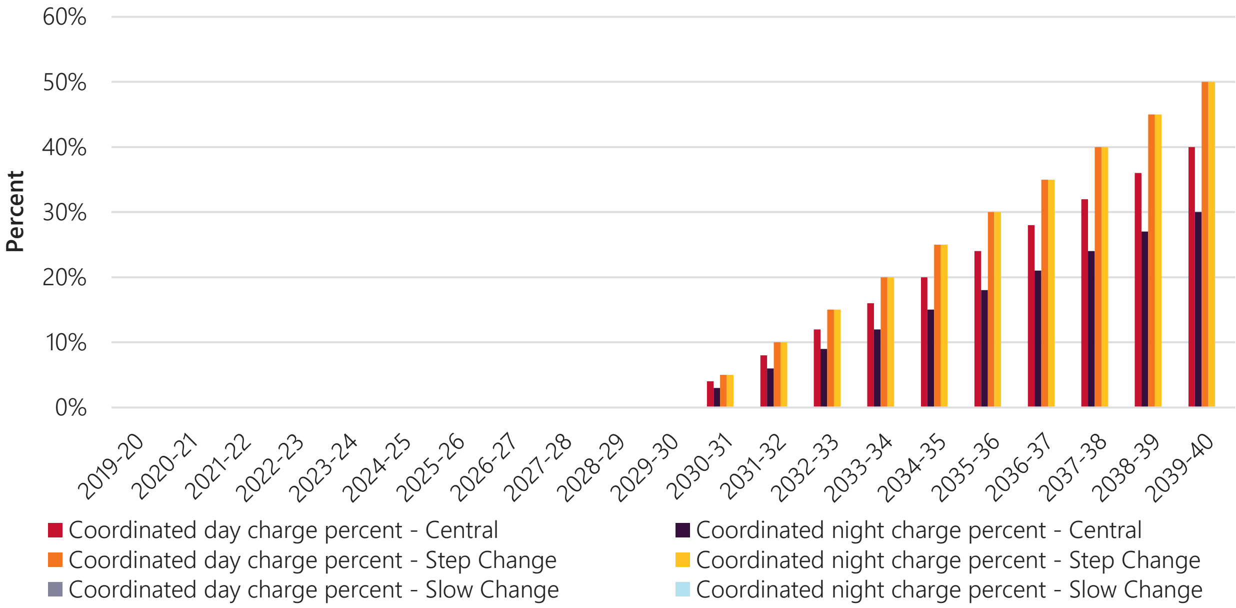
The method and frequency of EV charging will impact the daily load profile. Charging is likely to be influenced by the availability and type of public and private charging infrastructure, tariff structures, energy management systems, and the driver's routine and preferences.

For 2020-21 publications, AEMO has incorporated four charge profiles, in line with those used in 2019:

- Convenience charging – vehicles assumed to have no incentive to charge at specific times.
- 'Smart' daytime charging – vehicles incentivised to charge during the day, with available associated infrastructure to enable charging at this time.
- 'Smart' night-time charging – vehicles incentivised to charge overnight, with available associated infrastructure to enable charging at this time.
- Highway fast-charging – vehicles require a fast-charging service while in transit.

In addition to these profiles, 'smart' daytime and 'smart' night-time charging has been further split so a proportion of this is charged in a coordinated manner (for example as part of a VPP that optimises vehicle charging for low demand times) to minimise undesirable spikes in demand. The proportion assumed to be charged in a coordinated manner under each scenario is detailed in Figure 8 below.

Figure 8 Assumed proportion of daytime and night-time charging that is coordinated, by scenario

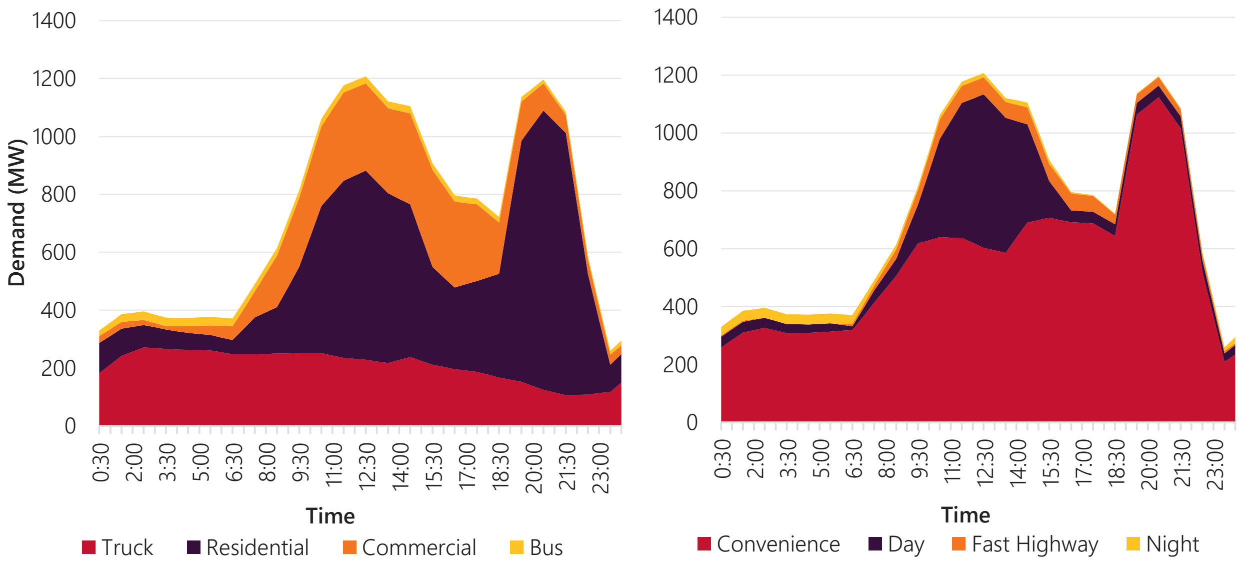


Charge profile preferences are forecast to change over time. The increasing electrification of the transport sector is expected to lead to greater charging infrastructure development and tariff change, providing consumers with greater choice to charge their vehicles in ways that are increasingly convenient, 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.

However, 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 9 below shows examples of the forecast contribution to demand from EV charging.

Figure 9 **Average weekday non-coordinated EV demand by vehicle type (left) and by charge profile (right) assumed for the Central scenario in January 2040 for New South Wales**



For the first time, AEMO has included a degree of coordinated EV charging in the 2020 forecasts. Figure 10 and Figure 11 below provide examples of this during conditions when electricity demand is both high and low for the Central and Step Change scenarios. 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 EV charging was uncoordinated).

The influence on minimum demand is particularly noticeable in the chart on the left in Figure 11 for the Step Change penetration of EVs. Without coordinated charging in this example, minimum demand would be close to zero. Successful development of this behaviour would reduce the costs of grid augmentation associated with PV and EV uptake, and reduce the need for operator intervention during minimum demand periods.

Figure 10 **Example of coordinated EV charging profiles during mild conditions (October) (left) and high demand conditions (January) (right) in the Central scenario in 2040 for New South Wales**

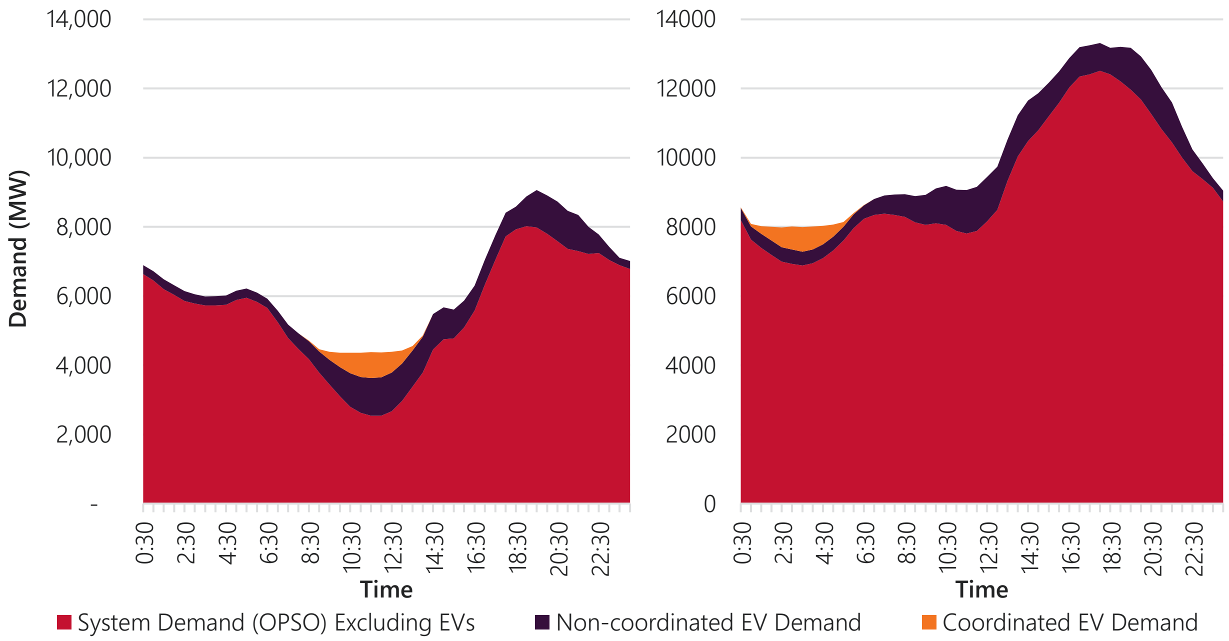
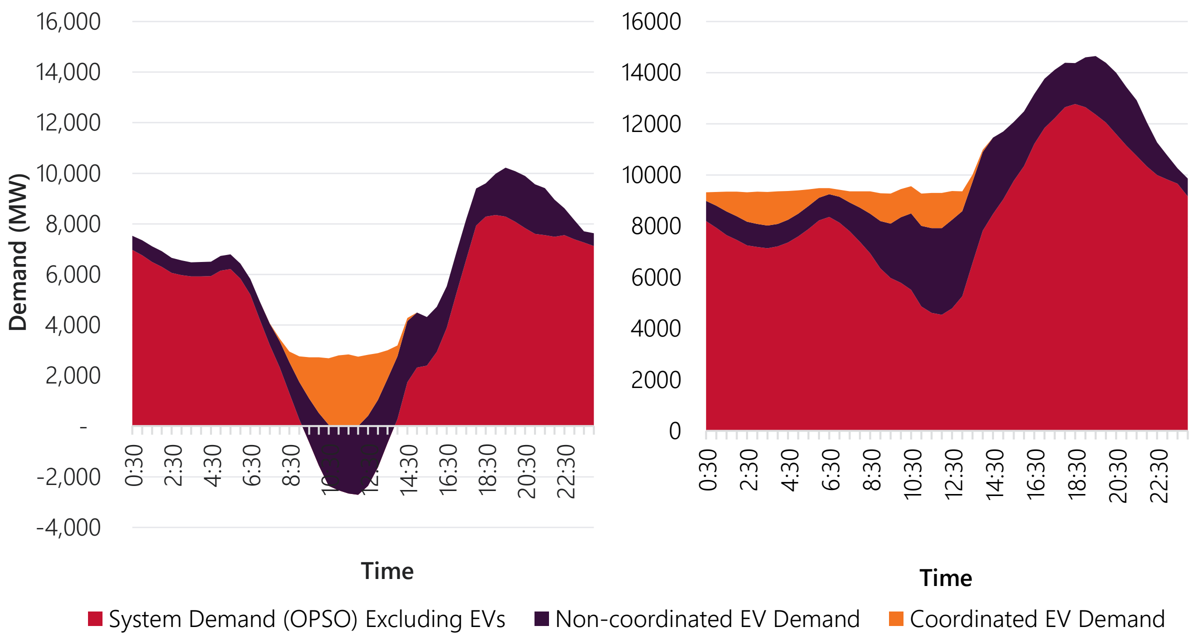


Figure 11 Example of coordinated EV charging profiles during mild conditions (October) (left) and high demand conditions (January) (right) in the Step Change scenario in 2040 for New South Wales



3.1.2 Economic forecasts, including the influence of COVID-19

Forecast component relationships: **Residential sector**

Business sector (Small-medium enterprises and an influence on industrial loads)

In 2020, AEMO engaged BIS Oxford Economics to develop long-term economic forecasts for each Australian state and territory as a key input to AEMO's demand forecasts.

The COVID-19 pandemic has introduced an unprecedented level of near-term uncertainty around the international and domestic economic outlook, affecting population migration and influencing energy consumption, maximum and minimum demand forecasts. AEMO has sought to investigate, research, measure and model possible impacts on the electricity forecasts, and this is described in detail in the 2020 ESOO (for maximum demand) and Electricity Demand Forecasting Methodology (for annual consumption influences). AEMO has worked closely with BIS Oxford to ensure the forecasts considered the most up-to-date[31] view on the economic impact as possible, leading to an April update which included "downside" sensitivities to complement the economic growth forecasts applied to the core Central scenario, with social and economic restrictions continuing until June 2021. These sensitivities have been considered in the 2020 ESOO, and more information on the forecasts is available in the two BIS Oxford reports (see Table 1).

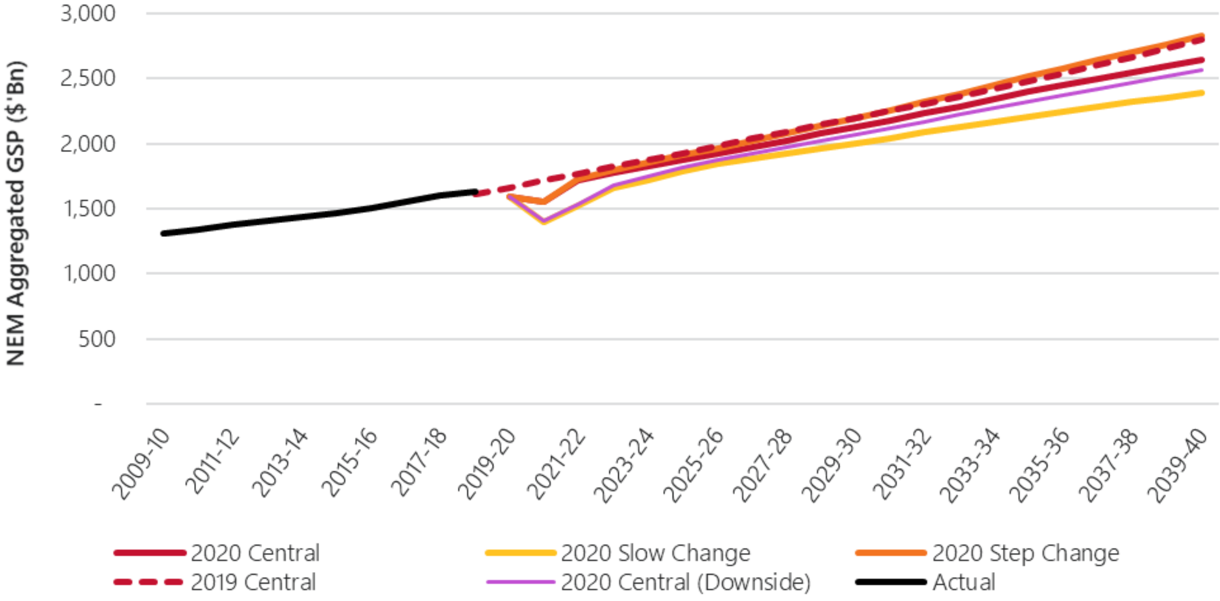
The COVID-19 pandemic is having a significant impact on the domestic (and global) economy. In Australia, this has particularly affected services trade (tourism and education), supply chain disruptions (production and distribution), energy and fuel markets (uncertainty in global demand), and equity markets (sharp corrections due to uncertainty in the economic outlook). Under all scenarios, restrictions on activity were assumed until at least the end of June 2020, and then relaxed gradually in Q3 and Q4. As restrictions are removed, economic activity is expected to slowly normalise, with assumed stimulus to encourage recovery. The duration of economic and social restrictions has varied across scenarios, with between six and 18 months applied, as outlined in Table 3.

The extent of COVID-19 restrictions leads to significant variance in the forecast economic outcomes of the coming years. Despite fiscal stimulus throughout the shut-down period, and assumed to continue during economic recovery, many domestic businesses will not survive the downturn, resulting in some loss of

[31] Most up-to-date information at the time of the forecast, which was March 2020, and updated in April 2020 with newer information available.

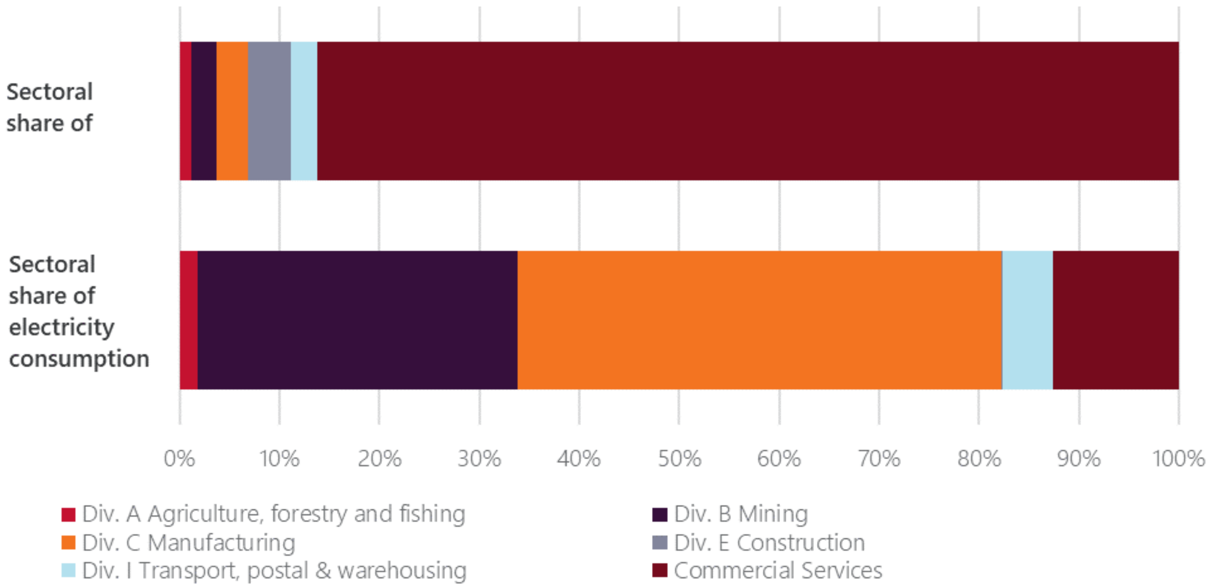
economic activity, particularly in the travel, tourism and higher education sectors. Manufacturing output is forecast to contract, due to supply chain disruptions and a sharp decline in the export of manufactured goods, while mining is expected to remain relatively resilient.

Figure 12 NEM aggregated gross state product ($'Bn)



Not all sectors of the economy are as energy-intensive as others, so the impact of an economic downturn that does not affect all sectors homogeneously results in an electricity consumption forecast that might not follow the exact trend of economy-wide economic activity. For example, while commercial services[32] might dominate the Australian economy, this sector is dwarfed by the manufacturing and mining sectors' contribution to electricity consumption[33], as shown in Figure 13.

Figure 13 NEM GVA share of economic activity versus NEM annual electricity usage by the associated industries (2017-18)



[32] Includes ANZSIC divisions F, G, H, J, K, L, M, N, O, P, Q, R, S.

[33] AEMO applied insights of energy use in the Australian Energy Update (2019) - Table F: Total net energy consumption in Australia by industry, produced by the Department of Industry, Science, Energy and Resources, at https://www.energy.gov.au/publications/australian-energy-update-2019.

By forecasting sub-sectors of the Australian economy, through Gross Value Added (GVA) economic indicators at the ANZSIC[34] divisional level, AEMO's forecasts capture the detailed impact of the economic recovery and growth across the sub-sectors.

3.1.3 Households and connections forecasts, including the influence of COVID-19

Forecast component relationships: Residential sector

As Australia's population increases, so too 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. A downturn in construction was forecast by AEMO's economic forecasters BIS Oxford 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.

In May 2020, the Housing Industry of Australia estimated a 43% reduction in dwelling starts nationwide and did not expect the industry to fully recover within two years[35]. AEMO revised down the growth in the residential building stock model for the Central and Slow Change scenarios in accordance with Table 5. The Step Change scenario forecast remained unchanged.

Table 5 COVID adjustments to dwelling starts in the Residential Building Stock Model

Financial year	Central	Slow Change
2020-21	43%	43%
2021-22	22%	43%
2022-23		21.5%
2023-24		10.75%

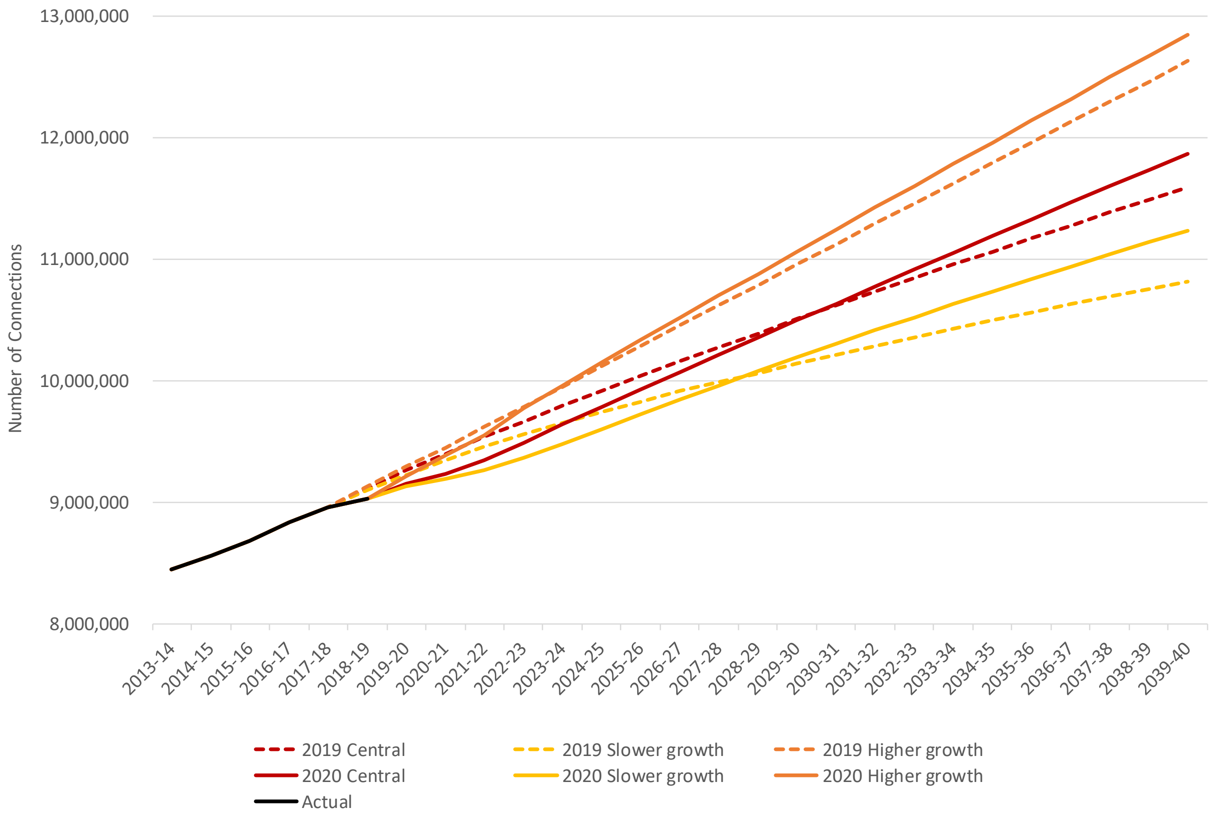
AEMO will continue to monitor the impact of COVID-19 on the housing construction industry, as well as the impact of government support packages designed to stimulate construction activity.

Figure 14 compares the 2020 and 2019 connections forecasts. Overall, the 2020 connections forecasts are lower than 2019 forecasts in the short to medium term as a result of the impact COVID-19 is having on interstate population movements and net overseas migration. In the longer term, the forecasts are reflective of the latest growth trends in the ABS household projections data.

[34] Australian and New Zealand Standard Industrial Classification (ANZSIC) divisional descriptions, at https://www.abs.gov.au/AUSSTATS/abs@.nsf/0/AF04F89CEE4E54D6CA25711F00146D76?opendocument.

[35] See https://hia.com.au/-/media/HIA-Website/Files/Media-Centre/Media-Releases/2020/national/half-a-million-jobs-at-risk.ashx.

Figure 14 2020 NEM residential connections actual and forecast, 2013-14 to 2039-40, all scenarios, and compared to 2019



3.1.4 Energy efficiency forecasts

Forecast component relationships: **Residential sector**

Business sector (particularly small-medium enterprises)

Energy efficiency (EE) means obtaining more output or service from each unit of energy[36]. The Commonwealth Government and state governments have developed measures to mandate or promote EE uptake across the economy, and AEMO has considered the impact of these measures on forecast electricity consumption.

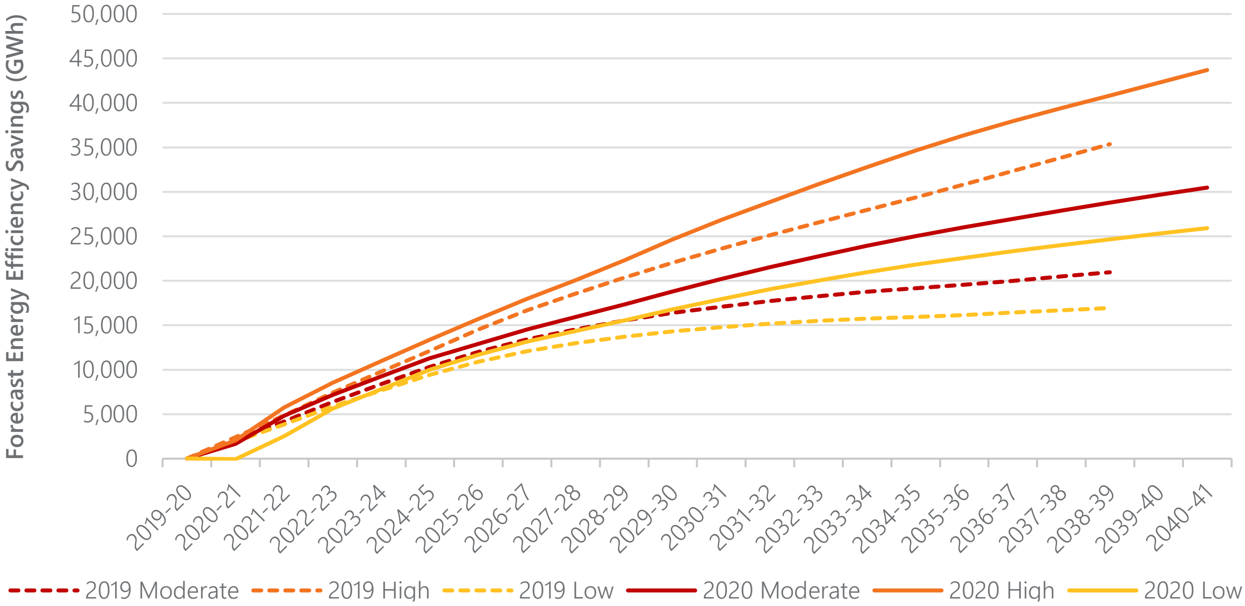
AEMO's 2020 forecast includes more EE savings than in 2019, as shown in Figure 15, largely due to the anticipated continuation and expansion of state schemes beyond legislated end dates and revisions to commercial building stock savings[37]. Some differences may also be attributed to updated economic and demographic input data for the 2020 ESOO.

AEMO's 2020 forecasts focus on three EE scenarios, which are then applied to the five core forecasting and planning scenarios.

[36] From Murray-Leach, R. 2019, The World's First Fuel: How energy efficiency is reshaping global energy systems, Energy Efficiency Council, Melbourne. Available at https://www.eec.org.au/uploads/Documents/The%20Worlds%20First%20Fuel%20-%20June%202019.pdf (viewed 1 April 2020).

[37] For more details, see Electricity Demand Forecasting Methodology Information Paper, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

Figure 15 Forecast energy efficiency savings, 2019-20 to 2039-40, and compared to 2019 ESOO



The EE scenarios provide a degree of spread, with the Low scenario applying similar underlying drivers as the Moderate scenario, but with lower economic, population, housing and connections growth settings. The High scenario incorporates additional measures representing feasible, yet ambitious future standards for buildings and equipment[38] to drive greater EE savings.

The connections forecast uses a yearly construction gross value added (GVA) per capita index[39], relative to the Central connections forecast. The index value varies by region, and ranges from 0.93 to 0.99 in the Slower growth connections forecast, and 1.02 to 1.07 in the Higher growth connections forecast by 2041.

The EE forecasts include the following measures:

- Building energy performance requirements contained in the Building Code of Australia (BCA) 2006, BCA 2010, the National Construction Code (NCC) 2019, and, for the High scenario (applied in Step Change scenario), higher building performance requirements in the future.
- Building rating and disclosure schemes such as the National Australian Built Environment Rating System (NABERS) and Commercial Building Disclosure (CBD).
- The Equipment Energy Efficiency (E3) program of mandatory energy performance standards and/or labelling for different classes of appliances and equipment. The High scenario (applied in Step Change) also considers additional measures that are in proposal stage or are currently suspended but could be reactivated.
- 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).

The impact of state-based schemes is evident in the short to medium term, with tapering growth from the late 2020s to 2030s in the Moderate (Central) and Low (Slow Change) scenarios as currently legislated schemes end, such as the SA REES program in 2020 and the VEU Program in 2030. For the High (Step Change) scenario AEMO extends the SA REES program to 2030, in line with current recommendations[40]. For

[38] The two measures include future changes to the National Construction Code and activities under the Equipment Energy Efficiency program that are in proposal stage, or are currently suspended but could be reactivated.

[39] The index is based on the economic consultant's construction GVA and population forecasts. Their report is available at https://aemo.com.au/-/media/files files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/bis-oxford-economics-macroeconomic-projections.pdf?la=en.

[40] See Review into the South Australian Retailer Energy Efficiency Scheme Review Report December 2019, at http://www.energymining.sa.gov.au/__data/assets/pdf_file/0008/356228/2019_REES_Review_Report.pdf.

the NSW ESS, the state government has committed to a higher target and an extension of the program from 2025 to 2050[41], and this is modelled for all AEMO scenarios.

AEMO assumes that at least 75% of scheme savings persist beyond the lifetime of the schemes, to account for ongoing changes in behaviour that would occur despite the cessation of scheme incentives. This does not apply to the NABERS and CBD programs, which are expected to saturate in uptake, such that their forecast energy savings fall from the mid-2020s.

In the longer term (after 2030), energy savings increase at a slower rate for the Moderate and Low scenarios. In both scenarios, the Greenhouse and Energy Minimum Standards (GEMS) program provides modest savings, and NCC-related savings are a function of net growth in residential dwellings and commercial building stock. For the High scenario, the two additional measures related to higher building and equipment standards deliver stronger savings to 2040 than the other scenarios.

3.1.5 Fuel-switching

Forecast component relationships: **Residential sector**

Business sector (a potential influence on industrial loads)

The electricity consumption forecasts consider policies and programs that induce fuel switching behaviour, between electricity and natural gas, through the EE forecasts and the residential sector's forecast of appliance growth. The EE forecasts assume a shift from gas to electricity for space conditioning when calculating energy savings from the NCC. In the residential sector, for example, the share of reverse-cycle air-conditioning is expected to increase by up to 15%, depending on region and scenario. In the commercial sector, the EE forecasts adopt fuel mix assumptions from building code regulation impact statements.

In 2020, AEMO revised forecast appliance growth to account for fuel-switching effects from policies not captured by the EE forecasts, including the NCC 2022 for residential water heating, the Victorian Solar Homes Program for solar electric water heating, the ACT Gas Heater Rebate, and the planned E3 Zoned Space Heating Label Program (E3Program). AEMO also estimated the potential impact of the Australian Capital Territory Government's Climate Change Strategy, which is legislated to achieve net zero emissions from gas use by 2045[42]. For space conditioning, for example, AEMO applied a proportion of the potential stock change from the E3 program, from 2.5% for the Low scenario, 5% for the Moderate scenario and 25% for the High scenario. For NCC 2022 water heating, AEMO assumed a percentage of new single dwellings would install heat pump hot water, from a base case of instantaneous gas water heating[43] as follows: 25% for the Low scenario, 50% for the Moderate scenario, and 75% for the High scenario. The fuel switching effect of the Victorian Solar Homes Program and ACT Gas Heater rebate is consistent across all scenarios[44].

3.1.6 Consumer behavioural response

Forecast component relationships: **Residential sector**

Business sector (small-medium enterprises, and a potential influence on industrial loads)

Electricity prices are assumed to initiate both structural changes (such as decisions to invest in DER) and behavioural changes (such as how electricity devices are used or energy consumption is managed) by consumers.

Consumption forecasts consider the price elasticity of demand (that is, the percentage change in demand for a 1% change in price). Due to actions consumers have already taken in response to higher prices (such as

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[41] See New South Wales Electricity Strategy November 2019, at https://energy.nsw.gov.au/media/1926/download.

[42] ACT Government, ACT Climate Change Strategy 2019-2025, at https://www.environment.act.gov.au/__data/assets/pdf_file/0003/1414641/ACT-Climate-Change-Strategy-2019-2025.pdf/_recache.

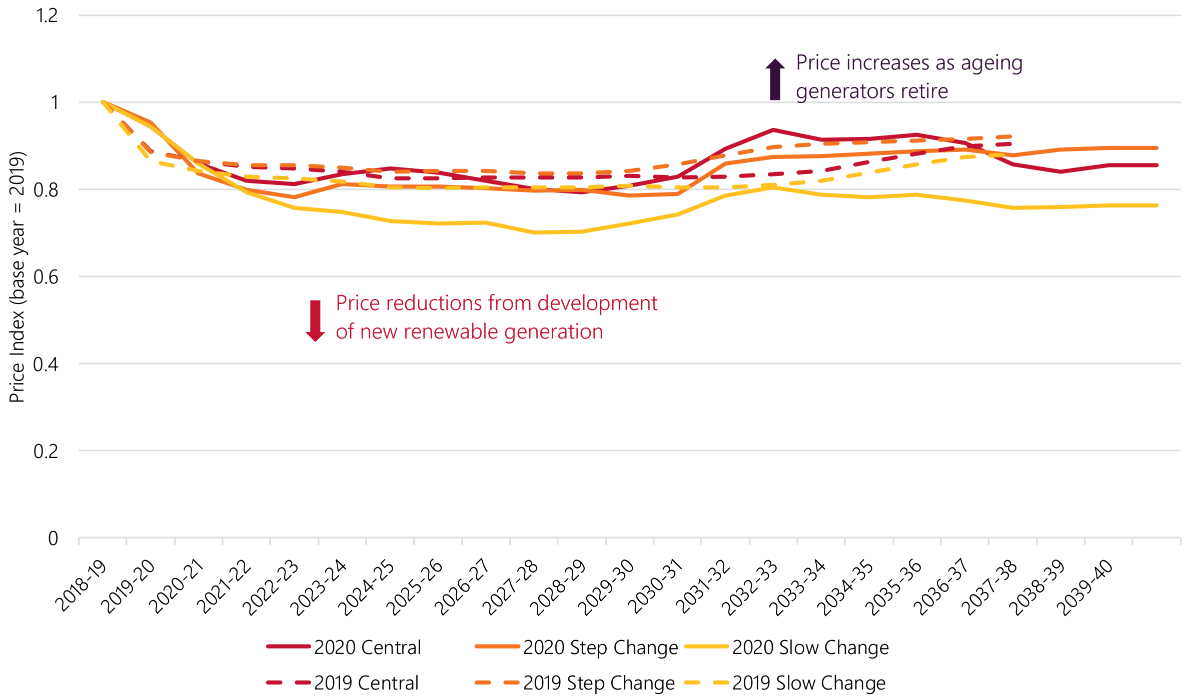
[43] For Class 1 base case assumptions, see Annex 3 of the Trajectory for Low Energy Buildings report December 2018, at http://coagenergycouncil.gov.au/publications/trajectory-low-energy-buildings .

[44] In accordance with published information and data provided by the former Commonwealth Department of Environment and Energy. See https://www.premier.vic.gov.au/victorian-solar-hot-water-systems-rebate-now-available/ and https://www.actewagl.com.au/support-and-advice/save-energy/appliance-upgrade-offers/heating-and-cooling-upgrade/terms-and-conditions-hcu.

installing more energy efficient appliances or improving productive efficiency), demand increases in response to price reductions are assumed to be more muted than demand decreases in response to higher prices.

Figure 16 shows the retail price index assumed for the Central, Slow Change and Step Change scenarios[45] which were formed from bottom-up projections of the various components of retail prices. The retail price structure follows the Australian Energy Market Commission (AEMC) 2019 Residential Electricity Price Trends report, and the wholesale price forecasts are informed by analysis derived from AEMO's Draft 2020 ISP published in December 2019.

Figure 16 Residential retail price index, NEM (connections weighted)



* Price weighted by the number of households.

As Figure 16 shows, prices across the NEM are forecast to decline in the short to medium term as increasing supply (both grid-scale and DER) is expected to lead to downward pricing pressure. As a result, the electricity consumption attributed to consumer behaviour is expected to increase.

AEMO has applied a lower price elasticity of demand in the short term, reducing the impact of falling prices on consumption (that may otherwise increase consumption) to account for the increased uncertainty in consumer confidence due to COVID-19 for the next few years.

For small-medium enterprise business loads, a short-term price elasticity of demand of -0.01 was applied in the Central, High DER and Fast Change scenarios, before returning to the long-term price elasticity of -0.02. A single price elasticity of demand of -0.04 and -0.01 was utilised in the Step Change and Slow Change scenarios, respectively.

For residential loads, the price response is influenced by the appliance forecast, with 'baseload appliances' (such as refrigerators, washing machines, ovens/microwaves and lighting) not applying a price response, while appliances that are 'weather-sensitive' such as heating and cooling loads, apply a price elasticity of demand of -0.1.

[45] The High DER and Fast Change scenarios use the Central price forecast.

3.1.7 Applying historical climatic conditions to forecast years

Forecast component relationships: **Maximum and Minimum Demands**

Market modelling

AEMO's models consider the weather conditions which influence energy consumption (including maximum demand and minimum demand), water inflow variability affecting hydro-generators, network ratings, DER generation, and large-scale renewable generation profiles (including wind and solar generation).

AEMO's methodologies distinguish between the historical conditions used in forecasting maximum and minimum demands and those used in dispatching the power system and projecting supply adequacy and supply evolution.

In forecasting peak demands, AEMO's demand forecasting methodologies consider the last 20 weather years, warmed to reflect the expected temperature conditions of future years (as outlined in Table 3)[46]. For instance, Table 3 shows that the Central scenario is expected to warm by between 2.5⁰C and 2.7⁰C by 2100. AEMO's market modelling methodologies ensure consistent treatment of weather conditions to develop 'reference year traces' that maintain relevant correlations between affected components of the energy system in dispatching and forecasting supply evolution. As outlined in AEMO's market modelling methodologies, simulated 'reference years' include the financial years 2010-11 to 2019-20.

3.1.8 Demand side participation

Forecast component relationships: **Demand side participation forecasts (applied directly in market modelling)**

AEMO's forecast approach considers DSP explicitly in its market modelling, meaning that consumer demand history and forecasts must exclude 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, supplemented by historical meter data.

Distribution of historical DSP responses

As explained in AEMO's DSP Methodology Document[47], 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.

For transparency around the spread of observed responses, Figure 17 to Figure 21 below show response probability curves (estimated observed responses against calculated baseline sorted from smallest to largest) for each NEM region for each half-hour where the half-hourly market prices exceeded $2,500/MWh during the period April 2017 to March 2020. These probability curves were used to determine the 50th percentile historical response used in the 2020 DSP forecasts. The distribution for even higher-price triggers generally looks similar.

As explained in the DSP methodology document, the estimates of observed DSP are based on the difference between observed demand and calculated baseline demand. Any baseline methodology is an approximation and inherently assumes customers follow a particular trend, such as a similar day in the past. In reality, any load (aggregate or individual) will either be over or under this in the absence of any DSP response (with a perfect baseline, the split would be 50/50). For that reason, the observed program load for some half-hours can show as an increase relative to the baseline (negative DSP response). This basically represents a random drift in consumption around an average baseline at times where there is no response. The figures below show negative values seen up to 20% of the half-hourly observations. A similar number of half-hours would see a reduction in consumption, without this being driven by customer action (positive DSP response).

[46] Future physical symptoms of climate change, specifically increases in extreme temperatures and reductions in average rainfall, are superimposed on these reference years going forward in time (see Section A2.3 of AEMO's Demand Forecasting Methodology Information Paper for more details of how changes in extreme temperature are captured in the demand forecasts).

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

Removing negative values creates a bias towards over-forecasting DSP unless a similar amount of upwards random drift is removed. However, as AEMO uses the 50th percentile of responses, any bias will be negligible, and no adjustments are required.

Figure 17 New South Wales – distribution of observed DSP against baseline for prices ≥$2,500/MWh

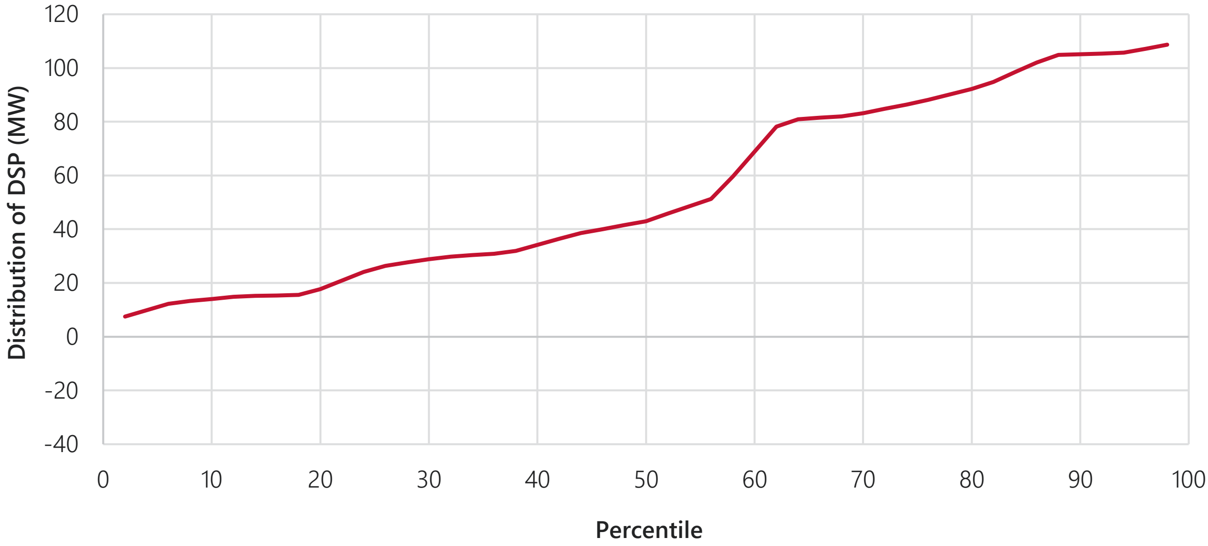


Figure 18 Queensland – distribution of observed DSP against baseline for prices ≥$2,500/MWh

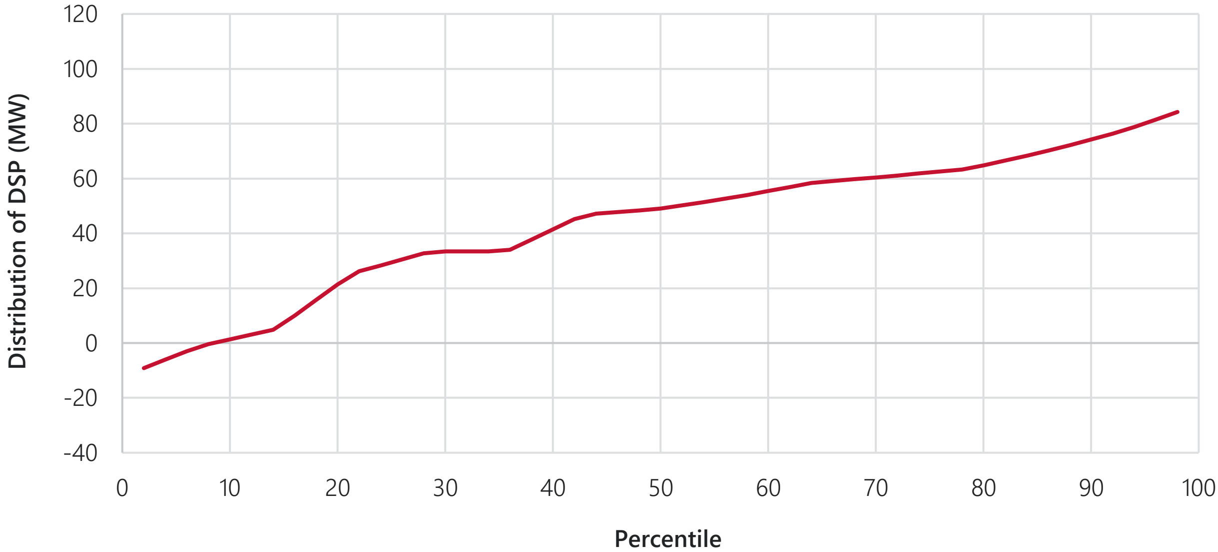


Figure 19 South Australia – distribution of observed DSP against baseline for prices ≥$2,500/MWh

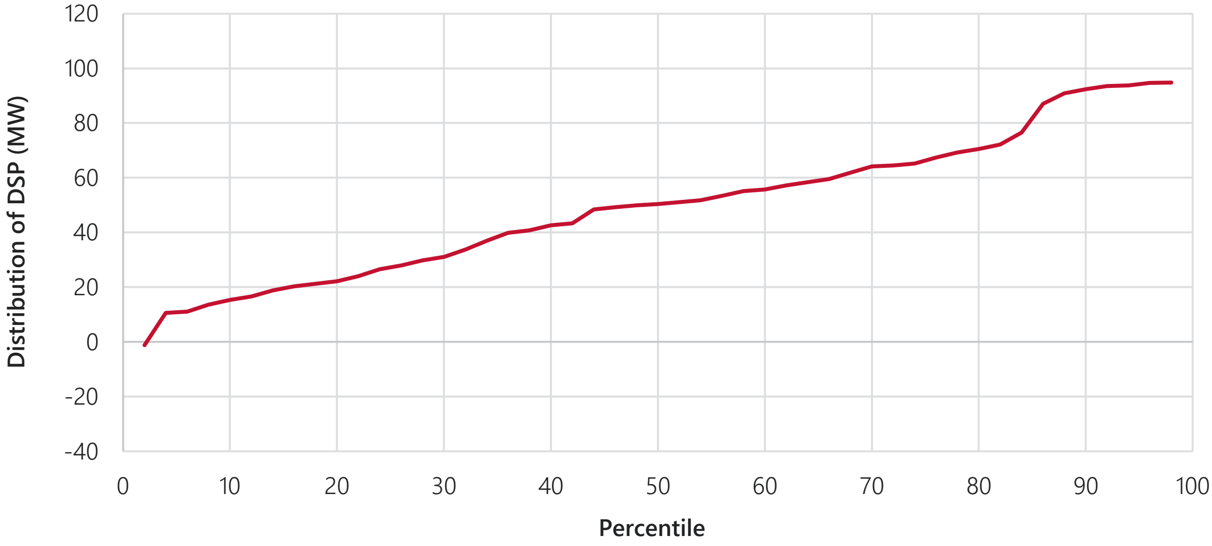


Figure 20 Tasmania – distribution of observed DSP against baseline for prices ≥$2,500/MWh

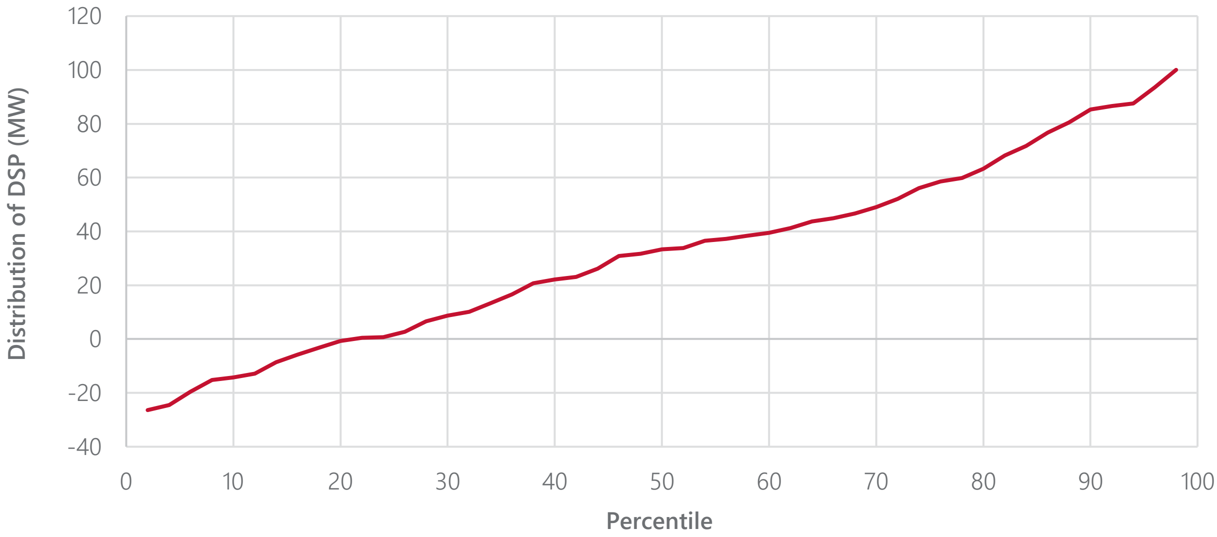
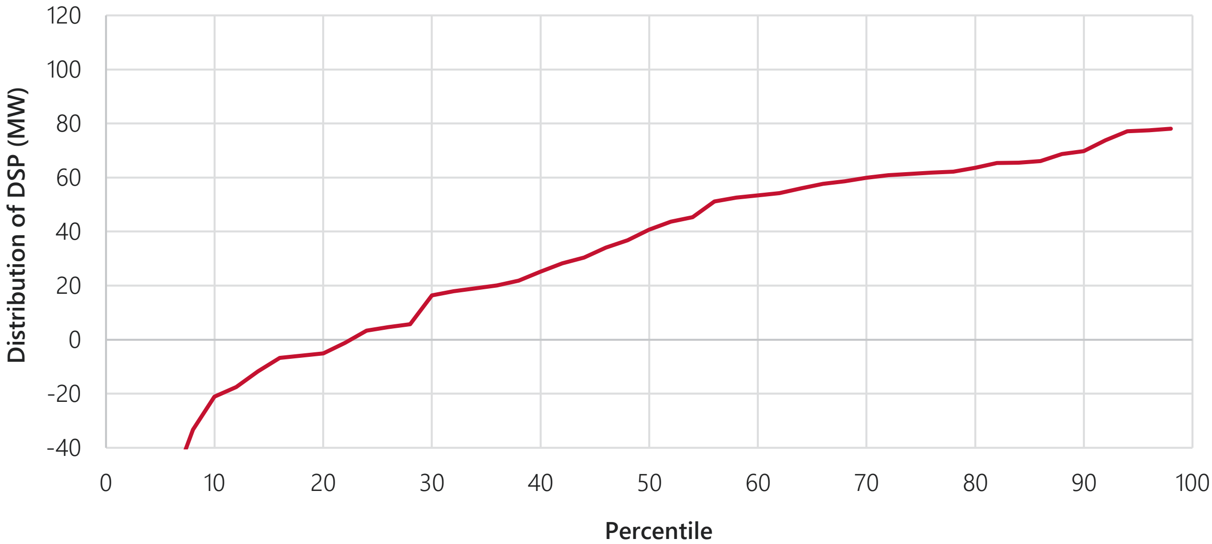


Figure 21 Victoria – distribution of observed DSP against baseline for prices ≥$2500/MWh



DSP in AEMO's medium- to long-term reliability processes

The Medium Term Projected Assessment of System Adequacy (MT PASA), ESOO, and Energy Adequacy Assessment Projection (EAAP) modelling currently apply estimated levels of DSP for the entire forecasting horizon, as no information has been provided by participants about future changes to DSP that would be as firm as the generator commitment criteria used[48].

DSP in AEMO's long-term planning studies

For long-term planning studies like the ISP, the DSP projection is prepared based on current levels and adopting a level to be met by the end of the outlook period. The level is defined as the magnitude of DSP relative to maximum demand and linearly interpolated between the beginning and ends of the outlook period. The level reflects scenario assumptions and region-specific features where necessary.

A review of international literature and reports of demand response potential (primarily in the United States and Europe) indicated that the adopted (high) level of 8.5% of maximum demand (also adopted for the 2018 ISP) is a reasonable upper estimate for growth in DSP. Further findings of the review indicated:

- Expanding existing best practice DSP, focusing on commercial and industrial programs, could feasibly achieve DSP potential of 9% of maximum demand; some United States markets where demand response programs are advanced are already seeing participation levels between 2% and 10% of peak demand[49,50].
- Reported current demand response potential, in markets where DSP is advanced, can range from 3% to 12%[51].
- DSP potential in European countries is estimated to be between 7.5% and 10%, with some outliers outside this range, and one estimate suggesting the level was 9.4% for 34 countries represented[52,53,54].
- Large (five- or eight-fold) differences between current active DSP and future potential DSP may exist[55].
- Market structures (wholesale price market or capacity market) and DSP policy design (conditions on participation) play a role in incentivising or creating barriers to DSP.

The 2050 targets used for the scenarios for each NEM mainland region are as follows:

- Step Change – high DSP growth to reach 8.5% of peak demand as found above.
- High DER – high DSP growth to reach 8.5% of peak demand as found above.
- Fast Change – moderate DSP growth to each 4.25% of peak demand (half of the growth above).
- Central – moderate DSP growth to each 4.25% of peak demand (half of the growth above).
- Slow Change – current level of DSP as percentage of peak is maintained.

For Tasmania, which is not capacity constrained and therefore less incentivised do deploy DSP solutions, the growth in the first four scenarios is half of that listed for the mainland regions.

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[48] Examples of what are considered firm changes to DSP are provided in the DSP forecast methodology document, at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2020/demand-side-participation/final/demand-side-participation-forecast-methodology.pdf.

[49] FERC, 2009 Assessment of Demand Response and Advanced Metering, 2009, at https://www.ferc.gov/legal/staff-reports/sep-09-demand-response.pdf.

[50] FERC, 2018 Assessment of Demand Response and Advanced Metering, 2018. at https://www.ferc.gov/legal/staff-reports/2018/DR-AM-Report2018.pdf.

[51] ERCOT Annual Report of Demand Response (2019), at http://www.ercot.com/services/programs/load.

[52] SIA Partners, Demand Response: A study of its potential in Europe, February 2015, at http://energy.sia-partners.com/demand-response-study-its-potential-europe.

[53] Gils, H. C., Economic potential for future demand response in Germany – Modelling approach and case study, Applied Energy 162 (2016) 401-415.

[54] Gils, H. C. Assessment of the theoretical demand response potential in Europe, Energy 67 (2014) 1-18.

[55] SEDC & RAP, Slides presented on Potential of Demand Response in Europe, Workshop on Demand Participation in Electricity Markets and Demand Response: Regulatory Framework and Business Models, 2017, at https://www.raponline.org/wp-content/uploads/2017/11/rap_sedc_rosenow_thies_fsr_slides_2017_oct.pdf.

3.2 Key policy settings

Section 2.3 outlined the policy settings to apply in each scenario. The following sections outline the policy assumptions in greater detail and explains how the carbon budgets of the Fast Change and Step Change scenarios are derived.

3.2.1 Emissions reductions and climate change

Each scenario narrative is associated with a particular atmospheric greenhouse gas concentration, as outlined in Table 3 (in Section 2.3).

In the Central and High DER scenarios, AEMO applies existing national and state emissions and renewable energy policies (such as Australia's existing commitment to 26% emissions reduction on 2005-levels by 2030, and state policies such as the VRET and QRET). The Central and High DER scenarios also apply generator closure dates supplied to AEMO by the respective facility owners and operators. These settings are expected to drive ongoing emission reductions.

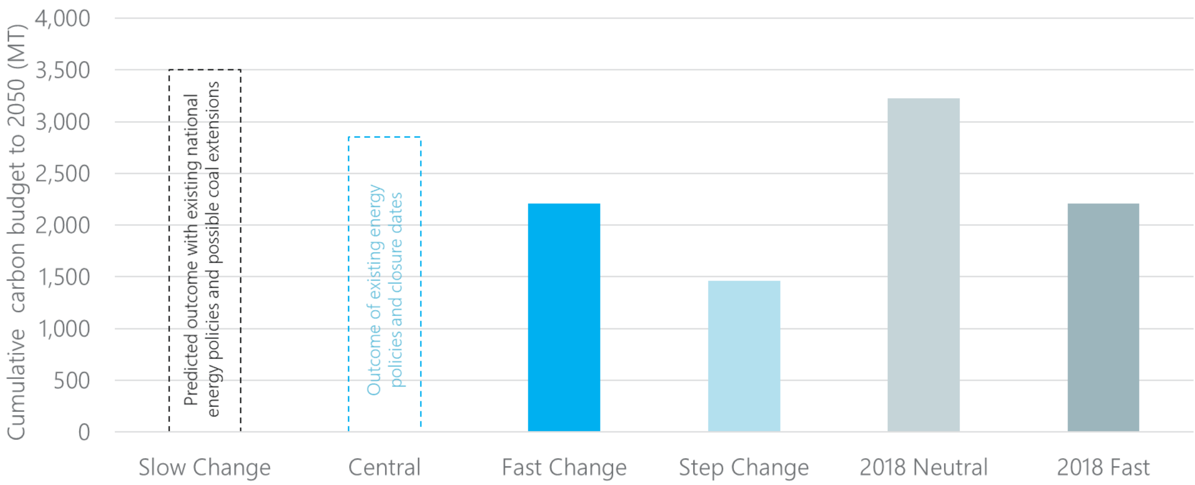
In the Slow Change scenario, AEMO applies Australia's existing 26% emissions reduction on 2005 levels by 2030, while state policies are not extended from currently legislated levels, and may be scaled back below current targets (as is the case in the QRET). The Slow Change scenario allows life extensions of coal generators for 10 years beyond current closure dates if the system value of these extensions is greater than the refurbishment cost.

In the Fast Change and Step Change scenarios, AEMO applies carbon budgets that target a specific decarbonisation objective, with the electricity sector expected to provide a significant contribution. These cumulative budgets require the electricity sector to constrain emissions to a specified volume between 2020 and 2050. The trajectory of emissions reductions over time is optimised within the market models to meet the carbon budget as efficiently as possible. To achieve the decarbonisation objective, the model may retire and replace emission-intensive plant (black and brown coal generators) with large-scale renewable generation or lower emissions technologies (gas-powered generation [GPG]) earlier than the current announced generator closure dates, so long as the minimum notice of closure requirements are maintained.

No explicit carbon price is included in any scenario.

The emissions intensities of each generator are detailed in the 2020 Inputs and Assumptions Workbook.

Figure 22 Cumulative NEM electricity sector emissions to 2050 that will be input as carbon budgets



The specific carbon budget assumptions for each scenario have been developed as follows:

- Each scenario has been allocated a "Representative Concentration Pathway" (RCP) that represents the global greenhouse gas concentration trajectory consistent with the scenario narrative. The RCPs have been developed by climate scientists to describe possible pathways for atmospheric greenhouse gas concentrations, and the associated climate change impacts. Development of "Shared Socio-economic Pathways" (SSP) has broadened the future climate scenarios, providing narratives around global emissions drivers, mitigative capacity and adaptive capacities that may result in particular RCPs. The RCP/SSP framework is designed to be complementary, and AEMO has considered it appropriate to continue to focus on the RCPs selected, thereby maximising flexibility in scenario specification.

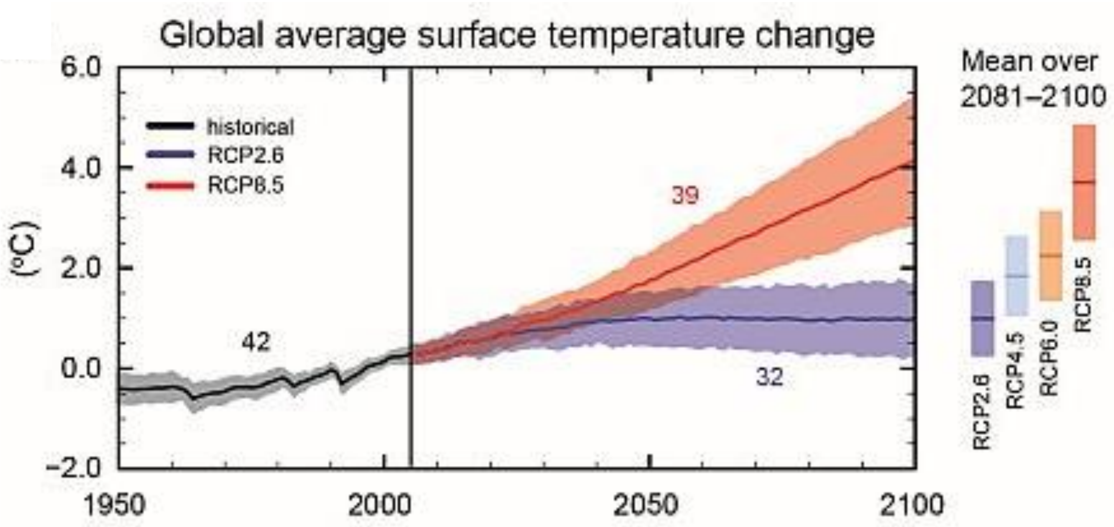
- The global trajectories have been translated to Australian trajectories using methodologies broadly consistent with the modified contraction and convergence approach suggested by the Climate Change Authority[56] for use in setting Australian emissions budgets. This method considers an equitable allocation of responsibility between countries with global convergence towards equal per person rights.
- A NEM budget was then developed based on the Australian budget and relevant scenario narrative. For example, the NEM may lead the Australian budget in scenarios with aggressive decarbonisation goals and may remain parallel in others. The budget informing the Step Change scenario is broadly consistent with the Climate Change Authority's Special review electricity research report[57].

While some scenarios include high levels of emission reductions, they do not reach zero NEM emissions by 2050. It is assumed that some emissions will be required for system black start and synchronous and peaking support capabilities, and/or that emissions reductions will become more cost-effective in other sectors of the economy.

Despite emissions not reaching zero, the Step Change scenario is considered appropriate for either RCP2.6 or RCP1.9 global outcomes. In this scenario, the electricity sector has led national emissions reduction efforts to the degree that remaining abatement must be driven by other sectors of the economy.

The physical symptoms of climate change vary across the scenarios to reflect the scenario narratives. For example, the timing and magnitude of global action in the Step Change scenario will be far greater than in the Slow Change scenario, and in response will result in less climate change. In the context of the energy sector, Australian-specific climate information on regional changes in average and extreme temperatures and long-term average rainfall has been estimated through close collaboration with CSIRO and the Bureau of Meteorology as part of the Electricity Sector Climate Information (ESCI) project, sponsored by the Australian Government[58]. Figure 23 shows the global temperature change expected for the four atmospheric greenhouse gas concentrations (RCP2.6-RCP8.5) applied across the scenarios[59].

Figure 23 Climate pathways modelled across ISP scenarios



[56] Climate Change Authority, Targets and Progress review, at http://climatechangeauthority.gov.au/reviews/targets-and-progress-review-3 (Appendix C).

[57] Climate Change Authority, 2016. Special review electricity research report, at www.climatechangeauthority.gov.au/reviews/special-review/special-review-electricity-research-report.

[58] See http://www.environment.gov.au/climate-change/adaptation.

[59] Global climate change projections, at https://www.climatechangeinaustralia.gov.au/en/climate-campus/global-climate-change/global-projections/.

3.2.2 Renewable energy targets

Large-scale Renewable Energy Target (LRET)

The national LRET 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 GreenPower scheme and Australian Capital Territory (ACT) reverse auction programs.

AEMO applies the national LRET in proportion to the energy consumption in NEM versus non-NEM energy regions, resulting in approximately 84% of the LRET target being targeted for development in the NEM.

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 5,500 MW of committed or proposed wind generation projects, and approximately 2,900 MW of committed or proposed solar generation projects[60].

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 1,300 MW of committed or proposed wind generation projects, and almost 13,000 MW of committed or proposed solar generation projects (over 48% of all committed or proposed solar generation projects across the NEM)[60].

Tasmanian Renewable Energy Target (TRET)

The Tasmanian Government recently announced[61] its intent to establish a 200% renewable energy target by 2040, with an interim target of 150% by 2030. This extends the Tasmanian Government's existing commitment to 100% renewable energy by 2022. The details of the target are yet to be legislated, however in modelling this target in some scenarios, AEMO has included it as measured against total Tasmanian consumption, similar to the QRET, including renewable DER.

Distributed energy resources policies

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

- South Australia – Home Battery Scheme[62].
- Victoria – Solar Homes Scheme[63].
- New South Wales – Clean Energy Initiatives[64].
- Emission Reduction Fund and Victorian Energy Saver Incentive Scheme (additional PVNSG revenue stream via Victorian Energy Efficiency Certificates (VEECs) or Australian Carbon Credit Units (ACCUs))[65].
- Australian Capital Territory Next Generation Energy Storage program[66].

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[60] AEMO 29 July 2020 Generation Information release, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[61] Draft Tasmanian Renewable Energy Action Plan 2020, at https://www.stategrowth.tas.gov.au/energy_and_resources/energy/renewable_energy#:~:text=Tasmanian%20Renewable%20Energy%20Action%20Plan%202020&text=Tasmania%20can%20harness%20the%20immense,clean%2C%20reliable%20and%20affordable%20energy.

[62] Details at https://homebatteryscheme.sa.gov.au/.

[63] Details at https://www.solar.vic.gov.au/.

[64] Details at https://energy.nsw.gov.au/renewables/clean-energy-initiatives.

[65] For details see pages 30-33 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.

[66] Details at https://www.actsmart.act.gov.au/what-can-i-do/homes/discounted-battery-storage.

- Trial programs to integrate VPPs and explore how a network of small-scale PV and batteries can be collectively controlled and fed into the grid[67].

AEMO has incorporated each of these schemes in the DER uptake and behavioural analysis performed within the 2020 demand forecasts.

3.3 Key technical and economic settings affecting energy supply

3.3.1 Generators and storage data

AEMO's Generation Information page[68] publishes data on existing and committed generators and storage projects (size, location, capacities, seasonal ratings, and expected closure years), and non-confidential information provided to AEMO on the pipeline of future potential projects

The cost and performance of generic new generation technologies reflect the most current pricing and estimates of future cost and performance data of new generation technologies. AEMO has collaborated with the Clean Energy Council (CEC), CSIRO, GHD, Aurecon, and other stakeholders through the GenCost project[69] to develop these estimates of future generation costs and other resource parameters. This information will be updated annually, and includes:

- Fixed and variable operating and maintenance costs.
- Thermal efficiency factors.
- Emissions factors.
- Unit auxiliary loads.
- Capital costs for new generation developments.

According to Aurecon, the current cost estimates (if constructed in July 2019), used as a starting point to project reductions in future costs based on learning curves, have an expected accuracy range of +/- 30%, depending on the level of definition of the generating plant and information available.

Candidate generation technology options

GenCost includes projected build costs for a range of new generation technologies. AEMO applies a filtered list of technologies from this GenCost technology list, guided by stakeholder feedback, and based on technology maturity, resource availability, and energy policy settings.

Table 6 below presents the list of generation technologies included within AEMO's capacity outlook models (used for ISP or RIT-T assessments, or gas powered generation forecasts), for consideration in each scenario.

Technologies excluded from this list include:

- Nuclear generation – nuclear generation is excluded, as currently Section 140A of the *Environment Protection and Biodiversity Conservation Act 1999*[70] prohibits the development of nuclear installations.
- Carbon capture and storage – currently no domestic carbon capture and storage technologies are in operation, and there is insufficient data available that would allow complete modelling of the generation, capture, transmission, and storage of emissions using dedicated pipeline infrastructure to new CO_2 storage facilities. Should the technology advance further, with sufficiently granular data becoming available, then it may be possible to include in future ISPs.

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[67] 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.

[68] 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.

[69] CSIRO, GenCost 2019-20, at https://publications.csiro.au/publications/#publication/PIcsiro:EP201952/SQgencost/RP1/RS25/RORECENT/STsearch-by-keyword/LISEA/RI1/RT4 .

[70] Australian Government, *Environment Protection and Biodiversity Conservation Act 1999*, at https://www.legislation.gov.au/Details/C2012C00248.

- Geothermal technologies – geothermal technologies are considered too costly and too distant from existing transmission networks to be considered a bulk generation technology option in any REZ, 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 within AEMO's Capacity Outlook models. Presently, SAT projects also provide much more proposed capacity than DAT and FFP projects. Given this broad preference and the relative cost advantage, and considering the relatively small difference in expected generation profiles of each technology, AEMO models all future solar developments with a SAT configuration.
- Biomass – AEMO's models include a single representation of biomass as a standalone electricity generation source, however in reality many projects may identify biomass solutions as optimal, particularly where cogeneration or waste materials are produced, and electricity generation is not the primary objective of the facility.
- Tidal/wave technologies – this is not sufficiently advanced or economic to be included in the modelling.

Table 6 Candidate generation technology options

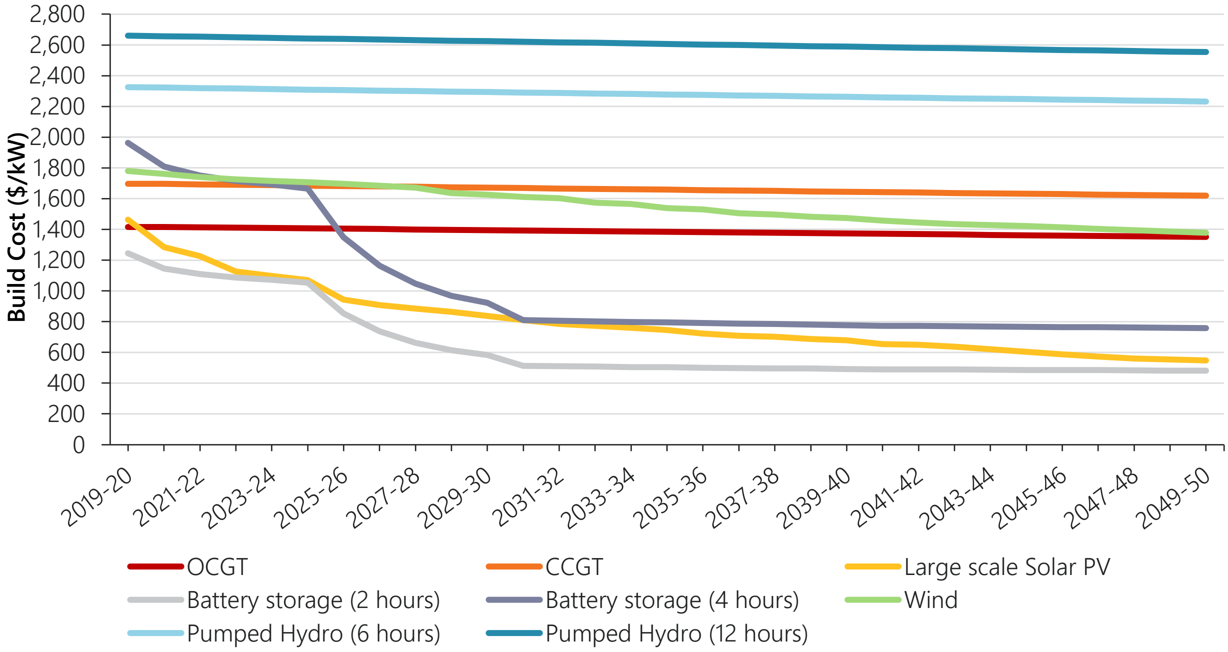
Technologies available for future generation expansion (in the 2020 ISP, for example)	Commentary (if applicable)
Combined cycle gas turbines (CCGT)	
Open cycle gas turbines (OCGT)	For new OCGTs, a typical aero-derivative based configuration has been selected based on GenCost stakeholder feedback.
Supercritical black coal	Given the market need for flexible plant to firm low-cost renewable generation, new coal generation would be highly unlikely in any scenario with emissions abatement objectives, particularly given the long-life nature of any new coal investment.
Supercritical brown coal	
Synchronous condenser	
Biomass (wood) – electricity only	
Solar photovoltaics – single axis tracking	
Solar thermal central receiver with storage	
Wind – onshore	
Wind – offshore	Victorian offshore locations (off the Gippsland REZ) are included, given expanded data sets obtained from DNV-GL.
Battery storage	AEMO includes 2- and 4-hour variants of battery storages in its models. No geographical or geological limits will apply to available battery capacity.
Pumped hydro energy storage (PHES)	AEMO includes 6-hour, 12-hour, 24-hour, and 48-hour variants of PHES.

Build costs

CSIRO's GenCost build cost projections are a function of global and local technology deployment. Note that these costs only represent the capital cost component of a new power station. To understand the delivered cost of energy for each technology, a number of additional factors need to be considered, for example, fuel costs (if applicable) and capacity factors. These further details are presented in the 2020 Inputs and Assumptions Workbook.

Figure 24 presents GenCost build cost projections for selected technologies (using Melbourne as a development location for indicative purposes).

Figure 24 Build cost projection for selected technologies for Central scenario ($/kW)



Locational cost factors

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, and regional labour cost differences, all contribute to locational variances of technologies, ignoring localised environmental/geological/social drivers.

GHD estimated locational cost adjustment factors in 2018 that may be applied to technologies to capture the known drivers of cost differences. These have not been adjusted in 2020.

Figure 25 presents the overlaid regional cost factor map prepared by GHD over the REZ map. Three cost regions are presented – low, medium, and high – and summarise locational multiplicative scalars that should apply between developments of equivalent type but across different locations. Detailed values are provided in AEMO's 2020 Inputs and Assumptions Workbook.

Because the relativity between locational cost groupings differs based on development cost weightings, the figure is to be interpreted with consideration of Table 7, which shows the relativity of the regional costs between locational cost groupings, per region. For ease of use, the 2020 Inputs and Assumptions Workbook provides this for each technology, given development cost shares.

Cost projections to build new generation technologies developed for GenCost are the overnight costs for construction in Melbourne. To calculate the capital costs of these technologies elsewhere in Australia, the locational cost factors provide a multiplicative scaler to the respective generation development costs.

Each region has a different relative contribution of the technology cost components listed in Table 7. This technology cost breakdown is provided in Table 8. Technology build costs consider the cost adjustments from both data sources. The 2020 Inputs and Assumptions Workbook provides these details, plus provides the resulting technology, regional cost adjustment factors.

Figure 25 Locational cost map

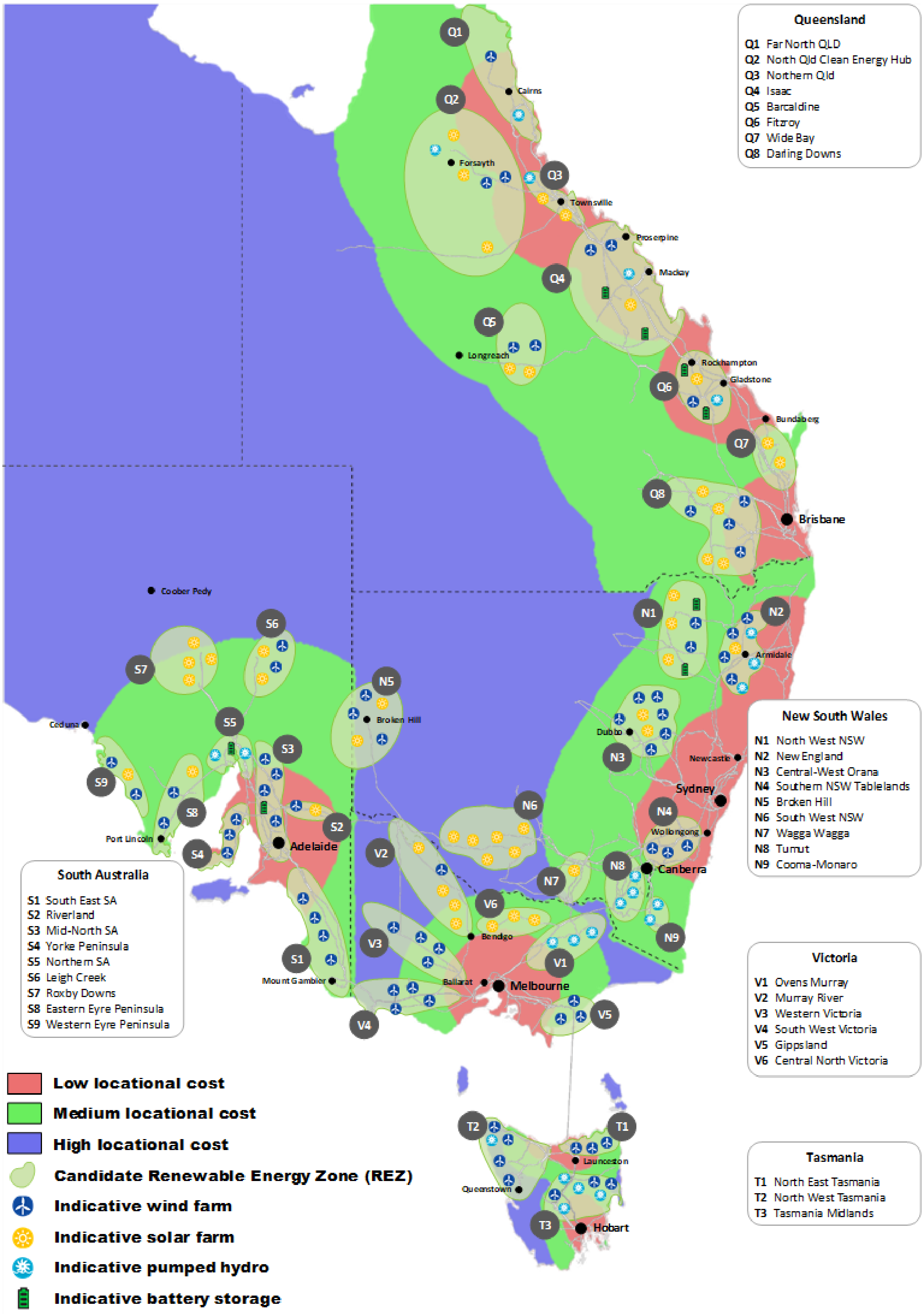


Table 7 NEM locational cost factors

Region	Grouping	Equipment costs	Fuel connection costs	Cost of land and development	Installation costs	O&M costs
Victoria	Low	1.00	1.00	1.00	1.00	1.00
	Medium	1.03	1.03	1.00	1.03	1.03
	High	1.05	1.05	1.00	1.05	1.05
Queensland	Low	1.00	1.05	1.00	1.10	1.07
	Medium	1.05	1.16	1.00	1.27	1.20
	High	1.10	1.27	1.00	1.44	1.34
New South Wales	Low	1.00	1.09	1.00	1.18	1.13
	Medium	1.05	1.17	1.00	1.30	1.22
	High	1.10	1.26	1.00	1.42	1.32
South Australia	Low	1.00	1.01	1.00	1.02	1.01
	Medium	1.05	1.11	1.00	1.17	1.13
	High	1.10	1.21	1.00	1.32	1.25
Tasmania	Low	1.00	1.04	1.00	1.07	1.05
	Medium	1.05	1.11	1.00	1.18	1.14
	High	1.10	1.19	1.00	1.29	1.23

Table 8 Technology cost breakdown ratios

Technology	Equipment costs	Fuel connection costs	Cost of land and development	Installation costs
CCGT	85%	0%	8%	7%
OCGT	86%	0%	8%	6%
Black Coal (supercritical PC)	71%	4%	16%	9%
Brown Coal (supercritical PC)	73%	0%	17%	11%
Battery storage (2 hrs storage)	71%	0%	6%	23%
Battery storage (4 hrs storage)	71%	0%	6%	23%
Biomass	30%	0%	17%	54%
Large scale Solar PV	87%	0%	6%	7%
Solar Thermal (8hrs Storage)	83%	0%	6%	11%
Wind	82%	0%	3%	14%
Wind – offshore	77%	0%	3%	19%

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 improvement is expected to lead to more energy output for the same installed capacity, lowering the investment cost per unit of energy ($ per megawatt hour [MWh]). To reflect this trend in AEMO's models, transformation of the CSIRO inputs is required.

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.

3.3.2 Storage technology modelling

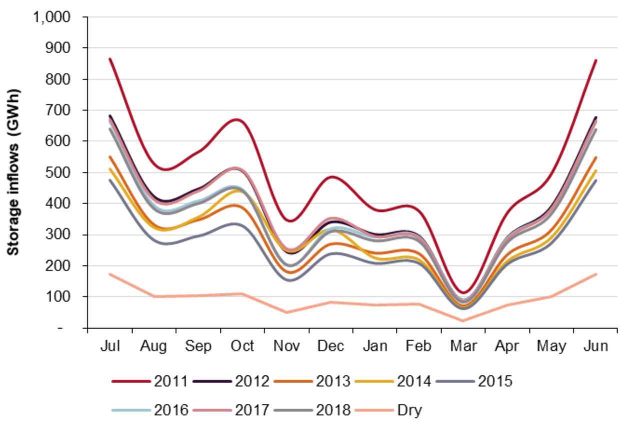
AEMO includes a range of storage options in the market modelling conducted for the 2020 ISP. Storage expansion candidates in each region include pumped hydro energy storage (PHES), large-scale batteries, concentrated solar thermal (CST), and DER.

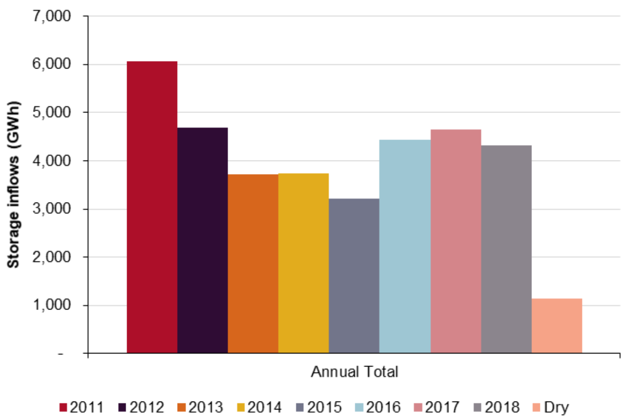
AEMO captures the location of storage developments considering the regional build limits presented in the 2020 Inputs and Assumptions Workbook, and for pumped hydro technologies, the sub-regional limits within the 2018 Entura report[71], which AEMO has modified to reflect the latest information and generator interest while still observing the regional limits. Exact storage locations are identified by 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.

Hydro generator modelling

AEMO models each of the large-scale hydro schemes using inflow data for each generator, or aggregates some run-of-river generators, as explained in AEMO's Market Modelling Methodology Paper[72]. AEMO also obtains data directly from existing large-scale hydro operators. The 2020 Inputs and Assumptions Workbook provides the variation in hydro inflows for key hydro schemes. An example of this is shown in Figure 26 below, for Snowy Hydro. Hydro scheme inflows in Queensland, Victoria (excluding the Victorian units of Snowy Hydro) and Tasmania are also available in the 2020 Inputs and Assumptions Workbook.

Figure 26 Hydro inflow variability across reference weather years





[71] 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.

[72] AEMO Market Modelling Methodologies, July 2020, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/market-modelling-methodology-paper-jul-20.pdf?la=en.

Pumped hydro energy storage (PHES)

AEMO includes PHES options equivalent to six, 12, 24, and 48 hours of energy in storage. This portfolio of candidates complements deep strategic initiatives (such as Snowy 2.0), and existing traditional hydro schemes.

Build costs and locational costs for these pumped hydro storage sizes have been obtained from Entura[73], and adjusted as considered appropriate from feedback received during AEMO's 2020 IASR consultation. As with all technologies, future costs are influenced by forecast technology cost improvements. For PHES, AEMO has applied the forecast capital cost reduction of six hours pumped hydro storage to all PHES sizes, as forecast in the GenCost report. These are provided in detail in the 2020 Inputs and Assumptions Workbook.

Feedback received during the Draft ISP consultation was that PHES costs were under-estimated in the Draft ISP, and a high degree of uncertainty exists for desktop cost estimates of this type. In addition, it was recognised that there are higher risks and barriers to investment in PHES compared to other forms of storage, as evidenced by the higher number of utility scale battery projects currently being planned across the NEM. Anecdotal evidence provided in submissions, in discussions with some proponents and through engagement with reputable consultants with experience in PHES developments, suggest an increase in costs of approximately 50% was more appropriate. This magnitude of increase is aligned with experience in other major infrastructure projects, where it was noted that major infrastructure projects by their nature can experience capital cost increases over initial estimates during the implementation.

For clarification, the capital cost increases assumed for PHES projects only apply to future uncommitted PHES projects, and do not apply to the Snowy 2.0 project. AEMO considers Snowy 2.0 as a committed project and is not aware of any changes to the capital costs since the publication of its feasibility study.

As with other new entrant technologies, locational cost factors apply to PHES options, to distinguish those regions with natural resource and cost advantages. Tasmania, for example, is assumed to have materially lower development costs for PHES than the mainland, for most PHES options. As shown in Table 9[74], Tasmanian PHES facilities are at least approximately 24% lower cost than Victorian alternatives. The table also demonstrates the assumed level of cost dispersion that is increasingly significant with rising storage depth.

Table 9 PHES locational cost factors

Region	PHES: 6hrs	PHES: 12hrs	PHES: 24hrs	PHES 48hrs
Victoria	1.00	1.00	1.00	1.00
Queensland	1.00	1.05	0.93	0.87
New South Wales	1.03	1.03	0.94	0.74
South Australia	1.26	1.51	1.67	N/A
Tasmania	0.76	0.73	0.62	0.46

Batteries

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

Assumptions for battery storages of both 2-hour and 4-hour duration depths are available for 2020-21 modelling. Battery round-trip efficiency is assumed to be 81% – equivalent to a 90% charge and 90% discharge efficiency respectively. Battery storages' deterioration, in terms of efficiency, power, or capacity, is not modelled, given the computational complexity of incorporating degradation (particularly in capacity

[73] 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.

[74] These locational cost factors are also provided in the 2020 Inputs and Assumptions Workbook.

outlook models). However, like all technologies, the battery will retire at the end of its technical life, which is set to 20 years for batteries[75] (approximating the expected warranted technical life). Based on stakeholder feedback, this technical battery life for batteries was extended from 2019 assumptions which applied a 15-year life.

The cost of battery disposal was not considered, as cost information on this activity is not within AEMO's data sets. This may understate 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.

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 battery storage object, rather than applying a static storage discharge trace.

3.3.3 Weighted Average Cost of Capital (WACC) and social discount rate

In most scenarios, AEMO applies the discount rate of 5.90% (real, pre-tax) for NPV calculations, consistent with the Regulatory Investment Test for Transmission (RIT-T) guidelines and sourced from Energy Networks Australia's RIT-T handbook[76]. Applying a risk premium to emissions-intensive generation technologies is unlikely to significantly impact the outcomes, given technology cost movements of renewable energy projects relative to thermal alternatives. The Slow Change scenario's settings are associated with lesser economic stimulation, challenges to trade flows and lower economic conditions. To account for the more challenging economic environment, which is likely to result in lower returns and a generally greater challenge to make major investments, AEMO used a higher discount rate of 7.90% as a simple way to account for these issues in the decision-making process.

AEMO adopts this WACC for all generation and transmission options in a technologically agnostic manner. AEMO considers that applying technology-specific values, particularly applying a risk premium to emissions-intensive generation technologies, is unlikely to significantly impact the outcomes, given technology cost movements of renewable energy projects relative to thermal alternatives.

3.4 Existing generator assumptions

3.4.1 Generator operating parameters

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. AEMO collected information from all generators on the timing, duration, and severity of unplanned forced outages, via its annual survey process. This data was used to calculate the probability of full and partial forced outages in accordance to the ESOO and Reliability Forecasting Methodology document[77].

As part of preparations for the 2020 ESOO, AEMO commissioned AEP Elical[78] to provide the forward-looking outage values for coal-fired generators. AEMO also requested operators of coal-fired generators and some gas-fired generators to provide forward-looking projections of forced outages over the next 10 years. Both of

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[75] As detailed in Aurecon's 2019 Costs and Technical Parameter Review report, battery projects are expected to experience a mid-life refurbishment to replace the initial battery cells after 10 years of operation. This notional timing has been considered in determining the economic life of the project, which is the time assumed for the project to recover build costs. With this mid-life reimbursement, the technical life of the project can be extended to 20 years, at which point the project will be retired.

[76] At https://www.energynetworks.com.au/sites/default/files/ena_rit-t_handbook_15_march_2019.pdf.

[77] At https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

[78] 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.

the forecasts are intended to capture a combination of improvements and deteriorations in outage performance across the generation fleet.

Where possible, AEMO has relied on the information provided by participants. However, for some generators where a forward-looking projection was not provided or where outage projections were not sufficiently substantiated with explanations or evidence, AEMO has relied on the forecasts provided by AEP Elical. The forecasts applied are expected to capture a combination of improvements and deteriorations in outage performance across the generation fleet.

High Impact Low Probability (HILP) outages

As described in the ESOO and Reliability Forecast Methodology document, AEMO has removed outages with a duration longer than five months from historical outage data from 2010-11 to 2019-20. For the ESOO, AEMO then used an extended historical period of 10 years to determine HILP outage rates, which are applied in addition to the more regular forced outage rate assumptions. The HILP outages used in 2020 ESOO modelling, and in other reliability assessments such as MT PASA and EAAP, are shown in Table 10 below.

In other publications, such as the ISP, that do not use as many Monte Carlo simulations, the HILP outage rates are added to the standard full forced outage rate. For the capacity outlook model, these standard full forced outage rates are used to de-rate the capacity of units based on the average availability of the units that is expected throughout the year. More information on treatment of outage rates across AEMO's modelling is in the Market Modelling Methodology Paper[79].

Table 10 HILP outage assumptions

Technology	HILP outage rate (%)	MTTR (hours)*
Brown coal	0.65	5,290
Black coal New South Wales	0.84	5,568
Black coal Queensland	0.23	4,656
Open cycle gas turbine (OCGT)	0.43	4,032

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

Forced outage rate trajectories

The base forced outage rates assumed for 2020-21 for each technology are shown in Table 11 below. The long-term projections for the equivalent full forced outage rate[80] of coal-fired generation are in Figure 27.

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.[81] For those stations where the forced outage rate trajectories provided by the operator were used, AEMO extended the trajectories beyond 2030 using the station-level incremental growth rates provided by AEP Elical.

[79] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Market-Modelling-Methodology-Paper.pdf.

[80] Where effective full forced outage rate = Full forced outage + partial outage rate x average partial derating.

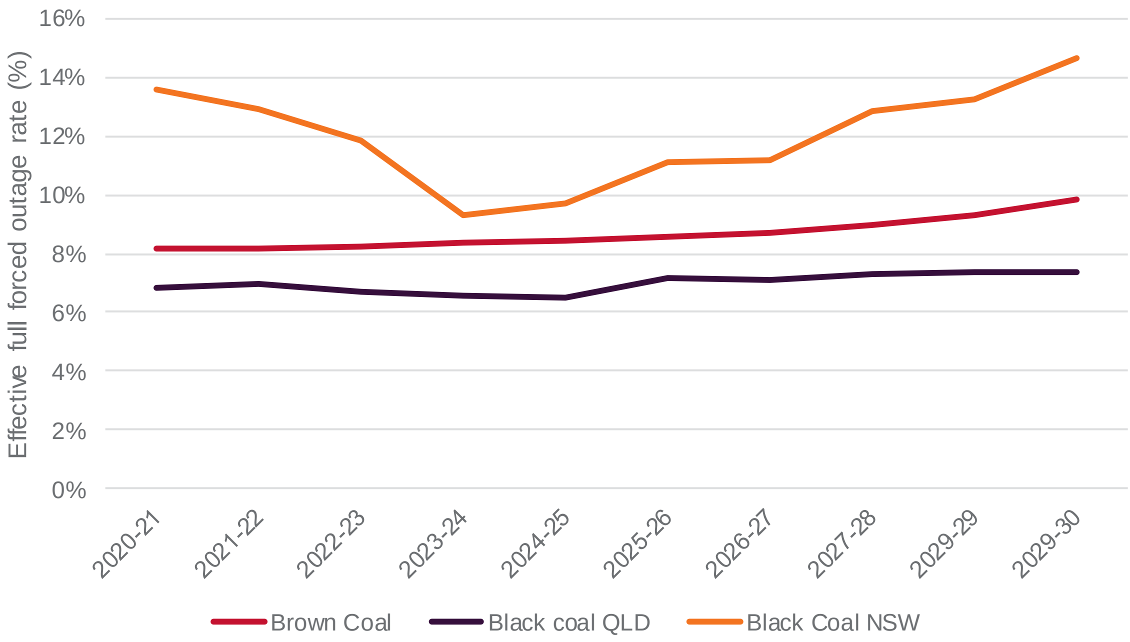
[81] Beyond 2030, the number of stations in each aggregation diminishes, and as such the presentation of aggregated information would reveal individual station-level trajectories.

Table 11 Forced outage assumptions (excluding HILP) – for 2020-21 base year

Generator aggregation	Full forced outage rate – 2020 ESOO (%)	Full forced outage rate – 2019 ESOO (%)	Partial forced outage rate (%)	Partial derating (% pf capacity)	MTTR – Full outage (hours)	MTTR – Partial outage (hours)
Brown coal	5.51	5.43	9.72	20.46	94	10
Black coal (Queensland)	3.00	2.30	14.09	25.49	69	42
Black coal (New South Wales)	5.44	6.22	39.91	18.33	161	44
CCGT	2.53	1.73	0.11	3.68	41	1
OCGT*	2.42	1.2	0.72	4.05	9	13
Small peaking plant*	4.57	3.52	0.49	15.86	53	24
Steam turbine	5.19	3.30	8.95	12.52	163	131
Hydro	2.52	2.34	0.07	31.08	27	48

* OCGT plants are generally classified as those greater than 150 MW, but this category also includes Bell Bay/Tamar peaking plants. which have high utilisation. Small peaking plants are generally classified as those less than 150 MW in capacity, but this category also includes Colongra, which has low utilisation.

Figure 27 Effective full forced outage rate projections for coal-fired generation technologies



The 2020 Inputs and Assumptions Workbook provides more detailed information on the forced outage rate parameters of each technology over time. More information about the calculation of forced outage rates is provided in AEMO's 2020 ESOO and Reliability Forecasting Methodology report[82].

[82] 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.

Auxiliaries

AEMO's models dynamically estimate auxiliary load based on generator dispatch in each modelling interval. AEMO currently sources per unit auxiliary rate assumptions from participants through the latest Generator Information surveys[83]. Auxiliary rates used in the 2020 ESOO are shown in Table 12, aggregated by technology for confidentiality.

Table 12 Auxiliary rate by technology

Generation type	Auxiliary (%)
Black coal	6.0
Brown coal	8.3
CCGT	3.0
Hydro	0.3
Peaking gas + liquids	0.7
Solar	0.4
Wind	0.9

Retirements

For existing generators, AEMO applies expected closure years provided by generators through AEMO's Generation Information[83] page, with allowable adjustments to these as described for the various scenarios previously.

AEMO assesses the cost of mid-life refurbishments on high-utilisation thermal assets (such as coal-fired generators and combined-cycle gas turbines [CCGTs]), to ensure the ongoing operation at high loading is efficient and presents the least financial cost to the system, taking into account the large capital outlay associated with mid-life turbine refurbishment.

Coal refurbishment costs are applied to the annual operations and maintenance cost in the year of refurbishment. The refurbishment year is approximated as each tenth year preceding the closure year. For example, for a generator with a closure year of 2035, a refurbishment is scheduled at 2025, and for a generator with a closure of 2048, refurbishments are scheduled at 2038 and 2028. This approach captures the financial impact of asset refurbishment in the least-cost assessments without impacting the complexity of the optimisation model.

AEMO also assesses the revenue sufficiency of existing coal-fired generation and CCGTs (particularly at assumed time of mid-life refurbishments) to determine whether there is likelihood in the scenario that a generator may retire on economic grounds.

Possible extensions to the nominated closure year of coal generators are modelled in the Slow Change scenario through additional refurbishments costs. In this scenario, AEMO extends the closure year of all coal generation by 10 years and applies an additional refurbishment cost at the original closure year. The optimal closure therefore is calculated by the capacity outlook models; the refurbishment cost will be avoided if the value of that life extension in minimising system costs is not greater than the cost of the refurbishment itself.

For new technologies, AEMO applies the technical life of the asset, which effectively retires new builds according to the technical life assumptions of each installed technology. For some technologies that are developed early, there may be instances of greenfield replacement of new developments in modelling exercises with sufficiently long simulation periods (such as the ISP). While replacements are not greenfield in

[83] AEMO, Generation information, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

nature typically, technology improvements often mean that much of the original engineering footprint of a 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 in 2020-21 modelling.

Site repatriation costs are incorporated in the 'closure costs' of each generation technology, excluding battery storage technologies where disposal cost data is not known (as discussed in Section 3.3.2).

3.4.2 Fuel prices

For generator fuel costs, AEMO applies the following sources:

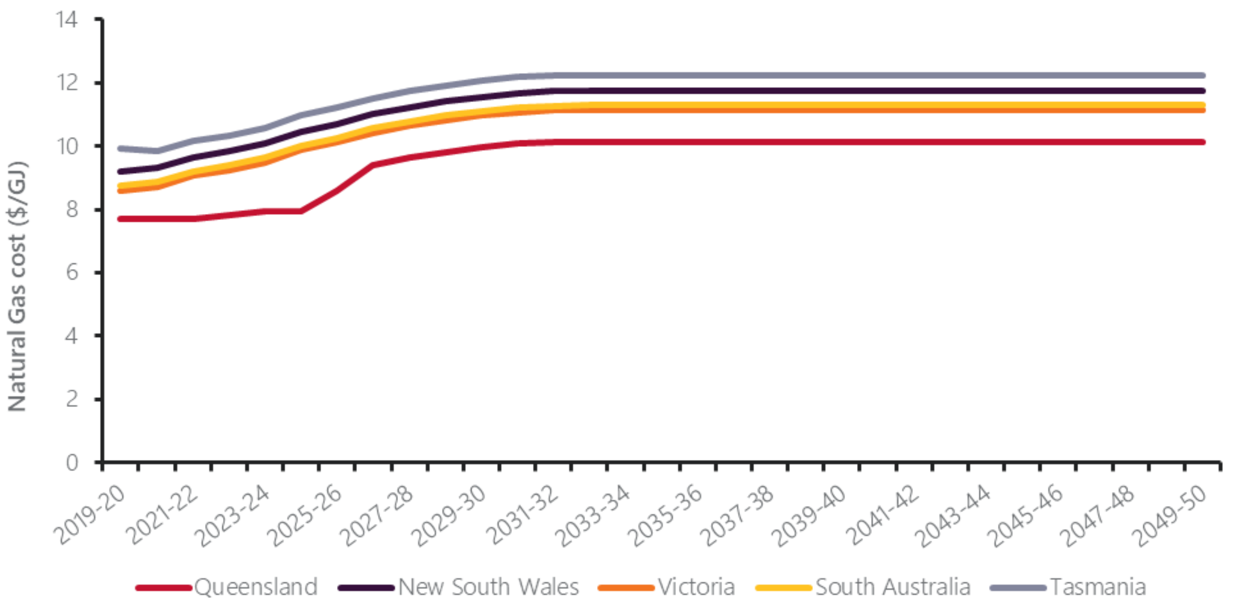
- Natural gas prices and forecasting method – Core Energy Group[84].
- Coal prices and forecasting method – Wood Mackenzie.
- Renewable resource profiles and availability – DNV-GL, complemented by data from the Bureau of Meteorology (BOM).

Reports from Core Energy Group and Wood Mackenzie supplement this IASR, providing additional information on the forecasting methodologies and outcomes for each – as outlined in Table 1, in Section 1.2.

Figure 28 presents regional gas prices for CCGT[85] GPG for the Central scenario, and Figure 29 presents regional prices for coal generators for the Central scenario. The 2020 Inputs and Assumptions Workbook provides further information on locational fuel costs across all scenarios.

These prices reflect long-term contracted prices; all generators are assumed to adopt fuel contracting to stabilise fuel prices. AEMO does not model generator fuel costs that might be sourced from short term transactions on commodity spot markets.

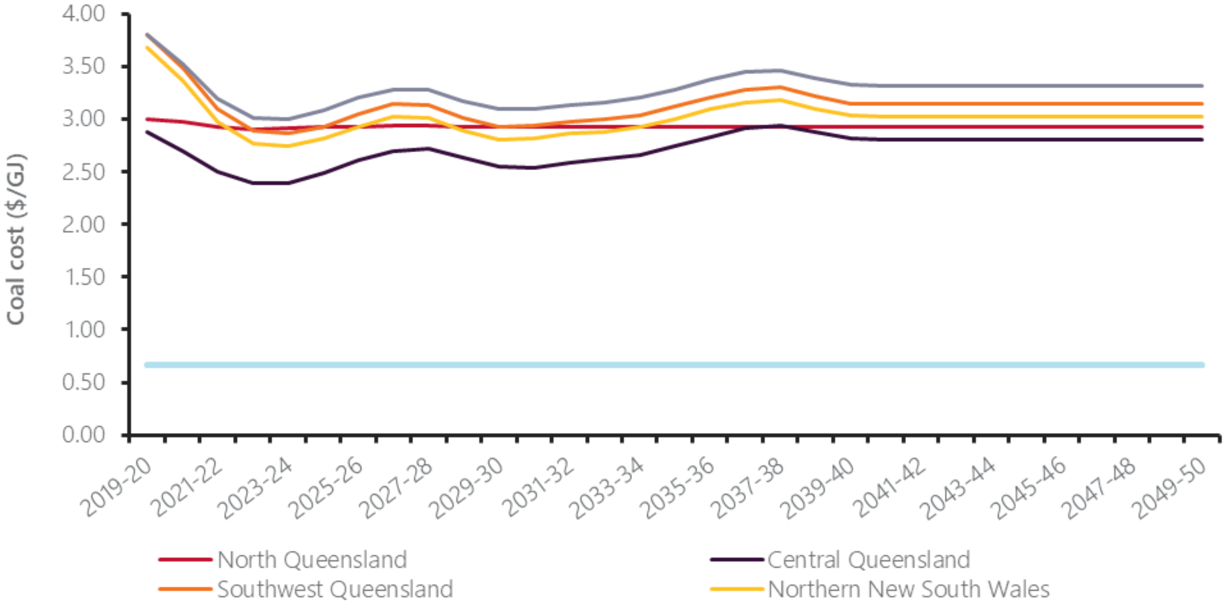
Figure 28 Regional gas prices in the 2020 Central scenario for new entrant CCGT plant



[84] Gas prices are currently being updated for use in the 2021 GSOO.

[85] Peaking generation incurs a gas price premium to reflect the relatively low volumes these generators consume and the pass-through of peak supply costs, including, for example, the cost of using gas storage facilities or the use of gas transmission linepack.

Figure 29 Regional coal prices in the 2020 Central scenario



3.4.3 Minimum stable levels, unit commitment and other technical assumptions

In long-term planning studies, AEMO applies assumptions related to operational characteristics of plant, to project future investment needs. It is recognised that the actual limits and constraints that would apply in real-time operations will depend on a range of factors, as the real-world conditions will often vary to some extent from those assumed in planning projections, no matter how reasonable the assumptions applied.

The objective of the capacity outlook models in combination is to minimise the capital expenditure and generation production costs over the long-term planning outlook, subject to:

- Ensuring there is sufficient supply to reliably meet demand at the current NEM reliability standard, allowing for inter-regional reserve sharing.
- Meeting current and likely policy objectives.
- Observing physical limitations of the generation plant and transmission system.
- Accounting for any energy constraints on resources.

In the capacity outlook models, the relative coarseness of the models requires that these limitations are applied using simpler representations, such as minimum capacity factors, to represent technical constraints or likely gas consumption. This helps ensure that relatively inflexible coal-fired generators are not dispatched intermittently, and that likely gas consumption is not under-estimated at this initial stage.

Minimum and maximum capacity factors are informed through analysis of historical behaviours, and through endogenous application of the iterative nature of the layered market models. That is, the capacity outlook models are informed initially by applying capacity factors limits that reflect physical constraints, such as fuel delivery constraints, which may be identified through historical analysis and refined as informed by more detailed time-sequential analysis[86].

Minimum stable levels are defined by GHD's minimum stable levels, and where variances were seen between these and historical behaviours, AEMO applied operational experience to verify or substitute those values. These limits are applied for baseload generators only in the capacity outlook models, and for baseload and mid-merit generators in the time-sequential models. If a baseload plant was identified to be operating at low utilisation levels, the iterative modelling may relax the application of minimum stable levels in each model.

[86] Physical constraints can manifest in many forms, including fuel supply or delivery constraints; for example, CLP Holding's 2019 Interim Results identified that Energy Australia's Mt Piper coal-fired power station was impacted by coal supply constraints (see https://www.clpgroup.com/en/Investors-Information-site/Announcements%20and%20Circulars/2019/e_Interim%20Results%20Announcement_2019_Final.pdf).

Additional technical limitations are incorporated in the time-sequential models, such as minimum up time and down times, and start-up and shut-down profiles. These are included in the 2020 Inputs and Assumptions Workbook.

Also included in some time-sequential models are complex heat rate curves that feature a constant marginal heat rate but variable average heat rate, derived from input/output curves of new entrants' generic technologies provided by GHD. Where generic curves were not available, publicly available historical information from both the Gas Bulletin Board and AEMO's Market Management System data were used to derive the gas usage as a function of hours online and electrical output data for each station. The complex heat rates used are included in the 2020 Inputs and Assumptions Workbook.

Unit commitment optimisation and minimum stable levels are not relevant for peaking plant when using a 30-minute or hourly model resolution, and are therefore not included in the market models. These technologies are capable of starting up to operate for minutes rather than hours, and it is inappropriate to constrain operations for an entire hour if dispatched. These peaking units also do not materially impact the annual gas consumption that would need to be reflected in the gas-electricity integrated market model.

AEMO models all other cost and technical assumptions in accordance with the 2020 Inputs and Assumptions Workbook. This Workbook includes technical data of each existing and new-entrant generator, including fuel costs, efficiency curves, outage rates, build limitations, and other factors captured within the modelling.

3.5 Transmission modelling

AEMO applies a varying degree of model complexity regarding transmission capabilities and reliability. For time-sequential modelling such as in the ESOO and that component of the ISP, AEMO applies transmission constraint equations to ensure that the network flows remain within the technical limitations of the power system. When assessing power system reliability, for example in the ESOO, AEMO further adopts a transmission outage model to understand the significance of transmission outages on the reliability forecast. More information is available within AEMO's Market Modelling Methodology Paper[87].

3.5.1 Existing transmission limitations

AEMO's time-sequential modelling applies a comprehensive set of network constraint equations that represent the thermal and stability limits that currently constrain dispatch in the NEM. These constraint equations act at times to limit generation, but also frequently limit interconnector transfer capacity. Additionally, transmission outage constraints are applied for simulated unplanned outages in reliability assessments.

Transmission outages in the ESOO

Modelling for the 2020 ESOO included the impact of a number of key unplanned transmission line outages or deratings which affect inter-regional transfer capability (see Table 13). AEMO assessed the probability of these outages using historical outage data from 2007 to 2020, updating the assumptions applied in the 2019 ESOO by including the past 12 months of data.

AEMO has applied transmission outages to the same key flowpaths that were chosen in the 2018 ESOO and 2019 ESOO:

- Dederang to South Morang – the double circuit line from Dederang to South Morang is the critical flowpath between northern Victoria and Melbourne. An outage of this line limits the ability to import generation from New South Wales and results in higher levels of curtailment for hydro generation in the north of Victoria. These lines are susceptible to the impact of bushfires; the impact of bushfires last summer is responsible for the increase in outage rate since the 2019 ESOO.
- Heywood to South East – the double circuit line between Heywood and South East is also known as the Heywood interconnector. An outage at one of the two lines was used to represent the incidence of an

[87] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Market-Modelling-Methodology-Paper.pdf.

outage on the flowpath between Melbourne and Adelaide. The South Australia islanding that occurred during the 2019-20 summer is responsible for the increase in outage rate compared to the 2019 ESOO.

- Basslink – the interconnector between Tasmania and Victoria has had a number of forced outages in recent years. The extended outage in 2015-16 was excluded from the calculation of the Basslink outage rate. Basslink is assumed to operate within a 478 MW limit in both directions.

Table 13 Transmission outage rates

Transmission flowpath	Unplanned outage rate (%)	Mean time to repair (hours)
Dederang – South Morang	0.53	25.65
Heywood – South East (Heywood interconnector)	2.64	80.87
Basslink	0.07	1.87

3.5.2 Interconnector losses

Interconnector losses are modelled based on interconnector loss functions. For existing interconnectors, these parameters are sourced from the most recent marginal loss factor (MLF) calculations[88]. Interconnector augmentations result in adjustments to these loss functions, details of these parameters can be found in the 2020 Inputs and Assumptions Workbook.

3.6 Generation capacity developments

AEMO publishes the capacity of existing, withdrawn, committed, and proposed generation projects in the NEM on its Generation Information webpage[89]. This information is updated regularly, with the most recently available information adopted for each of AEMO's publications (and clearly identified in each publication).

Generation capacity development assumptions in the 2020 ESOO

In the 2020 ESOO, AEMO includes only existing and new generation and battery storage projects that meet the commitment criteria published in AEMO's July 2020 Generation Information Page. AEMO uses information provided by both NEM participants and generation project proponents, including information under the three-year notice of closure rule.

The 2020-21 modelling includes projects classified in the Generation Information update as either:

- For the ESOO:
  - Committed[90] or
  - Advanced – projects under construction and well advanced to becoming committed[91].
- For the ISP and GSOO, the categories above and also Anticipated projects[92].

Committed projects are considered to become operational on dates provided by the participants, and for ESOO purposes includes projects that are classified as advanced and under construction.

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[88] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries.

[89] For details, see https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

[90] 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.

[91] In AEMO's Generation Information page these projects are called Committed* or Com*. Projects classified as advanced have commenced construction or installation; they meet AEMO's site, finance, and date criteria but are required to meet only one of the components or planning criteria.

[92] Anticipated projects demonstrate progress towards three of five of AEMO's commitment criteria, in accordance with the AER FBPG and RIT-T guidelines.

Advanced projects are assumed to commence operation after the end of the next financial year (1 July 2022). reflecting uncertainty in the commissioning of these projects. For further details please refer to the Reliability Forecasting Methodology Final Report[93].

3.7 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:

- The quality of its renewable resources.
- 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.

Geographical boundaries of proposed REZ candidates are modelled at a high level and do not reflect detailed planning considerations. These, along with community consultations, are intended to be addressed in greater detail by transmission network service providers (TNSPs) during the RIT-T process.

Further information on REZs is available in the 2020 ISP.

3.7.1 REZ candidates

During the 2018 ISP project, 34 REZ candidates were identified across the NEM, through consideration of a mix of resource, technical, and other considerations. The purpose of this analysis was to identify the timing, scale, and location of REZs that would minimise the total cost of supply to consumers.

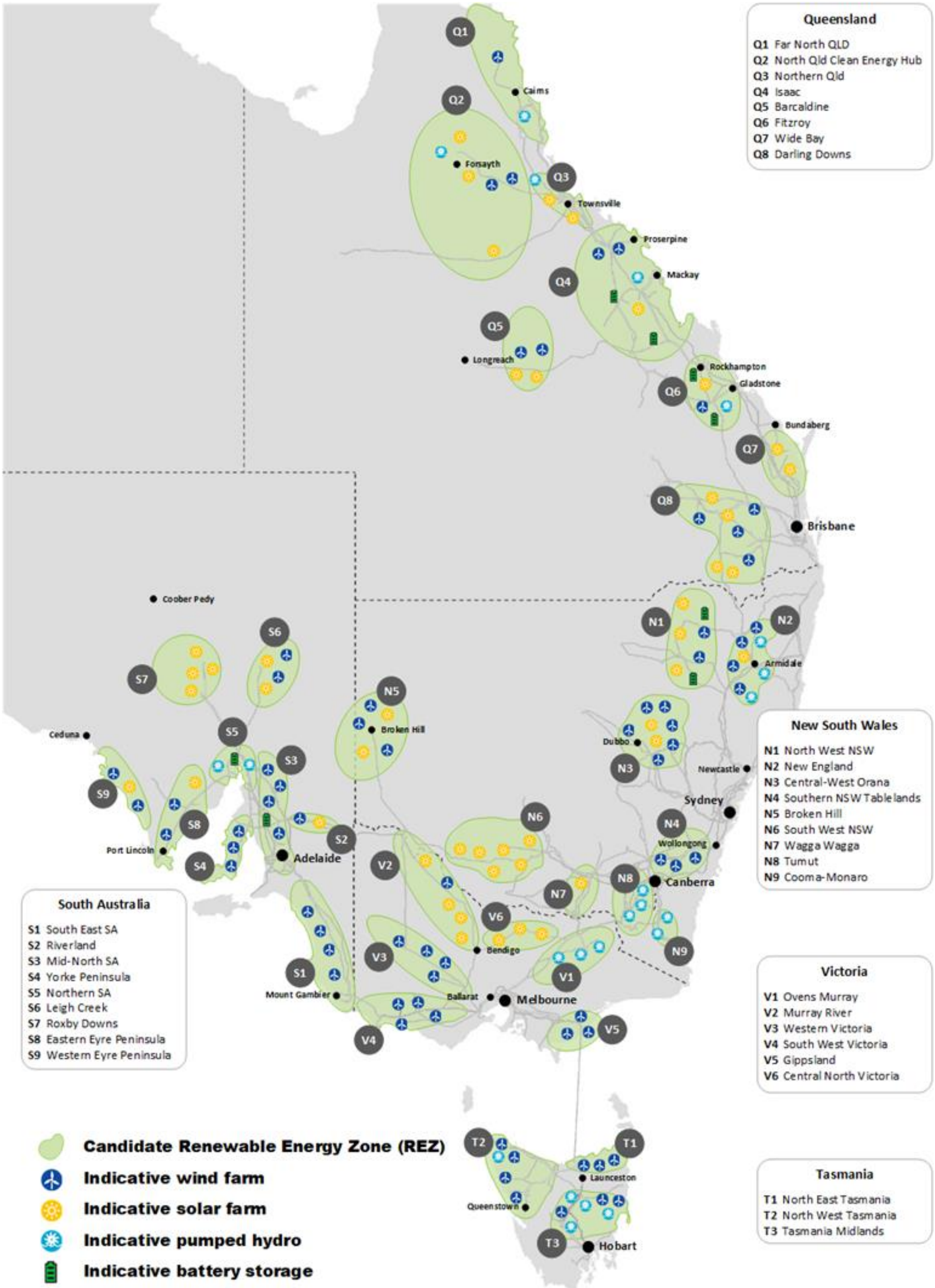
AEMO's selection of REZ candidates considered the following factors:

- Wind resource – a measure of high wind speeds (above 6 metres per second [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.

Figure 30 below shows the zones to be applied in 2020-21 modelling.

[93] 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.

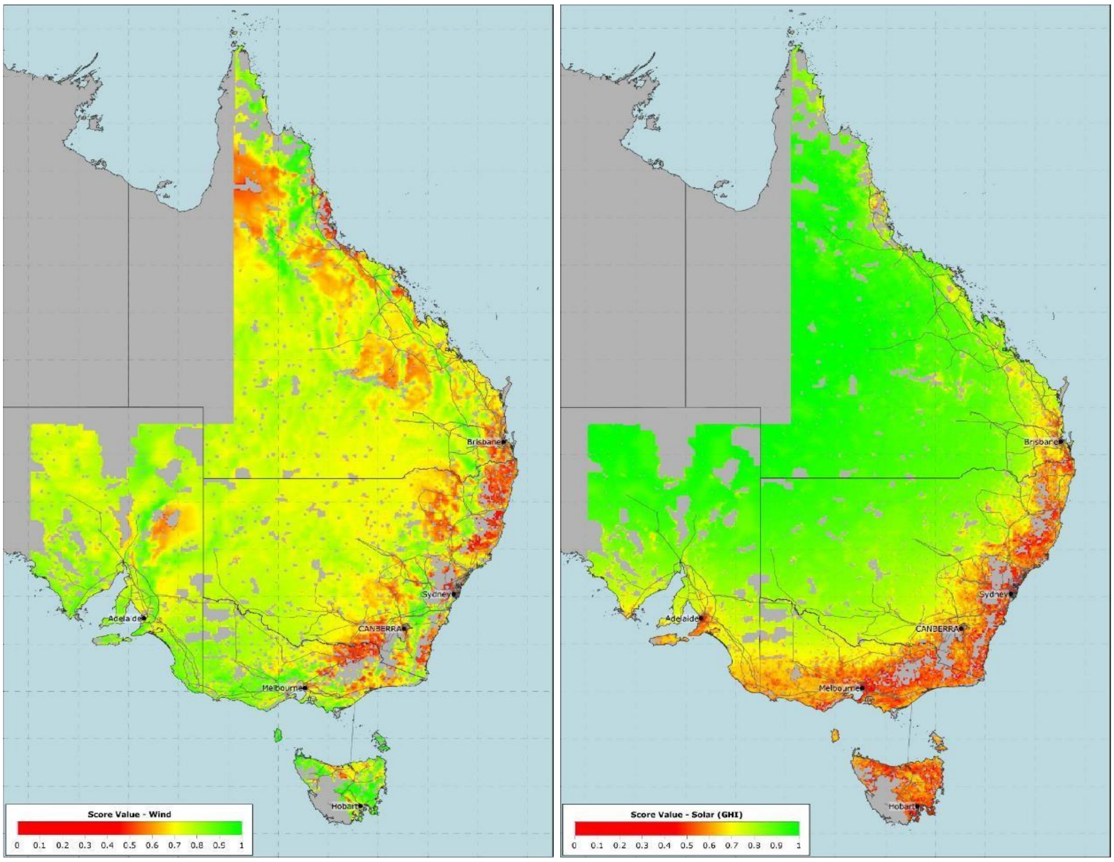
Figure 30 2020 REZ locations



Renewable generation resource profiles

For AEMO's planning models, energy availability data for individual wind and solar generators reflect the available renewable energy resource, as calculated by DNV-GL. Figure 31 below illustrates the relative strength of the underlying renewable energy resource for each of these technologies (in these figures, green represents a stronger resource, red represents a weaker resource).

Figure 31 Weighted wind (left) and solar (right) resource heat map



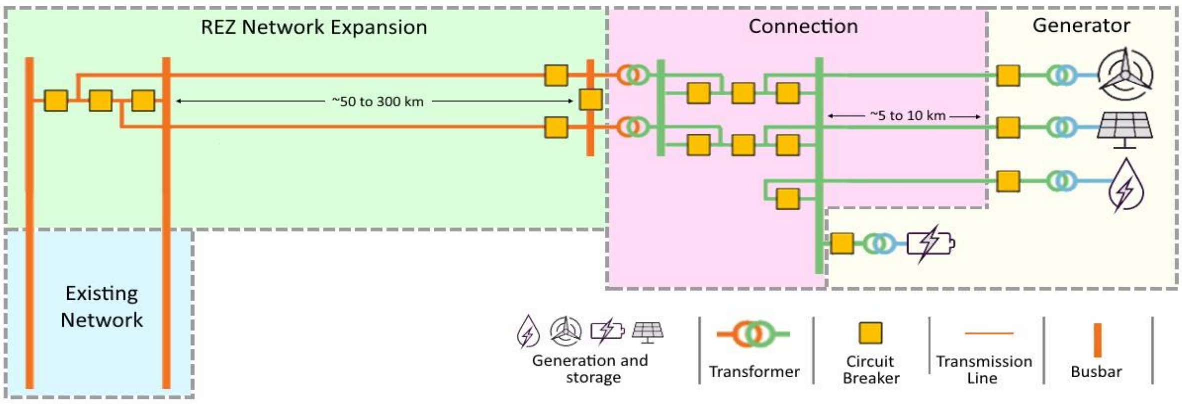
3.7.2 REZ cost assumptions

There are several important costs to consider when estimating the cost of a REZ:

- REZ network expansion costs – the cost of expanding the transmission network to provide access for generator and storage connections.
- Connection costs – the cost of connecting a generator to the hub of the REZ (that is, the local high-voltage network).
- Generator costs – the cost involved in establishing generation or energy storage projects.

An example of how these costs are allocated is shown in Figure 32.

Figure 32 Division of REZ costs



Note: The connection cost of battery storage is lower than other storage and generation options because battery storage has more flexibility in its location. Due to resource location, wind, solar, and PHES projects will often be located 5-10 km from the existing network.

REZ connection and network expansion costs

REZ connection and network expansion costs consider increasing network capacity to a REZ. In some instances, this could require building new transmission, and in others, could require upgrading existing transmission. These costs are generally dominated by the cost of long transmission lines. This cost component generally includes:

- Circuit breakers and switchgear at an existing substation.
- Transmission line (for example, 50 to 300 km per line).
- Substation site establishment (15,000 square metres).
- Communication (SCADA).
- Provision of local system strength via plant such as synchronous condensers where required.

REZ connection and network expansion costs are listed in the 2019 Inputs and Assumptions Workbook for each REZ and technology. These costs vary based on specific network characteristics such as voltage, terrain, technology, and distance of resources to transmission infrastructure.

3.7.3 Network losses

Network losses occur as power flows through transmission lines and transformers. Increasing the amount of renewable energy connected to the transmission network remote from load centres will increase network losses. As more generation connects in a remote location, the higher the power flow over the connecting lines and on the alternating current (AC) system, and the higher the losses.

In the NEM, transmission network losses are represented through MLFs. The modelling calculated network losses by applying the methodology described in AEMO's Forward-Looking Transmission Loss Factors[94]. Specific MLFs applied to each generator are available in the Inputs and Assumptions Workbook.

3.8 Gas modelling assumptions

AEMO also considers the eastern and south-eastern Australian gas markets when optimising decisions for the development of the NEM, in recognition of the high degree of coupling of the gas and electricity sectors. Given the strongly integrated nature of these systems, any development or shortfalls in the gas market would have direct implications for the operation of GPG in the electricity market. Similarly, any significant shortfalls in electricity supply would have a significant impact on the capability of the gas market to operate.

Thus, as part of the modelling process, AEMO uses an integrated model to determine optimal developments considering both gas and electricity systems simultaneously, to ensure optimal outcomes for the energy system as a whole.

The gas portion of the integrated model utilises the model topology, input assumptions and settings developed for the 2020 GSOO[95]. The new supply options studied under the 2020 GSOO have been implemented as expansion options in this integrated model, utilising build costs derived from publicly available information for the chosen projects. New supply options may include:

- LNG import terminals.
- New field developments.
- Pipeline interconnection.

Assumptions relevant to the gas market are provided in the 2020 Inputs and Assumptions Workbook, and outlined in Table 14 below.

[94] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Loss_Factors_and_Regional_Boundaries/2019/Marginal-Loss-Factors-for-the-2019-20-Financial-year.pdf.

[95] 2020 GSOO report, modelling methodology, and supplementary materials, at http://aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

Table 14 Gas modelling assumptions – key components and assumptions source

Component	Source
Pipeline capacities	GSOO stakeholder surveys
Production facility capacities	GSOO stakeholder surveys
Gas storage facility operational capabilities (including injection and withdrawal rates, and storage capacity)	GSOO stakeholder surveys
Pipeline transmission tariffs	Gas consultant*
Reserves and resources estimates by resource category (2P, 2C and prospective)	GSOO stakeholder surveys and gas consultant
Gas field production costs	Gas consultant
Gas expansion candidate build costs	Gas consultant
Wholesale gas prices, as described in Section 3.1	Gas consultant

* AEMO engaged CORE Energy to assist in supporting the development of input assumptions for the 2020 GSOO. Links to CORE Energy's reports are provided in Table 1 in this report.

More information on the gas modelling methodology, gas demand forecasting methodology, and market models used for gas (and electricity) market modelling is available on AEMO's website[96].

[96] GSOO gas demand forecasting and gas supply adequacy methodologies, at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo. AEMO's 2020 Market Modelling Methodologies, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/market-modelling-methodology-paper-jul-20.pdf?la=en.

A1. Summary of responses to stakeholder submissions

This appendix summarises the non-confidential stakeholder submissions to AEMO's Consultation paper on inputs and assumptions to be used for forecasting and planning publications in 2020, and outlines how AEMO has taken this feedback into account. This stakeholder consultation was conducted between December 2019 and February 2020. AEMO thanks all stakeholders for their contributions to this valuable process in developing key inputs and assumptions to AEMO's key forecasting and planning activities.

The submissions provided a subset of common themes:

- Storage costs, capabilities and risks for various technologies being either too high or too low – particularly regarding pumped hydro storage projects and utility scale battery technologies
- DER forecasting, and suggested amendments that may address perceived errors in forecast accuracy from 2019's forecasts. This included rooftop PV, EVs and domestic batteries.
- Generation technology costs and technical parameters, particularly the appropriateness of assumptions proposed in the Draft 2020 GenCost report as developed by CSIRO in collaboration with AEMO.
- The appropriateness of assumptions pertaining to maximum demand forecasts, including the role of consumer behaviours in increasing or avoiding peak demands.
- The role of weather patterns in future forecasting assessments, including the role of extreme weather events.
- Consistency in methodology and assumptions relating to transmission network service provider (TNSP) RIT-Ts.
- The appropriate treatment of offshore wind opportunities in the Draft 2020 GenCost report

Table 15 below outlines general feedback and AEMO's response to that feedback. Table 16 summarises specific responses regarding nuclear energy opportunities, given the volume of submissions on this topic.

In some instances, the feedback received related specifically to the 2020 Integrated System Plan. AEMO has considered that feedback within the ISP Consultation process, and would direct stakeholders to the 2020 ISP Consultation Summary Report, available at: https://aemo.com.au/-/media/files/major-publications/isp/2020/2020-isp-consultation-summary-report.pdf?la=en.

Table 15 Summary of received submissions – general

Stakeholder	Type of group	Key topic(s)	Summary of submission	AEMO response
Tesla	Industry (batteries and EVs)	• Batteries • Battery technical capabilities • EVs • Utility-scale storage • Modelling should focus on storage characteristics rather than technology type	• AEMOs capital cost for batteries is too high (and pumped hydro costs probably too low). • There is a lack of utility-scale storage included in the ISP modelling in general. • The market-reflective value potential of batteries (or RE/battery combinations) has not been fully considered (eg the ability of batteries to provide ancillary services, inertia contributions and system security benefits). • AEMO should adjust the technical assumptions of batteries to include broader parameters currently being observed (duration, rate of charge etc). • A broader scope of modelling methodology will be increasingly important as market reforms progress to reward faster and more accurate services likely to be of 2 to 4-hour duration. • AEMO should have better consideration of the pipeline of battery storage projects and government policy (incentives) indicating much greater uptake of batteries. • Adjusting technical parameter assumptions for batteries to account for increasing round trip efficiency, increasing warranties, expanding rate of charge, lowering lead-time for utility-scale batteries. • AEMO's 2018 vs 2019 modelling EV numbers appears to have dramatically decreased. Is this an error?	• AEMO has incorporated the feedback regarding battery costs in the GenCost review, and included updated battery cost trajectories and technical settings in assumptions for 2020. • AEMO's capacity outlook projections now focus on dispatchable storages of various durations, rather than battery versus PHES storage developments. AEMO identifies storage depth classifications rather than the specific storage technologies that may provide that storage depth. • AEMO's capacity outlook model identifies the least cost outlook for the system to operate in a reliable and secure state. It does not identify the potential revenue streams from grid services. The technical capabilities of technologies to manage the flexibility needs of the future power system is examined in AEMO's time-sequential modelling, where appropriate.. • AEMO works closely with independent engineering consultants to prepare technical operational parameters for all technologies. Where possible and appropriate these parameters are included in the suite of modelling tools as detailed in AEMO's Market Modelling Methodology document. AEMO would welcome continued collaboration on these technical settings as part of the GenCost 2021 work program to capture technical improvements for future work. • AEMO would welcome continued collaboration on its market modelling methodologies to identify any potential improvements. • AEMO includes all committed, under construction, and anticipated projects within its modelling. The pipeline of announced projects provides useful guidance, but cannot be relied upon to develop. The 2020 inputs reflected in this report have considered stakeholder feedback and reflect greater behind the meter battery installations than were considered in 2019. • AEMO applies the technical parameters identified for current and future projects as part of the GenCost project. AEMO would welcome data submissions to the GenCost 2021 work program to capture expected technical improvements that may complement cost reductions over time. AEMO's forecasts of EVs, prepared by CSIRO and outlined in Section 3.1 of this report, have increased consumption outcomes relative to 2019. The 2019 forecasts did reduce relative to 2018 given a reduction in assumed vehicle sales, saturation levels, and consideration of competing fuel-cell vehicles. ESOO 2020's forecast includes consideration of electrified articulated trucks, which increase consumption trends. AEMO presented these forecasts during FRG sessions and finalised with CSIRO based on stakeholder feedback and the respective scenario definitions. More information on the forecast differences is available within the 2019 and 2020 CSIRO reports.

Stakeholder	Type of group	Key topic(s)	Summary of submission	AEMO response
Powerlink QLD	Networks	• Rooftop PV • Uptake of rooftop PV • Weather data in Queensland • Consumption and maximum demand in Queensland	• It is possible that the assumptions around rooftop PV installation are incorrect and that Queensland will continue to see high rates of rooftop PV installed. • The range between the 10% and 90% POE narrower than the 2018 ESOO. • AEMOs weather assumptions are based on data from one weather station (Archerfield) – this is inadequate for a state as large as Queensland and adding data from additional stations would help improve accuracy or forecasting.	• CSIRO has reviewed its PV uptake methodology and incorporated a trend-influenced forecast for the near term. As outlined in this report, the forecast PV uptake trajectories are higher in 2020 than those forecast in 2019, particularly in the near-term despite an assumed slowdown of uptake from COVID-19. • The distribution in maximum demand in Queensland is narrower than other regions due to its relatively stable climate (compared to Victoria and South Australia). However, after further development of AEMO's GEV modelling approach, the 2020 ESOO forecast has a wider POE distribution than the 2019 ESOO but still more stable (narrow distribution) than other NEM regions. • AEMO investigated the use of multiple weather station across the NEM regions, which was presented to the FRG in February 2019[97]. Queensland showed marginal improvements, while other NEM regions did not. As the distribution of weather outcomes measured at Archerfield is reasonably representative of variability in weather outcomes elsewhere, the single weather station is sufficient to give good regional outcomes as it is correlated with other weather stations. The simulation process further captures the diversity in intra-regional weather outcomes through the stochastic residual. AEMO found the resulting POE's were not substantially different and did not warrant the increase in model complexity. AEMO may revisit this as computation power becomes more accessible.
Origin Energy	Generator	• EVs • Rooftop PV • Uptake of rooftop PV • Industrial load forecasts • Cost assumptions • Further modelling details requested	• Consumption forecasts appear to grow at a faster rate from late 2020. What is driving this? If it's increased EVs, then please provide evidence. • Has the risk of smelters closing down been incorporated into AEMO modelling on load demand forecasts? • The trends for rooftop PV installations in the modelling appear flatter than are being currently seen in reality. What are the assumptions behind this? • Are the gas price estimates incorporating the uncertainty in gas market policy? • It appears that Wood Mackenzie's scenarios and assumptions differ from those used by	• Forecast consumption and peak demand growth trends are provided in the 2020 ESOO. • Industrial load closures are considered in the Slow Change scenario • CSIRO has reviewed its PV uptake methodology and incorporated a trend-influenced forecast for the near term. As outlined in this report, the forecast PV uptake trajectories are higher in 2020 than those forecast in 2019, particularly in the near-term despite an assumed slowdown of uptake from COVID-19. • The gas price estimates reflect CORE Energy's bottom-up methodology which considers the wholesale, transmission and peak supply costs, as well as interactions with international oil price estimates from CORE, informed by the forecasts of the US Energy Information Administration (EIA). Further information on the gas price forecasts is available in the December 2019 CORE Energy Wholesale Gas Price Outlook report, listed in Table 1. CORE do list gas policy uncertainty as a 'key risk or uncertainty'. • Both gas and coal price projections are based on the scenario definitions as defined through consultation with stakeholders, which consider both policy and production expectations.

[97] See meeting material from the February 2019 FRG meeting here: https://aemo.com.au/-/media/files/stakeholder_consultation/working_groups/other_meetings/frg/2019/forecasting-reference-group-meeting---27-february---meeting-pack.zip?la=en

Stakeholder	Type of group	Key topic(s)	Summary of submission	AEMO response
			CORE energy. There should be internal consistency to support robust findings. • In the interests of transparency, please share full modelling and outputs.	• Detailed modelling outcomes are published with each publication. For the ISP, as an example, this includes both Generation and Transmission outcomes for each considered development path.
SunWiz	Renewables industry	• Rooftop PV • Uptake of rooftop PV	• The assumptions underpinning the projections for rooftop PV uptake appear very low • Please review the current trends and adjust accordingly	• CSIRO has reviewed its PV uptake methodology and incorporated a trend-influenced forecast for the near term. As outlined in this report, the forecast PV uptake trajectories are higher in 2020 than those forecast in 2019, particularly in the near-term despite an assumed slowdown of uptake from COVID-19.
Victorian government (Department of Energy, Environment and Climate Change)	Government	• Rooftop PV • Uptake of rooftop PV • Residential batteries • Demand side management • EE	• The Victorian Government has a large rooftop PV and battery program underway which will increase household uptake. Has this been considered in the modelling? • Demand Side Portal improvement issues – could AEMO please provide more detail on this. • How much has demand side management been considered in the modelling? Recent Victorian experience with industry indicates that it has the potential for significant DSM gains. • Further consideration should be given to the impact improved household EE (especially air-conditioners) can have to reduce peak demand.	• AEMO's 2020 DER forecasts includes all current State and Federal policy, including Victoria's solar home scheme, as described in this report. As outlined, in Chapter 3.1.1, AEMO now apples the Solar Homes Scheme across all scenarios (previously was in the 2019 Step Change scenario) . • AEMO has subsequently consulted on changes to DSP forecasting methodology and has commenced consultation on DSP Information collection. AEMO would certainly welcome and encourage stakeholder input to this consultation.[98] • The level of DSP included in the 2020 ESOO is detailed in the ESOO appendices, and the 2020 Inputs and Assumptions Workbook. It shows an increase relative to the 2019 assumptions. Growth beyond this is assumed in AEMO's capacity outlook models, driven by initiatives like Wholesale Demand Response. • AEMO explicitly forecasts the potential energy savings from efficiency improvements in appliances and building standards as outlined in Section 3.1.4. These savings will be accounted for both in the annual consumption forecast and maximum demand forecast. Following an investigation into the historical ratio between consumption and peak demand, AEMO has adopted a linkage that results in a similar percentage saving from energy efficiency measures overall for both underlying consumption and peak demand. This ensures forecast growth of peak demand is in alignment with observed historical rate of improvement in energy efficiency and other underlying drivers for demand.
Fluence	Industry (battery manufacturer)	• Batteries • Total project costs • Battery technical capabilities	• The cost assumptions for batteries are too high (modelled cost of $250/kWh versus $156/kWh currently being observed in market. • The cost assumptions for installation and balance of plant also appear too high and not reflective of what is being observed in market.	• AEMO has worked with CSIRO to incorporate the feedback regarding battery costs and PHES costs in the 2020 GenCost report and includes updated (lower) battery cost trajectories and technical settings and higher PHES costs in its assumptions for 2020. • AEMO's updated DER forecasts for 2020 demonstrate a higher forecast level of consumer investment in behind-the-meter storage potential than forecast in 2019.

[98] DSP Forecast Methodology consultation, available at https://aemo.com.au/en/consultations/current-and-closed-consultations/demand-side-participation-forecast-methodology-consultation

Stakeholder	Type of group	Key topic(s)	Summary of submission	AEMO response
			• By focusing on utility-scale batteries, the considerable market-reflective value potential of smaller batteries (or RE/battery combinations) has not been fully considered – there are stacked revenue streams not being considered. • The transmission cost and time associated with pumped hydro do not appear to have been factored in, which means the modelling is not reflective of the true cost of production. • 1-hour duration batteries should be included in the modelling for the value they bring in system security and reliability services.	• AEMO's forecasts of utility scale battery developments are focused on least-cost efficient developments; revenue streams (particularly for non-energy services, such as ancillary services), are not considered. • Generation developments include the transmission connection costs on a technology by technology basis. The Assumptions Workbook also includes development lead times for each technology. AEMO would welcome continued collaboration on these technical settings as part of the GenCost 2021 work program to capture technical and cost improvements for future work. • AEMO's technology development options include 2-hour and 4-hour storage depth battery options only, given modelling complexity and that grid services are not optimised within the capacity outlook model. Embedded storages may provide shallower storage management solutions.
ERM power (Shell)	Generator / Retailer	• Demand reduction • Price elasticity • Temperature & climate change • Battery technical capabilities • High cost assumptions (battery & PV) • DSP • Further modelling details requested	• AEMOs demand forecast have previously been and are currently too conservative (eg Victoria has experienced a decline in energy consumption from 2008 and recency bias may have overstated the potential rise in electricity demand). • Better consultation with industry can support more informed forecasts, and AEMO should share all the modelling outputs for transparency. • Price elasticity of demand should remain constant across residential, SMEs and LILs. • The assumptions around the impact of temperature change caused by climate change (0.5°C by 2040) should have additional sensitivity analysis included (lower and upper bounds). • DER – the assumptions behind the technical capabilities of batteries may not be correct, and the benefits of residential batteries may be overstated. • Half-hourly demand scaling and the appropriateness or otherwise of 5-day scaling requires further explanation by AEMO.	• AEMO notes the methodology commentary, but focuses these responses on inputs and assumptions. • AEMO continues to strive for increased consumer engagement, and thanks stakeholders for their contributions in this and other relevant consultations throughout 2020, as well as participation at AEMO's FRG that supports our stakeholder collaboration approach. • The 0.5°C climate warming is the average warming for the RCP 4.5 climate pathway (used in the Central Scenario). AEMO adopts a range of climate models from the BoM and CSIRO that result in a range of temperature outcomes for a given RCP. This range in temperature outcomes is captured in the POE range. AEMO also adopts different RCP climate pathways in its maximum and minimum demand forecast outline in Table 3 and Figure 23 of the IASR to capture the range in climate scenario uncertainty. • As explained in Appendix 8 of the demand forecasting methodology information paper, the trace growing algorithm dynamically selects the number of target days. It initially attempts to grow to *n* target days (typically four days). If it does not solve, the algorithm will add another *m* target days (typically five). It does this recursively until it solves for all targets (consumption, minimum and maximum demand). Higher demand POEs tends to solve with fewer target days due to the long-tailed distribution of demand. For instance, 10% POE may solve with four target days grown (this has been found to reflect the number of high demand days in extreme demand years observed in history) while 50% POE may sometimes require nine or more target days to be grown to solve. This outcome may vary by reference year, region and scenario though. • For the 2020 ESOO, AEMO has applied forward looking outage rate trends to base outage rates. Base outage rates use the last four years of historical data, yet adjustment is allowed for based on feedback from power station operators and remove the impact from HILP

Stakeholder	Type of group	Key topic(s)	Summary of submission	AEMO response
			• Outage parameters should be based on 10-year rolling averages rather than previous four years. Have AEMO cherry picked the data to suit desired outcomes? • The assumptions in falling PV and battery costs are overstated. The supply costs should be higher to achieve rigorous modelling. • More diverse supply input assumptions should be included (eg solar/wind farms supported by gas turbines, alternative forms of gas technology, pumped hydro costs for both pre-existing and new storage reservoirs). • A sensitivity case for a high DSP rate should be considered.	outages. AEMO generally relied on information provided by participants for the forward looking outage rate trends. • AEMO has incorporated stakeholder feedback regarding battery costs within the Draft GenCost review, and includes updated battery cost trajectories and technical settings in this 2020 IASR. • DER forecasts provided by CISRO and GEM consider the technical capability and forecast economic influences in driving uptake and usage patterns. Certainly AEMO will consider specific feedback on any technical assumptions within future forecasts, and would welcome continued stakeholder engagement in the GenCost 2021 work program to enable this. • Cost outcomes of PV and batteries are prepared and consulted with stakeholders through the CSIRO GenCost work package. This comprehensive review has considered feedback regarding future cost trends (domestically and internationally) to inform cost projections. Given cost uncertainties, AEMO applies variation across scenarios of these costs in line with the scenario narratives. • AEMO includes the capacity for many generation technology types to be developed, as described in Chapter 3.3.1. Hybrid VRE + storage or VRE + gas generators are not included in this list as a bespoke solution, but both VRE + storage or VRE + gas solutions may be developed if least cost. Regarding PHES, AEMO notes the suggestion regarding pre-existing storage options, and is seeking to improve data availability regarding existing and new storage options beyond what has been available for this IASR. AEMO will collaborate with stakeholders regarding any improvements / expansion to this data set when available to be used in future modelling. • AEMO considers a range of DSP projections across the scenarios.
Energy Queensland	Industry	• Uptake of rooftop PV • Batteries • Residential demand • EVs • Further modelling details requested	• In the forecast model, half-hourly reads are not representative of most residential consumers in Australia (very few have half-hourly meters), expected electricity consumption should only include PV internal use rather than gross generation; and how growth in customer connections and electricity prices impacts consumption forecasts. • The relationship between the network delivered price and energy and peak demand has become more complicated, including through factors such as new retail contract models, rooftop PV and price arbitrage etc.	• Corrections are factored in to ensure sample biases are removed, and that the result does reflect average usage and generation. AEMO's forecasting methodology considers the gross generation from PV to inform the scale of energy exported to the grid, rather than the level of consumption from households. • AEMO's methodology includes consideration for both connection growth and price response to price rises. The interaction between technology, such as PV and retail tariff incentives is complex and can cause changes to both consumption and maximum demand. Through its annual Forecast Accuracy Assessment, AEMO is monitoring closely that consumption and demand is in line with observed behaviour. • AEMO removes outlier events from its minimum and maximum demand models such as major load shedding events, or transmission failure event (such as the 2015-16 Basslink outage), unserved energy arising from floods, cyclones, etc. from its data set used for forecasting, where those events can be identified and have an impact to demand.

Stakeholder	Type of group	Key topic(s)	Summary of submission	AEMO response
			• Maximum and minimum demand forecasting should take account of regional aspects (population and weather etc) and events that cause outlier minimum data (eg floods or cyclones) should be removed to improve data integrity. • The first impacts of minimum demand on low levels of distribution networks should be accounted for at the feeder and substation levels well before they are seen at system or state aggregations. • The residential and commercial use of electric vehicles should be modelled separately due to forecasts of significant and rapid uptake of electric buses. • DER categories should be modelled separately as their impacts can offset each other and contribute to load volatility. • Please clarify the inputs into AEMOs battery assumptions – are they residential or commercial-scale etc?	• At the connection point level, the data is similarly cleaned for outages, load shifting and block loads before forecasting demand is attempted. • AEMO's consultant CSIRO forecasts all electric vehicle types (passenger cars, light-commercial vehicles, articulated trucks) independently. Further information on the share of vehicle segments per scenario is available within the CSIRO 2020 DER report. • AEMO's consultant CSIRO forecasts all DER (PV) installation types (small, medium and large scale PV) are forecast separately, although they may be presented in an aggregated form within this report. Further information on the DER developments per scenario is available within the CSIRO 2020 DER report. • Full details of AEMO's battery assumptions are available within CSIRO's report (embedded batteries) and AEMO's inputs and assumptions workbook (grid-scale).
Engie (Simply Energy)	Generation and retail	• Network distribution losses	• Network distribution losses – unclear how losses will be used in long range modelling. However, it is inappropriate to maintain these as constant over time, and a dynamic approach is needed. A dynamic approach could be based on expected network augmentations and the penetration of distributed generation and storage. These would serve to change usage patterns and at times offset demand and hence the distribution loss factors.	• AEMO appreciates the commentary on potential improvements for accounting for changing losses. AEMO will consider the methodology change suggested.
Energy Australia	Industry, generation	• RIT-T • Batteries • Battery costs and value	• Will the AEMO 2020 Forecasting Inputs Report constitute the 'Inputs, Assumptions and Scenarios Report' or contain 'ISP parameters' that must be adopted or varied (with	• This report is the 2020 IASR, summarising assumptions used in the 2020 ESOO and proposed to be used in subsequent 2020-21 forecast and planning publications unless otherwise stated. A new consultation on the appropriate settings for the 2022 ISP will commence later this year.

Stakeholder	Type of group	Key topic(s)	Summary of submission	AEMO response
		• Pumped hydro cost • Uptake of rooftop PV • Further modelling details requested	explanation) by Regulatory Investment Test proponents? • AEMO should clarify which assumptions it does not intend to update for the ISP but does for the ESOO, and we otherwise encourage these to be aligned. • The costs of batteries appear lower than what is currently being observed in market, and forward projections seem to indicate incorrect trends in pricing (ie price does not drop as expected). • The full market value of battery revenue streams (arbitrage, capacity, market and ancillary services etc) is missing from the ISP modelling. • Clearer differentiation between grid scale and residential scale batteries is required. • Questions around assumptions of battery discharge seem too simplistic in a disrupted energy market with new retail offers and opportunity for price arbitrage etc. • Cost estimates for pumped hydro require sensitivity analysis – they appear too conservative as is. • Forecast uptake of rooftop PV seems understated and not reflective of current trends and does not take into account current incentive schemes (eg Victoria). • OCGT assumptions should be re-visited to support the opportunity for various sized gas plants that could play a key role in grid stability as coal-fired power stations come offline. • Impact of weather on inverter based resources – recommend AEMO review the firmness assumption (capacity and thermal de-rates) in light of recent extreme weather conditions.	• This report, and the companion 2020 Inputs and Assumptions Workbook, provides updated assumptions applied to the 2020 ESOO, and to apply in 2020-21 forecasting and planning. • AEMO has worked with CSIRO to incorporate the feedback regarding battery costs within the 2020GenCost, and includes updated battery cost trajectories and technical settings in its assumptions for 2020. • AEMO's capacity outlook model identifies the least cost outlook for the system to operate in a reliable and secure state. It does not identify the potential revenue streams from grid services. The technical capabilities of technologies to manage the flexibility needs of the future power system is examined in AEMO's time-sequential modelling, where appropriate.. • DER battery forecasts refer to embedded (residential and commercial) battery installations. AEMO's forecasts of grid-scale batteries are endogenous outputs of the system development optimisation, and reported in the ISP. • AEMO has incorporated the feedback regarding PHES, and updated its cost assumptions, increasing PHES by 50%. • AEMO is continuing to undertake analysis of methodological improvements that could better reflect the impact of thermal deratings on VRE generation. AEMO has received more detailed information on capacity under extreme summer conditions compared to more typical conditions through the July 2020 Generation Information page. • CSIRO has reviewed its PV uptake methodology and incorporated a trend-influenced forecast for the near term. As outlined in this report, the forecast PV uptake trajectories are higher in 2020 than those forecast in 2019, particularly in the near term, despite an assumed slowdown of uptake from COVID-19. • The GenCost project has identified small-size OCGTs as more appropriate for the Australian market than the previous larger unit sizes. AEMO recognises that larger unit sizes may bring operational cost efficiencies. AEMO would welcome continued collaboration in the GenCost 2021 program of work to reflect on whether both traditional and smaller sized units are appropriate for this peaking plant role, and provided they would be able to be differentiated in the modelling. • The temperature derating in the normalized generation profile for distributed PV is implicit in the model that correlates solar irradiance with energy output. See above point on VRE for grid scale deratings. • AEMO received a range of views on gas prices throughout FRG sessions in particular. Many stakeholders considering the gas prices too high. AEMO will be re-forecasting gas prices ahead of the 2021 GSOO and will include these gas prices in future IASR consultation. • Further detail of the requested modelling detail is provided in respective demand forecasting, market modelling, and ISP methodology reports. Renewable energy traces are

Stakeholder	Type of group	Key topic(s)	Summary of submission	AEMO response
			• Gas price forecasts appear too low: (1) 2019 prices are below average prices actually settled in the Declared Wholesale Gas Market, and (2) the 2020 forecast is below the ACCC's assessment of contract prices, and (3) the Sydney-Brisbane price differential is too low. • Could AEMO please provide more modelling detail and commentary around the assumptions affecting: – **Demand elements**: maximum demand forecast, use of Reference Years and stochastic results, and regional demand traces, DSP. – **Supply elements**: Renewable energy traces. – **Network elements**: Inter-regional loss factor equations, costs of transmission projects.	available for all years / reference years on AEMO's ESOO and ISP web databases. Transmission project costs are available within the 2020 Inputs and Assumptions Workbook, and published separately in the 2020 ISP Transmission project cost summary[99].
Ausnet Services	Industry (distribution and transmission)	• Firm capacity generators • Weather events • Uptake or rooftop PV and batteries	• Augmentation options for VNI West should be reconsidered. • Firm capacity of generators: models should take into account the recent weather events that have demonstrated that the firm capacity for aging thermal infrastructure cannot be relied upon. • Output and reliability impacts of extreme weather and prolonged periods of higher temperatures on both renewable and non-renewable resources should be modelled. • Transmission network planned maintenance has a material impact on the outflows on DER into the grid and this should be reflected in the modelling. • The DER uptake projections appear internally inconsistent and perhaps understated.	• AEMO has considered the VNI West augmentation option in detail in the 2020 ISP. Several options have been investigated, with final option preferences to be investigated in further detail within the RIT-T. • AEMO continues to develop improved methods for capturing thermal or age-related reliability degradation, as outlined in the forced outage rate assumptions in this report. • AEMO applies historical weather patterns in its forecasting, thereby incorporating prolonged weather impacts where those have been observed in weather conditions in the recent past. • AEMO is continuing to undertake analysis of methodological improvements that could better reflect the impact of thermal deratings on VRE generation. AEMO has received more detailed information on capacity under extreme summer conditions compared to more typical conditions through the July 2020 Generation Information page. • AEMO's modelling is unable to consider the routine maintenance cycle of transmission and distribution businesses. Critical transmission outages are considered within the ESOO reliability assessment. • CSIRO has reviewed its PV uptake methodology and incorporated a trend-influenced forecast for the near term. As outlined in this report, the forecast PV uptake trajectories are

[99] Available at: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2020-isp-inputs-and-assumptions

Stakeholder	Type of group	Key topic(s)	Summary of submission	AEMO response
				higher in 2020 than those forecast in 2019, particularly in the near-term despite an assumed slowdown of uptake from COVID-19.
ElectraNet	Industry	• RIT-T • Uptake of rooftop and utility-scale PV • Minimum demand forecasting	• Review the appropriateness of AEMOs adoption of minimum capacity factors for South Australian gas plant, considering the observations made by the AER in its recent Determination on the South Australian Energy Transformation (SAET) RIT-T. • Review the methodology and outcomes for distributed PV forecasts in South Australia – they appear much lower than is currently being experienced. • Minimum demand forecasts seem unrealistically high – please review the methodology and outcomes for minimum demand forecasting, based on current outcomes in South Australia. • Adopt the 90% POE 'shoulder season' minimum demand forecast (the period most likely to lead to minimum demand) alongside the summer 10% POE forecast in constructing the demand traces to be used in the ISP (and other) modelling exercises.	• AEMO has reviewed the use of minimum capacity factors for its capacity outlook (integrated model [IM] and detailed long-term [DLT]) models. Detail of AEMO's applied methods for GPG operation in capacity outlook and time-sequential models is described in detail in the Market Modelling Methodology Report. This includes minimum capacity factor treatment and use of more complex heat rates (when warranted) in South Australia. • CSIRO has reviewed its PV uptake methodology and incorporated a trend-influenced forecast for the near term. As outlined in this report, the forecast PV uptake trajectories are higher in 2020 than those forecast in 2019, particularly in the near term, despite an assumed slowdown of uptake from COVID-19. The impact of this update on minimum demand is provided in detail in the 2020 ESOO. • For its modelling, AEMO currently uses traces that are derived from the same POE for both maximum and minimum demand. For example, a trace with 10% POE maximum demand will also have 10% POE minimum demand. AEMO acknowledges that this is an over-simplification but it is unclear whether it makes a material impact on outcomes. AEMO will consider if other combinations will be more relevant for future publications. • In developing the traces AEMO uses summer and winter maximum demand and annual minimum demand. Annual minimum is generally in shoulder for mainland regions and Summer in Tasmania.
Electrical Trades Union	Union	• Offshore wind	• Thorough analysis of offshore wind should be included in the forecasting as it is a proven, safe, reliable technology – much more so than nuclear, which is mentioned in the report despite it having no presence in Australia.	• AEMO's technology options includes the opportunity for off-shore wind development in the Gippsland region of Victoria • Due to limited data availability, AEMO cannot include other off-shore locations without wind data improvements. AEMO would welcome alternate datasets from stakeholders.
Maritime Union of Australia	Union	• Offshore wind	• Thorough analysis of offshore wind should be included in the forecasting as it is a proven, safe, reliable technology – much more so than nuclear, which is mentioned in the report despite it having no presence in Australia.	

Table 16 Summary of received submissions – nuclear

Stakeholder	Type of group	Key topic(s)	Summary of submission	AEMO response
SMR Nuclear Technology Pty Ltd (Tony Irwin)	Nuclear industry	• Nuclear • High cost assumptions	• The cost assumptions appear too high for nuclear. • Some advancements have been made on nuclear in the past few years in the United States, and this could support modelling inputs.	Currently Section 140A of the *Environment Protection and Biodiversity Conservation Act 1999*[100] prohibits the development of nuclear installations. As such, AEMO does not include nuclear options in its forecasting and planning publications. CSIRO reviewed the submissions, and GHD's assessment of costs[101], and found that while cost uncertainties do exist, overall the costs were high.
John Patterson (individual)	Nuclear advocate	• Nuclear • Small Module Reactors • Cost assumptions	• Modelled cost of nuclear is too high, gives examples of small nuclear projects overseas which have achieved lower costs. • Nuclear power should be a key backup power supply in the transition from coal to renewable resources over the next 30 years.	
Bright New World	Nuclear industry/NGO	• Nuclear • High cost assumption	• The cost assumptions appear too high for nuclear. • Alternative types of nuclear technology should be considered. • Better engagement with the nuclear industry should be undertaken in the future.	
Australian Nuclear Association	Nuclear industry	• Nuclear • High cost assumption	• The cost assumptions appear too high for nuclear. • Alternative types of nuclear technology should be considered.	
Dylan Hem (individual)	Nuclear advocate	• Nuclear • High cost assumptions	• Nuclear power has the potential to support a low-cost decarbonisation of the electricity industry. • The AEMO cost assumptions may be too high for nuclear. • Small Module Reactors may be a viable low-cost nuclear option for Australia.	
NuScale	Nuclear industry	• High cost assumptions • Small Module Reactors	• The cost assumptions for nuclear may be excessive in the modelling. • Small Module Reactors may be a more cost-effective solution. • This company produces SMRs and have some examples of proposed costs.	

[100] Australian Government, *Environment Protection and Biodiversity Conservation Act 1999*, at https://www.legislation.gov.au/Details/C2012C00248.

[101] At https://publications.csiro.au/publications/#publication/PIcsiro:EP201952/.

A2. FRG engagement on inputs, assumptions

AEMO's Forecasting Reference Group (FRG) is a monthly forum with AEMO and industry's forecasting specialists. Table 17 summarises the topics that have been discussed through the year, to complement and augment the IASR consultation performed formally in December 2019 to February 2020, as allowed and encouraged by the Interim FBPG.

Further information (presentation materials, agenda, meeting minutes) is available for download at the FRG webpage[102].

Table 17 Forecasting Reference Group history, by topic

Presentation topic	Description	FRG date
Consumption forecasts	Consumption Forecasts Maximum and Minimum Demand Forecasts Connection Point Forecasts	May 2020 Jun 2020 Jul 2020
COVID -19	COVID-19 Update COVID-19 Impacts	Mar 2020 May 2020
DER	DER Register DER Trends – CER DER forecasts and methodology – CSIRO DER forecasts and methodology – GEM DER forecasts - AEMO	Sep 2019 Feb 2020 Mar 2020 Apr 2020
DSP	DSP Update DSP Methodology DSP Forecasts	Sep 2019 Apr 2020 Jun 2020
Economic Forecasts	Macroeconomic Long-Term Forecasts COVID-19 Economic forecast update	Jan 2020 Apr 2020
ESOO	ESOO Recap IASR Update	Aug 2019 Mar 2020
EV	Electric Vehicle Modelling Roadmap	Sep 2019
Forecast Accuracy	Forecast Accuracy Report Summary Forecast Improvement Program Forecast Accuracy Report Methodology	Jan 2020 Apr 2020

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

Presentation topic	Description	FRG date
FRG	FRG Engagement	Nov 2019
Generation	Seasonal Generator Ratings Thermal Power Station Retirement and Revenue Sufficiency Standing Data Request Forward looking outages – AEP Elical AEMO Forced Outage Rates Forecasts	Aug 2019 Nov 2019 Jun 2020
GSOO	GSOO Scenarios GSOO Consumption Methodology CORE Gas Price Outlook GSOO Commitment Classification Gas model improvements & forecast performance Draft GSOO Consumption & Peak Day Gas Forecast GPG Forecasts Gas Supply Forecasts	Oct 2019 Jan 2020
Weather	NEAR Project Extreme weather and climate	Nov 2019 Jul 2020
WEM	WEM ESOO Methodology	Mar 2020