Draft 2021 Inputs, Assumptions and Scenarios Report

December 2020

Draft report for consultation

For use in Forecasting and Planning studies and analysis

Important notice

PURPOSE

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

DISCLAIMER

AEMO has made all reasonable efforts to ensure the quality of the information in this publication but cannot guarantee that information, forecasts and assumptions are accurate, complete or appropriate for your circumstances. 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
1.0	11/12/2020	Initial release

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).

Publication of this draft 2021 Inputs, Assumptions and Scenarios Report (Draft 2021 IASR) commences formal consultation on the scenarios, inputs and assumptions proposed for use in AEMO's 2021-22 forecasting and planning activities, including the 2022 ISP. The Draft 2021 IASR also provides detail on the process by which any inputs and assumptions will be updated and consulted on prior to modelling commencing, to mitigate risks associate with data latency and maintain publication relevance.

The details provided in this Draft 2021 IASR are critical to AEMO's forecasting and planning publications, and also to the Regulatory Investment Test for Transmission (RIT-T) assessments undertaken by transmission network service providers (TNSPs) under the new actionable ISP framework.

Consultation process thus far

Prior to the release of this Draft 2021 IASR, AEMO has sought to engage very widely with as many stakeholders as practical, particularly in the development of the proposed scenarios, with the goal of preparing robust proposals for further consultation. AEMO held five webinars and workshops with stakeholders across the energy industry, including network businesses, generators, retailers, consumer groups and other stakeholders, that provided essential views and input to help AEMO construct the proposed scenarios for wider consultation. AEMO is committed to continued engagement on the content of this Draft 2021 IASR in the interests of increasing transparency and stakeholder engagement. The commitment to engagement is also consistent with the principles outlined in the National Electricity Rules (NER, clause 5.22.8) and the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines.

AEMO has received valuable feedback from stakeholders on the engagement to date, particularly on the need to extend the dimensions of the scenarios in some important areas. These included the pathways to recovery from the COVID-19 pandemic, the scale of decarbonisation ambition across the scenarios, and the consideration of greater electrification and potential hydrogen production within the scenario collection (as means of achieving strong decarbonisation across sectors). AEMO has also reflected on stakeholder feedback regarding the penetration of distributed energy resources (DER) across the proposed scenarios.

The feedback has enabled some consolidation of the 2020 ISP scenarios, while retaining a set of broad, distinct, internally consistent and plausible proposed scenarios.

For regulatory network and non-network investment purposes, including both the ISP and RIT-Ts, the proposed scenarios increase the emphasis that was applied in the 2020 scenario collection to test the risks of under- and over-investment in transmission-related projects in a balanced manner. In developing the proposed scenarios, AEMO has also taken into consideration the guidance provided in the AER's cost benefit analysis guidelines (CBA Guidelines).

Most importantly, AEMO values the expertise and knowledge of our stakeholders and understands that the feedback provided on the proposals in this report will help improve the quality of AEMO's forecasting and planning, and associated outcomes for energy consumers and the energy sector.

Notice of Consultation: Invitation for written submissions

All stakeholders are invited to provide a written submission to the questions outlined in this Draft 2021 IASR, and on any other matter related to the scenarios, inputs and assumptions. Submissions need not address every question posed and are not limited to the specific consultation questions contained in each chapter.

Submissions should be sent via email to forecasting.planning@aemo.com.au and are required to be submitted by **Monday 1 February 2021**. Feedback will be particularly helpful where views are accompanied by supporting information. AEMO requests that, where possible, submissions should provide evidence that support any views or claims that are put forward.

Proposed scenarios

The scenarios proposed in this Draft 2021 IASR have been developed taking into consideration the major sectoral uncertainties affecting the costs, benefits and need for investment in the NEM. These uncertainties relate to the rate of decarbonisation of the NEM, the speed and scale of DER penetration, economic and population growth, relative costs of various generation and storage technologies, and the extent of electrification of other sectors in pursuit of decarbonisation. Depending on how these five uncertain dimensions are combined, the assumed pace of the energy transition in the NEM, and therefore the need for investment, can vary considerably.

The proposal for the Central scenario reflects current federal and state government policies (including those that will be current by the time modelling commences), and assumes that the future is shaped by market forces (that is, the markets are primary in determining future outcomes, including in response to announced policy). This scenario contains the most probable outcome across each of the five dimensions, to the extent possible while maintaining internal consistency and plausibility.

The other scenarios are proposed to examine a plausible range of variations in the pace of the transition, as follows:

- **Sustainable Growth** – reflecting a possible future world that encompasses high global and domestic decarbonisation ambitions, aligned with strong consumer action on DER, and higher levels of electrification of other sectors. This would be supported by strong economic and population growth.
- **Slow Growth** – reflecting a possible future world that encompasses prolonged lower levels of economic growth following the global COVID-19 pandemic, and increasing probability of industrial load closures. Included in this scenario would be targeted stimulus to aid the recovery from COVID-19, that increases the uptake of distributed photovoltaics (PV) initially, and without direct policy for long-term decarbonisation.
- **Diversified Technology** – reflecting a possible future world that encompasses lower domestic gas prices due to government incentives and interventions. Higher global investment in alternative low emissions technologies and local research and development in carbon capture and storage (CCS) provide opportunities for greater dispatchable technology diversity than other scenarios.
- **Export Superpower** – reflecting a possible future world that encompasses very high levels of global electrification, Australian hydrogen export opportunities, and domestic hydrogen usage that supports low-emission manufacturing, fuelled by strong policy to support growth and strong decarbonisation.

Additionally, AEMO's scenario collection is proposed to be extended to examine a balanced range of risks that could lead to under-investment or overdue investment, or over-investment or premature investment, for example:

- Early Victorian coal closure, under conditions aligned with the Central scenario (which could lead to over-investment or premature investment in inter-regional transmission if local dispatchable capacity replacement is the only option available in time to respond to this early closure).
- Early northern New South Wales coal closures, under conditions aligned with the Central scenario (which could lead to under-investment or overdue intra-regional investment to support load centres in Sydney and surrounding areas).

- Marinus Link funding arrangements not resolved, under conditions aligned with the Central scenario (which could lead to under-investment or overdue investment in alternatives).
- More moderate DER uptake, in line with the Central trajectory, under conditions aligned with the Sustainable Growth scenario (which could lead to more rapid development of variable renewable energy (VRE) and under-investment or overdue investment in renewable energy zone [REZ] transmission).
- Development of the CopperString transmission line to connect Queensland's north-west minerals province to the NEM, under conditions aligned with the Central scenario (which could lead to over-investment or premature investment in other REZ alternatives and under-investment or overdue intra-regional transmission investment in Queensland).

While some of the above proposed scenarios and risks may be considered relatively unlikely, their purpose is to inform policy-makers, investors, consumers, researchers and other energy stakeholders of the possible opportunities in these directions, and critically, what would be needed to access these opportunities.

In addition to providing submissions on this Draft 2021 IASR, AEMO invites stakeholders to participate in a survey to provide your views on the likelihood of the possible futures encompassed in the proposed scenarios, including risk scenarios (or, indeed, on any other possible scenarios you consider should be examined). This survey is available on the consultation webpage[1].

Inputs and assumptions

This Draft 2021 IASR describes in detail the current inputs and assumptions in relation to:

- Policy settings.
- Carbon emissions constraints.
- Energy consumption forecasting components, including DER.
- Existing generation and storage assumptions.
- New entrant generation assumptions, including capital cost projections.
- Fuel price assumptions.
- Financial and economic parameters.
- REZ assumptions.
- Transmission modelling assumptions.
- Assumptions related to other power system security inputs.
- Gas modelling inputs.
- Assumptions related to the modelling of hydrogen production and demand.

This Draft 2021 IASR describes the source of each input assumption and documents the most up-to-date information that is available. The report also details how and when any of the inputs and assumptions will be updated, and the mechanisms that will provide stakeholders with opportunities to provide further feedback on these updates.

This Draft 2021 IASR is supported by associated data artefacts that are provided on AEMO's website[1] along with this report. These artefacts include the Draft 2021-22 Inputs and Assumptions Workbook, which provides more granular detail for the inputs and assumptions under construction for use in 2021-22 forecasting, modelling and planning processes and analysis.

[1] At https://aemo.com.au/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-scenarios-and-assumptions.

Next steps

Following receipt of submissions by 1 February 2021, AEMO will facilitate a workshop to discuss the key issues raised in the submissions, focusing discussions on inputs and assumptions referenced most frequently across the stakeholder submissions. This workshop will also seek feedback on the relative likelihood of the scenarios.

Further opportunities for engagement on inputs and assumptions are outlined throughout this report.

AEMO is engaging with governments to further understand the detail of various policy initiatives for inclusion, ensuring they adhere to the frameworks set out in NER 5.22.3. As public policy is a key dimension of all scenarios, it is essential that AEMO receives all relevant detail to confirm inclusion by May 2021, prior to the finalisation of the IASR in July 2021.

While this report does not solely focus on the input variables and parameters used by the ISP, the ISP is a key consumer of these inputs, assumptions and scenarios. Details on major milestones in the ISP process can be found in the ISP Timetable[2], and additional information on upcoming events and consultations for the ISP are outlined on AEMO's website[3]. Details on how to get involved in the consultation process are also provided on the website[4].

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[2] AEMO. 2022 Integrated System Plan Timetable, at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-isp-timetable.pdf.

[3] AEMO. 2022 ISP – Opportunities for engagement, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/opportunities-for-engagement.

[4] Available at https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/get-involved

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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). The final five years of the 10-year ESOO forecast provide an indicative forecast of any future material reliability gaps. The ESOO also includes 20-year forecasts of annual consumption, maximum demand and demand side participation (DSP). It is published annually, with updates if required.
- **Gas Statement of Opportunities (GSOO)** – provides AEMO's forecasts of annual gas consumption and maximum gas demand, and uses information from gas producers about reserves and forecast production, to project the supply-demand balance and potential supply gaps over a 20-year outlook period. It is published annually, with updates if required.
- **Integrated System Plan (ISP)** – is a whole-of-system plan that efficiently achieves the power system needs of a transforming energy system in the long-term interests of consumers. It serves the regulatory purpose of identifying actionable and future ISP projects, as well as the broader purposes of informing market participants, investors, policy decision-makers and consumers. It provides a transparent, dynamic roadmap over a planning horizon of at least the next two decades, with consideration extending to 2050, 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 new ISP rules framework in July 2020. It is published every two 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 supply in an attempt to reduce costs and decarbonise, and are thus having a direct impact on the electricity sector. Furthermore, opportunities for hydrogen production in Australia could have a transformative impact on the domestic energy sector if the Federal Government's vision for Australia to become a world leader in hydrogen production and export is realised. .
- Existing supply sources, particularly thermal generators, are ageing and approaching the end of their technical lives. Expected closure years are provided by participants, but risks of earlier than expected closures still need to be managed. These resources must be replaced in a timely manner to maintain a reliable and secure power system that meets consumer demand at an affordable cost as well as achieving public policy requirements. Depending on the preferred replacement resources, this may require investment in network infrastructure to enable delivery of new energy production to consumers.

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

This Draft 2021 Inputs, Assumptions and Scenarios Report (Draft 2021 IASR) outlines the scenarios that have been developed through consultation to date, and that AEMO is proposing to use in its forecasting and planning publications, including the 2021 ESOO and the 2022 ISP. The scenarios are of critical importance in AEMO's planning and forecasting publications but also in the regulatory investment test for transmission (RIT-T) assessments conducted by transmission network service providers (TNSPs).

AEMO is seeking feedback on the proposed scenarios and the extent to which they address major sectoral uncertainties and explore risks of over- and under-investment in the NEM.

This Draft 2021 IASR also describes key inputs and assumptions proposed to be used in AEMO's modelling and outlines the process by which any inputs and assumptions will be updated and consulted on in the year ahead. The report will be finalised by July 2021.

The information in this report is supported by the Draft 2021-22 Inputs and Assumptions Workbook[5], which provides more granular detail for the inputs and assumptions under construction for use in 2021-22 forecasting, modelling and planning processes and analysis.

All dollar values provided in this report are in real June 2020 Australian dollars (unless stated otherwise).

1.1 Formal consultation

NER 5.22.8(a) requires AEMO to develop, consult and publish the IASR in accordance with the Australian Energy Regulator's (AER's) Forecasting Best Practice Guidelines. Under these Guidelines, AEMO is required to follow a "single stage process" which requires that the publication of this Draft 2021 IASR follows from meetings with Consulted Persons.

AEMO is also required to have regard to how best employ the following three consultation practices:

- Effectively and meaningfully engaging with stakeholders at all key stages of the ISP development process;
- Consulting on key modelling outputs and their drivers such that stakeholders can relate inputs to ISP outputs; and
- Transparently disclosing all key inputs.

In preparing this Draft 2021 IASR, AEMO has engaged with stakeholders through a number of workshops and webinars, which have helped inform the initial development and specification of proposed scenario narratives. Table 1 below provides more detail on these activities. AEMO has taken the feedback provided in these engagement opportunities to refine and adjust the proposed scenarios, inputs and assumptions presented in this report.

Table 1 Stakeholder engagement to date

Activity	Date	Consultation type
Hydrogen in the 2021 GSOO Workshop	18 September 2020	Consultation/discussion
Forecasting and Planning Scenarios Workshop	14 October 2020	Consultation/discussion
Forecasting and Planning Scenarios Webinar	22 October 2020	Informing/discussion
Forecasting and Planning IASR - Scenarios Webinar	11 November 2020	Informing/discussion
Forecasting and Planning IASR Workshop	20 November 2020	Consultation/discussion

The publication of this Draft 2021 IASR commences the process of formal consultation. Stakeholders are invited to submit written feedback on any issues related to inputs, assumptions and scenarios. If stakeholders consider that the scenario collection currently proposed does not adequately capture the range of

[5] At https://www.aemo.com.au/consultations/current-and-closed-consultations/2021-Planning-and-Forecasting-Consultation-on-Inputs-Assumptions-and-Scenarios.

uncertainties that materially impact supply and demand in the NEM, opportunity still remains for stakeholders to suggest additional distinct, plausible and internally consistent scenarios through written submissions.

Further consultation will continue throughout the first half of 2021, particularly on those input assumptions which are yet to be updated. The final inputs, assumptions and scenarios that will be applied in the Draft 2022 ISP and the 2021 ESOO will be documented in the final 2021 IASR in July 2021.

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

Submissions should be sent via email to forecasting.planning@aemo.com.au and are required to be submitted by **Monday 1 February 2021**.

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

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

Following the completion of the submission window (1 February 2021), AEMO will publish a summary of the issues raised across the submissions, and outline how feedback is being addressed. Following the completion of the updates to inputs and assumptions, AEMO will then publish a final version of the IASR in July 2021.

AEMO will schedule a further workshop or webinar in the week commencing 22 February 2021 to discuss the key issues raised in the submissions and will focus on in-depth discussions on the inputs and assumptions most frequently referenced across the stakeholder submissions. This workshop will also seek feedback on the relative likelihood of the scenarios. Invitations will be sent out in early January 2021 to register for this workshop/webinar.

Continued engagement opportunities on Draft 2021 IASR

AEMO is committed to engagement with stakeholders that enables participation, collaboration and co-operation, to ultimately improve the industry's decision-making and ensure that AEMO's planning outcomes deliver for energy consumers, particularly within the context of the 2022 ISP. This approach has regard to the heightened need for stakeholder engagement within the AER's Forecasting Best Practice Guidelines, which require AEMO to engage closely with stakeholders, provide evidence of its considerations of stakeholder feedback, and engage transparently and with sufficient information to inform stakeholders contributions.

Considering a best-practice approach to stakeholder engagement, AEMO proposes employing a wide range of engagement strategies that collectively ensure the final IASR will appropriately consider stakeholder feedback. While the formal consultation to this Draft 2021 IASR is essential to ensure stakeholder views are formally documented and responded to, AEMO acknowledges that more work is required to finalise many of the inputs and assumptions that will define the proposed scenarios. As such, AEMO will use various means, including workshops and webinars, one-on-one discussions, and presentations to AEMO's Forecasting Reference Group (FRG), to provide opportunities for discussion, consultation and broad engagement throughout the input finalisation process.

Details on major milestones in the ISP process can be found in the ISP Timetable[6]. Additional information on upcoming events and consultations for the ISP are outlined on AEMO's website[7]. The key dates related to the IASR are:

[6] AEMO. 2022 Integrated System Plan Timetable, at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-isp-timetable.pdf.

[7] AEMO. 2022 ISP – Opportunities for engagement, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/opportunities-for-engagement.

- **January 2021** – AEMO will host a Transmission Cost Database Webinar to engage with stakeholders on a proposed approach to transmission cost estimation for the ISP, including development of a public Transmission Cost Database.
- **1 February 2021** – submissions to this Draft 2021 IASR are due.
- **Week commencing 22 February 2021** – AEMO will host an IASR webinar to discuss feedback to the Draft 2021 IASR and outline the next steps in the consultation process .
- **May 2021** – AEMO will publish a transmission cost database and draft Transmission Cost Report. Written submissions will be invited over a four week period that closes in June 2021. AEMO will provide a webinar in late May to support the engagement process. The final transmission costs will be included in the IASR.
- **30 July 2021** – AEMO will publish the IASR.

Engagement updates will be provided to the ISP and FRG mailing lists and published on AEMO's website[8].

1.2 Alignment with update cycles for key inputs

As outlined in the previous section, at the time of preparing this Draft 2021 IASR, many of the inputs and assumptions have not been finalised, due to key dependencies on other information (such as historical DER installations, operational demand data, policy or investment decisions, macro-economic forecasts, or other component forecasts) that are annually updated and made available closer to modelling commencing.

To strike an appropriate balance between the principles of transparency, stakeholder engagement and accuracy, AEMO has presented indicative values for these inputs and assumptions in this Draft 2021 IASR, and outlined the update and consultation processes proposed to ensure the most relevant, and up-to-date information is used at the time forecasts are performed. This includes acknowledging which inputs will rely on consultant support to finalise, and the opportunities to engage on these consultant outputs.

Where indicative or interim values have been used, they have been clearly identified; in most instances, they reflect the inputs and assumptions used for the 2020 ESOO and/or 2020 ISP. Stakeholder feedback on the reasonableness of these assumptions, or expectations as to how these should change in the current environment, will be valuable in informing the update process.

1.3 Supporting material

In addition to the Draft 2021-22 Inputs and Assumptions Workbook, Table 2 documents additional information related to AEMO's inputs and assumptions.

Table 2 Additional information and data sources

Organisation	Document/source	Link
ACIL Allen	2014 Fuel and Technology Cost Review	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/ntndp/2014/data-sources/fuel_and_technology_cost_review_report_acil_allen.pdf
ACIL Allen	2016 Emission Factor Assumptions Data	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/ntndp/2016/data_sources/acil-allen---aemo-emission-factors-20160511.xlsx?la=en&hash=A6915CE66351E07CAD6B49C4024F8D8F
AEMO	Generation Information	https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

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

Organisation	Document/source	Link
AEMO	Transmission Cost Database Phase 1 Report	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/Transmission-Cost-Database-Phase-1-Report.pdf
AEMO	2020 GSOO Stakeholder Surveys and gas supply input data	https://www.aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2020/2020-gsoo-supply-input-data-files.zip?la=en
AEP Elical	2020 Assessment of Ageing Coal-Fired Generation Reliability	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/aep-elical-assessment-of-ageing-coal-fired-generation-reliability.pdf?la=en
Aurecon	2020-21 Cost and Technical Parameter Review	Report: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/Aurecon-Cost-and-Technical-Parameters-Review-2020.pdf Workbook: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/Aurecon-Cost-and-Technical-Parameters-Review-2020-workbook.xlsb
BIS Oxford Economics	2020 Macroeconomic forecasts October update	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/BIS-Oxford-Economics-Macroeconomic-Forecasts-Update-October-2020.pdf
CSIRO	Draft GenCost 2020-21	https://publications.csiro.au/publications/publication/PIcsiro:EP208181 https://data.csiro.au/collections/collection/CIcsiro:44228v2/DItrue
CSIRO	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
Energy Networks Australia	RIT-T Handbook	https://www.energynetworks.com.au/resources/fact-sheets/ena-rit-t-handbook-2020/
Entura	Pumped Hydro cost modelling	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Report-Pumped-Hydro-Cost-Modelling.pdf
GHD	2018-19 AEMO Costs and Technical Parameter Review	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/9110715-rep-a-cost-and-technical-parameter-review---rev-4-final.pdf?la=en&hash=AFEFC07973CE5E2244A0FC0FF8773AA8
Green Energy Markets	Projections for distributed energy resources – solar PV and stationary energy battery systems	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/green-energy-markets-der-forecast-report.pdf?la=en
Lewis Grey Advisory	Lewis Grey Advisory Fuel Prices	https://www.aemo.com.au/consultations/current-and-closed-consultations/2021-Planning-and-Forecasting-Consultation-on-Inputs-Assumptions-and-Scenarios
Wood Mackenzie	Wood Mackenzie Coal Prices	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/Wood-Mackenzie-Draft-Coal-cost-projections-2020.pdf

2. Scenarios

AEMO uses scenario modelling and cost-benefit analysis to determine economically efficient ways to provide reliable and secure energy to consumers through the energy transition. Exploring scenarios helps assess the risks, opportunities and development needs through the energy transition, in the long-term interests of consumers. To do so, the selected scenarios must cover a broad range of plausible operating environments for the energy sector, and the potential changes in those environments, in an internally consistent way.

The proposed scenarios in this Draft 2021 IASR have regard to the guidance provided in the Cost Benefit Assessment (CBA) Guidelines to examine future supply and demand conditions to value investments within an uncertain environment. Major sectoral uncertainties have been identified through insights developed in the 2020 ISP and recent stakeholder engagement; these include:

- The size of consumer energy demand (including the scale of energy avoided and self-generated, and future outlook for energy intensive large industrial loads (LILs).
- Generation and storage technology cost evolution, both grid-scale and distributed energy resources.
- Environmental outcomes, particularly decarbonisation objectives, and the scale and timing of coal-fired generation closures.
- Government policies to support regional economic development, domestic manufacturing and jobs growth, build energy resilience, and keep downward pressure on energy prices.
- The extent of electrification and location of this demand, as other sectors decarbonise and new industries such as hydrogen production emerge.

2.1 Scenario overview

AEMO assesses future forecasting and planning requirements under a range of plausible scenarios over a period sufficiently long to support stakeholders' decision-making in the short, medium, and long term.

Since the publication of the 2020 ISP, AEMO has engaged with stakeholders to develop the proposed set of scenarios now under consultation for use in 2021-22 forecasting publications.

In developing the proposed set of scenarios, and having regard to the requirements established in the Forecasting Best Practice Guidelines, AEMO has considered several core principles:

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

2.2 The scenario development process

Recognising the importance of acknowledging and considering stakeholders' views and the valuable input they provide, AEMO sought to engage collaboratively with stakeholders as early as possible to help inform the development of these scenarios. This engagement provided an open opportunity for stakeholders to assist in the definition of scenarios that would test the potential risks of over- and under-investment, without needing to be tied to the 2020 IASR scenarios.

Nevertheless, AEMO has recognised that much overlap exists between the 2020 ISP scenarios and those developed with stakeholders over the past few months. Keeping alignment with 2020 IASR scenario narratives, where appropriate, is beneficial as the continuity enables greater transparency and understanding of what factors are driving any potential changes to the optimal development path from one ISP to another.

To develop this Draft 2021 IASR, AEMO conducted surveys and held two workshops to collaborate with stakeholders on scenario development, as well as two webinars to inform stakeholders, provide greater clarity, and seek stakeholder feedback. In addition, early insights on the treatment of an emerging hydrogen industry were gathered from stakeholders in a distinct, targeted workshop prior to the broader scenario development workshops, and considering the forthcoming 2021 GSOO publication.

A wide range of stakeholders have been represented at these workshops and webinars, with representatives from retailers, generators, industry bodies, network businesses and consumer groups in attendance. Given the critical importance of consumers to this process, AEMO has formed a Consumer Panel[9] to ensure a greater focus on engagement with consumers, given that they are often under-represented in broader workshops relative to their importance as stakeholders in forecasting and planning processes.

Workshop 1 – Hydrogen in the 2021 GSOO

On 18 September 2020, AEMO held a workshop to examine the incorporation of hydrogen production in the 2021 GSOO. This workshop captured stakeholder perspectives on the potential scale, timeline and location of hydrogen development and consumption in Australia, with a focus on the impact of high hydrogen deployment on Australia's energy infrastructure.

Stakeholders provided their views in both a pre-workshop survey and interactive activities in the workshop itself. The insights from this workshop then informed the broader scenario narratives and input settings discussed in subsequent workshops.

Workshop 2 – Scenario development

In advance of a scenario development workshop on 14 October 2020, AEMO asked stakeholders via a survey to build and submit three scenario narratives (other than a Central case) that, in their view, were most important to future energy sector planning and decision-making.

Stakeholders were asked to do this using a scenario development framework which relied on five key dimensions (see Figure 1), which were identified by AEMO as being major sectoral uncertainties based on insights from the 2020 ISP. This expanded the two-dimensional scenario framework used in the 2020 ISP process, to allow for a more diverse set of scenarios to be explored. .

Dimensions in the framework provided a theme for key assumptions (for examples, uptake rates for electric vehicles [EVs] and distributed photovoltaics [PV]). The dimensions varied in their degree of independence to each other. When building the scenario collection, the dimensions needed to follow the internal consistency principle; that is, the dimensions were set relative to each other in such a way that the resulting overall scenario narrative was internally consistent.

By combining these five dimensions in an internally consistent way, stakeholders created plausible future world scenario narratives that were submitted as part of their survey response.

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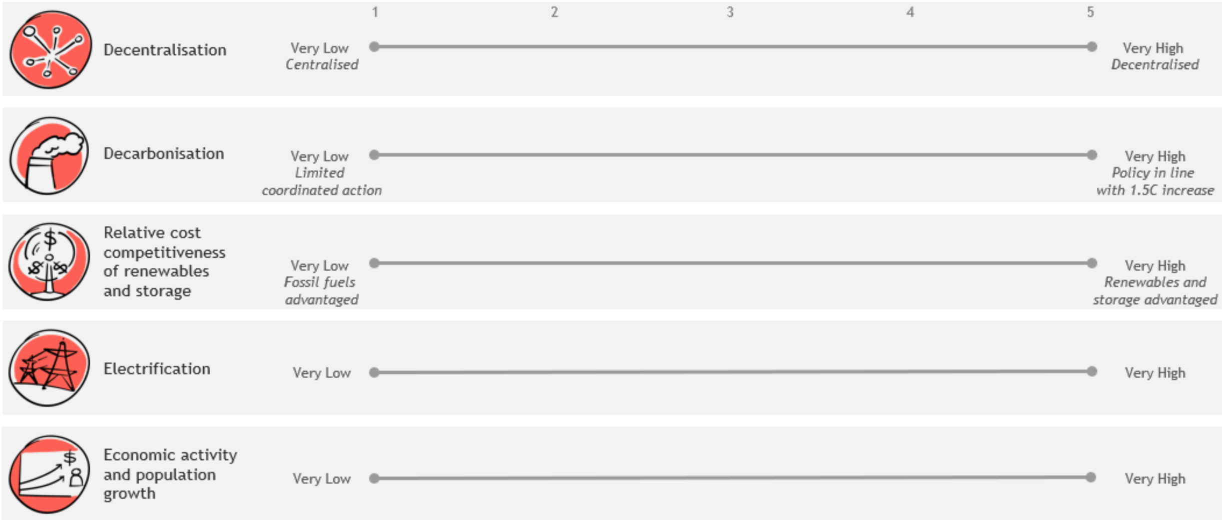
[9] At https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/get-involved/consumer-panel.

Figure 1 The scenario development framework



AEMO analysed the survey responses and developed an initial set of seven scenarios, which were presented at the 14 October workshop. This set aimed to best reflect the 100+ scenario submissions, while adhering to the principles outlined previously.

During the workshop, stakeholders were initially provided an opportunity to provide feedback on the dimensional framework and the set of seven scenarios proposed. Stakeholders were then divided into workgroups to discuss each scenario in detail, interrogate the internal consistency of the scenario dimension settings, and develop a more detailed scenario narrative. This step allowed AEMO to test its interpretation of the stakeholder submissions and build consensus within each workgroup of the scenario dimensions. As a result, in some cases, the dimensions were modified from what was initially presented to stakeholders.

Feedback was then sought in a post-workshop survey which asked whether there were any issues not addressed in the workshop discussions. While most stakeholders were comfortable with the breadth of issues covered by the scenarios, some feedback identified that uncertainties remained, particularly relating to the pathways to a post COVID-19 era, and the influence of further technology disruption.

Key risks of over- or under- investment under each scenario were also ranked by stakeholders during the workshop to help AEMO assess whether additional scenarios should be included in the mix.

Webinar 1 – Review of scenario development insights

Following the 14 October workshop, AEMO collated and analysed its outputs, and on 22 October 2020 presented via webinar[10] the consolidated views on scenario dimensions and narratives from each workgroup.

This again allowed AEMO to test its interpretation of stakeholder views on the developing scenarios, and also gave stakeholders an opportunity to review the emerging scenario narratives. The primary purpose of this webinar was to inform stakeholders unable to attend the workshop.

Webinar 2 – Consolidating the scenario narratives

On 11 November 2020, AEMO presented stakeholders with a consolidated set of four scenario narratives (in addition to the Central scenario) and a set of risk scenarios, via webinar[11].

The consolidation from the initial seven scenarios was in line with feedback received at the 14 October workshop and 22 October webinar. It recognised the overlap between several proposed scenarios, and the

[10] The webinar presentation can be accessed at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/scenario-narrative-development-webinar-presentation-slides.pdf?la=en.

[11] The webinar presentation can be accessed at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/202122-forecasting-and-planning-iasr-scenarios-webinar-presentation.pdf.

need for sufficient breadth, in line with the scenario development principles. Stakeholders were then invited to provide feedback on the consolidated set of scenarios. Some stakeholders sought further clarity on individual scenario settings, which was provided in the subsequent workshop and in this Draft 2021 IASR.

Stakeholders were also asked if there were other scenarios which they felt were not covered by the proposed set, at which point a number of ideas were raised. These included suggestions of increased battery penetration, a more disorderly transition, delays to transmission investment, higher consumer DER, and increased enablement of transportation as providing grid support services, such as via vehicle-to-grid discharging. In many of these instances, AEMO has considered that these are within the set of proposed scenarios (such as the range of DER trajectories and transportation charging and discharging behaviours), or within risk scenarios (described in Section 2.5, such as more disorderly transition through earlier closures), or within the ISP methodology for assessing investments (for example, regarding development pathways with earlier or later transmission development).

Workshop 3 – Inputs, assumptions and scenarios

AEMO held a further workshop on 20 November 2020 to collaborate on the more detailed input assumptions appropriate for each scenario.

Approach to consultation feedback on the scenarios

The scenarios proposed in this Draft 2021 IASR have benefited from this continued engagement with stakeholders.

A broad range of stakeholders provided feedback to AEMO throughout the scenario development process. This feedback has been considered through the process and has influenced the development of scenarios and the determination of relevant scenario settings.

AEMO has exercised judgement in responding to feedback, and has been anchored by several key considerations when consolidating the range of feedback received and defining the proposed scenarios in this Draft 2021 IASR. These considerations, informed through the scenario development guidance provided in AER's CBA Guidelines, are as follows:

- **Breadth** – it is critical that across the scenarios there is a representative spread of inputs for key drivers. For example, the set of scenarios should explore trajectories/settings which are higher and lower than the central and best estimate.
- **Fit for purpose** – the set of scenarios as a whole needs to consider the risks of over- and under-investment, which requires exploring combinations of settings which provide a reasonable bound on outcomes which influence the need for investment.
- **Utility** – all scenarios must be internally consistent and plausible, yet sufficiently distinct from each other that they achieve a particular purpose.

These considerations are reflected in how AEMO has responded to feedback provided throughout the webinar and workshop engagement opportunities, ahead of the release of this Draft 2021 IASR.

Matters for consultation

- Please provide feedback on the consultation process that preceded the release of this Draft 2021 IASR. Do you feel you were able to provide feedback? What could AEMO have done better?
- Are there other scenarios, not currently proposed, that could lead to under- or over-investment, and are sufficiently distinct to warrant inclusion? What would be the scenario narrative for such a scenario, and how would it help inform energy sector decision-making?

2.3 Scenario narratives and descriptions

AEMO's scenarios for examining the future needs of the power system, and the investments required to support consumers' energy transition, are centred on a **Central** scenario that represents AEMO's baseline view of key inputs of all key drivers, considering current policies across all jurisdictions of the NEM. The Central scenario reflects current and likely future trends in energy consumption, consumer energy investments, and technology costs, and includes all current environmental and energy policies (provided the policy has been sufficiently developed to enable AEMO to identify its impacts on the power system). More detail around policy inclusions is provided in Section 4.1.

To complement the Central scenario, AEMO has developed the following four scenarios, considering the insights provided by stakeholders across the engagement opportunities previously described:

- **Sustainable Growth** – reflecting a possible future world that encompasses high global and domestic decarbonisation ambitions, aligned with strong consumer action on DER, and higher levels of electrification of other sectors. This would be supported by strong economic and population growth.
- **Slow Growth** – reflecting a possible future world that encompasses prolonged lower levels of economic growth following the global COVID-19 pandemic, and increasing probability of industrial load closures. Included in this scenario would be targeted stimulus to aid the recovery from COVID-19, that increases the uptake of distributed PV initially, and without direct policy for long-term decarbonisation.
- **Diversified Technology** – reflecting a possible future world that encompasses lower domestic gas prices due to Government incentives and interventions. Higher global investment in alternative low emissions technologies and local research and development in carbon capture and storage (CCS) provide opportunities for greater dispatchable technology diversity than other scenarios.
- **Export Superpower** – reflecting a possible future world that encompasses very high levels of global electrification, Australian hydrogen export opportunities, and domestic hydrogen usage that supports low-emission manufacturing, fuelled by strong policy to support growth and strong decarbonisation.

The sections which follow outline the scenario narratives in greater detail.

Further details on scenarios which explore risks within the above scenario narratives are provided in Section 2.5.

Scenario likelihood

Each scenario identified above and described in the sections below has been constructed to help inform decision-making in the presence of uncertainty. The scenarios can help identify investment risks and opportunities in the energy sector, as well as signposts that warn of the need to adapt as uncertainty reveals itself.

While some of the proposed scenarios may be considered relatively unlikely, their purpose is to inform policy-makers, investors, consumers, researchers and other energy stakeholders of the possible opportunities in these directions, and critically, what would be needed to access these opportunities.

In addition to providing submissions on this Draft 2021 IASR, AEMO invites stakeholders to participate in a survey to provide your views on the likelihood of the possible futures encompassed in the proposed scenarios (or, indeed, on any other possible scenarios you consider should be examined).

2.3.1 Central scenario

Narrative summary

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

In this scenario, the transition from fossil fuels to renewable generation is generally led by continued strong uptake of DER, market forces driving coal-fired generation retirements, and state government support for renewable energy zones (REZs).

Purpose

To provide a basis on which to assess the development of the system under currently funded and/or legislated policies and commitments, using the most probable value/best estimate for each input.

Similarity to 2020 ISP scenario narratives

This scenario is very similar to the 2020 ISP Central scenario, although with firmer net zero decarbonisation objectives in the long term, and updated to include new government policy commitments and current market trends.

In this scenario:

- Uptake of DER, energy efficiency measures, and the electrification of the transport sector proceeds in line with AEMO's current best estimates.
- Moderate growth in the global economy is in line with a central estimate, noting that 'moderate growth' is to be taken in the context of COVID-19 economic recovery.
- Global decarbonisation efforts are modest in the long term, with Australia achieving the 2030 ambition of reducing emissions by 26-28% on 2005 levels, and proceeding towards net zero emission in the second half of this century.
- Currently legislated or materially funded state-based VRE policies and targets are achieved, but no further expansion of these policies is considered. Any environmental or energy policies that meet the public policy criteria listed in clause 5.22.3 of the National Electricity Rules (NER) by end of May 2021 will be included in this scenario for the 2022 ISP and 2020 ESOO.
- Sectoral change beyond current policies is driven by commercial decision-making as ageing power stations close at, or before, the end of their technical lives. The costs of VRE and storage technologies continue to fall and are increasingly competitive with existing fossil-fuelled generation.
- In the long term, modest global carbon reduction ambitions lead to higher global and domestic temperatures and more extreme weather conditions.

Matters for consultation

- Acknowledging that AEMO will consider current committed policy settings within this scenario which meet the criteria outlined in Section 4.1 and clause 5.22.3 of the NER, and considering AEMO's best estimates of all key drivers, do you have any feedback on the Central scenario as proposed?

2.3.2 Sustainable Growth

Narrative summary

Higher decarbonisation ambitions are supported by rapidly falling costs for battery storage and VRE, which drive consumers' actions and higher levels of electrification of other sectors. These ambitions are supplemented by strong economic and population growth.

Compared to the Central scenario, this future has:

- Higher levels of economic and population growth, decarbonisation, and electrification, and strong uptake of distributed energy resources.
- Increased cost-competitiveness of VRE and batteries relative to fossil fuel generation.

Purpose

- To understand the impact of rapid decarbonisation and DER uptake on the needs of the electricity system, and in particular to explore the potential risk of under-investment in the infrastructure required to facilitate this transition in a timely and efficient manner.
- To understand the effect of strong decarbonisation ambitions and high DER uptake (including electric vehicle uptake) on power system needs.

Similarity to 2020 ISP scenario narratives

This scenario is similar to the 2020 ISP Step Change scenario, but with increased regional growth to reflect remote working becoming commonplace. The extent of transport electrification is higher than that modelled in the 2020 ISP, consistent with the increased electrification of transport in the 2020 ESOO.

In this scenario:

- Higher levels of awareness towards the impacts of climate change from increasingly technology and energy literate consumers result in a greater degree of individual consumer action to reduce emissions.
- With governments also taking decisive action to tackle climate change, this scenario is consistent with the Paris Agreement goal of limiting temperature increases well below 2ºC by the end of the century. Domestically, federal and state policies are in line with this goal, going beyond existing climate policy. Australian emissions fall rapidly throughout the period, reaching net zero emissions by 2050.
- There is an increase in regional population growth, with increased regional growth as remote working is becoming commonplace. This process is supported by technology that facilitates home office productivity.
- At the same time, the world sees relatively high levels of economic growth. Increased levels of disposable income allow consumers to fund the rapid DER uptake that characterises this scenario.
- This DER uptake is driven by consumers seeking to take a greater degree of ownership over their consumption, choosing when and how to consume energy. This is also aided by continued technological advances that extend the strong uptake in DER technologies.
- Energy consumers are more engaged with the energy market, with reforms in two-sided markets resulting in higher levels of price-responsive DSP.
- High levels of growth and decarbonisation do not lead to material electricity consumption on the NEM, with electrical loads associated with hydrogen production not being NEM-connected. Manufacturing industries that decarbonise to contribute to the net-zero objectives may gain access to low-emissions fuels, such as hydrogen or biofuels, although to a lesser extent than if production was NEM-integrated. As such, while some amount of hydrogen availability is expected, it is not envisaged to materially impact the

NEM in this scenario. AEMO explores an alternative future with greater grid-integrated hydrogen production in the Export Superpower scenario, described in Section 2.3.5.

- There are high levels of electrification of transport, and a high degree of fuel switching towards low carbon electricity across the energy sector. With the highest level of EV uptake, EVs are in line with becoming the dominant form of road passenger transportation.

Workshop feedback

When polled on the usefulness of this scenario during the second webinar, over 80% of stakeholders considered this scenario useful, with no stakeholder expressing a negative view.

Stakeholders provided several points of feedback which have been reflected in the scenario settings (shown in Table 4 in Section 2.4), including:

- Whether the scenario should have higher levels of DSP than the Central scenario. AEMO considered that, despite mixed stakeholder views, this scenario would be the most likely of the five to have greater consumer demand response. Given that the scenarios should cover the breadth of possibilities of key drivers, a strong DSP outlook is proposed.
- Generally strong support for the high levels of DER in this scenario and the linkage to global ambition to keep temperature increases to well below 2°C by 2100, and Australia reaching net zero emissions by around 2050. However, there were some requests for understanding the potential for decarbonisation without DER uptake above a central outlook. AEMO proposes exploring the investment impacts of lower DER uptake in the risk scenarios in Section 2.5.
- There was some support for enforcing early coal closures in this scenario, with an expectation that early closures may be an inherent economic outcome of the scenario settings. AEMO's ISP modelling methodology currently allows earlier than expected generation retirements if economic life is determined to be shorter than technical life. AEMO proposes to continue to apply this method. Considering the decarbonisation objectives of the scenario, this may lead to earlier economic retirements across the emissions-intensive generation fleet.
  - By enforcing early closures across the fleet of coal generators as a scenario assumption, the modelling would no longer be identifying the most economically efficient mix of retirement and investment decisions to deliver the core decarbonisation objectives of this future world. It would be simpler and more replicable to model, but investment outcomes would also be highly dependent on the choice of generation that would be forced to retire early. If all retirements were simply brought forward, perhaps five years, then the utility of the scenario may also be diminished as only the timing of investments would likely differ from the Central scenario. As a result, AEMO is seeking further feedback on whether retirement timing should be a mandatory feature in this scenario (an exogenous input), or remain an endogenous outcome of the modelling.

Matters for consultation

- What, if any, elements of the Sustainable Growth scenario as proposed are not plausible or internally consistent, and how would you suggest they should be altered?
- What approach should be used in determining the timing of coal closures in the Sustainable Growth scenario? If you consider that early retirements should be treated as an exogenous input, should this be applied consistently to all power stations, or should only specific power stations be identified and brought forward?

2.3.3 Slow Growth

Narrative summary

This scenario includes the lowest level of economic growth following the global COVID-19 pandemic, which increases the risk of industrial load closures. Decarbonisation at a policy level takes a back seat, but strong uptake of distributed PV continues, particularly in the short-term in response to a number of incentives assumed to be implemented as part of a COVID-19 recovery plan.

Key differences to the Central scenario include:

- Very low economic activity and population growth, and some industrial load closures.
- Lower levels of electrification.
- Lower levels of decarbonisation ambitions both internationally and domestically.
- Stronger DER uptake in the near term.

Purpose

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

Similarity to 2020 ISP scenario narratives

- This scenario is similar to the 2020 ISP Slow Change scenario, but without refurbishments that extend the life of coal-fired generation, or the removal of some policy drivers.

In this scenario:

- Australia's population growth slows due to a combination of domestic and international drivers, with falling birth rates and immigration levels, partly due to sustained global travel restrictions. The COVID-19 recovery is slow, supressing global growth, investment and employment levels, and resulting in lower levels of growth in Australia. More insular trade policies and increased protectionism take hold globally.
- The rate of technological development and cost reductions stagnates, as falling private investment reduces the speed of cost reductions in technologies such as battery storage.
- In search of cost savings, and in response to low interest rates, consumers continue to install distributed PV at high rates, continuing the trends observed during 2020 where uptake has held up and in many regions increased to record levels, despite adverse economic conditions. This strong uptake is further boosted by a government-funded roll out of distributed PV for social housing. Over time these impacts dissipate and distributed PV uptake moderates.
- In contrast, investment in battery storage and EVs stagnates due to more muted cost reductions, the impact of lower disposable incomes, softening in price signals for peak demand management, and longer vehicle replacement cycles.
- Government policy focuses on supporting the ailing domestic economy, with decarbonisation policy being less of a priority. Market forces and reductions in operational consumption drive emission reductions. The same is true internationally, where insufficient action is taken globally to achieve the objectives of the Paris agreement.

Workshop feedback

This scenario featured frequently in pre-workshop stakeholder submissions and has been refined in line with stakeholder feedback across the collection of workshops.

This scenario is intended to test the risk of over-investment in transmission infrastructure, and explore potential system security issues that could arise as a result of falling levels of minimum demand.

Stakeholder support for this scenario is relatively high, with over 55% of stakeholder participants in our second webinar considering it a useful scenario to explore power system needs and understand the risk of over- and under-investment; 14% of participants rated it not useful.

In the second scenario workshop, stakeholders consistently indicated that distributed PV should be at best consistent with the Central outlook, rather than being above these levels in the long term. AEMO has therefore refined the assumption in this scenario to reflect this feedback, while continuing to retain a more rapid decline in minimum demand in the near term to support assessment of potential power system security risks. Rather than assuming distributed PV uptake would continue on a higher trajectory than the Central scenario, AEMO is proposing that this scenario will take into account the potential for stronger uptake over the next few years only.

This would reflect the response observed during COVID-19 (influenced by a combination of changing consumption patterns and low interest rates), and the potential for further government stimulus to incentivise distributed PV as part of stimulus packages. Beyond the next few years, the distributed PV trajectory is then proposed to transition towards the Central outlook, reflecting stakeholders' views that it was not credible to continue a stronger uptake of distributed PV with low economic activity.

There were mixed opinions in response to the request for feedback on whether coal closures should be able to be deferred beyond their nominated retirement date if it was economic to do so. AEMO considers that this scenario may present challenging economic dynamics for coal generators, and life-extension investment activities may be prohibited by the economic environment. AEMO therefore has not included in the scenario the possibility of refurbishments that extend the life of coal-fired generation, but welcomes stakeholder feedback on the appropriateness of this approach.

Matters for consultation

- What, if any, elements of the Slow Growth scenario as proposed are not plausible or internally consistent, and how would you suggest they should be altered?
- Do you support AEMO's proposal to adjust the level of distributed PV towards a central outlook in this scenario to provide a broader range of possible minimum demand levels for assessment across scenarios?
- Do you believe that the Slow Growth scenario should allow for the extension of generator retirements beyond their expected closure years if economic to do so? If so, what purpose does this achieve?

2.3.4 Diversified Technology

Narrative summary

This reflects a world in which affordably priced and secure gas supplies are achieved as part of the Federal Government's plan to lead Australia out of the COVID-19 recession. Higher global investment in alternative low emissions technologies and local research and development in CCS accelerate cost reductions and provide further commercial technology alternatives.

In comparison to Central, this scenario has:

- Lower levels of distributed PV uptake.
- Lower levels of energy efficiency.
- Greater cost reductions in alternative low-carbon technologies to VRE and battery storage.
- Similar levels of economic activity and population growth.
- Greater decarbonisation ambition globally, but similar levels domestically.

Purpose

- To understand the implications of lower gas prices on investments in the energy sector, in particular whether lower gas prices in the next decade increase the risk of over-investment in transmission infrastructure.
- To understand whether greater gas consumption from generation or higher levels of CCS uptake may arise from more favourable input drivers (this scenario does not force either outcome, nor does it assume that either will occur).

Similarity to 2020 ISP scenario narratives

- This scenario reflects the Federal Government's commitment to encourage investment to unlock Australia's gas resource potential and enable affordably priced and secure gas supplies. It is a new scenario that was not considered in the 2020 ISP.

In this scenario:

- The level of economic and population growth is in line with central estimates, with the world recovering from the impacts of COVID-19.
- In the short term, changes to the gas sector to increase competition and access to low-cost gas result in lower gas prices, which continue over the next decade.
- In the longer term, federal policy support for CCS and greater international investment enables significant technological advances and cost reductions over the period. Increased global investment in a diverse technology mix results in more significant cost reductions in CCS technologies and more limited cost reductions for batteries, solar and wind. This helps de-risk investment in gas powered generation, by coupling it with CCS, if needed, to meet the longer term net-zero emission objectives.
- The global forces that drive reductions in EV costs continue, and result in a similar level of electrification of transport to that of Central scenario. However, the level of fuel switching from gas to electricity is more limited, given the greater cost-competitiveness of gas.
- Global decarbonisation ambitions are targeted at limiting the temperature rise to well below 2°C by 2100 (helping drive CCS cost reductions), although Australia lags behind, with the level of Australian ambition equivalent to that assumed in the Central scenario.

Workshop feedback

This scenario has received less support from stakeholders than the other scenarios, with 38% of surveyed stakeholders at our second webinar considering it useful in exploring power system needs and the risk of over/under-investment, and 32% not useful.

While some groups during the workshops felt the narrative was broadly internally consistent, others expressed doubts regarding the setting of some of the dimensions, particularly the decarbonisation dimension, and considered the scenario unlikely.

Stakeholders argued that understanding what drives the sustained low gas prices is key to determining the internal consistency of the scenario. Low gas prices could arise as a result of government intervention in the market, incentivising the development of infrastructure and gas exploration, which would increase supply. As the Federal Government is still consulting on possible initiatives to support their gas-led recovery goals, AEMO has chosen to focus on the desired outcome rather than make assumptions about the mechanism deployed to drive the outcome. It is envisioned that initiatives such as the prospective national gas reservation scheme currently under consideration, or other initiatives to encourage investment that unlocks Australia's gas resource potential cost-competitively, have been implemented.

Stakeholders questioned whether the scenario represented no more than a low gas price sensitivity, rather than an inherently different future world. AEMO considers that the potential investment impacts of the settings associated with this scenario (lower gas prices, increased cost-competitiveness of a diverse technology mix) warrant a more comprehensive assessment than would be afforded a sensitivity.

To improve the internal consistency of the scenario, the narrative has been refined to reflect that this scenario is consistent with global decarbonisation ambitions equivalent to the assumption applied in the Diverse Technology scenario in the CSIRO GenCost study. This provides a more logical explanation for the CCS technology cost breakthroughs. If, through lower gas prices and CCS technology cost reductions, gas with CCS is more efficient than alternate technologies in the NEM in the long term, the model will select these irrespective of any national decarbonisation targets.

Stakeholder feedback considered that the level of distributed PV in this scenario should be at least equivalent to the Central trajectory. AEMO has considered this feedback, but proposes lower levels of distributed PV to keep this scenario distinct from others, and internally consistent. In this scenario, there is less government support for DER, and greater focus on research and development in utility technology solutions. Further, lower electricity prices are expected due to the lower assumed gas prices, so the payback period for DER is longer. In aligning the scenario settings in this manner, a greater range of future DER uptake is considered across scenarios – both faster and slower than the Central scenario – to reflect uncertainties in this parameter.

This scenario was considered by stakeholders to be the most likely to have lower levels of energy efficiency uptake. AEMO has reflected this in the scenario settings.

Stakeholders also considered this scenario to be less likely than the preceding three. As indicated earlier in Section 2.3, AEMO is seeking stakeholder feedback on the relatively likelihood of the scenarios to inform the scenario weighting that will be defined in the Final 2021 IASR.

Matters for consultation

- What, if any, elements of the Diversified Technology scenario as proposed are not plausible or internally consistent, and how would you suggest they be altered?
- If the scenario as specified is not considered to be useful in assessing the costs, benefits and/or need for investment in the NEM or eastern and south-eastern gas systems, are there adjustments that could be applied which would increase the utility of the scenario, while exploring similar risks and opportunities?

2.3.5 Export Superpower

Narrative summary

This proposed scenario represents a world with very high levels of electrification and hydrogen production, fuelled by strong decarbonisation targets and leading to strong economic growth.

Key differences to the Central scenario include:

- The highest level of international decarbonisation ambition, consistent with a target of limiting the global temperature rise to 1.5^{0}C by 2100 over pre-industrial levels – this also results in the strongest decarbonisation requirement in the NEM across the scenarios.
- Stronger economic activity and higher population growth.
- Continued improvements in the economics of hydrogen production technologies that enable the development of a significant renewable hydrogen production industry in Australia for both export and domestic consumption.
- Higher levels of electrification across many sectors, though with limited growth in EVs after 2030 due to competition from hydrogen fuel-cell vehicles.

Purpose

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

Similarity to 2020 ISP scenario narratives

- This scenario reflects a much stronger decarbonisation objective and the rise of a hydrogen economy. It is a new scenario that was not considered in the 2020 ISP.

In this scenario:

- Strong political pressure (both international and domestic) results in significant political action to tackle climate change and reduce emissions. Globally the effort is focused on meeting the 1.5ºC goal, and Australia targets net zero emissions by 2040.
- Capitalising on significant renewable resource advantages, Australia establishes strong hydrogen export partnerships to meet international demand for clean energy. Achieving this requires significant government investment in early years to stimulate the hydrogen economy, including initial domestic applications.
- Both domestic and export hydrogen demand is fuelled, at least in part, by NEM-connected electrolysis powered by additional VRE development.
- As a result of this emerging industry, Australia's economy experiences strong growth, enabling productivity improvements, and increased demand for skilled labour increases migration.
- Hydrogen production via electrolysers powered by low-cost VRE may impact the demand for other traditional energy sources such as coal and gas, both domestically and internationally.
- Fuel switching to electricity and hydrogen takes place across all sectors of the economy.
- The energy transition in Australia is embraced by consumers, as they seek clean energy and energy efficient homes and vehicles. Consumers also take advantage of hydrogen to access the benefits of combustion-based heating and cooking appliances, while still achieving a low carbon footprint.

Workshop feedback

Stakeholders have been encouraging AEMO to explore the impact of potential development of large-scale hydrogen production opportunities in future ISPs, and to consider scenarios that go beyond the ambitions previously applied in the Step Change scenario.

When presented with this scenario, stakeholders indicated that it is useful in exploring the needs of the power system and in understanding the risks of under- or over-investment. AEMO has engaged broadly with stakeholders on this scenario, including an additional targeted hydrogen stakeholder workshop in September 2020 to explore the most likely means by which large-scale hydrogen production would impact the NEM.

It is recognised that grid-scale, grid-connected electrolysis is one way hydrogen could be produced at scale in Australia, and other methods exist including off-grid electrolysis, steam methane reformation or coal gasification. Similarly, Australia's renewable energy advantages could be harnessed to produce energy-intensive export commodities, such as green steel or other high-value manufacturing products, value-adding to the energy before export.

The proposed scenario narrative is considered over other competing potential scenarios that include large scale hydrogen production, because:

- Investment signals are showing a preference for "green hydrogen", sourced from electrolysis and fuelled by renewable energy.
- A large number of grid-connected electrolysers would have a significant impact on the NEM, and this impact needs to be understood. In contrast, the Sustainable Growth scenario considers a future whereby any hydrogen production, if produced in Australia, is off-grid.
- Exploring hydrogen export represents the most direct interpretation of this scenario. If the hydrogen was used as a feedstock for production of green steel or other high-value commodities the characteristics of the scenario would be more complicated and yet the outcomes would be largely similar (that is, greater demand for electricity).

Stakeholders raised several issues which have been reflected in some of the settings (shown in Table 4 in Section 2.4), including:

- There was generally mixed feedback on whether the level of DER, energy efficiency and DSP should be higher than a central outlook. AEMO has adjusted several settings from preliminary views (for example, increasing the assumed level of distributed storage to a higher trajectory) to reflect what was favoured in the workshops.
- There were also mixed views on the uptake of EVs. AEMO will continue to engage on this topic as part of the updated forecast of EVs in early 2021; this will include consideration of the role of hydrogen fuel-cell vehicles.
- There was limited support for the inclusion of additional industrial load closures in this scenario (particularly in the gas and coal mining sectors), despite the global decarbonisation objectives which will likely result in significant reductions in the long term demand for emissions-intensive industry, without fuel transformation to a greener alternative. AEMO is continuing to seek feedback on these assumptions. The effects of this though may not be felt for several decades.
- There was concern about the scale of hydrogen production resulting in significant transmission line or pipeline expansion and unduly influencing any justification for network investment based on power system need. The scenario is expected to locate VRE and hydrogen production facilities in complementary locations while minimising system costs. With significant growth in energy consumption, the relative postage-stamp cost borne by consumers of the transmission system may reduce on a per megawatt hour (MWh) basis.

AEMO considers this scenario is critical for investors and policy-makers to consider, and to understand potential power system implications, but it may not be a significant influence on the near-term actionable investments that may be signalled by the 2022 ISP. Depending on the relative likelihood assigned to this scenario following consultation, it may carry little or no weight in any subsequent regulatory investment tests conducted by NSPs.

Matters for consultation

- What, if any, elements of the Export Superpower scenario as proposed are not plausible or internally consistent, and how would you suggest they be altered?
- Do you think the uptake of EVs (based on batteries) is likely to be affected significantly by competition with hydrogen-powered vehicles?
- Should this scenario assume that some industries are contracting, for example, coal mining and gas exports?

Matters for consultation – all scenarios

- What are the key sectoral uncertainties (if any) that are not adequately explored in the collection of scenarios proposed?
- Do you consider that the collection of scenarios adequately considers the breadth of possible futures that are likely to impact energy supply and demand in the NEM, and are suitable for exploring risks of over- and under-investment? If not, what additional scenarios would better achieve these objectives?
- What scenarios in the proposed collection, if any, do you think should be removed? If any, please indicate why – is it because the scenario is not plausible, or because it does not achieve the primary purpose of exploring major uncertainties and risks of over- and under-investment?

2.4 Key scenario parameters

Table 3 below presents the public policy settings to be applied to each scenario. The settings reflect AEMO's understanding of the current status of federal and state government policy against the stated public policy commitment criteria; these may of course change before the release of the Final IASR in July 2021, so AEMO's inclusion of policies may evolve over this time given the progression of policy objectives and ambitions. Any change in the status of policy settings after May 2021 will require AEMO to carefully consider the impact and materiality of any policy development, and the impact on the delivery of the Draft or Final 2022 ISP if it were to be included. Further details on the process for the inclusion of policy settings are in Section 4.1.

As Table 3 below shows, AEMO proposes to adopt all public policies that have been legislated by the relevant jurisdictions, particularly where there is funding in place and an implementation mechanism defined. This includes the various renewable energy targets and direct investment policies in REZs.

AEMO proposes implementing the decarbonisation targets through carbon budgets, as outlined in Section 4.3. These do not include various state net zero ambition statements that are not sufficiently developed to enable AEMO to identify the impacts on the power system.

Table 3 Public policy settings

Scenario setting	Export Superpower	Sustainable Growth	Central	Diversified Technology	Slow Growth
26% reduction in emissions by 2030 (NEM)	✓	✓	✓	✓	✓
VRET – 40% by 2025, 50% by 2030	✓	✓	✓	✓	✓
TRET – 100% by 2022	✓	✓	✓	✓	✓
TRET – 150% by 2030, 200% by 2040	✓	✓	✓	✓	✓
QRET – 50% by 2030	✓	✓	✓	✓	✓
NSW Electricity Infrastructure Roadmap (Electricity Infrastructure Investment Act 2020 NSW)	✓	✓	✓	✓	✓
National Electricity (Victoria) Act (NEVA) – Amendment for expedited approval of transmission upgrades	✓	✓	✓	✓	✓
Victoria net zero emissions target	✓	✓	✓	✓	✓
Australian Capital Territory Emission Reduction Targets	✓	✓	✓	✓	✓
Current DER and EE policies	✓	✓	✓	✓	✓
NEM carbon budget to achieve 2050 emission levels	✓	✓	*x*	*x*	*x*

✓ included in the scenario
x excluded in the scenario

Table 4 consolidates key demand drivers, technological improvements, investment considerations, and climatic assumptions to be applied for each of the scenarios, considering the public policy settings described in Table 3. Details are provided in the Draft 2021-22 Inputs and Assumptions Workbook[12].

Table 4 2021-22 scenario settings

Scenario	Export Superpower	Sustainable Growth	Central	Diversified Technology	Slow Growth
Economic growth and population outlook*	High	High	Moderate	Moderate	Low
Energy efficiency improvement	High	High	Moderate	Low	Moderate
DSP	High	High	Moderate	Moderate	Low
Distributed PV	High	High	Moderate	Low	Moderate, but elevated in the short term
Battery storage installed capacity	High	High	Moderate	Moderate	Low

[12] At https://www.aemo.com.au/consultations/current-and-closed-consultations/2021-Planning-and-Forecasting-Consultation-on-Inputs-Assumptions-and-Scenarios.

Scenario	Export Superpower	Sustainable Growth	Central	Diversified Technology	Slow Growth
Battery storage aggregation / VPP deployment by 2050	High	High	Moderate	Moderate	Low
Battery Electric Vehicle (BEV) uptake	Moderate/High	High	Moderate	Moderate	Low
BEV charging time switch to coordinated dynamic charging by 2030	Moderate/High	High	Moderate	Moderate	Low
Shared Socioeconomic Pathway (SSP)[13]	SSP1	SSP1	SSP2	SSP1	SSP3
International Energy Agency (IEA) 2020 World Energy Outlook (WEO) scenario	Net Zero Emissions by 2050 case (NZE2050)	Sustainable Development Scenario (SDS)	Stated Policy Scenario (STEPS)	SDS	Delayed Recovery Scenario (DRS)
Representative Concentration Pathway (RCP) (mean temperature rise by 2100)	RCP1.9 (<1.5°C)	RCP2.6 (~1.8°C)	RCP4.5 (~2.6°C)	RCP2.6 (~1.8°C) Australian ambition equivalent to RCP4.5	RCP7.0 (~4°C)
Generator and storage build costs	CSIRO GenCost High VRE	CSIRO GenCost High VRE	CSIRO GenCost Central	CSIRO GenCost Diverse Technology	CSIRO GenCost Central
Generator retirements	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 years, or earlier if economic to do so.	In line with expected closure years, or earlier if economic to do so.	In line with expected closure years, or earlier if economic to do so.
Relative project finance costs	As per Central	As per Central	In line with current long-term financing costs appropriate for a private enterprise	As per Central	Lower than Central, reflecting lower rates of return with lower economic growth

* All scenarios account for the short-term impact of COVID-19

2.5 Risk scenarios

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 market conditions and the resulting alternative futures. If adequately designed, scenarios can ensure that the resulting investment plan is robust to significant events capable of changing the investment landscape.

Sensitivities serve a different purpose; they are designed to test the materiality of uncertainty associated with individual input parameters, and are not modified across scenarios. They aim to increase the depth of analysis, and the confidence in investment decisions, by testing specific uncertainties.

[13] Further details on the IEA scenarios, SSPs and RCPs are provided in Section 4.2.

Risks: modelled as scenarios rather than sensitivities

AEMO is modelling each of the identified risks within the context of a scenario, rather than as a sensitivity. This means the analysis will include more comprehensive assessments of the impact of various investment options, akin to all other scenarios.

Given that risks can lead to significant benefit, and regret, of over and/or under-investment, AEMO expects that these risk scenarios may inform potential decision rules that influence some investments. This further supports the need for a scenario, rather than a sensitivity definition, to enable network investments to consider these risks in evaluating credible investment options.

Before the first scenarios workshop, AEMO surveyed stakeholders on the top three risks they considered most pertinent for energy sector planning. These submissions informed the discussions and activities that were conducted in the workshop. Subsequent discussions, activities, and polling in the first scenarios workshop helped identify what are considered to be the most material risks to investment needs.

Table 5 below outlines the proposed risks for AEMO to explore, which address risks that impact each region of the NEM. Not all these risk scenarios may be included in the final 2021 IASR; they are given below so stakeholders have an opportunity to provide feedback. Other risks and sensitivities may be identified during the course of the analysis and will be consulted on as required.

Table 5 Possible risk scenarios

Risk scenario	Purpose
Central with early Victorian coal closure	To assess the potential for over-investment or premature investment in inter-regional transmission if local dispatchable capacity replacement is the only option available in time to respond to this early closure.
Central with early northern NSW coal closures	To assess the risk of under-investment or overdue intra-regional investment to support load centres in Sydney and surrounding areas.
Central with Marinus Link funding arrangements not resolved	To assess the risk of under-investment or overdue investment in other alternatives to this transmission option.
Sustainable Growth scenario with Central DER uptake	To assess the impact of more rapid development of VRE and under-investment or overdue investment in REZ transmission.
Central with CopperString* included.	To assess over-investment or premature investment in other REZ alternatives and under-investment or overdue intra-regional transmission investment in Queensland.

* CopperString refers to a proposed high-voltage transmission line that will connect the people and communities of Mount Isa and the North West Minerals Province in western Queensland to the NEM. It is a privately proposed transmission development; more information is available at http://www.copperstring2.com.au/.

Matters for consultation

- Which of these risks represents the most important considerations for forecasting and planning the NEM? Please rank the risks listed in order of importance, and separately, in order of likelihood.
- Are there any other risks that are more material to forecasting and planning the NEM than those proposed above? If so, which of the above would be of least importance?

3. Continuing engagement on inputs and assumptions

This report documents the current draft of inputs, assumptions and scenarios resulting from several months of engagement and consultation. These drafts include information that have recently been updated, and other information that is interim and will be further updated during continued engagement ahead of the final 2021 IASR in July 2021. Table 6 below lists the inputs and assumptions, their current status and the forward plan for engagement for those that require continued development ahead of the final 2021 IASR.

One of the key ongoing consultation mechanisms is AEMO's Forecasting Reference Group (FRG). The FRG is a monthly meeting open to all stakeholders, that focuses on facilitating constructive discussion on matters relating to gas and electricity forecasting and market modelling. It is an opportunity for stakeholders to validate assumptions, share expertise, and explore new approaches to addressing the challenges of forecasting in a rapidly changing energy industry. The FRG is designed to complement the formal consultation for this Draft 2021 IASR and ISP Methodology and other consultations on the Forecasting Approach[14], by increasing the opportunity for stakeholder consultation.

AEMO uses the FRG to seek feedback on draft component forecasts that are updated regularly to avoid data latency issues. These have included many key forecast inputs such as macro-economic conditions, DER, consumption, maximum and minimum demand, DSP, and forward-looking generator forced outage rates.

Some of the key inputs described in the Draft 2021 IASR have key dependencies, and therefore cannot be updated ahead of this publication. The FRG therefore provides an opportunity for stakeholders to engage in the development of these key inputs in a timely manner and provides AEMO with the flexibility to consult on the latest information available ahead of inclusion in the final 2021 IASR.

As outlined in AEMO's Interim Reliability Forecast Guidelines[15], agenda items presented during an FRG may be for discussion, or for consultation. Where AEMO defines the engagement as "for consultation", stakeholders have a two-week window following the meeting to provide formal written feedback on the issue raised for consultation, and AEMO's consideration of this feedback will be documented and published. Updates to key inputs that use an established methodology and are most material to the reliability forecast or ISP are consulted on through this FRG consultation process, if final values are not available when the annual draft IASR is published for formal consultation using the AER's single stage consultation process. Other inputs may be for discussion only.

Where updated input assumptions are not yet available, the annual draft IASR provides insights and seeks feedback on the previous years' assumptions to help inform the update of that input. For the purpose of this Draft 2021 IASR, these are referred to as interim inputs.

Table 6 classifies each input and assumption by the following definitions:

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[14] The Forecasting Approach encompasses the breadth and depth of AEMO's medium and long term electricity forecasting methodologies for the NEM.

[15] See https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2019/interim-reliability-forecast-guidelines/interim-reliability-forecast-guidelines.pdf?la=en&hash=60625FB646196188683BCECA7F9DE438.

- **Interim** – an input that has not been updated since the 2020 IASR (released in August 2020) but is intended to be updated before the release of the final 2021 IASR. Where inputs are interim, the forward plan column indicates the planned timing and mechanism of consultation.
- **Draft** – an input that is considered final unless AEMO receives sufficient evidence to change as part of this Draft 2021 IASR consultation.
- **Current view** – an input or assumption which is regularly updated in a standardised process to reflect the most up-to-date observations; for example, metered demand data, or the continued development of new generation projects that are included within AEMO's Generation Information data set, or even environmental and energy policies that meet the commitment criteria. The final 2021 IASR published in July 2021 will document the status of these inputs and assumptions at that time and their intended application in the 2020 ESOO and the draft 2022 ISP.

The information in Table 6 is correct at time of publishing; please check AEMO's website for updates[16].

Table 6 Status and update process for key inputs and assumptions

Input	Current status	Forward plan for updating inputs and assumptions
Policy and emissions reduction settings		
Policy settings	Current view	Contingent on changes in status of government policy. Criteria for inclusion is outlined in Section 4.1.
Emissions reduction	Current view	Contingent on changes in status of government policy. Criteria for inclusion is outlined in Section 4.2.
Consumption and demand historical and forecasting components		
Historical demand data	Current view	Meter data is updated when available.
Historical weather data	Current view	Weather data is updated when available. The 2021 ESOO will include the 2020-21 historical reference year, and drop the 2010-11 reference year from its 10 year sample.
Historical other non-scheduled generation	Current view	Updated based on historical meter data.
Historical regional transmission and distribution network losses	Current view	To be updated once AER data is received in April-June 2021.
Climate change factors	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.
Distributed PV	Interim	Capacity to be updated through consultancy, scheduled for FRG consultation in March, with a follow up FRG discussion in April 2021. Normalised generation updated through ongoing data service provider
Battery storage uptake and Virtual Power Plant (VPP) aggregation	Interim	To be updated through consultancy, scheduled for FRG consultation in March with follow up discussion in April. Dependent on updated consultant's forecasts of economic and population growth, delivered in February 2021.
Electric and fuel-cell vehicles	Interim	To be updated through an FRG discussion in February and an FRG consultation, scheduled for March with a follow up in April. Dependent on updated consultant's forecasts of economic and population growth, delivered in February 2021.
Electrification of other sectors	Interim	Updated through consultancy, scheduled for FRG discussion in April 2021.

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

Input	Current status	Forward plan for updating inputs and assumptions
Economic and population, including connections	Interim	To be updated through consultancy, scheduled for FRG consultation in February. Connections updated to reflect population forecasts, and scheduled for FRG discussion in March 2021.
Energy efficiency	Interim	To be updated through an energy efficiency workshop scheduled for February and a subsequent consultancy, with forecasts, informed by the policies and forecasts of each NEM jurisdiction. Scheduled for FRG consultation in April 2021.
Appliance uptake and fuel switching	Interim	To be updated through a workshop scheduled for February, and scheduled for FRG discussion in April 2021.
Electricity prices	Interim	To be updated based on internal wholesale price forecasts and Australian Energy Market Commission's (AEMC's) Retail Electricity Price Trends report. These wholesale price forecasts are in the process of being updated as part of the GSOO analysis. Scheduled for FRG discussion in April 2021.
Industrial load forecasts	Interim	Industrial load forecasts will be sourced via participant surveys conducted in April to use latest information possible. Scheduled for FRG discussion in April 2021.
Energy consumption, maximum and minimum demand forecasts	Interim	To be updated using the Forecasting Methodology, and incorporating latest inputs and forecast components. Draft forecasts scheduled for FRG discussion in May (for consumption) and June 2021 (for maximum and minimum demand).
Demand side participation	Interim	To be updated based on an analysis of 2020-21 summer behaviour, and supported by the DSP Information Portal. The portal is updated by all market participants in April 2021. Growth rates for ISP modelling are scenario settings, outlined in Section 4.4.11. Scheduled for FRG discussion in May 2021.
Existing generator and storage assumptions		
Generation and storage data	Current view	New generation and storage developments sourced from AEMO's Generation Information survey, updated quarterly. The July 2021 update will be used for 2020 ESOO and draft 2022 ISP modelling.
Technical and cost parameters	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.
Generator operating limits	Current view	An output from detailed ISP market modelling that is used as an input in less granular modelling to reflect reasonable operating envelopes for units such as gas-fired generators. Therefore this is an endogenous input that is updated during the process.
Forced outage rates	Interim	To be updated through data collection process from generators conducted annually in March-April. Scheduled for FRG consultation in June 2021.
Retirements and refurbishments	Current view	Retirement dates are sourced through AEMO's Generation Information data collection process and are updated to reflect latest information provided. The July 2021 update will be used for 2020 ESOO and draft 2022 ISP modelling.
Hydro inflows	Current view	Hydro inflow information based on information provided by participants which will be updated to reflect 2020-21 inflows when available.
Climate change factors	Draft	Any further updates will be based on feedback on this Draft 2021 IASR, and through FRG discussion scheduled for May 2021.

Input	Current status	Forward plan for updating inputs and assumptions
New entrant generator assumptions		
Candidate technology options	Current view	Assumptions reflect current view. AEMO's ISP Methodology* allows for the screening of technologies to apply in more granular models, allowing an endogenous adjustment to the technology options.
Technology build costs	Draft	Any further updates will be based on feedback on this Draft 2021 IASR and the CSIRO's draft GenCost 2020-21 consultation.
Locational cost factors	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.
Other technical and cost parameters	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.
Pumped hydro costs and limits	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.
Fuel assumptions		
Gas prices	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.
Coal prices	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.
Biomass and liquid fuel prices	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.
Financial parameters		
Discount rate	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.
Value of Customer Reliability	Current view	Information as per December 2019 AER calculation.
Renewable energy zones (REZs)		
REZ candidates	Draft	Any further updates will be based on feedback on this Draft 2021 IASR., and potentially in response to government policy.
REZ resource limits	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.
REZ transmission limits	Interim	To be updated and consulted on through ISP methodology.
REZ expansion costs	Interim	To be updated through the Transmission Cost Update process (see section 4.11.6). Updates will include system strength remediation costs and new costs for the Export Superpower scenario.
Connection Costs	Interim	To be updated through the Transmission Cost Update process (see Section 4.11.6).
Transmission		
ISP Zones	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.
Existing transmission capacity	Current view	Based on historical data and network capability assessment.
Committed transmission projects	Current view	Sourced from TNSPs/AER and updated as information is available.
Anticipated transmission projects	Current view	Sourced from TNSPs and updated as information is available.
Augmentation options	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.

Input	Current status	Forward plan for updating inputs and assumptions
Transmission augmentation costs	Interim	To be updated through Transmission Cost Update process (see Section 4.11.6)
Inputs from Preparatory activities	Current View	To be updated using information provided by TNSPs in June 2021, via preparatory activities (see Section 4.11.7).
Non-network options	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.
Inter-regional loss flow equations and loss proportioning factors	Interim	To be updated from AEMO's annual Region and Marginal Loss Factor Reports published in April 2021. These values may change further as the power system evolves. Any changes to these numbers will updated in accordance with the ISP Methodology.
Network Losses - MLF	Interim	To be updated from AEMO's annual Region and Marginal Loss Factor Reports published in April 2021. These values may change further as the power system evolves. Any changes to these numbers will updated in accordance with the ISP Methodology.
Transmission line failure rates	Interim	To be updated from AEMO's Network Outage Schedule. Subject to method change consultation as part of the Forecast Accuracy Report and associated improvement program. Scheduled for FRG consultation in June 2021.
Climate change factors	Interim	To be updated following completion of method consultation as part of the Forecast Accuracy Report and forecasting improvement program. Scheduled for FRG discussion in May 2021.
Gas system assumptions		
Pipeline capacities	Current view	Sourced annually in Q4 from GSOO stakeholder surveys.
Production facility capacities	Current view	Sourced annually in Q4 from GSOO stakeholder surveys.
Gas storage facility operational capabilities (including injection and withdrawal rates, and storage capacity)	Current view	Sourced annually in Q4 from GSOO stakeholder surveys.
Reserves and resources estimates by resource category (2P, 2C and prospective)	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.
Gas field production costs	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.
Gas expansion candidate build costs	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.
Hydrogen assumptions		
Hydrogen demand	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.
Hydrogen supply	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.
Hydrogen infrastructure needs	Draft	Any further updates will be based on feedback on this Draft 2021 IASR.

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

Table 7 below summarises upcoming consultations on inputs and assumptions[17]. This information is correct at time of publishing, please check AEMO's website for updates.

Table 7 Forward consultation processes (monthly overview)

Month	Consultation Format	Inputs / Assumptions / Scenarios or relevant methodology
December 2020	Draft 2021 IASR Publication and submission window opening	All
January 2021	Webinar	Transmission cost database
February 2021	Energy Efficiency Workshop	Energy Efficiency
	ISP Methodology consultation	ISP methodology
	IASR webinar	Summary briefing on feedback received from the Draft 2021 IASR Consultation.
	FRG consultation	Macroeconomics (Economic and population forecasts)
	FRG discussion	Electric vehicles
March 2021	FRG consultation	DER forecasts (Distributed PV, battery storage uptake and VPP aggregation, and Electric Vehicles)
	FRG discussion	Connections
April 2021	Publish Draft ISP Methodology	ISP Methodology
	FRG consultation	Energy efficiency forecasts
	FRG discussion	Appliances and Fuel switching Large Industrial Loads Electrification of other sectors Retail Prices DER update
May 2021	Draft Transmission Cost Report and submission window opening	Transmission Costs
	Transmission Costs Webinar	Transmission Costs
	FRG discussion	Demand side participation Climate change factors and assumptions Consumption forecasts
June 2021	ISP Methodology workshop	ISP Methodology
	FRG consultation	Forced outage rates – generation and transmission
	FRG discussion	Minimum and Maximum Demand forecasts
	Publish ISP Methodology	ISP Methodology
July 2021	Publish final 2021 IASR	All

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

Month	Consultation Format	Inputs / Assumptions / Scenarios or relevant methodology
August 2021	Publish 2021 ESOO	All existing and committed projects and associated scenarios, inputs and assumptions
November 2021 or sooner	Preliminary ISP Modelling Outcomes Workshop	All
December 2021	Publish draft 2022 ISP	All
January-April 2022	Draft 2022 ISP workshop	All
June 2022	Publish 2022 ISP	All

4. Inputs and assumptions

4.1 Public policy settings

Input vintage	Policy settings are based on current state and federal government policy commitments.
Source	Various
Update process	The inclusion of policy settings in the scenarios may evolve as initiatives progress through funding and/or legislative processes.
Get involved	Draft 2021 IASR consultation: 11 December 2020 to 1 February 2021

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

For all scenarios, AEMO applies the criteria set out in NER 5.22.3(b) in determining whether a policy is included. Some scenarios expand beyond the set of policies that meet this criteria if reflected in the scenario narrative. For a policy to be included in all scenarios, it must be sufficiently developed to enable AEMO to identify the impacts of it on the power system, and meet at least one of the following conditions:

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

The details below reflect AEMO's current view on the various state and federal policy positions and whether they meet any of the criteria above. As policy positions progress and more detail is made available, the treatment of these settings may change, and additional policies may be included across the scenarios up until a cut-off date of May 2021. The final 2021 IASR published in July 2021 will document the policies that will be applied for the Draft 2022 ISP.

Australia's 2030 emissions reduction target

The Federal Government has set a target to reduce greenhouse gas emissions economy-wide to 26% below 2005 levels by 2030. This was submitted to the United Nations Framework Convention on Climate Change (UNFCCC) in 2015, in Australia's first Nationally Determined Contribution (NDC) under the Paris Agreement. The next NDC will be submitted to the UNFCCC in 2025, with a post-2030 target[18]. The Emission Reduction Target will be implemented via a pro-rata share allocated to the NEM for all scenarios. In the 2020 ISP this target was exceeded across all scenarios to varying degrees, and AEMO expects that to continue being the case in the proposed scenarios. The latest government emissions projection[19] also estimates that Australia will overachieve its 2030 target.

[18] See https://www.industry.gov.au/policies-and-initiatives/australias-climate-change-strategies/international-climate-change-commitments.

[19] Australia's emissions projections 2019, Department of Environment and Energy,

Large-scale Renewable Energy Target (LRET)

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

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

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.

The LRET is generally considered to have been met[20] and the incentive it provides to construct additional VRE is minimal. As such, no explicit accounting for the policy is included in the modelling.

Victorian Renewable Energy Target (VRET)

The VRET mandates 40% of the region's generation be sourced from renewable sources by 2025, and 50% by 2030. The target is measured against Victorian generation, including renewable DER. Currently in the region there are over 5,300 megawatts (MW) of committed or proposed wind generation projects, and over 2,700 MW of committed or proposed solar generation projects[21]. The VRET is legislated[22] and therefore included in all scenarios.

Victorian 2020-21 budget initiatives affecting REZs and energy efficiency

In the Victorian 2020-21 budget[23], Victoria has set aside significant funding – a $1.6 billion investment – for the establishment of clean energy initiatives and energy efficiency upgrades to homes. This includes $540 million to establish six REZs.

The spending package also contains investments in energy efficiency, including $335 million to enable 250,000 gas to electric heater conversions for low income households. Additional funding is available for increased rebates for solar panel installations, extending the Government's existing Solar Homes program, as well as battery installation rebates. Funding support is also provided to enable energy innovation, such as to support hydrogen projects and off-shore wind generation in Victoria.

At the time of publication of this Draft 2021 IASR, this policy was not sufficiently detailed for AEMO to identify the specific impacts on the power system, but it may well be prior to 2022 ISP modelling commencing. If so, it will be included in all scenarios. AEMO will continue to work with the Victorian Government to ensure that all policy impacts and funding commitments can be appropriately captured in the scenarios.

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 over 12,600 MW of committed or proposed solar generation projects (over 50% of all committed or proposed solar generation projects across the NEM)[21].

Given that the Queensland Government has committed material funding to the delivery of the QRET in the 2020- 21 Queensland Budget Papers[24], the policy is included in all scenarios.

[20] See http://www.cleanenergyregulator.gov.au/RET/About-the-Renewable-Energy-Target/Large-scale-Renewable-Energy-Target-market-data.

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

[22] Section 7 *Renewable Energy (Jobs and Investment) Act 2017 (Vic)*

[23] See https://www.premier.vic.gov.au/making-victoria-renewable-energy-powerhouse.

[24] Queensland Budget Papers 2020-21 tabled in State Parliament Tuesday 1 December 2020.

Tasmanian Renewable Energy Target (TRET)

The Tasmanian Government has recently legislated[25] a 200% renewable energy target by 2040, with an interim target of 150% by 2030. This extends the Tasmanian Government's existing commitment for 100% renewable energy by 2022. As the targets are legislated, the TRET is included in all scenarios. The legislation provides that the target is for 15,750 GWh per year from Tasmanian renewable energy sources by 2030, and 21,000 GWh by 2040. DER and other non-scheduled generation are considered as part of the renewable generation component.

New South Wales Electricity Infrastructure Roadmap

The New South Wales Government has released an Electricity Infrastructure Roadmap[26] with the objective of delivering an indictive 11 GW of new transmission capacity to the Central-West Orana and New England REZs. These objectives will be progressed by several measures and processes.

The *Electricity Infrastructure Investment Act 2020* recently passed both houses of the New South Wales Parliament and is scheduled to fully commence by 1 July 2021[27]. The legislation sets out minimum objectives that, by the end of 2029, see the construction of renewable generation infrastructure that produces at least the same amount of electricity in a year as:

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

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

The legislation has a further minimum objective of the construction of 2 GW of long-duration storage infrastructure (classified as storage with capacity that can be dispatched for at least eight hours) by the end of 2029, in addition to Snowy 2.0.

Given the information available, AEMO is proposing to model the policy as a minimum constraint on development of new VRE in New South Wales by 2030 in addition to generation that was committed in the November 2019 Generation Information page which aligns with the release of the New South Wales Electricity Strategy. The energy constraint will be calculated based on the 12 GW of additional renewable energy specified above, using the relative mix of wind and solar generation from the 2020 ISP Step Change scenario to determine the appropriate energy target. As an alternative, the mix of generation from Aurora Energy Research's modelling, commissioned by the New South Wales Government, could be used to determine the energy constraint. This outlook is not necessarily the development pathway that will be adopted to implement the legislated objectives.

The Aurora modelling outcomes published in the New South Wales Electricity Infrastructure Roadmap Detailed Report show a consistent addition of new renewable capacity during the period between 2022 and 2030. AEMO is proposing to implement the 2030 constraint as a target, and – to ensure that the modelling does not excessively back-end the development – implement a minimum capacity build per year. The modelling will then optimise the timing of renewable energy development and associated network development subject to these constraints. In the legislation, the development pathway would be determined by the Consumer Trustee every two years, and will therefore always be subject to some uncertainty and iteration over time.

In the Slow Change scenario, the incentives for this level of VRE investment would likely be lower. AEMO is therefore proposing to assume that in that scenario, the additional energy required to be developed is equivalent to 12 GW of predominantly solar generation and that the trajectory will be delayed such that less

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

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

[27] See https://www.parliament.nsw.gov.au/bill/files/3818/Passed%20by%20both%20Houses.pdf.

renewable energy is needed to be developed in the first half of the 2020s, and where by 2030 a sufficient amount of generation has commenced construction but is not fully operational until 2032.

The indicative constraints are shown in Table 8. It shows the default trajectory based on the 2020 ISP Step Change scenario's development outlook. This trajectory is proposed to apply to all proposed scenarios except the Slow Growth scenario, which would apply the different constraints which are specified below.

Table 8 Indicative constraints on renewable energy development in New South Wales

Scenario(s)	Indicative minimum annual renewable energy (GWh)	Target Year – financial year ending	Renewable energy constraint (GWh)
All excluding Slow Growth	2,500	2030	35,500
Slow Growth	2,000	2032	29,000

To model the transmission elements, AEMO is proposing to assume that the New England (potentially including North West NSW REZ) and Central-West Orana REZ limits are expanded at lowest cost to consumers to facilitate the level of new capacity specified in the *Electricity Infrastructure Investment Act*[28,29]. To account for the certainty provided by policy for generation that is locating in a declared REZ, AEMO is proposing to apply a lower Weighted Average Cost of Capital (WACC) to generation projects within the declared REZ, specified as 2% lower than that applied to other generation and transmission investments. The application of this lower WACC has been guided by NAB's WACC report for the New South Wales Government[30].

The modelling would then optimise the location of generation considering the available transmission infrastructure at these REZs, and the inherent resource quality of the various sites across New South Wales. The New South Wales legislation also requires the Minister to declare three other REZs named "South West", "Illawarra" and "Hunter-Central Coast". The Department is yet to publish the indicative locations for the "Illawarra" and "Hunter-Central Coast" REZs.

AEMO also proposes to include the additional 2 GW of long-duration storage (which would include batteries or pumped hydro with eight or more hours of storage). Given the commissioning of Snowy 2.0 already scheduled for 2025-26, AEMO is proposing that this additional storage would be applied as a single development constraint by 2030, rather than a gradual build, given the lumpiness of investments in storage technologies, and to better align with expected coal retirements in the 2030s.

AEMO will continue to engage with the New South Wales Government in the coming months to determine an appropriate implementation of the policy in the ISP modelling.

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

The amendment to the NEVA in February 2020 was made to facilitate expedited approval of transmission system upgrades. The Act enables the Minister to approve augmentations of the Victorian transmission system. This process was recently used to procure 300 MW/377 MWh of battery storage at Moorabool[31]. For the purpose of the ISP, any Ministerial order that has progressed to the point of approval will be considered as a committed investment, and therefore included in all scenarios.

[28] Available at https://www.legislation.nsw.gov.au/view/html/inforce/current/act-2020-044.

[29] The transmission required to facilitate the level of new capacity specified will impact on the inter-zonal upgrade options. These impacts will be explored via preparatory activities and the future IASR and result in refined transmission options

[30] See https://energy.nsw.gov.au/sites/default/files/2020-11/NSW%20Electricity%20Infrastructure%20Roadmap%20-%20WACC%20Report.pdf

[31] See https://www.energy.vic.gov.au/__data/assets/pdf_file/0034/495079/Second-VNI-Ministerial-Order.pdf.

Distributed energy resources policies

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

- South Australia – Home Battery Scheme[32].
- Victoria – Solar Homes Scheme[33].
- New South Wales – Clean Energy Initiatives[34].
- Emission Reduction Fund and Victorian Energy Saver Incentive Scheme (additional PV non-scheduled generation [PVNSG] revenue stream via Victorian Energy Efficiency Certificates (VEECs) or Australian Carbon Credit Units (ACCUs))[35].
- Australian Capital Territory Next Generation Energy Storage program[36].
- Trial programs to integrate virtual power plants (VPPs) and explore how a network of small-scale PV and batteries can be collectively controlled and fed into the grid[37].

AEMO incorporates each of these schemes in its DER uptake and behavioural analysis. They impact both the operational energy consumption forecasts and the load shape (refer to Appendix A3 of the Demand Methodology Paper[38] for details of the current approach to incorporate DER).

Energy efficiency policies

The energy efficiency policies that are included in electricity demand forecasts consider various state-based policies that encourage investments in activities that will lower energy consumption, including:

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

Table 9 below maps the current energy efficiency programs and how they are proposed to be mapped to the scenarios outlined in this Draft 2021 IASR.

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32 Details at https://homebatteryscheme.sa.gov.au/.

33 Details at https://www.solar.vic.gov.au/.

34 Details at https://energy.nsw.gov.au/renewables/clean-energy-initiatives.

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

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

37 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.

38 See Appendix A3 available at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/2020-electricity-demand-forecasting-methodology-information-paper.pdf?la=en

Table 9 Current energy efficiency policy settings mapped on the proposed 2021-22 scenarios

2021-22 proposed scenario mapping	Central, Slow Growth	Diversified Technology	Sustainable Growth, Export Superpower
NABERS	Scheme is ongoing and is applied at current levels	Scheme is ongoing and is applied at current levels	Scheme is ongoing and is applied at current levels
CBD	Scheme is ongoing and is applied at current levels	Scheme is ongoing and is applied at current levels	Scheme is ongoing and is applied at current levels
GEMS (E3 Program)	Committed only	Committed only	Committed, plus programs that are presently stopped but may restart, or proposed programs
NCC Futures	Not applied	Not applied	Commercial: Low emissions trajectory 30% Residential: 7 Star buildings
State-based schemes			
NSW ESS	Committed	Committed scaled by lower scenario forecast	Committed scaled by higher scenario forecast
SA ESS	Committed	Committed	Committed plus scheme extension
Vic Energy Upgrades (note: policy update in progress)[A]	Committed based on existing activities	Committed based on existing activities	Committed based on existing activities

A. The Victorian Government has announced changes to the Victorian Energy Upgrades program which may change the application of how these are applied to AEMO's scenarios throughout 2021-22. Refer to https://www.energy.vic.gov.au/energy-efficiency/victorian-energy-upgrades for latest updates.

The details provided above reflect the way in which alternative trajectories were developed for 2020 scenarios. A similar process will be used to develop alternative trajectories for the proposed scenarios and will form part of the consultation on energy efficiency updates in early 2021, which will be consulted on through the FRG. At a high level:

- A trajectory will be developed that results in higher levels of energy efficiency and this will be applied in the Sustainable Growth and Export Superpower scenarios.
- A trajectory will be developed that results in lower levels of energy efficiency and this will be applied in the Diversified Technology scenario.
- The most likely/central trajectory will be developed and applied in the other scenarios.

Matters for consultation

- Do you support the approach outlined for the inclusion of government policy across the scenarios?
- Do you have any further views on the individual policies and their application?
- Are there any energy or environmental policies missing that you consider important to include in some or all of the proposed scenarios? Please provide details.

4.2 Scenario alignment to international climate outcomes

AEMO's scenarios have been aligned to a set of global narratives, to ensure they are consistent with possible future developments and to anchor them to possible global changes. They are aligned to both the International Energy Agency's (IEA's) World Energy Outlook 2020 scenarios and the Shared Socio-Economic Pathways (SSPs) and Relative Concentration Pathways (RCPs) framework. The latter will underpin future work by the Intergovernmental Panel on Climate Change (IPCC).

Alignment to IEA WEO scenarios

In its latest WEO, the IEA presents four scenarios varying in how the global energy system may recover following the COVID-19 pandemic, and evolve over the coming decades. The four scenario narratives are summarised in Table 10 below[39].

Table 10 IEA scenario narratives

IEA scenario	Summary narrative
Stated Policies Scenario (STEPS)	COVID-19 is brought under control and the global economy returns to pre-crisis levels in 2021. This scenario reflects all of today's announced policy intentions and targets, if they are backed up by detailed measures for their realisation. It is consistent with temperature increases of around 2.7°C in 2100.
Delayed Recovery Scenario (DRS)	This scenario has similar policy assumptions as STEPS, but with a late economic recovery, and therefore lower energy demand growth. Emissions as a result are also lower than STEPS, due to lower levels of activity.
Sustainable Development Scenario (SDS)	This scenario sees increased investment in low carbon technologies, as well as a surge in clean energy policies. With similar economic assumptions to STEPS, SDS is also consistent with meeting the Paris Agreement goal of 1.5°C and 2°C (depending on assumptions on negative emission technologies). Countries with net zero targets by 2050 successfully meet them, and global net zero is achieved by 2070.
Net Zero Emissions by 2050 case (NZE2050)	This scenario goes beyond SDS by targeting global net zero emissions by 2050, consistent with meeting a 1.5°C target without the need for large net negative emissions globally.

In mapping the IEA scenarios to the proposed scenarios in this Draft 2021 IASR, AEMO provides the following observations:

- The proposed Central scenario aligns suitably to STEPS, as it reflects currently legislated and/or funded policy positions, although some Australian commitment to continue reducing emissions beyond currently legislated targets is assumed, in line with recent Federal Government announcements of intent to achieve net zero emissions in the second half of this century.
- The IEA's SDS scenario targets no more than 2°C temperature rise, which therefore logically aligns to AEMO's proposed Sustainable Growth and Diversified Technology scenarios.
- With a more stringent emission target and large and significant structural changes in global energy consumption underpinning its narrative, the proposed Export Superpower scenario is most closely aligned to NZE2050.
- The proposed Slow Growth scenario is aligned with the IEA's DRS, as both scenarios see slower recoveries from COVID-19 and lower levels of demand growth.

[39] Further information on the IEA's World Energy Outlook scenarios can be accessed at https://www.iea.org/reports/world-energy-outlook-2020.

Alignment to the SSP/RCP framework

Over the last few years, a set of SSPs[40] have been developed by an international community of scientists, to ascertain how society, economics and population may change over the period to 2100. There are five SSPs, with varying levels of economic growth, technological development, and drive to decarbonise. The SSP framework is currently being used by the IPCC as it produces its Sixth Assessment Report (AR6)[41].

These SSPs act as potential baseline scenarios, with different energy and land-use changes that arise as a result of different world narratives. Each SSP therefore has a base level of projected emissions. Each SSP can then be associated with different emission trajectories and corresponding temperature increase projections (known as RCPs). Table 11 provides a summary of each of the SSP narratives[42], and the relevant RCP that will be used by the IPCC for AR6.

Table 11 SSP narratives and associated RCP

SSP title	Narrative	Associated RCPs in CMIP6 (temperature target by 2100)[A]
SSP1. Sustainability – Taking the Green Road (Low challenges to mitigation and adaptation)	The world shifts gradually, but pervasively, towards a more sustainable path, emphasizing more inclusive development that respects perceived environmental boundaries. Inequality falls both within and between countries, and consumption adjusts towards low material growth and lower resource and energy intensity.	RCP1.9 (<1.5°C) RCP2.6 (~1.8°C)
SSP2. Middle of the Road (Medium challenges to mitigation and adaptation)	The world follows a path in which social, economic, and technological trends do not markedly shift from historical patterns. While some environmental systems experience degradation, overall, they improve, while the resource intensity and energy use declines.	RCP4.5 (~2.6°C)
SSP3. Regional Rivalry – A Rocky Road (High challenges to mitigation and adaptation)	Policy reorients to focus more on national and regional issues, while investments in education and technological development decline. Economic development is slow, with material-intensive consumption and increased inequality. Strong environmental degradation occurs in some regions, as environmental policy loses importance.	RCP7.0 (~4.0°C)[B]
SSP4. Inequality – A Road Divided (Low challenges to mitigation, high challenges to adaptation)	Increased levels of inequality between and within countries, with a widening gap in environmental policy and technology development between higher- and lower-income countries. Environmental policies focus on local issues around middle- and high-income areas.	RCP6 (~3.2°C) RCP3.4 (~2.2°C)
SSP5. Fossil-fuelled Development – Taking the Highway (High challenges to mitigation, low challenges to adaptation)	High levels of economic and social development are coupled with increased use of fossil fuels and resource-and energy-intensive lifestyles. Rapid economic growth, with increased faith in the role of technology in managing ecological systems, including via negative emission technologies and other types of geo-engineering.	RCP8.5 (~4.3 °C)

A. Mean temperature increases for each RCP sourced from the SSP database.
B. RCP7.0 is consistent with SSP2 baseline temperatures.

Each of the scenarios proposed in this Draft 2021 IASR has been associated with a particular SSP and RCP, consistent with a mean temperature increase over pre-industrial levels by the end of the century. Details can be seen in Section 2.4. This frames the proposed 2021 IASR scenarios within a global context that considers broad social, economic and demographic trends across the globe.

[40] SSP data can be accessed via the SSP database (https://tntcat.iiasa.ac.at/SspDb/dsd?Action=htmlpage&page=50). Emission pathways have been sourced from the Coupled Model Intercomparison Project sixth phase (CMIP6) tab. The CMIP coordinates climate model experiments from international modelling teams worldwide and is a project of the World Climate Research Program (WCMP). The latter provides the climate science underpinning the UN's Framework Convention on Climate Change.

[41] The IPCC AR6 is currently under development, https://www.ipcc.ch/assessment-report/ar6/.

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

In mapping to the scenarios, the following observations are provided:

- The proposed Central scenario can be linked to SSP2, as the scenario represents a continuation of current trends, with no marked socioeconomic changes.
- The proposed Sustainable Growth, Export Superpower and Diversified Technology scenarios are best aligned with SSP1, where the greatest transition towards low carbon technologies takes place.
- The proposed Slow Growth scenario is aligned to SSP3, as they both have lower levels of economic and population growth, as well as less of a decarbonisation drive.

In terms of RCP:

- The proposed Export Superpower scenario sees a global drive to limit temperature rise to 1.5°C by the end of the century and is therefore aligned to RCP1.9.
- The proposed Sustainable Growth scenario is aligned to RCP2.6 (consistent with a temperature rise less than 2°C by the end of the century, in line with the Paris Agreement). Global ambition in the Diversified Technology scenario is also aligned with RCP2.6.
- The proposed Central scenario is aligned to RCP4.5 (consistent with a temperature rise of approximately 2.6°C by the end of the century), which in turn is aligned with the temperature rise envisioned by the IEA's STEPS scenario. The Diversified Technology scenario is assumed to be aligned with the same level of domestic decarbonisation ambition as the Central scenario, despite global ambition leading to lesser temperature rise as noted above.
- The proposed Slow Growth scenario is aligned to RCP7.0, which would see a temperature rise of approximately 4°C by the end of the century).

Table 12 below summarises the mapping of each 2021 IASR scenario to the WEO, SSP and RCP scenarios. The 2021 IASR scenarios are also mapped to GenCost global scenarios discussed further in Section 4.6.3.

Table 12 Scenario mappings

2021 IASR scenario	WEO scenario	SSP	RCP	GenCost (CSIRO)
Central	STEPS	SSP2 – Middle of the Road	RCP4.5 (around 2.6°C increase in temperatures by the end of the century)	Central (assumes global climate policy ambition does not prevent a greater than 2.6°C increase in temperature)
Slow Growth	DRS	SSP3 – Regional Rivalry	RCP7.0 (around 4°C increase in temperatures)	Central (assumes global climate policy ambition does not prevent a greater than 2.6°C increase in temperature)
Diversified Technology	SDS	SSP1 – Sustainability	RCP2.6 (consistent with a less than 2°C increase in temperatures, in line with the Paris Agreement)	Diverse Technology (assumes strong global climate policy consistent with maintaining temperature increases to 2°C)
Sustainable growth	SDS	SSP1 – Sustainability	RCP2.6 (consistent with a less than 2°C increase in temperatures, in line with the Paris Agreement)	High VRE (assumes strong global climate policy consistent with maintaining temperature increases below 2°C)
Export Superpower	NZE2050	SSP1 – Sustainability	RCP1.9 (consistent with limiting temperature increases to 1.5°C)	High VRE (assumes strong global climate policy consistent with maintaining temperature increases below 2°C)

Changes since the 2020 IASR

Compared to the scenarios in the 2020 IASR, the Central scenario is now aligned with RCP4.5 rather than RCP7.0. The Slow Growth scenario is now aligned with RCP7.0, rather than RCP8.5 (for Slow Change scenario), which was consistent with temperature increases of over 4.5°C. Finally, global ambition in Export Superpower, Sustainable Growth and Diversified Technology are now aligned to the range of RCPs previously considered in Step Change (RCP1.9 or RCP2.6).

These changes have been made for two reasons:

- First, to increase alignment to scenarios published by the IEA in their latest World Energy Outlook, which, for example, considers that STEPS is consistent with temperature increases of under 3°C.
- Second, the Climate Action Tracker[43] (CAT), which is an independent scientific analysis that tracks global government activities to the Paris Agreement, considers that while recent global announcements that target net zero emissions place the Paris Agreement's 1.5°C target within reach, little positive momentum has been committed to improve the nationally determined commitments (NDC) for 2030. As such, the CAT assesses that current policies place expected temperature rises at approximately 2.9°C, and adding additional pledges and targets reduce the expected temperature rise to 2.6°C.

The SSP/RCP combinations are in line with the subset of combinations that form part of CMIP6 and will be examined by the IPCC in their Sixth Assessment Report (AR6), to be published in 2021-22. Depending on the availability of these updated assessments AEMO may incorporate these prior to finalising the final 2021 IASR. AEMO will consider the feedback provided in the Draft 2021 IASR Consultation to inform whether any update should be considered, and will engage with stakeholders when more information is available, if appropriate.

Matters for consultation

- Do you consider the proposed scenario alignment to the IEA scenarios appropriate?
- Do you consider the proposed scenario alignment to the SSPs appropriate?
- Do you consider the global temperature pathways proposed to be assigned to each scenario appropriate?
- Would you support the use of the AR6 updated climate assessments, if available ahead of the final 2021 IASR?

4.3 Domestic emission targets and reduction

In the Export Superpower and Sustainable Growth scenarios AEMO proposes applying carbon budgets that target a specific decarbonisation objective, with the electricity sector expected to provide a significant contribution[44].

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

- Each proposed scenario has been allocated an SSP and RCP that aligns with scenario narratives, as outlined in Section 4.2. Each SSP results in different levels of baseline emissions, depending on the broad, long-term changes that are assumed within each narrative. For example, the proposed Export Superpower and Sustainable Growth scenarios are considered consistent with SSP1, as discussed in Section 4.2.
- The resulting global trajectories of emissions abatement have been translated to Australian trajectories using methodologies broadly consistent with the modified contraction and convergence approach suggested by the Climate Change Authority[45] for use in setting Australian emissions budgets. This method

[43] Available at https://climateactiontracker.org/. The CAT has recently published a Global Update reflecting on updated policy ambitions and commitments, available at https://climateactiontracker.org/publications/global-update-paris-agreement-turning-point/.

[44] The Slow Growth scenario is proposed to be excluded, because under its proposed settings, the emissions constraint would be sufficiently large as to never impact the system development.

[45] Climate Change Authority, Targets and Progress review, at http://climatechangeauthority.gov.au/reviews/targets-and-progress-review-3 (Appendix C, Sharing the global emissions budget).

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. To determine the NEM budget, the Australian emission budget over 2021-50 was scaled down by the current share of NEM electricity emissions in total Australian emissions[46]. The electricity sector currently represents the largest source of emissions in the National Greenhouse Gas Inventory[46]. The pathways that represent temperature rises at or below 2°C become net negative (in total across Australia) in the 2040s. In ISP modelling it is assumed the NEM will maintain some level of emissions until 2050 in all scenarios. In these more ambitious decarbonisation scenarios, the electricity sector therefore has to reduce emissions more rapidly than other sectors in the early years to meet its share of the total carbon budget.

Figure 2 presents the proposed Australia-wide emissions trajectories developed using the above approach, and consistent with a range of temperatures. A 1.5°C target sees domestic Australian emissions falling rapidly, reaching net zero in the early 2040s, while a 2°C target also reaches net zero before 2050. All other pathways see emission reductions of varying degrees, although no other scenario is proposed to reach net zero over the first half of the century. The trajectory associated with the Central scenario (2.6°C warming by 2100) would reach net zero in the second half of this century.

Figure 2 Proposed Australia-wide pathways consistent with different RCPs

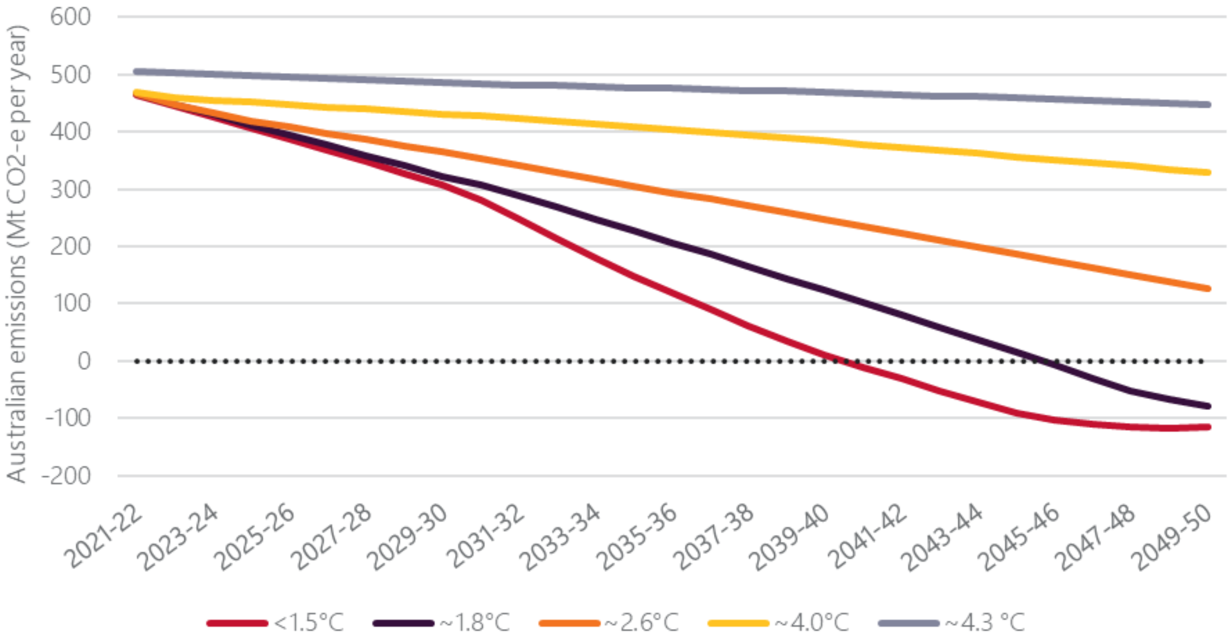


Figure 3 below presents the proposed NEM electricity sector carbon budgets, consistent with the economy-wide trajectories and approach discussed above. The methodology does not attempt to take into account the potential for electricity to absorb emissions "allocated" to other sectors as they electrify. In part this is because as these sectors reach high levels of electrification in most scenarios, the level of emissions is already heavily reduced so any electrification would need to be at very low emissions intensity. The carbon budget assumed therefore applies to all NEM demand, including demand from other sectors that have been electrified.

Furthermore, the methodology currently assumes the emissions budget for the electricity sector is based on its current share of emissions, when it is often noted that electricity may need to decarbonise more rapidly and do "more of the heavy lifting" given its advantages in this regard over other sectors. This would therefore

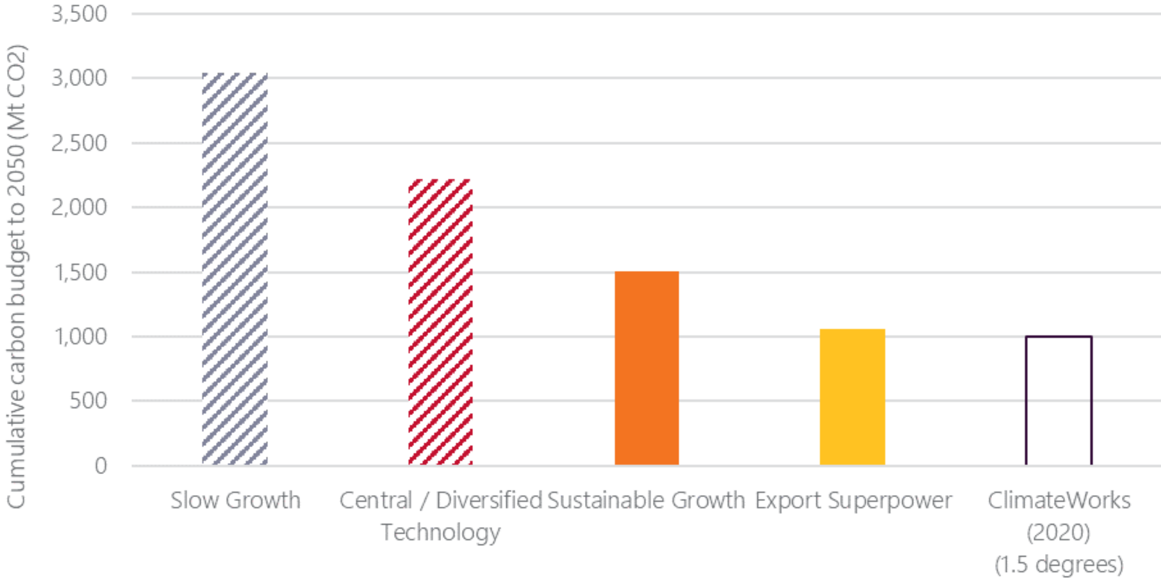
[46] See https://www.industry.gov.au/sites/default/files/2020-08/nggi-quarterly-update-march-2020.pdf.

result in a tighter emissions budget for the sector, which would offset any increase through cross-sector allocation.

The proposed Export Superpower scenario results in a significantly lower budget than the 2020 ISP's Step Change scenario over the period 2021-2050 due to the more ambitious global decarbonisation target. This is similar to the estimated cumulative electricity carbon budget consistent with a 1.5°C world as derived by ClimateWorks in its Decarbonisation Futures 2020 publication[47], estimated using multi-sectoral modelling.

As described in Table 4, the Diversified Technology scenario is expected to result in similar emissions outcomes to the NEM as the Central scenario, despite it's more ambitious global decarbonisation setting.

Figure 3 Cumulative NEM electricity sector emissions, 2021-50



Note: ClimateWorks budget extracted from electricity sector emission trajectory as above.

While some proposed scenarios include high levels of emission reductions from the energy sector, they do not enforce zero NEM emissions by 2050. Some operation of thermal plant may be cost-effective to maintain synchronous and peaking support capabilities, and it would then become more cost-effective to reduce emissions in other sectors of the economy than to decarbonise the final incremental emissions-intensive activities in the electricity grid.

There are zero-emissions synchronous technologies available that would potentially be able to deliver these services while maintaining a carbon-neutral NEM; however, given the lack of surety and detail on these options in the NEM setting, AEMO currently considers that it is appropriate to allow some fossil-fuelled generation to remain in the electricity system provided the cumulative carbon budget is not exceeded.

Nevertheless, when applying the RCP 1.9 and RCP 2.6 targets with the methodology described above, Australia is required to achieve net zero emissions by 2050 at the latest. With no negative emission technologies modelled in the electricity sector, the proposed NEM-specific carbon budget implicitly assumes that the land use, land use change and forestry (LULUCF) sector (or another sector) will balance leftover emissions from energy by acting as a carbon sink. The LULUCF can sequester carbon via the conservation of high-carbon ecosystems, combined with increased afforestation, reforestation, and agroforestry rates, or through investment in technology-based solutions such as CCS. The Draft 2021 IASR does not investigate the scale or economic appropriateness of this assumption.

[47] See https://www.climateworksaustralia.org/wp-content/uploads/2020/04/Decarbonisation-Futures-March-2020-full-report-.pdf. Estimate of ClimateWorks' electricity budget has been derived by applying the share of NEM emissions in electricity emissions to the electricity sector's emission trajectory extracted from the 1.5°C scenario.

No explicit domestic carbon price is included in any proposed scenario. The emissions intensity of each generator and new entrant technology is detailed in the Draft 2021-22 Inputs and Assumptions Workbook.

Matters for consultation

- Do you consider the proposed Australian pathway and proposed NEM budgets appropriate for each scenario?
- Do you have an alternative proposed method to decompose global emission pathways to a NEM target? What is it? How would you account for emission reductions in other sectors, and the contribution of the LULUCF sector?

4.3.1 State-based emissions targets

Most Australian states have some form of ambition or policy that targets emissions reduction; a number of these are framed around targeting net zero emissions. However, in most cases, these policies have limited detail, funding or underpinning legislative framework. As such, in general they are not considered to be applicable across all scenarios. Although the inclusion of these policies could be applicable given the narrative of the Sustainable Growth and Export Superpower scenarios, they are not necessary given the Australia-wide trajectories already reflect net zero emissions nationally in similar timeframes. This section documents the state-based emissions targets that do meet the requirements to be included across all scenarios.

Victorian emissions reduction targets

Under the Victorian *Climate Change Act 2017*, the Victorian Government is required to set five-yearly greenhouse gas emissions reduction targets starting from 2021, with the aim of reaching net zero emissions by 2050[48]. Interim targets for 2025 and 2030 have not yet been set, however an Independent Expert Panel has recommended targets of 32-39% below 2005 levels by 2025, and 45-60% below 2005 levels by 2030[49]. AEMO will continue engaging with the Victorian Government to assess the most appropriate implementation of the emissions reduction targets in the modelling.

Australian Capital Territory emissions reduction targets

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

Matters for consultation

- Do you believe AEMO should implement high-level, state-based emission targets in any scenarios, if not legislated?
- In your view, what is the best way to implement such targets? How would you estimate the contribution of "carbon sink" sectors, such as LULUCF, and the use of carbon offsets?

[48] Department of Environment, Land, Water and Planning, Climate change targets 2021-2030, at https://engage.vic.gov.au/climate-change-targets-2021-2030.

[49] At https://www.climatechange.vic.gov.au/__data/assets/pdf_file/0016/420370/Final-Report_Interim-Emissions-Reduction-Targets.pdf.

[50] Environment, Planning and Sustainable Development Directorate, Emission Reduction Targets, at https://www.environment.act.gov.au/cc/act-climate-change-strategy/emission-reduction-targets.

4.4 Consumption and demand: historical and forecasting components

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

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

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

AEMO updates its projections of energy consumption and demand at least annually[51], and includes significant stakeholder consultation through the FRG, industry engagement via surveys, consultant data and recommendations, and AEMO's internal forecasting of each sector and sub-sector affecting energy consumption and peak demands.

Key components in the forecasts include:

- DER uptake and generation/charging/discharging patterns:
  - Distributed PV.
  - Customer energy storage systems (ESS).
  - EVs.
  - The role of ESS aggregation and VPPs.
- Economic and population growth drivers, including meter connections.
- Energy efficiency forecasts.
- Fuel switching.
- Climate.
- Stakeholder surveys, including for large industrial loads across various sectors, including 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[52]. For gas demand forecasting, the GSOO's demand forecasting methodology[53] also outlines the usage of these key inputs.

AEMO's 2020 consumption forecasts for the NEM are shown in Figure 5 below. These will be updated using latest input assumptions prior to publishing the final 2021 IASR.

Figure 6 demonstrates the spread between scenarios observed in the 2020 ESOO forecasts.

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

[52] At https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/2020-electricity-demand-forecasting-methodology-information-paper.pdf.

[53] At https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2020/gas-demand-forecasting-methodology.pdf.

Figure 4 Annual electricity consumption forecasts, by component, for the 2020 ESOO Central scenario

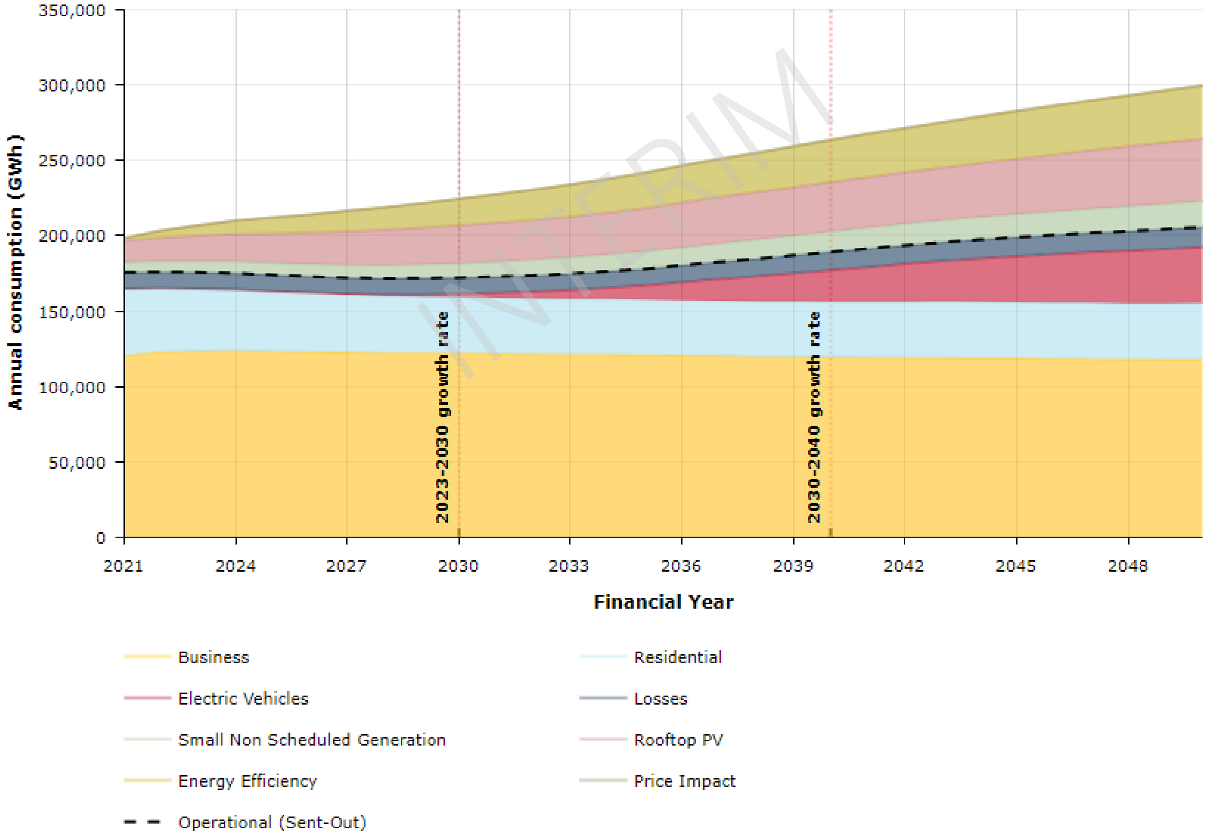
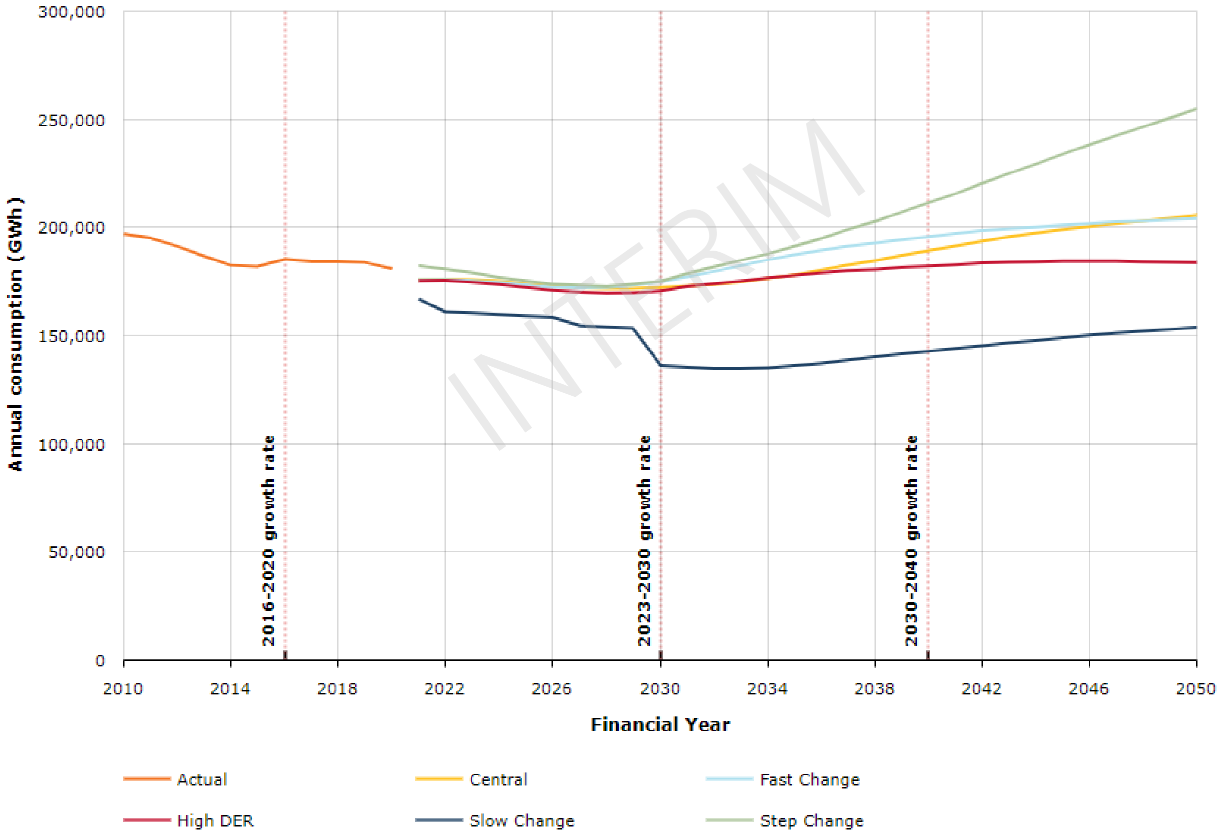


Figure 5 Annual electricity consumption forecasts, by scenario, for the 2020 ESOO Central scenario



More detail on component consumption forecasts, and the maximum and minimum demand forecasts by region, is available on AEMO's Forecasting Portal[54].

Matters for consultation

- Do the component forecasts produce an overall trend in electricity consumption that is consistent with your expectations, considering the breadth of uncertainty and consistent with the scenario narratives?
- Are the component forecasts providing the magnitude of contribution that you would expect?

The following sections describe the individual component inputs that underpin the component forecasting methodologies that are deployed to prepare the electricity consumption forecasts, as well as key inputs to the maximum and minimum demand forecasts.

4.4.1 Historical demand data

Input vintage	• Live currency • June 2020 for loss data
Source	• SCADA/EMMS/NMI Data • Generation Information page • AER and network operators
Update process	Continuously updated. Loss data will be updated in April-June 2021
Current accuracy	N/A
Get involved	N/A

Operational demand

Operational demand as-generated is collected through the electricity market management system (EMMS) by AEMO in its role as the market operator. Operational demand as generated includes generation from scheduled generating units, semi-scheduled generating units, and some non-scheduled generating units[55].

Generator auxiliary load

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

Network losses

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

[54] At http://forecasting.aemo.com.au.

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

Large industrial loads

AEMO maintains a list of LILs. AEMO collects the historical demand of these LILs from National Metering Identifier (NMI) metering data.

Residential and business demand

The split of historical consumption data into business and residential segments is performed using a combination of sampling of AEMO residential meter data and annual ratios between the two segments provided by electricity distribution businesses to the AER as part of their processes in submitting a regulatory information notice. Further details of the approach are in Appendix 7 (Data Segmentation) of the 2020 Electricity Demand Forecasting Methodology Paper.

Distributed PV uptake and generation

AEMO sources historical PV installation data from the Clean Energy Regulator (CER) and applies a solar generation model to estimate the amount of power generation at any given time. Refer to Section 4.4.5 for details.

Matters for consultation

- Is there a better source of historical distribution and transmission losses at higher frequency?

4.4.2 Historical weather data

Input vintage	Daily currency
Source	Bureau of Meteorology (BoM)
Update process	Live data stream from the BoM
Current accuracy	N/A
Get involved	N/A

AEMO uses historical weather data for training the annual consumption and minimum and maximum demand models as well as forecast reference year traces. The historical weather data comes from the Bureau of Meteorology (BoM)[56], using a subset of the weather stations available in each region, as shown in Table 13.

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

AEMO has assessed the accuracy of its forecasts with one weather station and with multiple weather stations per region, and has not found sufficient improvement in model fit to increase the complexity of the forecast models. This was presented in February 2019 FRG[57]. It was further consulted on in the 2020 IASR; see Appendix A1 – Summary of responses to stakeholder submissions[58].

[56] Bureau of Meteorology Climate Data, at http://www.bom.gov.au/climate/data/.

[57] See meeting material from the February 2019 FRG meeting at 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.

[58] See 2020 IASR at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/2020-forecasting-and-planning-inputs-assumptions-and-scenarios-report-iasr.pdf?la=en.

Table 13 Weather stations used in consumption, minimum and maximum demand

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

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

Input vintage	Daily currency
Source	• Generation Information page • Settlements data • NMI data
Update process	Continuously updated
Current accuracy	N/A
Get involved	N/A

AEMO reviews its list of other non-scheduled generators using information from AEMO's Generator Information dataset obtained through surveys, as well as through submissions from network operators (to assist with connection point forecasting) and publicly available information. Through these three streams of information, AEMO collects withdrawn, committed, and proposed ONSG (non-scheduled generation that excludes distributed PV[59]) connections and site information. AEMO uses the generator's Dispatchable Unit Identifier (DUID) or NMI to collect generation output at half-hourly frequency.

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

AEMO's current view of ONSG is contained in the Generation Information page. As at the November 2020 release, aggregated ONSG by NEM region is shown in Figure 6.

[59] Distributed PV is discussed in Section 4.4.4.

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

> **Matters for consultation**
>
> - Do you have any comments on the inputs described?

4.4.4 Distributed energy resources

Input vintage	• Updated since ISP 2020. • Forecast in March 2020. • Applied in ESOO 2020.
Source	• CSIRO • Green Energy Markets
Update process	Under review. Forecast accuracy identified as needing attention.
Current accuracy	Inaccuracy observed in the 2020 Forecast Accuracy Report, explainable by inputs and assumptions
Get involved	FRG: February – April 2021

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 will engage with consultants to develop DER forecasts that match the new scenarios and consult on these through FRG meetings. The Draft 2021-22 Inputs and Assumptions Workbook contains AEMO's latest DER forecasts provided by consultants in 2020. Any feedback received on these will be shared with consultants for consideration when developing new DER forecasts in the new year.

At a high level, the scenarios will map to DER forecasts that are either the Central forecast, or take some higher or lower trajectory, as described in Table 14.

Table 14 Mapping of DER settings and assumptions to proposed scenarios

	Export superpower	Sustainable growth	Central	Slow growth	Diversified Technology
Distributed PV uptake	High	High	Central	Central/High	Low
Battery uptake	Central	High	Central	Central	Low
Battery aggregation as VPP	Low	High	Central	Central	Low
BEV Uptake	High until 2030 – lower uptake from this point onwards	High	Central	Low	Low
BEV infrastructure and tariffs	Moderate adoption of infrastructure and tariffs to enable 'better' charging options.	Faster adoption of infrastructure and tariffs to enable 'better' charging options.	Moderate adoption of infrastructure and tariffs to enable 'better' charging options.	Delayed adoption of infrastructure and tariffs to enable 'better' charging options.	Moderate adoption of infrastructure and tariffs to enable 'better' charging options.
Level of coordinated BEV charging	Some move from time-of-use flex charging to fully coordinated dynamic charging post 2030.	Significant move from time-of-use flex charging to fully coordinated dynamic charging post 2030.	Some move from time-of-use flex charging to fully coordinated dynamic charging post 2030.	No move from time-of-use flex charging to fully coordinated dynamic charging.	Some move from time-of-use flex charging to fully coordinated dynamic charging post 2030.
Fuel cell electric vehicles	Higher relative penetration of fuel cell vehicles in heavy and light vehicles	Higher penetration of fuel cell vehicles in heavy vehicles. Light vehicles prefer battery electric.	Of the moderate adoption of alternative fuelled vehicles, higher penetration of fuel cell vehicles in heavy vehicles. Light vehicles prefer battery electric.	Of the relatively low adoption of alternative fuelled vehicles, higher penetration of fuel cell vehicles in heavy vehicles. Light vehicles prefer battery electric.	Of the moderate adoption of alternative fuelled vehicles, higher penetration of fuel cell vehicles in heavy vehicles. Light vehicles prefer battery electric.

Matters for consultation

- Are the proposed mappings of DER trajectories to scenarios reasonable?

Distributed PV

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

Distributed PV normalised generation half-hourly profiles are provided by Solcast[60]. PVNSG normalised generation half-hourly profiles are generated by AEMO using satellite solar irradiance data provided by Solcast. The solar irradiance data is a key input into the System Advisory Model[61] from the National Renewable Energy Laboratory to construct generation profiles.

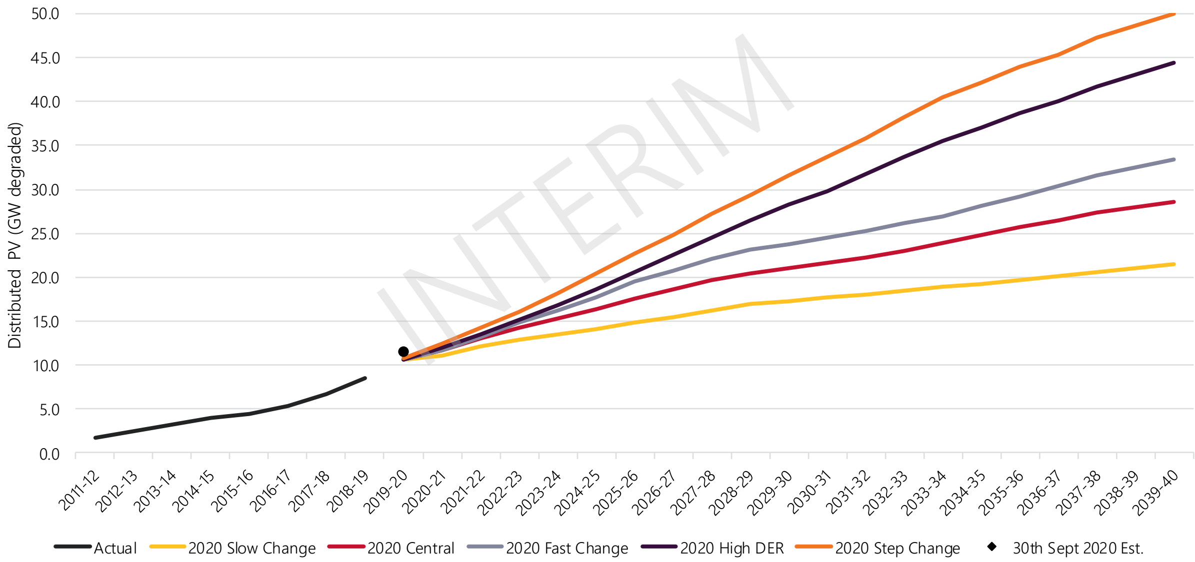
[60] Rooftop PV normalised generation half-hourly profiles prior to 2007 were provided by the University of Melbourne in collaboration with AEMO.

[61] For more on the SAM model, see https://sam.nrel.gov/.

The uptake of distributed PV systems, including residential rooftop and commercial systems, continues to grow strongly. The total capacity of distributed PV systems in the NEM is approximately 11.6 GW[62].

Figure 7 shows the uptake forecasts across the 2020 scenarios. Additional information on these forecasts is available in the CSIRO and GEM reports (see Section 1.3).

Figure 7 NEM distributed PV installed capacity (degraded), assessed at 30 September 2020



AEMO has identified that the 2020 forecasts of distributed PV underestimated uptake across most regions. As outlined in its 2020 Forecast Accuracy Report[63], AEMO has identified the distributed PV forecast as a key continuous improvement area, with a particular focus on enhancing the starting point and short-term trend. This includes supplementing the use of CER installation data with data from the new DER Register.

AEMO will be commissioning updates to the distributed PV forecast, which will be consulted on through the February, March and April FRG meetings in 2021. These updates will reflect the assumptions and narratives for the proposed new set of scenarios (summarised in Table 14 above).

AEMO assumes a rebound of energy consumption equal to 20% of the energy generated by the PV systems as lower future bills may change consumption behaviour or trigger investments in equipment that uses more electricity.

Matters for consultation

- Was the breadth of distributed PV uptake trajectories used in the 2020 scenarios appropriate to sufficiently cover the range of possible long-term uptake?
- What other factors should be considered in the development of distributed PV uptake? How should potential limitations in the distribution system be incorporated into distributed PV forecasts, if at all?

[62] Installed capacity estimate as at 30 September 2020, adjusted for degradation.

[63] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/forecasting-accuracy-reporting

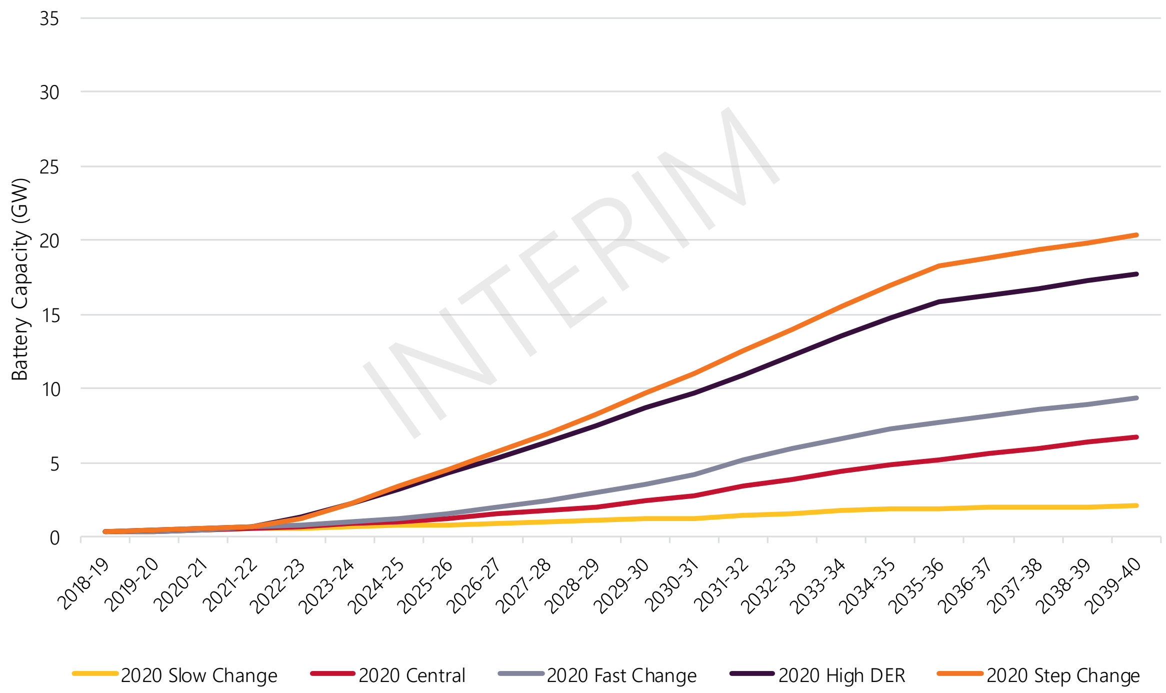
Battery storage uptake

Behind-the-meter residential and commercial battery systems have the potential to change the future demand profile in the NEM, particularly the maximum and minimum demand of the power system. The extent of 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 various tariffs and associated battery charge/discharge operation modes[64].
- 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.

Figure 8 shows the total forecast installed capacity of customer battery systems across the NEM for the 2020 scenarios. Additional information on these forecasts is available in the CSIRO[65] and GEM[66] reports.

Figure 8 Behind-the-meter battery forecasts for the NEM



AEMO will be commissioning updates to these forecasts, which will be consulted on through the February, March and April FRG meetings in 2021 and will take into account the new scenario narratives in Table 14.

Matters for consultation

- Was the breadth of behind-the-meter battery storage uptake trajectories used in the 2020 scenarios appropriate to sufficiently cover the range of possible outcomes?
- What other factors should be considered in the development of these forecasts?

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

[65] See https://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2020/CSIRO-DER-Forecast-Report.

[66] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/green-energy-markets-der-forecast-report.pdf?la=en.

Battery storage profiles and virtual power plants

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

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

AEMO is proposing to model a projected level of aggregation among distributed storage systems which would operate to meet system peaks (rather than household drivers), effectively acting as a VPP (interim assumptions are provided in Figure 9). The schedulable component of the aggregated batteries (the VPP) would be operated in the market models in the same way as large-scale batteries. These batteries are assumed to operate with perfect foresight and optimise charge and discharge to minimise system cost. If supply-demand balance is tight, this will mean batteries are operated to offset as much unserved energy as possible.

Battery systems installed by homeowners and not aggregated would be assumed to behave to minimise grid costs for that household, which may impact the charging and discharging behaviours of these assets. As such, this much more passive behaviour may not optimally discharge to meet market signals, reducing the system benefits relative to VPPs. An example of the type of profile that AEMO has used to model the default charging behaviour is shown in Figure 10.

Household and utility-scale batteries are currently modelled with a 2:1 energy to power ratio only, and 90% or 80% round-trip efficiency respectively. This means that, from fully charged, the battery could provide two hours of supply if discharging at full capacity, although to meet consumer energy needs the battery may not be operated in this manner, as discussed above.

Figure 9 Aggregation trajectories for interim VPP forecasts

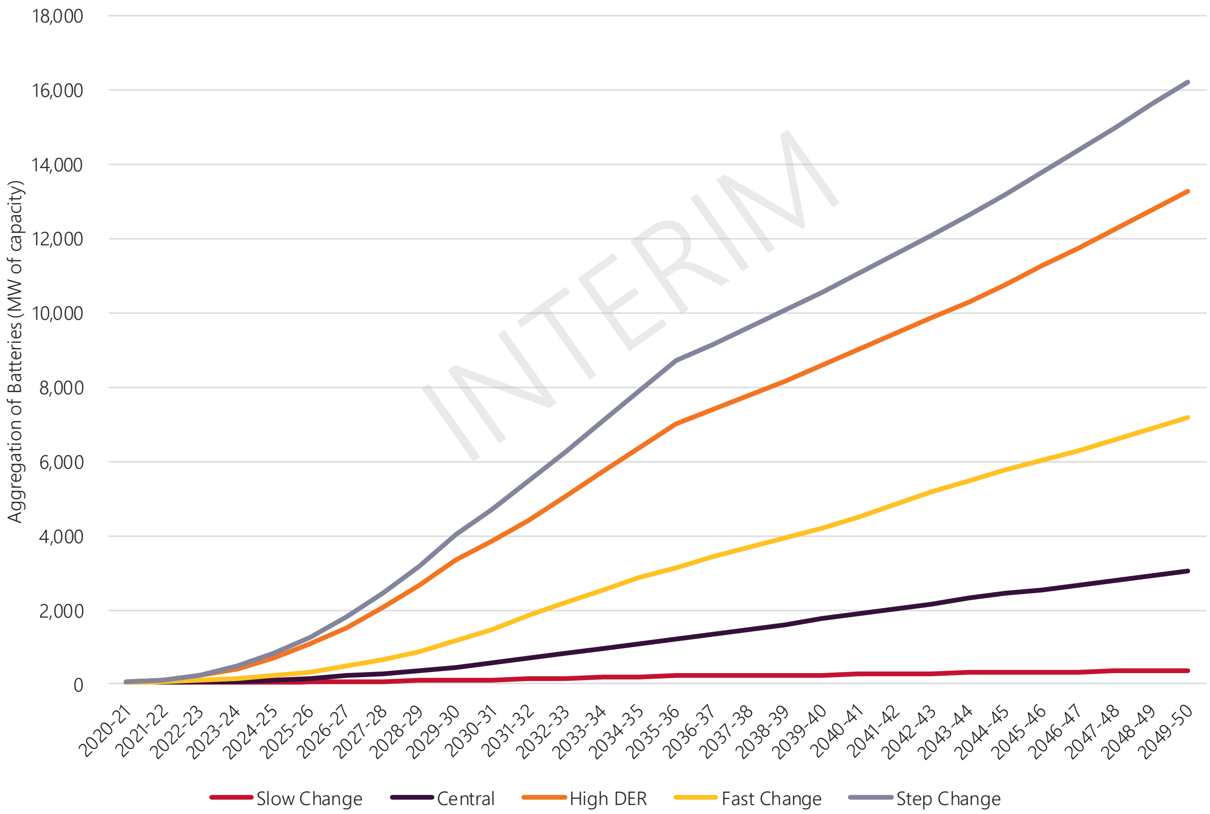
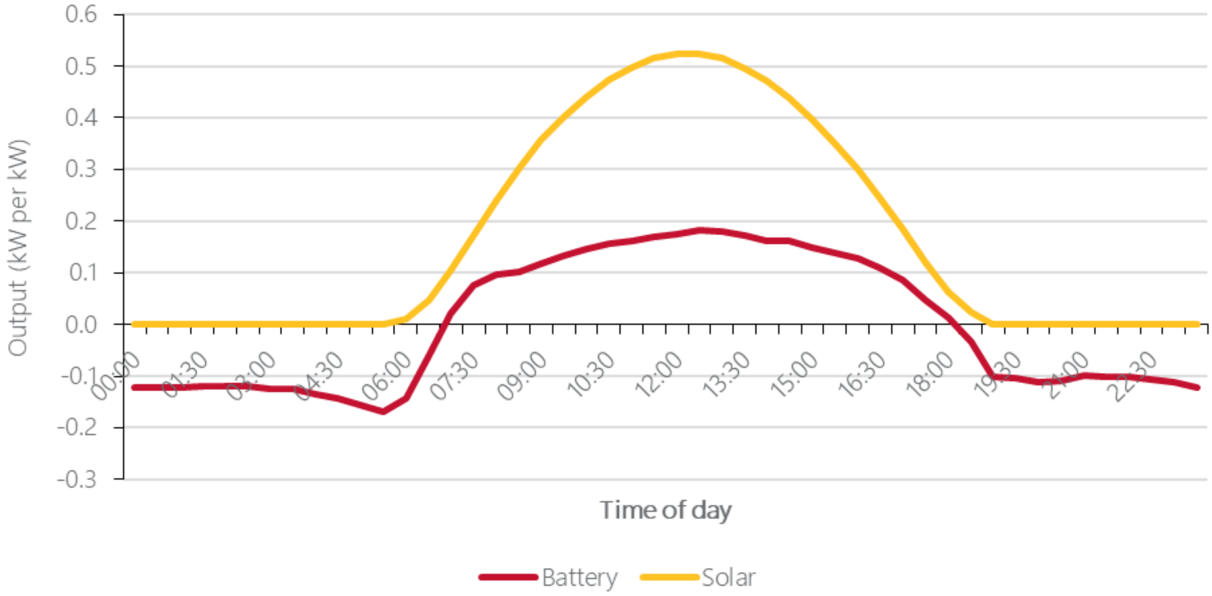


Figure 10 shows the typical charge and discharge behaviours of non-aggregated batteries, demonstrating the average operation expected of households which operate to minimise their energy costs.

Figure 10 Example average normalised non-aggregated battery daily charge/discharge profile for New South Wales in summer (February)



AEMO will be engaging with consultants in early 2021 to update the forecast of battery storage uptake and the level of aggregation. The updated forecasts will be consulted on through the FRG meetings in February, March and April 2021.

Matters for consultation

- Are the trajectories that were applied for the proportion of VPPs in 2020s forecasting still considered appropriate?
- Is the breadth of proposed DER input trajectories appropriate to sufficiently cover the different levels of assumed DER uptake in the scenarios?

Battery electric vehicle and fuel-cell vehicle uptake

Electrification of the transport sector will increase electricity consumption in future. Key factors for battery EV (BEV) adoption (including battery and plug-in hybrid EVs) include:

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

Currently, BEVs are estimated to represent less than 1% of the total vehicle fleet across the NEM. Based on the current level of uptake, AEMO's interim Central outlook (as forecast by CSIRO) assumes that the uptake of EVs across the NEM will reach only 3%, or about half a million vehicles, by 2029-30. Growth is forecast to accelerate in the late 2020s and 2030s, due to assumed access to more model and size choices, charging infrastructures, and falling vehicle costs.

Figure 11 shows the projected uptake by vehicle type in the 2020 ESOO Central scenario, with residential vehicles forecast to be the largest BEV sector, followed by light commercial vehicles and trucks.

Figure 11 NEM forecast number of EVs by vehicle type, Central scenario, 2017-18 to 2039-40

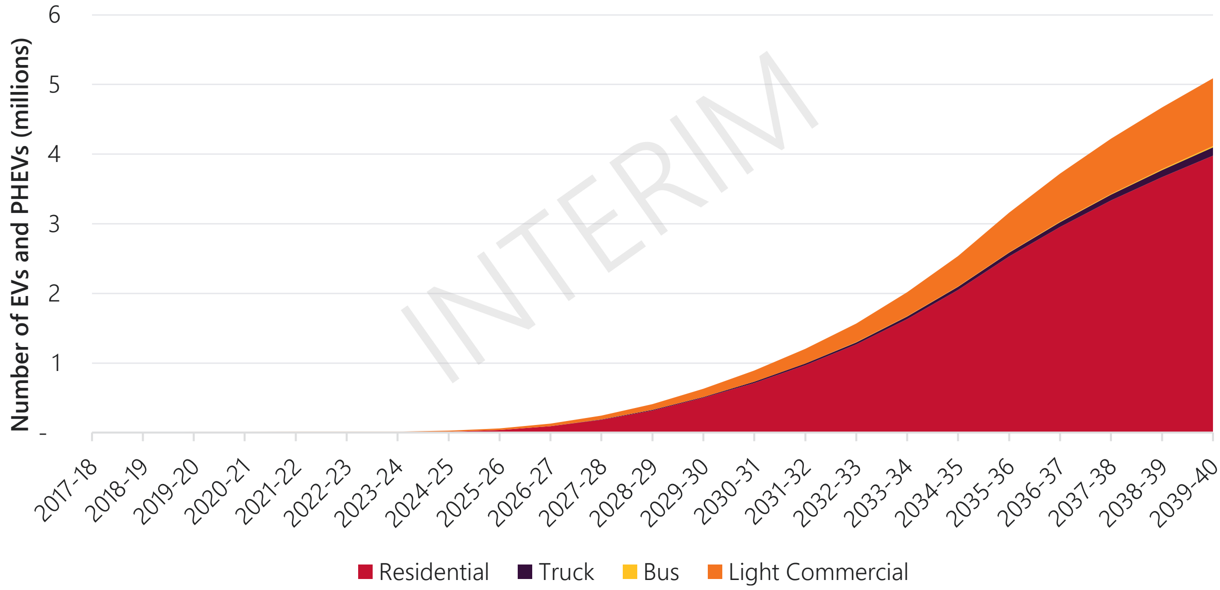
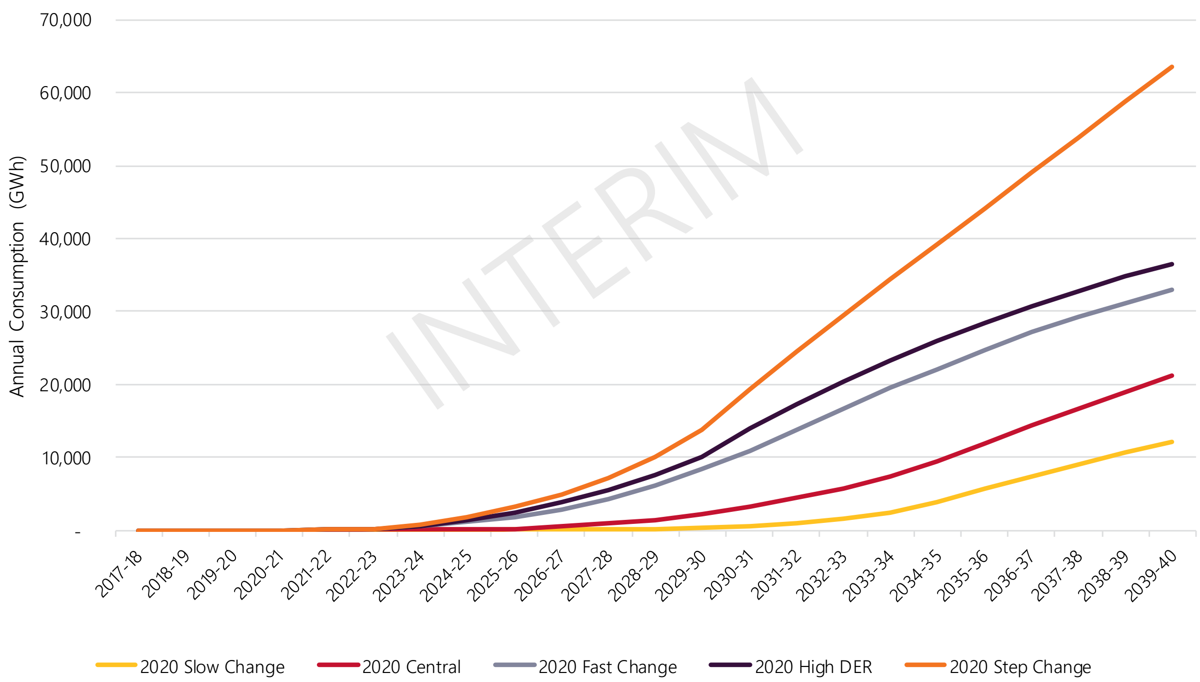


Figure 12 shows the interim forecast annual consumption attributed to EVs across the NEM in the next 20 years based on the 2020 scenarios.

Figure 12 NEM BEV annual consumption forecast, 2017-18 to 2039-40, all scenarios



The magnitude of transport electrification is highly uncertain, with EVs still in the early stages of adoption in Australia. The forecast BEV uptake spread is therefore wide across the scenarios.

AEMO will be updating the EV forecasts, both BEV and FCV, which will be consulted on through the February, March and April 2021 FRG meetings. Indications of the mapping of EV trajectories to the new set of proposed scenarios are shown above in Table 14; these show that EV uptake is stronger in the proposed Sustainable Growth scenario but more muted in the proposed Slow Growth and Diversified Technology scenarios. In the proposed Export Superpower scenario, the uptake of BEVs is initially strong but then plateaus due to the uptake of hydrogen fuel-cell vehicles.

Matters for consultation

- Are the proposed mappings of EV uptake to the new scenarios appropriate?
- Is the assumption that BEV uptake will plateau in the proposed Export superpower scenario, with an increased relative share of hydrogen fuel-cell vehicles, appropriate?
- Was the breadth of the EV uptake trajectories in the 2020 scenarios sufficiently broad to cover possible outcomes?
- What other factors should AEMO consider in developing the updated EV uptake forecasts?

EV charging behaviours

The method and frequency of BEV 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, the driver's routine and preferences in weekdays versus weekends and in different seasons, and topography of the road.

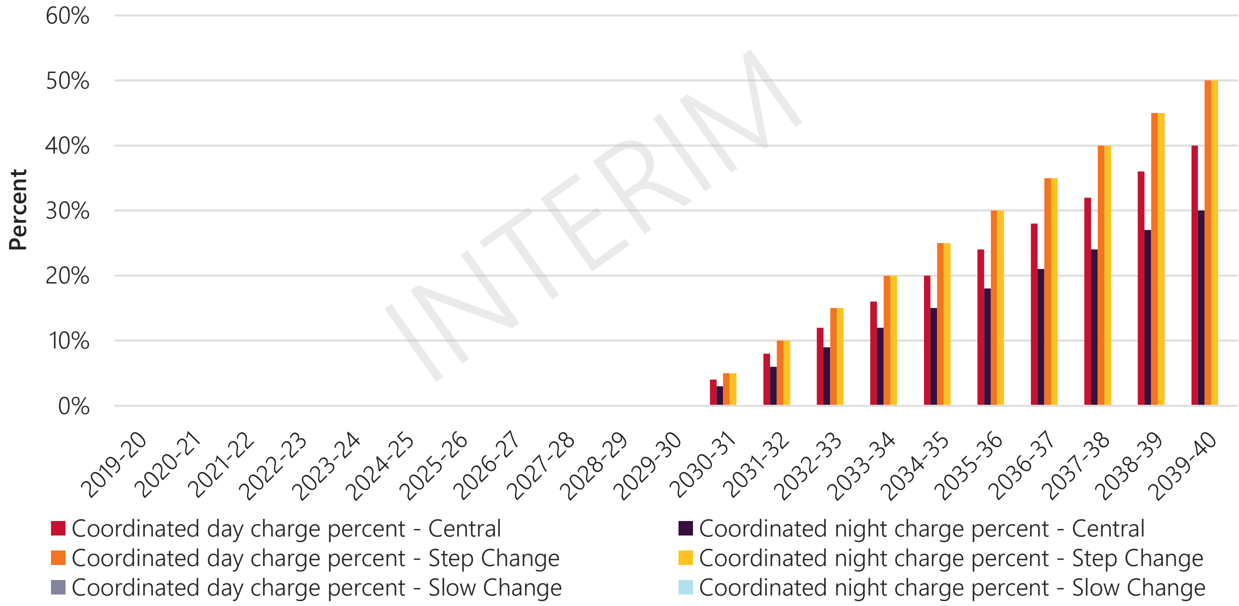
In the 2020 scenarios, AEMO incorporated four charge profiles:

- 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 have 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 2020 scenario is detailed in Figure 13 below.

Figure 13 Assumed proportion of daytime and night-time charging that is coordinated, by 2020 scenario

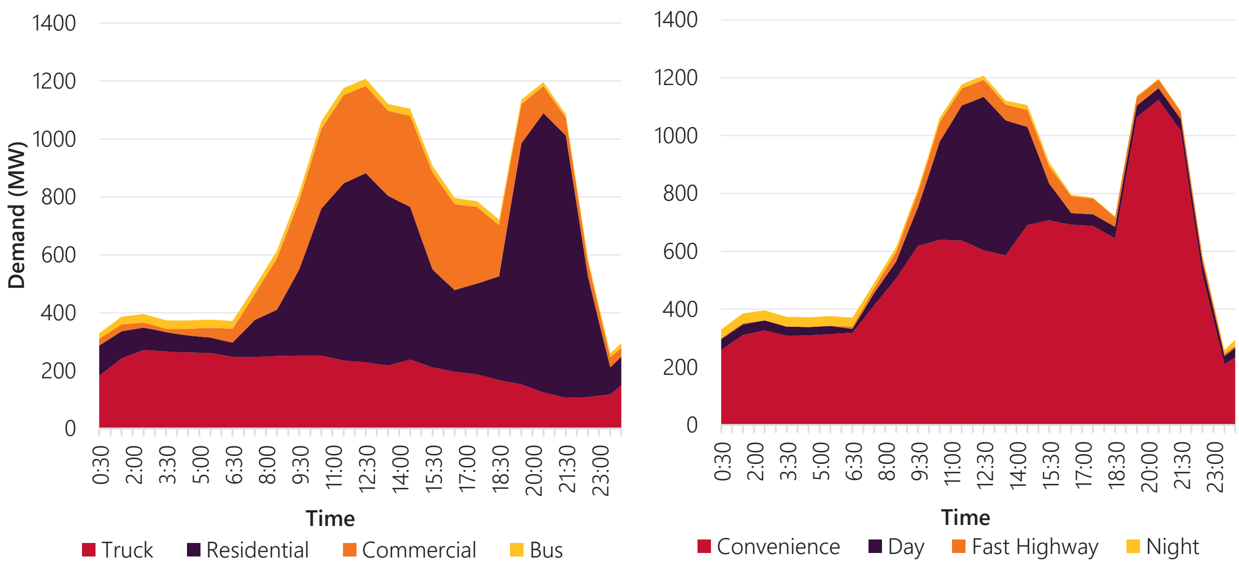


Charge profile preferences are forecast to change over time. The increasing electrification of the transport sector is expected to lead to greater charging infrastructure development and tariff change, providing consumers with greater choice to charge their vehicles in ways that are increasingly convenient, 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 14 below shows examples of the draft forecast contribution to demand from BEV charging.

Figure 14 Average weekday non-coordinated BEV demand by vehicle type (left) and by charge profile (right) assumed for the Central scenario in January 2040 for New South Wales



AEMO included a degree of coordinated BEV charging in the 2020 forecasts. Figure 15 and Figure 16 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 BEV charging was uncoordinated). The influence on minimum demand is particularly noticeable in the chart on the left in Figure 16 for the Step Change penetration of EVs.

Figure 15 Example of coordinated BEV charging profiles during mild conditions (October) (left) and high demand conditions (January) (right) in the Central scenario in 2040 for New South Wales

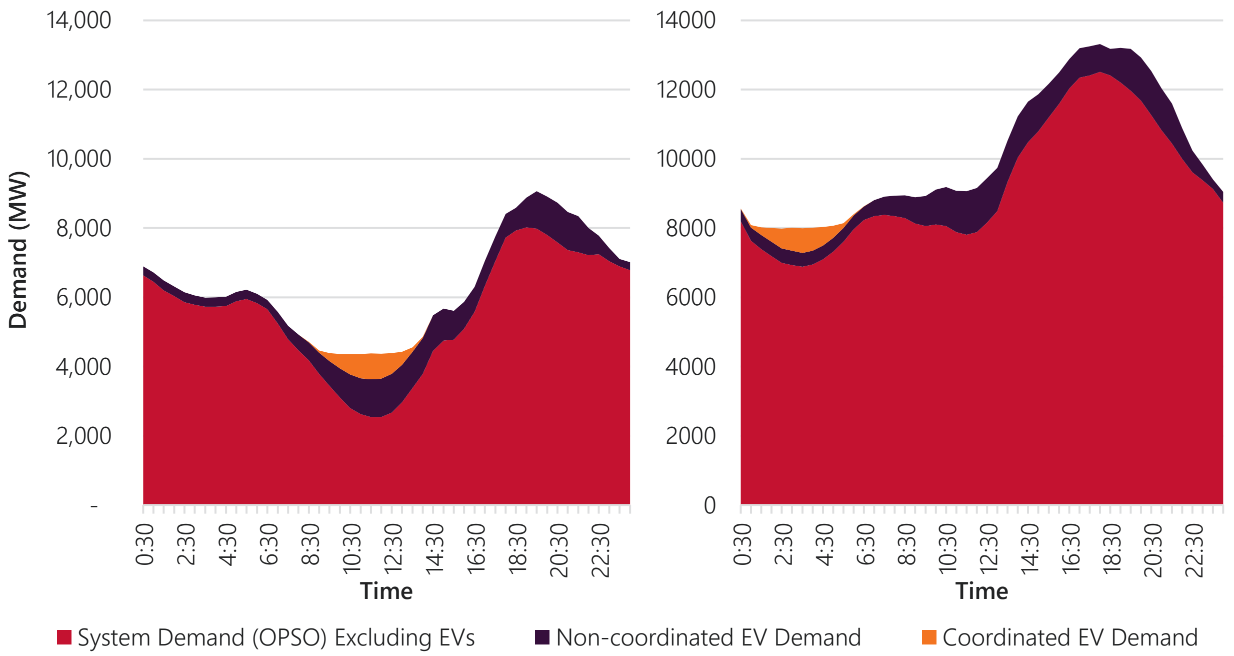
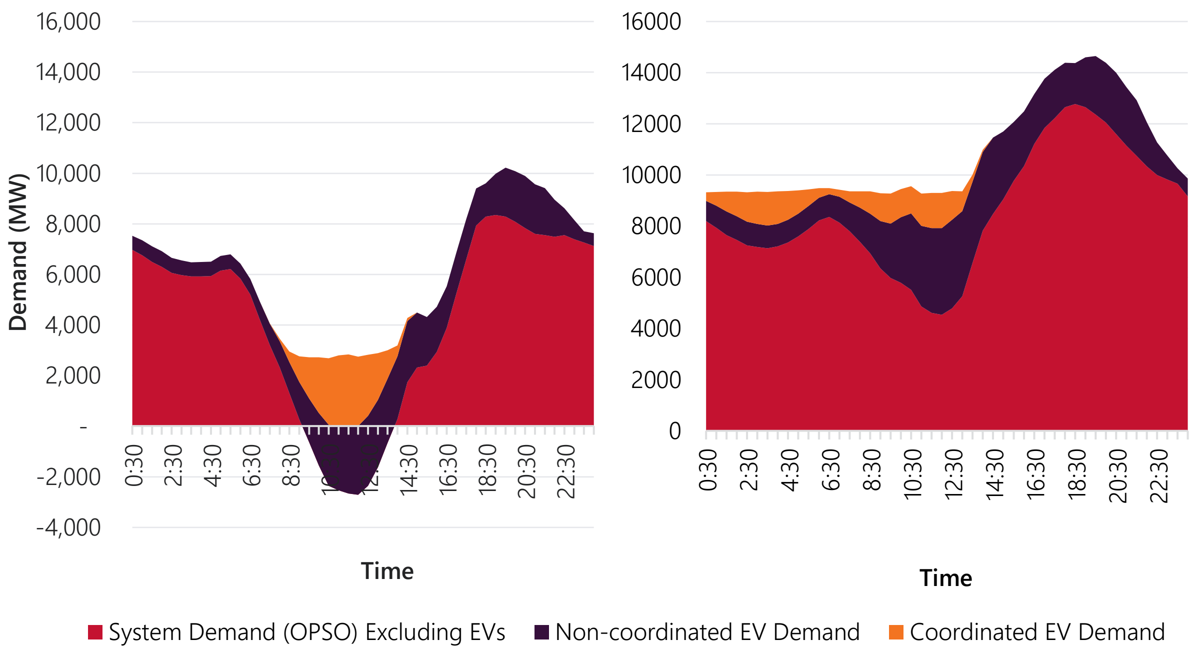


Figure 16 Example of coordinated BEV charging profiles during mild conditions (October) (left) and high demand conditions (January) (right) in the Step Change scenario in 2040 for New South Wales



AEMO proposes leveraging the same types of charging profile to be applied to the BEV forecasts developed in early 2021. The proportions of different profiles will vary across the scenarios, as they did previously, and are shown in Table 14 above.

Matters for consultation

- Are the proposed types of BEV charging considered appropriate?
- Do you consider the description of BEV charging considerations reasonable for the proposed new scenarios?

4.4.5 Economic and population forecasts

Input vintage	• Updated since 2020 ISP and 2020 ESOO for the 2020 GSOO • Forecast in October 2020
Source	• BIS Oxford Economics • ABS Population Series
Update process	Will be updated in early 2021 to reflect latest economic data and information about recovery from COVID-19.
Current accuracy	Inaccuracy observed in the 2020 Forecast Accuracy Report, explainable by the significant uncertainty provided by COVID-19
Get involved	FRG: February 2021

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. These forecasts were published in March 2020 and updated in April and October 2020 to take into account the evolving implications of COVID-19 for the domestic economy.

As the pandemic impacts abate, the service-intensive states of New South Wales and Victoria are assumed to lead the recovery in economic growth. This is, however, contingent on the re-opening of international borders, which will enable the resumption of international migration and travel.

Although the initial economic impact of the pandemic is less severe than was anticipated in April 2020, the recovery is now forecast (at October 2020) to be more drawn out, as a result of the more prolonged border closures and Victoria's second lockdown. BIS Oxford Economics expects the economy will take longer to recover, with a slower rebound now projected for FY22, and some permanent scarring[67].

Figure 17 shows the forecast economic outcomes for the aggregated NEM-region gross state product (GSP), demonstrating the significance of the pandemic, as well as the dispersion in economic recovery.

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[68] might dominate the Australian economy, this sector is dwarfed by the manufacturing and mining sectors'

[67] Presentation delivered at AEMO's FRG meeting on 30 September 2020. Slides available at https://aemo.com.au/-/media/files/stakeholder_consultation/working_groups/other_meetings/frg/2020/frg-meeting-35---meeting-pack.zip?la=en.

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

contribution to electricity consumption[69], as shown in Figure 18. Sectorial electricity usage data will be updated in 2021, reflecting the latest Australian energy data statistics[70].

Figure 17 NEM aggregated gross state product (GSP, $'Bn)

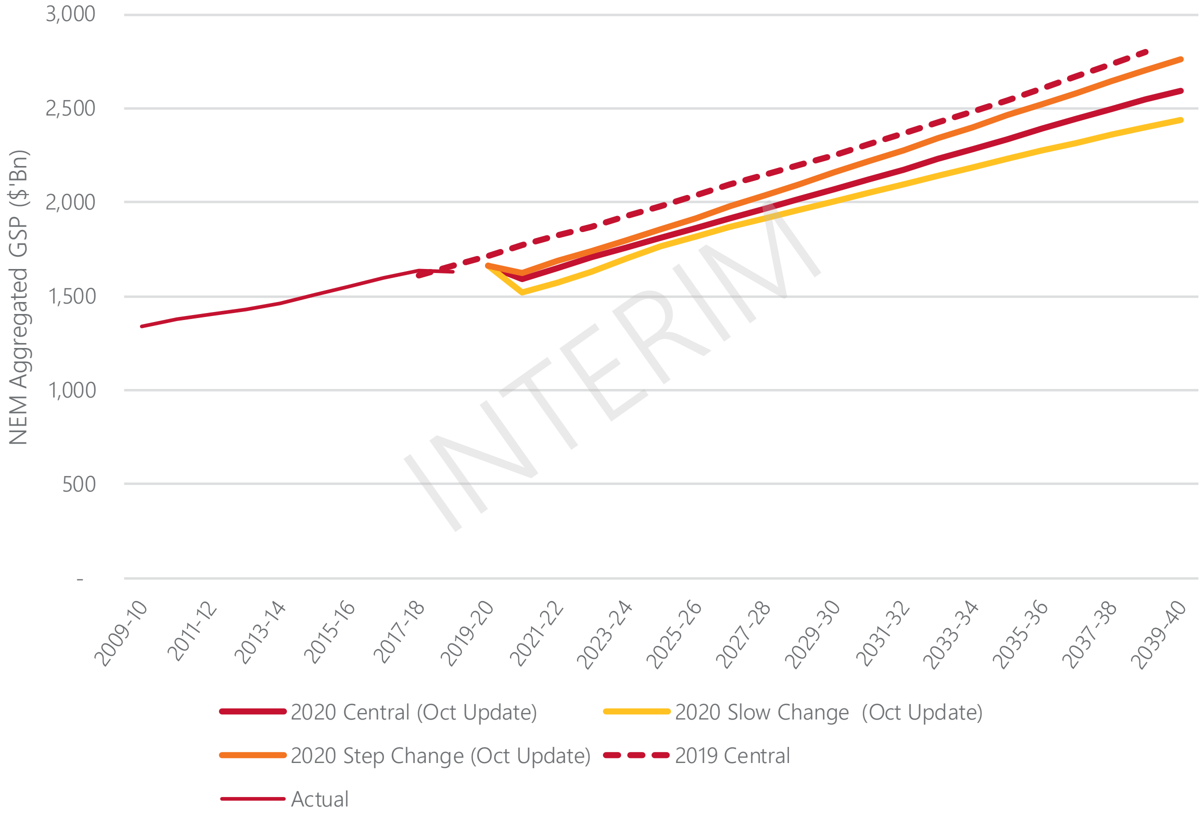
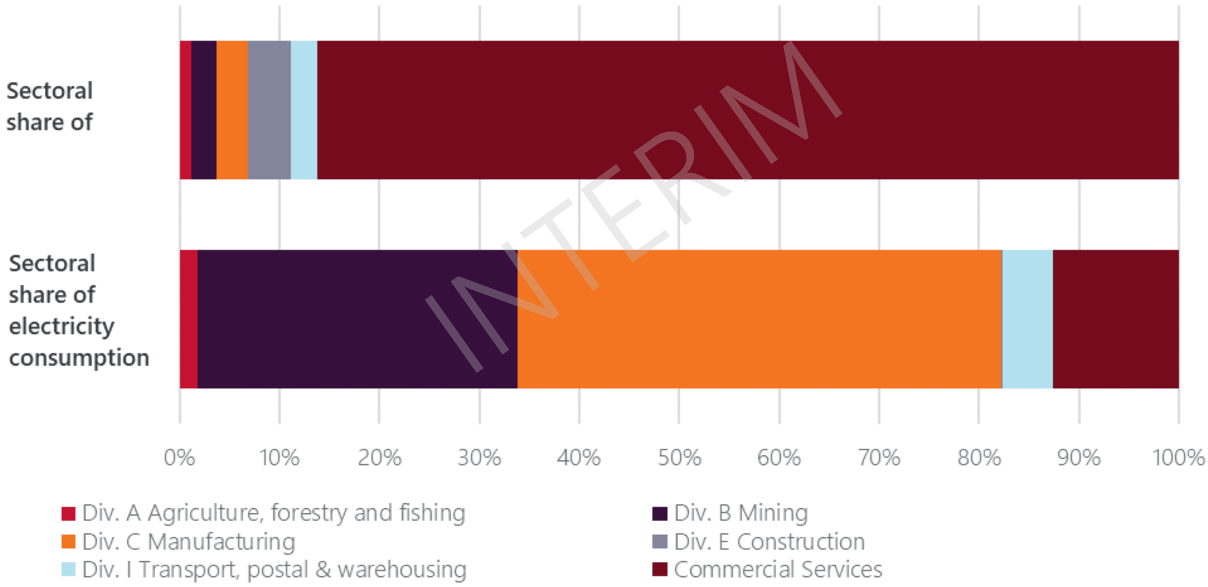


Figure 18 NEM gross value added (GVA) share of economic activity versus NEM annual electricity usage by the associated industries (2017-18) – interim



[69] 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.

[70] At https://www.energy.gov.au/publications/australian-energy-update-2020.

Population growth is also a key driver in Australia's GSP. Currently the economic consultants engaged by AEMO either use the Australian Bureau of Statistics (ABS) population data series directly or adapt it when assumptions on net overseas migration (NOM) and net interstate migration (NIM) differ.

The high-level mapping of the economic trajectories to the new scenarios is provided in Table 15 below.

Table 15 High-level mapping of economic and population settings for proposed scenarios

Scenario	Sustainable Growth	Export Superpower	Central	Slow Growth	Diversified Technology
Economic growth and population outlook	High	High	Moderate	Low	Moderate

Matters for consultation

- Do the economic forecasts reflect a reasonable spread of potential outcomes for the NEM, suitable for continued application in the 2021-22 scenarios?

4.4.6 Large industrial loads

Input vintage	• Updated since 2020 ISP and 2020 ESOO for the 2021 GSOO • Forecast in October 2020
Source	• Interviews/Surveys • Economic Outlook • Media search/announcements
Update process	Will be updated in early 2021.
Current accuracy	Forecast has performed as expected, as described in the 2020 Forecast Accuracy Report
Get involved	FRG: April 2021

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

AEMO currently sources information regarding LILs from:

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

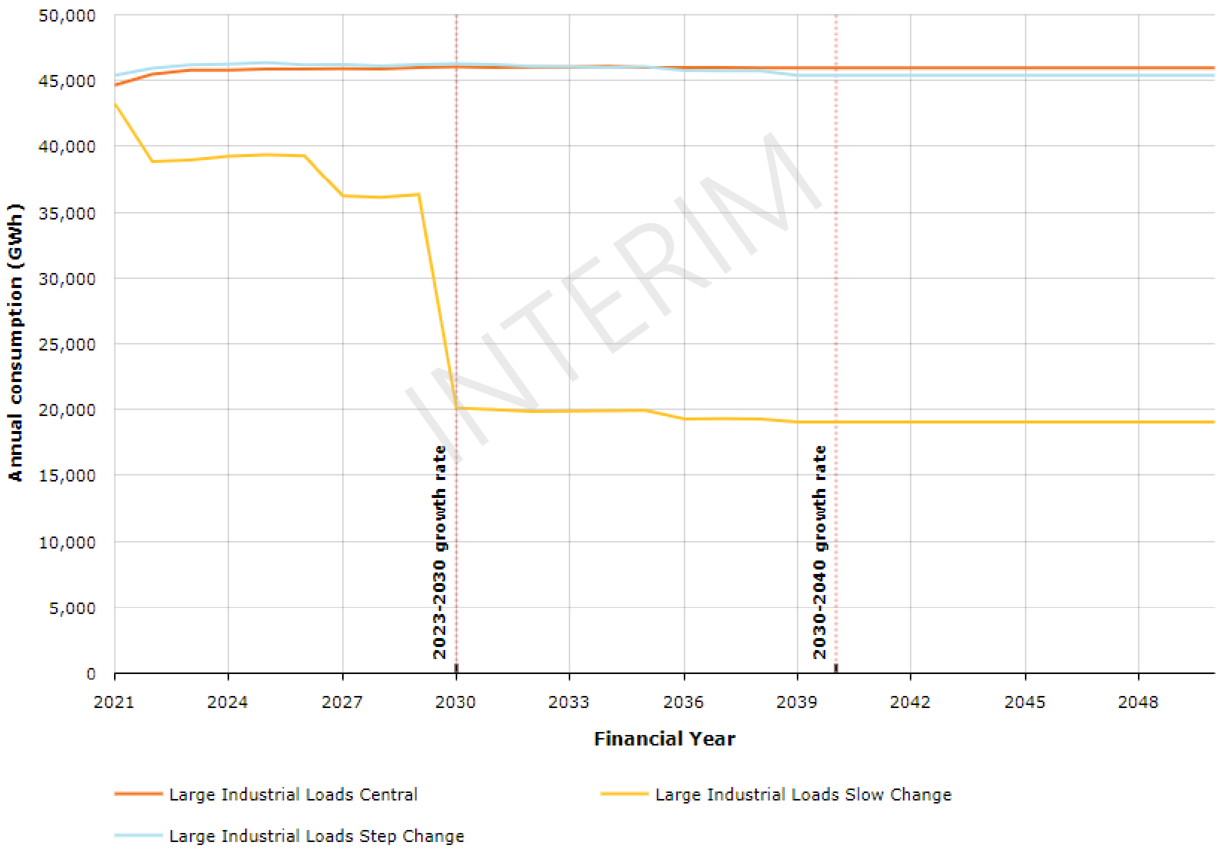
AEMO's current LIL forecasts are shown in Figure 19 below; more detailed data can be accessed from AEMO's forecasting portal[71], selecting the 'Business' category and 'Large Industrial Loads' from the sub-category menu.

[71] ESOO 2020 forecasts are available at http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational.

As the figure shows, in AEMO's existing industrial load forecast there is little new industrial load development captured across the three scenarios presented. There is, however, material downside risk of industrial load closures should economic conditions deteriorate for individual loads. AEMO's Slow Growth scenario is expected to once again provide the lower estimate for industrial loads, considering the insights gained from customer interviews considering the risks that would exist for large loads with the less favourable economic and/or policy settings influencing future operations and load investment decisions.

Figure 19 shows the 2020 industrial load forecast. For the 2021 forecasts, AEMO proposes to take a systematic approach to industrial load closures which considers load reductions which are equivalent to shutdowns of large aluminium smelters. AEMO proposes to implement load reductions in New South Wales, Tasmania and Victoria before 2030, and in Queensland after 2030. This approach is proposed as forecasting the potential shutdown of large loads such as smelters is challenging given the variety of considerations which influence those decisions. Instead the scenario is designed to test what the impact would be of major industrial load withdrawals, particularly within each region.

Figure 19 Large industrial load forecast in AEMO's 2020 ESOO forecast



Matters for consultation

- Do you support an approach that systematically applies closures using greater traceable logic, over existing methods which put more focus on insights provided during interviews with each facility?

4.4.7 Households and connections forecasts

Input vintage	• Updated since ISP 2020. • Forecast in March 2020. • Applied in ESOO 2020.
Source	ABS, Housing Industry Association, AEMO meter database, consultant
Update process	Under review. Forecast granularity at sub-region may be developed. Will be updated via new consultant forecasts in early 2021.
Current accuracy	Forecast has performed as expected, as described in the 2020 Forecast Accuracy Report
Get involved	N/A

As Australia's population increases, so does the expected number of new households which require electricity connections. AEMO's forecast of the increase in residential electricity consumption is mainly driven by electricity connections. 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[72]. AEMO revised down the growth in the residential building stock model for the Central and Slow Change scenarios in accordance with Table 16. The Step Change scenario forecast remained unchanged. These assumptions will be reviewed as part of the update for these assumptions in early 2021.

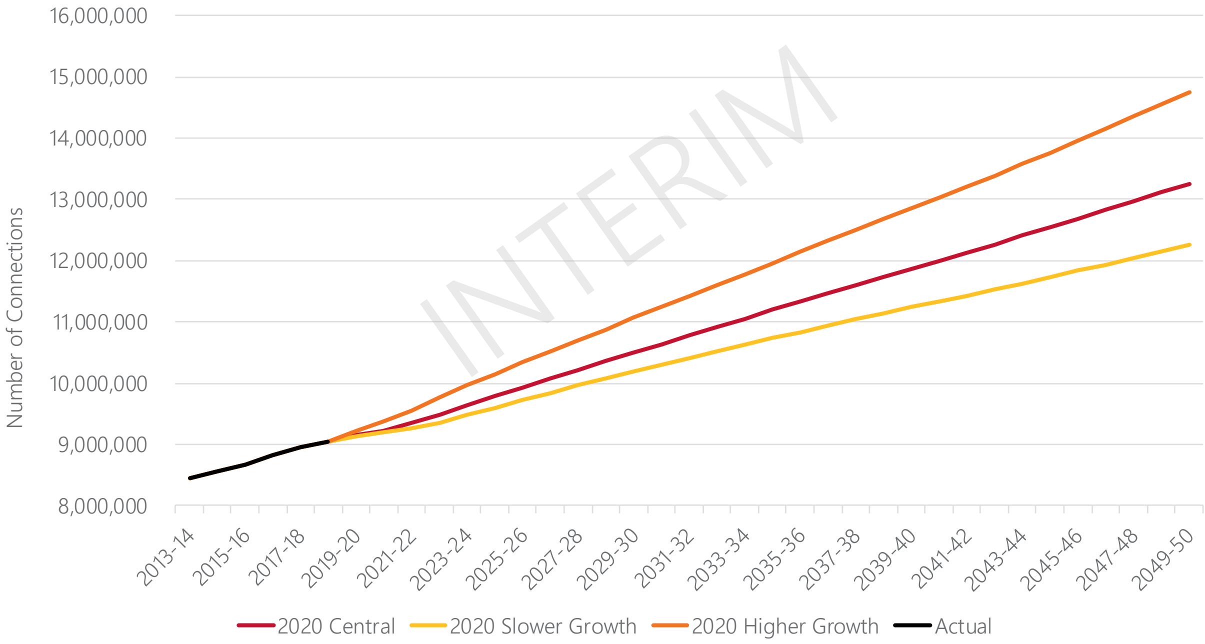
Table 16 COVID adjustments to dwelling starts in the Residential Building Stock Model

Financial year	Central	Slow Change
2020-21	43%	43%
2021-22	22%	43%
2022-23	-	22%
2023-24	-	11%

Figure 20 shows the connections forecast that were applied to the 2020 scenarios, demonstrating the assumed COVID-19 impacts to slow and/or lower growth in the short term. In the longer term, the forecasts are reflective of the latest growth trends in the ABS household projections data.

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

Figure 20 2020 NEM residential connections actual and forecast, 2013-14 to 2039-40, all scenarios



4.4.8 Energy efficiency forecast

Input vintage	• Updated since ISP 2020. • Forecast in March 2020. • Applied in ESOO 2020.
Source	• Information on state-specific schemes sourced directly from relevant government jurisdictions. • Housing stock model developed by consultant • Appliance uptake data sourced by Department of Energy
Update process	• Direct contact with state government jurisdictions. • Energy Efficiency Workshop (planned for early 2021), with consultant support to provide an independent forecast leveraging the insights shared at the workshop, and considering jurisdiction information.
Current accuracy	N/A
Get involved	Energy efficiency workshop with industry and policy experts in February 2021. FRG: April 2021

Energy efficiency means obtaining more output or service from each unit of energy[73]. The federal and state governments have developed measures to mandate or promote energy efficiency uptake across the economy, and AEMO has considered the impact of these measures on forecast electricity consumption.

AEMO's 2020 forecast included growing energy efficiency savings from continuation of state schemes beyond legislated end dates and revisions to commercial building stock savings[74], depending on the scenario.

[73] 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).

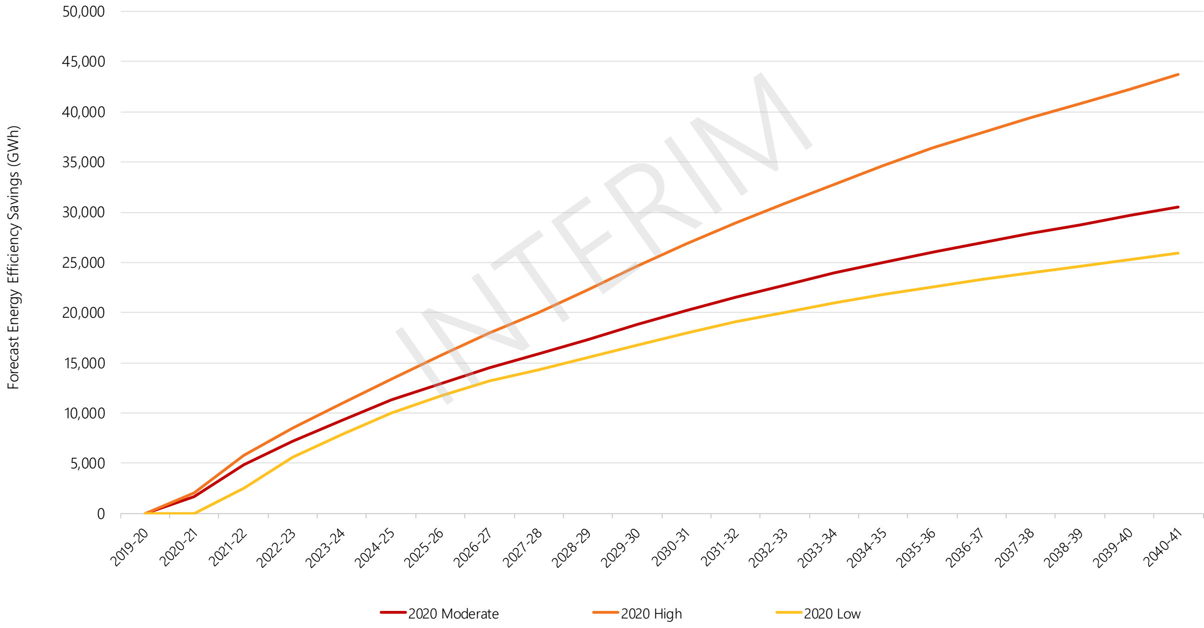
[74] For more details, see Electricity Demand Forecasting Methodology Information Paper, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

AEMO's 2020 forecasts focused on three energy efficiency scenarios, which were then applied to the five core forecasting and planning scenarios.

The energy efficiency 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 incorporated additional measures representing feasible, yet ambitious future standards for buildings and equipment[75] to drive greater energy efficiency savings.

The connections forecast uses a yearly construction gross value added (GVA) per capita index[76], 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.

Figure 21 Interim forecast energy efficiency savings, 2019-20 to 2039-40



The interim energy efficiency forecasts included the following measures, with proposed scenario-specific considerations as outlined earlier in Table 9:

- Building energy performance requirements contained in the Building Code of Australia (BCA) 2006, BCA 2010, the National Construction Code (NCC) 2019, and, for some scenarios, 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. Additional measures that are in proposal stage or are currently suspended but could be reactivated are proposed to be included in the highest decarbonisation scenarios.
- 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).

[75] 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.

[76] 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.

The impact of state-based schemes is evident in AEMO's interim forecast, as shown in Figure 21, particularly in the short to medium term, with tapering growth from the late 2020s to 2030s in the Moderate and Low trajectories as currently legislated schemes end, such as the SA REES program in 2020 and the VEU Program in 2030. For the High trajectory, AEMO extended the SA REES program to 2030, in line with current recommendations[77]. For the NSW ESS, the state government had committed to a higher target and an extension of the program from 2025 to 2050[78], and this was modelled for all AEMO 2020 scenarios.

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

In the longer term (after 2030), energy savings increased at a slower rate for the Moderate and Low scenarios. In both scenarios, the GEMS program was assumed to provide modest savings, and NCC-related savings were 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 delivered stronger savings to 2040 than the other scenarios.

The configuration of these trajectories will be developed as part of the process of updating energy efficiency forecasts in early 2021. With material policy adjustments occurring as part of each State's COVID recovery plans, the timing of this update is important to be completed closer to the commencement of each planning activity, to ensure there is no data lag in the ESOO or ISP assessments.

When applying the energy efficiency forecasts, AEMO presently assumes a rebound of energy consumption equal to 20% of the forecast savings as lower future bills may change consumption behaviour or trigger investments in equipment that uses more electricity.

Matters for consultation

- Do the programs described cover material drivers of efficiency savings? Are there other schemes not listed that warrant specific consideration?
- Is the long term assumption of persisting savings reasonable, despite the cessation of scheme incentives?
- Is the rebound of lower prices affecting energy consumption reasonable, in the context of energy efficiency savings?

[77] 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.

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

4.4.9 Appliance uptake and fuel switching forecast

Input vintage	• Updated since ISP 2020. • Forecast in March 2020. • Applied in ESOO 2020.
Source	• Department of Energy and Environment Energy 2015 Residential Baseline Study for Australia 2000 – 2030, (RBS, 2015) available at www.energyrating.com.au. • State and federal energy departments
Update process	• Request to the Department of Industry, Science, Energy and Resources (DISER) internal register of appliance sales trends. • Inclusion in research and consultation done for energy efficiency forecasts.
Current accuracy	N/A
Get involved	Energy efficiency workshop with industry and policy experts in February 2021. FRG: April 2021

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

For the forecasts developed for the 2020 ESOO, the energy efficiency forecast assumed 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 was expected to increase by up to 15%, depending on region and scenario. In the commercial sector, the energy efficiency forecasts adopted fuel mix assumptions from building code regulation impact statements.

AEMO used appliance data from the former Australian Government Department of the Environment and Energy (now DISER) to forecast growth in electricity consumption by the residential sector. The data allowed AEMO to estimate changes to the level of energy services supplied by electricity per households across the NEM. Energy services here is a measure based on the number of appliances per category across the NEM, their usage hours, and their capacity and size (Refer to Appendix A5 of AEMO's Demand Methodology Paper[79] for details on the methodology used).

AEMO includes dispersion across the scenarios by applying a per capita Household Disposable Income (HDI) index to the alternate scenarios, relative to the per capita HDI for the Central scenario (also detailed in Appendix A5 of AEMO's Demand Methodology Paper). The HDI index is available in the Draft 2021-22 Inputs and Assumptions Workbook.

In 2020, AEMO revised forecast appliance growth to account for fuel-switching effects from policies not captured by the energy efficiency 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 (E3 program). 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[80]. 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

[79] See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/2020-electricity-demand-forecasting-methodology-information-paper.pdf?la=en.

[80] 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.

dwellings would install heat pump hot water, from a base case of instantaneous gas water heating[81] 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 in 2020[82]. The Victorian Government recently announced in its 2020-21 Budget a spending proposal to replace older heating systems (wood, electric or gas) with more efficient heating and cooling appliances, for 250,000 low-income households[83]. AEMO will engage with the Victorian Government to capture this initiative (and other initiatives) in sufficient detail to incorporate within the forecasting, and this will be consulted on through the energy efficiency workshop and the FRG in April.

The configuration of the High, Moderate and Low appliance uptake and fuel-switching settings that will be applied to the new scenarios will be developed through the energy efficiency workshop and through further consultation with the FRG, but are provided at a high level in Table 17. Figure 22 shows the appliance uptake trajectory for the residential sector (that includes fuel-switching from gas to electric devices) in the 2020 scenarios. In the first two years of the forecast, appliance usage was projected to be higher, in part due to the modelled impact of COVID-19 leading to greater "work from home" energy consumption. Beyond this point, a forecast return to near pre-COVID-19 mobility levels was forecast, reducing appliance usage in all scenarios.

Figure 22 Interim fuel switching and appliance uptake – impact on the residential sector

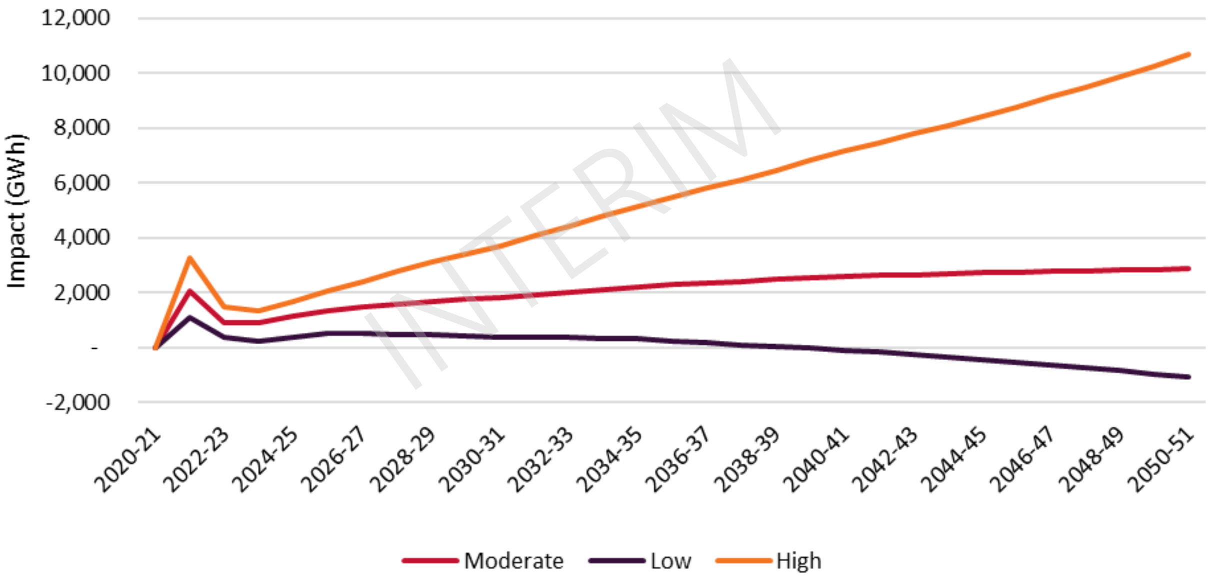


Table 17 High level-mapping of appliance uptake and fuel switching scenarios

Scenario	Sustainable Growth	Export Superpower	Central	Slow Growth	Diversified Technology
Appliance Uptake	High	High	Moderate	Moderate	Low
Fuel Switching	High	High	Moderate	Moderate	Low

[81] 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.

[82] 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.

[83] At https://s3-ap-southeast-2.amazonaws.com/budgetfiles202021.budget.vic.gov.au/2020-21+State+Budget+-+Budget+Overview.pdf (accessed 4 December 2020).

Matters for consultation

- Are the settings specified in the assumptions provided above appropriate and relevant for the proposed scenarios?

4.4.10 Electricity price indices

Input vintage	• Updated since ISP 2020. • Forecast in March 2020.
Source	• AEMC annual retail electricity price trends report, 2019 forecasts available at https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2019. • AEMO internal ISP wholesale price forecasts • AEMO internal transmission plan modelling costs
Update process	Retail price trends to be updated with the latest AEMC 2020 report and internal modelling to provide forecasts for wholesale price forecasts and transmission costs associated with the ISP.
Current accuracy	N/A
Get involved	FRG in April 2021.

Electricity prices are assumed to influence 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 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 23 shows the retail price index assumed in 2020 for the Central, Slow Change and Step Change scenarios[84] 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 were informed by analysis derived from AEMO's draft 2020 ISP published in December 2019.

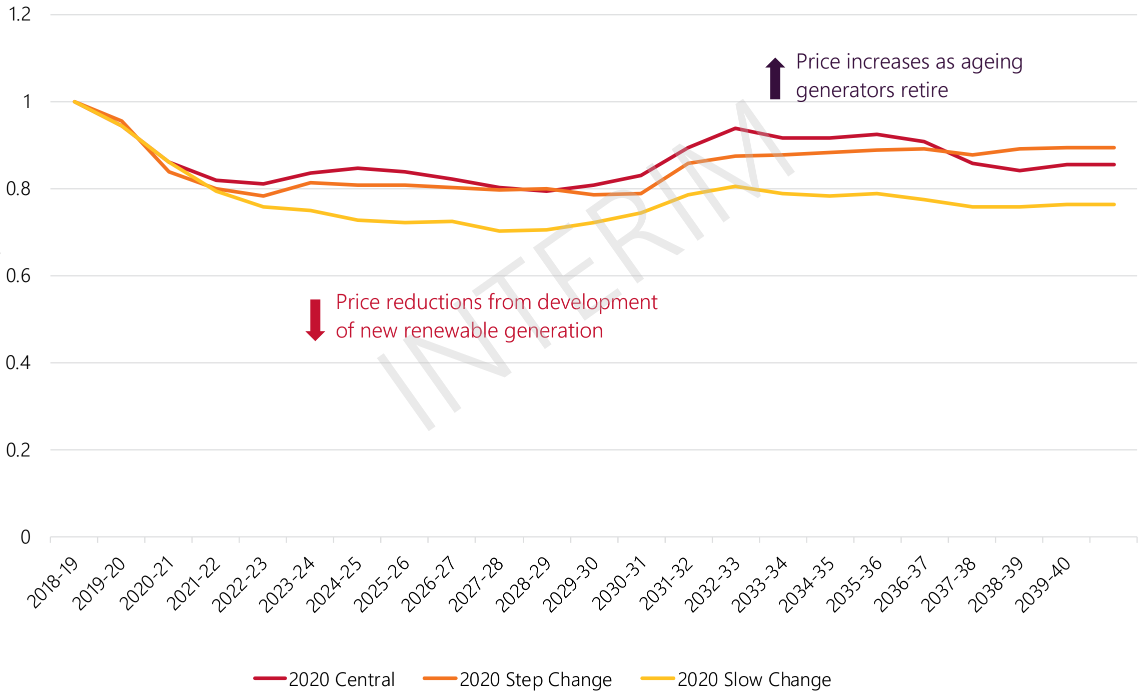
For the demand forecasts developed in 2021, AEMO will provide updated retail price indices using new information on retail price trends, and supported by updated wholesale price forecasts currently being developed for the 2021 GSOO.

AEMO 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.

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

Figure 23 Interim residential retail price index, NEM (connections weighted)



* Price weighted by the number of households.

The values applied in 2020 are proposed to apply in the proposed Draft 2021 IASR scenarios, with the Slow Growth and Diversified Technology scenarios applying the relatively low elasticity values of the 2020 Slow Change scenario (-0.01) as less capacity to increase demand (Slow Growth) and lower relative price (Diversified Technology) are expected. The Central Scenario is proposed to again apply the same settings as 2020. The Sustainable Growth and Export Superpower scenarios are proposed to apply the 2020 Step Change scenario settings. These relatively low price elasticity measures reflect the impact of investments in devices that reduce energy consumption, such as those within the energy efficiency and distributed energy resource components. With these investments, there is a lower exposure to any potential rebound in consumption associated with price reductions.

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, applying a price elasticity of demand of -0.1.

Matters for consultation

- Are there other factors (direct or indirect) that changes in energy prices may have on short- and long-term consumption patterns that need to be factored into the scenarios?
- Investments in DER and energy efficiency can assist consumers in reducing their exposure to higher energy prices to which AEMO model explicitly. Is it consistent with the scenario narratives to have a higher price elasticity of demand in scenarios where consumers do not invest as significantly in these technologies?

4.4.11 Demand-side participation

Input vintage	• Starting points updated since ISP 2020, target levels unchanged. • Forecast in May 2020. • Applied in ESOO 2020.
Source	Historical meter data analysis and DSP Information portal.
Update process	• Current levels and committed/planned changes updated after summer 2020-21 to reflect most recent information. • Target levels to be maintained.
Current accuracy	Forecast has performed as expected, as described in the 2020 Forecast Accuracy Report
Get involved	FRG: May 2021

AEMO's forecast approach considers DSP explicitly in its market modelling, meaning that demand 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 customer meter data. DSP responses are estimated for various price triggers and AEMO assumes the 50th percentile of observed historical responses is a reliable, central estimate of the likely response when the various price triggers are reached, as documented in AEMO's DSP Methodology Document[85].

For long-term planning studies like the ISP, the quantity of DSP is grown to meet a target level by the end of the outlook period. The target level is defined as the magnitude of DSP relative to maximum demand and linearly interpolated between the beginning and ends of the outlook period. It is based on a review of international literature and reports of demand response potential (primarily in the United States and Europe) indicated that the adopted (high) level of 8.5% of operational maximum demand is a reasonable upper estimate for growth in DSP.

The proposed settings for the 2021 IASR scenarios are provided in Table 18. The choice of settings has been proposed considering:

- The Sustainable Growth and Export Superpower[86] scenarios are both proposed to have high growth in DSP. These scenarios are expected to have significant growth in VRE resources, which is typically linked with increasing the capability of adjusting demand to meet the variable nature of supply.
- The Central and Slow Growth scenarios both are proposed to have moderate growth in DSP, reflecting the pursuit of cost effective ways to meet or reduce peak demand.
- The Diversified Technology scenario is proposed to have the lowest growth in DSP (maintaining the current penetration into the future) due to the potential impact of low gas prices on price volatility.

Table 18 Mapping of appliance uptake and fuel switching scenarios

Scenario	Sustainable Growth	Export Superpower	Central	Slow Growth	Diversified Technology
DSP Growth	High growth to reach 8.5% of peak demand by 2050	High growth to reach 8.5% of peak demand by 2050	Moderate growth to reach 4.25% of peak demand by 2050	Moderate growth to reach 4.25% of peak demand by 2050	No chance from current levels of DSP

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

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

For Tasmania, which is not capacity constrained and therefore less incentivised to deploy DSP solutions, the assumed growth in DSP is halved relative to mainland regions.

Matters for consultation

- Are the levels of DSP targeted across the proposed scenarios appropriate for the scenario narrative?
- Is the maximum level of 8.5% of maximum demand a reasonable target for an upper bound on the level of DSP?

4.5 Existing generator and storage assumptions

4.5.1 Generator and storage data

Input vintage	November 2020 Generation Information update
Source	Generation Information page
Update process	Updated quarterly in line with Generation Information
Get involved	The latest version of the inputs is available on AEMO's website.

AEMO's Generation Information page[87] publishes data on existing and committed generators and storage projects (size, location, capacities, seasonal ratings, auxiliary loads, full commercial use dates and expected closure years), and non-confidential information provided to AEMO on the pipeline of future potential projects. This information is updated quarterly, with the most recently available information adopted for each of AEMO's publications (and clearly identified in each publication).

4.5.2 Technical and cost parameters (existing generators and storages)

Input vintage	Technical parameters unchanged from the 2020 ISP inputs
Source	Various, see below
Update process	Subject to consultation responses and feedback.
Get involved	Draft 2021 IASR consultation: 11 December 2020 to 1 February 2021

AEMO has sourced the operating and cost parameters of existing generators and storages from several different sources, including AEMO internal studies[88]. They include:

- AEMO's Generation Information page.
- GHD, 2018-19 AEMO Costs and Technical Parameter Review.
- Aurecon, 2020-21 Cost and Technical Parameter Review.
- AEP Elical, 2020 Assessment of Ageing Coal-Fired Generation Reliability.

[87] 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.

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

- Generator surveys.

The specific parameters obtained from each of these sources is summarised in Table 19 below.

Table 19 Sources technical and cost parameters for existing generators

Source	Technical and cost parameters used in AEMO's inputs and assumptions
AEMO's Generation Information page	• Maximum capacities • Seasonal ratings (10% POE Summer, Typical Summer and Winter) • Auxiliary loads • Commissioning and retirement dates
GHD 2018-19 Costs and Technical Parameters Review	• Heat rates • Emissions factors • Maintenance rates • Fixed and variable operating and maintenance costs • Refurbishment costs • Ramp rates • Minimum up and down time • Start-up costs
Aurecon 2020 Cost and Technical Parameter Review	• Heat rate curves used for calculating complex heat rates
Generator surveys and AEP Elical	• Forced outage rates and high impact low probability (HILP) outages (Interim)
AEMO internal studies	• Complex heat rates, informed by Aurecon and GHD • Minimum stable levels • Minimum and maximum capacity factors

The draft assumptions on the parameters documented in this table are contained in the Draft 2021-22 Inputs and Assumptions Workbook. Forced outage rate assumptions are interim and will be updated through the 2021 ESOO process and will be subject to further consultation through the June FRG.

Capacity outlook models assumptions in the ISP

In long-term planning studies, AEMO applies assumptions related to operational characteristics of plant to project future investment needs. Actual limits and constraints that would apply in real-time operations will depend on a range of dynamic factors which are unreasonable to incorporate in an appropriate stochastic manner.

The relative coarseness of the capacity outlook models requires that some operational limitations are applied using simplified representations, such as minimum capacity factors, to represent technical constraints, likely gas consumption and power system security requirements. 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 due to the application of least-cost optimisation. The current view of these operational limits is described in the Draft 2021-22 Inputs and Assumptions Workbook, however these limits are an outcome of the iterative market modelling process and will be refined during the ISP.

Energy targets, including minimum and maximum capacity factors, are informed either by analysis of historical behaviours or through feedback from more detailed time-sequential modelling which applies more granular operational limitations.

Minimum stable levels for existing generators are sourced from GHD[89]. Where variances were seen between these and historical behaviours, AEMO has applied operational experience to verify or substitute those values. In the time-sequential models, minimum stable levels are applied for baseload and mid-merit generators and, for some units, minimum loads are enforced. However, in the capacity outlook models, minimum load levels are applied instead of minimum stable levels and to some baseload generators only, to manage computational complexity.

Additional properties used in time-sequential modelling in the ISP

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

- Minimum up time and down times and start-up profiles.
- Complex heat rate curves provided by Aurecon and GHD, or analysis of historical information from both the Gas Bulletin Board and AEMO's Market Management System data if necessary.
- Unit commitment optimisation and minimum stable levels, if the model granularity warrants the additional complexity. For hourly or half-hourly modelling purposes, these optimisation limits are inappropriate for many peaking plants, as we consider it inappropriate to constrain operations for an entire hour or half-hour if dispatched in the models.

Further details on the implementation of the application of these technical limitations can be found in AEMO's Market modelling methodology paper[90].

Matters for consultation

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

4.5.3 Forced outage rates

Input vintage	Updated for ESOO 2020
Source	Generator surveys and AEP Elical 2020
Update process	Forced outage rates to be updated as part of data collection process for 2021 ESOO
Get involved	FRG: June 2021

Forced outage rate collection process

Forced outage rates are a critical input for AEMO's reliability assessments and for modelling the capability of dispatchable generation capacity more generally. For the 2020 ESOO, AEMO collected information from all generators on the timing, duration, and severity of unplanned forced outages, via its annual survey process.

[89] GHD, 2018-19 AEMO Costs and Technical Parameter Review.

[90] See Section 2.4 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.

This data was used to calculate the probability of full and partial forced outages in accordance to the ESOO and Reliability Forecasting Methodology document[91].

AEMO also commissioned AEP Elical[92] to provide the forward-looking outage values for coal-fired generators, in addition to generator-supplied data sets. 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 20 below. These will be updated with the most recent year's history for use in 2021-22 publications.

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 provided in the Market Modelling Methodology Paper[93].

Table 20 Interim 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 in the 2020 ESOO for each technology are shown in Table 21 below. The long-term projections for the equivalent full forced outage rate[94] of coal-fired generation are in Figure 24.

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[95]. 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.

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

[92] 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.

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

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

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

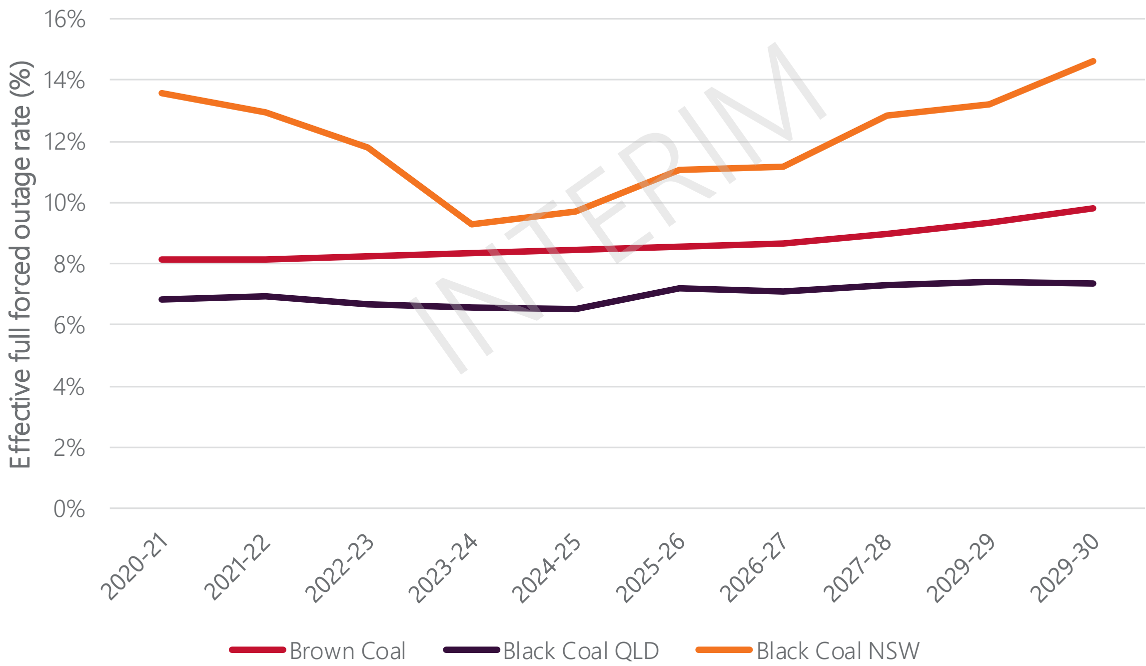
AEMO will update the forced outage trajectories for the first 10 years based on the data collection and consultation process for the 2021 ESOO. Further extrapolation of the trajectories may apply the same information developed with AEP Elical in 2020 or could be updated as part of the 2021 ESOO. Any update will be consulted on in the FRG in June 2021.

Table 21 Interim 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

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

Figure 24 Interim effective full forced outage rate projections for coal-fired generation technologies (excluding HILP)



The Draft 2021-22 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[96].

Matters for consultation

- Do you have any comment on the forced outage rate inputs and their application in AEMO's models?

4.5.4 Retirement and refurbishment

Input vintage	• Costs and refurbishment assumptions unchanged since 2020 ISP. • Retirement dates updated from November 2020 Generation Information page.
Source	• Generation Information page • GHD 2018
Update process	Expected closure years and closure dates updated as soon as practicable.
Get involved	Draft 2021 IASR consultation: 11 December 2020 to 1 February 2021

For existing generators, AEMO applies expected closure years provided by participants through AEMO's Generation Information[97] page, with allowable adjustments to these as described for the various scenarios previously. In contrast, registered closure dates, are applied consistently across all scenarios.

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.

Unlike the 2020 ISP, AEMO is proposing not to consider refurbishment opportunities to extend the life of coal plant across all scenarios. Considering the scale of investment required to refurbish the plant to extend the useful life of the asset, and the uncertainty that exists as to the impact of new developments that may encroach on the role that each coal unit may provide to generate baseload energy, AEMO considers that it is unlikely that life extensions of these deteriorating assets will eventuate, even in a Slow Growth scenario (which includes higher relative near-term growth in distributed PV systems as well).

Retirement costs by generation technology have been provided by GHD and are presented in the Draft 2021-22 Inputs and Assumptions Workbook. Retirement costs incorporate the cost of decommissioning, demolition, and site rehabilitation and repatriation, excluding battery storage technologies where disposal cost data is not known.

Matters for consultation

- Do stakeholders support AEMO's proposal to remove coal-life extensions across the scenarios (noting that the inclusion only featured in the Slow Change scenario in 2019-20)?

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[96] 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.

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

4.5.5 Hydro modelling

Input vintage	Unchanged since 2020 ISP.
Source	Inflows – hydro operators, considering insights from the Electricity Sector Climate Information (ESCI) project.
Update process	Hydro scheme inflows to be updated based on updated data received from participants when available.
Get involved	• AEMO will liaise with hydro operators directly. • AEMO will consult on climate impacts in June FRG

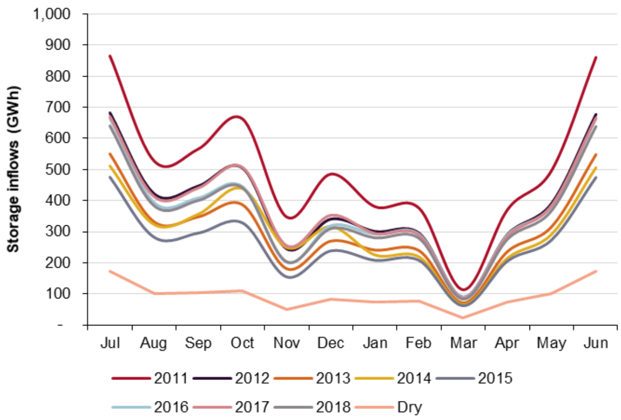
Hydro scheme inflows

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[98]. AEMO also obtains data directly from existing large-scale hydro operators. The Draft 2021-22 Inputs and Assumptions Workbook provides the variation in hydro inflows for key hydro schemes. An example of this is shown in Figure 25 below, for Snowy Hydro.

Australian-specific climate information on regional changes in long-term average rainfall over time has been estimated through close collaboration with CSIRO and the BoM as part of the Electricity Sector Climate Information (ESCI) project, sponsored by the Australian Government[99].

The impact of the temperature changes on hydro inflows is currently unchanged from those applied in the 2020 ISP. These assumptions may be updated if new climate science provides better estimates. Any updates to hydro factors, or other climate factors applicable to generator performance will be consulted on in the June 2021 FRG.

Figure 25 Hydro inflow variability across reference weather years



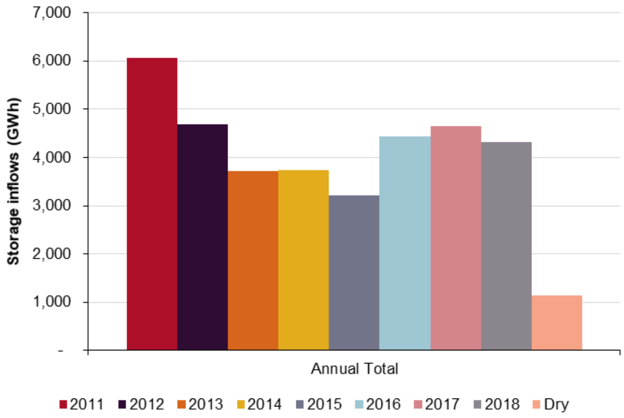


Table 22 shows some of the hydro climate factors extracted from the Draft 2021-22 Inputs and Assumptions Workbook. Mainland precipitation trends are sourced from climate change in Australia[100] with consideration for hydrological impacts as described in Potter et al[101]. The median scenario is represented by the ACCESS1-0 climate model with a 2.5 times streamflow reduction multiplier. Tasmanian streamflow trends are sourced

[98] 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.

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

[100] See www.climatechangeinaustralia.com.au.

[101] See http://www.bom.gov.au/research/projects/vicci/docs/2016/PotterEtAl2016.pdf.

from Chiew et al[102] where the median scenario is represented by the 50th percentile of the documented GCM ensemble.

Table 22 Draft median hydro climate factors, Central scenario

Region	2019-20	2029-30	2039-40	2049-50
Mainland regions	-2.3%	-6.3%	-10.2%	-14.1%
Tasmania	-2.5%	-4.1%	-5.8%	-7.4%

4.6 New entrant generator assumptions

4.6.1 New entrant generation projects included in different publications

Input vintage	November 2020 Generation Information update
Source	Generation Information page
Update process	Updated quarterly in line with Generation Information.
Get involved	The latest version of the inputs is available on AEMO's website.

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

The 2021-22 modelling will include projects classified in the Generation Information page July 2021 update (or October 2021 update in case of GSOO) as either:

- For the ESOO:
  - Committed[103] or
  - Committed* – projects under construction and well advanced to becoming committed[104].
- For the ISP and GSOO, the categories above, and also Anticipated projects[105].

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

Committed* 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[106].

[102] See https://publications.csiro.au/rpr/pub?list=SEA&pid=csiro:EP176302&sb=RECENT&expert=false&n=13&rpp=25&page=1&tr=167&q=Chiew%2C%20Francis&dr=all.

[103] 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.

[104] 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.

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

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

Anticipated projects are defined in a manner consistent with the AER's Cost Benefit Analysis Guidelines as being a project that "is in the process of meeting at least three of the five criteria for a committed project"[107].

AEMO plans to review the way it assesses whether a project is in the process of meeting commitment criteria in light of REZ policy developments and the role of Government-awarded contracts. AEMO will be consulting on this interpretation in the ISP methodology in 2021.

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

4.6.2 Candidate technology options

Input vintage	• Updated since ISP 2020. • Last update in May 2020.
Source	• CSIRO: GenCost 2020-21: Scenarios and Assumptions • Aurecon: 2020-21 Costs and Technical Parameters Review • GHD: 2018-19 Costs and Technical Parameters Review
Update process	Dependent on feedback to this Draft 2021 IASR
Get involved	Draft 2021 IASR consultation: 11 December 2020 to 1 February 2021

For the 2021-22 capacity expansion planning, a filtered list of technologies – selected from those provided by Aurecon and CSIRO (GenCost) – will be considered, based on technology maturity, resource availability, and energy policy settings. Table 23 below presents the filtered list of technologies proposed to be considered in the 2021-22 forecasting publications.

Table 23 List of candidate generation and storage technology options

List of technologies to be available in the 2021-22 ISP	Commentary
Advanced ultra supercritical PC – black coal with CCS	
Advanced ultra supercritical PC – black coal without CCS	Given the market need for flexible plant to firm low-cost renewable generation, new coal-fired generation would be highly unlikely in any scenario with emissions abatement objectives, particularly given the long-life nature of any new coal investment.
CCGT – with CCS	
CCGT – without CCS	
OCGT – without CCS, Small unit size	
OCGT – without CCS, Large unit size	Larger OCGT have been added based on stakeholder feedback from the 2020 ISP.
Reciprocating internal combustion engines	
Battery storage	AEMO includes storage sizes from 1-8 hours in its models. No geographical or geological limits will apply to available battery capacity given its small land footprint.

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

List of technologies to be available in the 2021-22 ISP	Commentary
Solar PV – single axis tracking	
Solar thermal central receiver with storage (8hr)	
Wind – onshore	
Wind – offshore	Victorian offshore locations (off the Gippsland REZ) are included, given expanded data sets obtained from DNV-GL.
Biomass – electricity only	
Pumped hydro energy storage (PHES)	AEMO includes 6-hour, 12-hour, 24-hour, and 48-hour variants of PHES.

AEMO proposes to exclude the following technologies from consideration as new entrants to keep problem size computationally manageable:

- New brown coal generation (with or without CCS) has been excluded given no such projects are publicly announced in the NEM and there are lower cost dispatchable alternatives that offer greater system flexibility and are more environmentally friendly. Investment risks for new brown coal developers are therefore assumed too high to be considered as a commercially viable alternative in forecasting and planning analysis.
- Nuclear generation – nuclear generation is excluded, as currently Section 140A of the *Environment Protection and Biodiversity Conservation Act 1999*[108] prohibits the development of nuclear installations.
- Geothermal technologies – geothermal technologies are considered too costly and too distant from existing transmission networks to be considered a bulk generation technology option in any REZ, nor have they been successfully commercialised in Australia. There may be targeted applications of geothermal technologies suitable for the NEM, but they are currently not included in ISP modelling.
- Solar PV fixed flat plate (FFP) and dual-axis tracking (DAT) technologies – AEMO acknowledges that the best solar configuration may vary for each individual project. Given current cost assumptions, single-axis tracking (SAT) generally presents a greater value solution in AEMO's Capacity Outlook models. Presently, SAT projects also provide more proposed capacity than DAT and FFP projects[109]. Given this 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.
- Tidal/wave technologies – this is not sufficiently advanced or economic to be included in the modelling.
- Hybrid technologies will be considered within the ISP Methodology, given the materiality of inclusion and the complexity of inclusion.

Matters for consultation

- Is AEMO's proposed list of candidate technologies reasonable? If not, what should be included/excluded?

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

[109] Based on November 2020 NEM Generation Information, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

4.6.3 Technology build costs

Input vintage	• Updated since ISP 2020. • Last update in December 2020.
Source	• CSIRO: GenCost 2020-21 Consultation draft • Aurecon: 2020 Costs and Technical Parameters Review • Entura: 2018 Pumped Hydro Cost Modelling
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR.
Get involved	• GenCost process. • Draft 2021 IASR consultation: 11 December 2020 to 1 February 2021

Capital cost trajectories

To capture the most current pricing for a more reliable future cost and performance estimation process, AEMO engaged Aurecon to support the AEMO/CSIRO partnership in developing the GenCost technology cost review by producing current technology costs and performance data. Where possible, AEMO ensures that the inputs to these processes (for example, discount rates) are consistent with AEMO's assumptions.

CSIRO GALLM build cost projections are a function of global and local technology deployment. The 2020 December GALLM build cost projections are given for three scenarios ("High VRE", "Central" and "Diverse Technology"). AEMO maps the forecasting and planning scenarios to these technology cost scenarios, as shown in Table 24 below. These scenarios are described in greater detail in CSIRO's GenCost Consultation draft.

As CSIRO's High VRE scenario is linked with strong decarbonisation ambitions and high levels of VRE development globally it has been applied to the Sustainable Growth and Export Superpower scenarios. CSIRO's Central scenario does not significantly expand renewable targets and has a more muted decarbonisation ambition and has therefore been applied in the Slow Growth and the Central scenarios. CSIRO's Diverse Technology scenario pairs most naturally with the Diversified Technology scenario as they both share narrative elements around greater investment in alternative low emissions technologies.

Table 24 Mapping AEMO scenario themes to the GenCost scenarios

AEMO Scenario	GenCost Scenario
Central	Central
Sustainable Growth	High VRE
Export Superpower	High VRE
Slow Growth	Central
Diversified Technology	Diverse Technology

Figure 26 and Figure 27 present CSIRO GALLM build costs projections[110] for selected technologies chosen for construction in Melbourne for the Central scenario, excluding connection costs.

[110] CSIRO, 2020, GenCost 2020-21 report.

Figure 26 Build cost trajectories forecast by GenCost, Central scenario, wind and solar

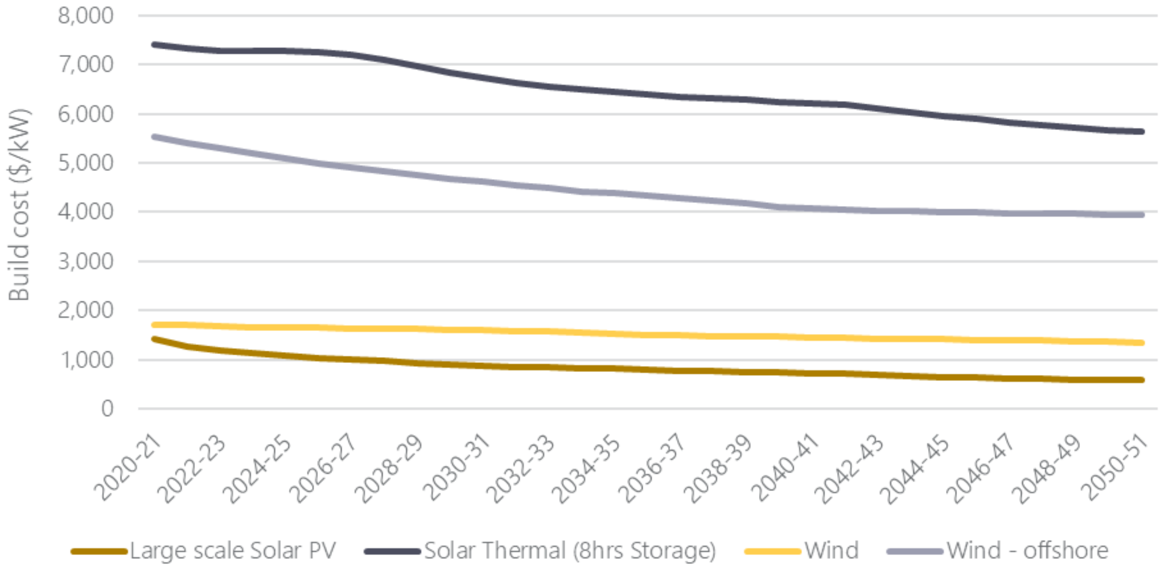
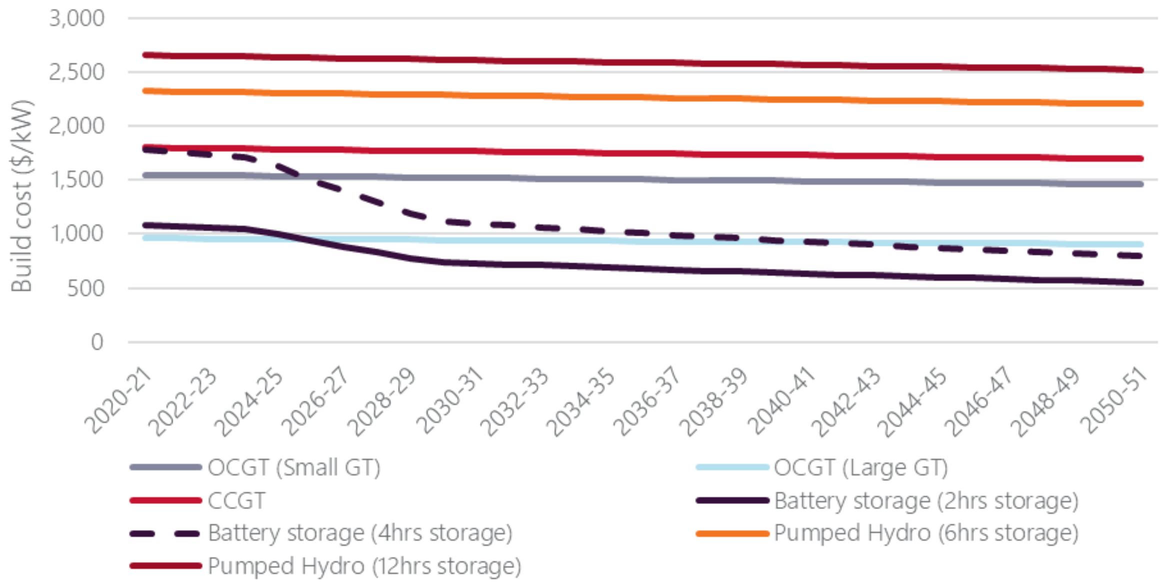


Figure 27 Build cost trajectories forecast by GenCost, Central scenario, gas and selected storage



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 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.

Matters for consultation

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

Locational cost factors

Input vintage	Last update in September 2018
Source	GHD: 2018-19 Costs and Technical Parameters Review
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR.
Get involved	Draft 2021 IASR consultation: 11 December 2020 to 1 February 2021

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.

In 2018 GHD developed three cost groupings – low, medium, and high – mapped across the NEM regions to summarise locational multiplicative scalars that should apply between developments of equivalent type but across different locations.

These are presented in Figure 28 with the location of REZs overlaid.

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 scalar to the respective generation development costs. These scalars are derived from regional development cost weightings by cost component, provided in Table 25, and technology cost component breakdowns, which are presented in Table 26.

The Draft 2021-22 Inputs and Assumptions Workbook provides additional details of these cost factors, plus provides the resulting technology, regional cost adjustment factors.

Figure 28 Locational cost map

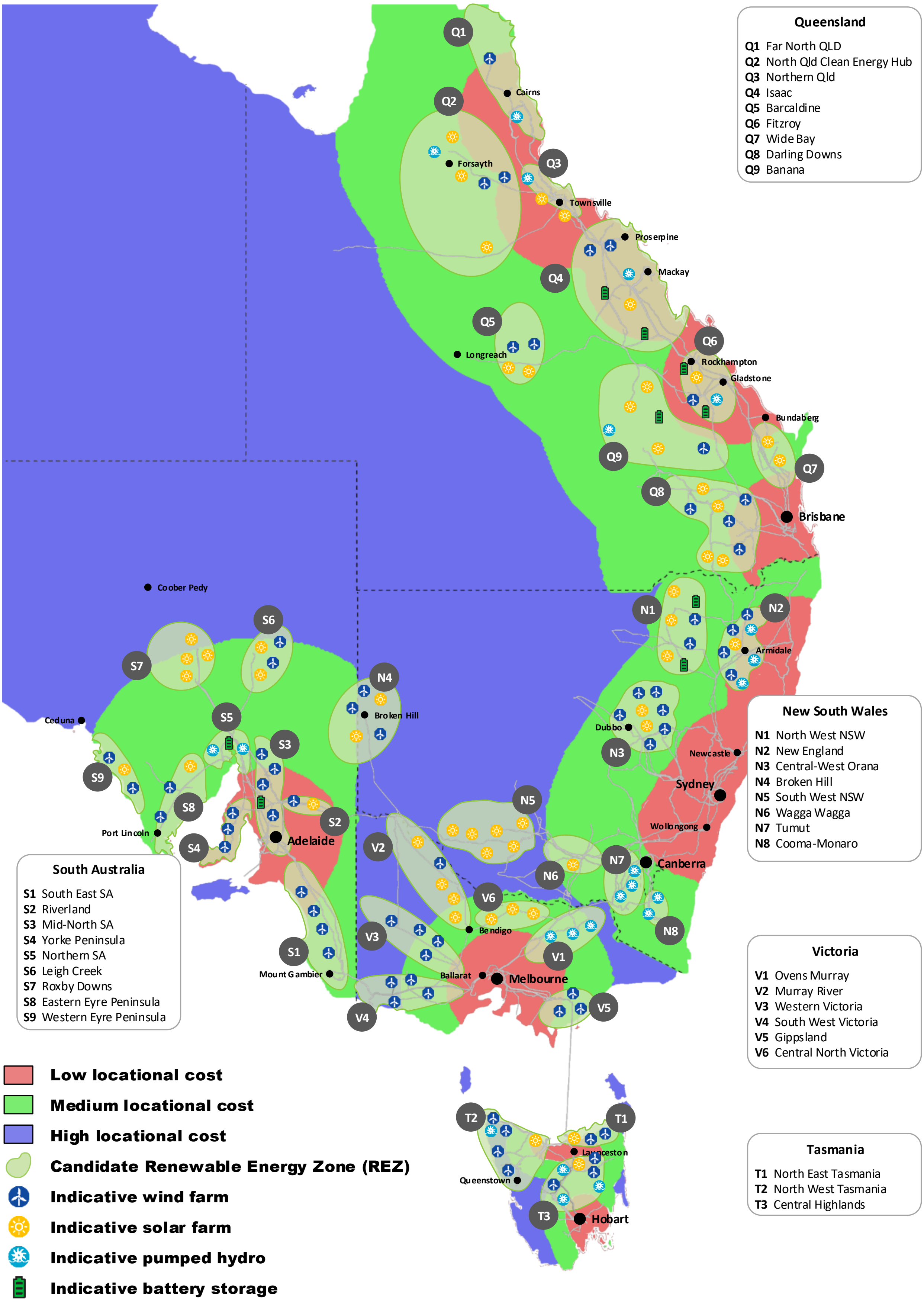


Table 25 NEM locational cost factors

Region	Grouping	Equipment costs	Fuel connection costs	Cost of land and development	Installation costs	O&M costs
Victoria	Low	1.00	1.00	1.00	1.00	1.00
	Medium	1.03	1.03	1.00	1.03	1.03
	High	1.05	1.05	1.00	1.05	1.05
Queensland	Low	1.00	1.05	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 26 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 (2hrs storage)	71%	0%	6%	23%
Battery storage (4hrs 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%

Matters for consultation

- Do you agree with AEMO's proposal to use the same regional cost factors used in the 2020 ISP for its 2021-22 modelling? If not, please provide suggestions for improvements or alternative data sources.
- Are there other social licence or competing land-use cost considerations that should be factored into these regional cost factors, or that would require use of more granular sub-regions?

4.6.4 Technical and other cost parameters (new entrants)

Input vintage	• Updated since ISP 2020. • Last update in May 2020.
Source	• Aurecon: 2020 Costs and Technical Parameters Review • GHD: 2018-19 Costs and Technical Parameters Review
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR.
Get involved	Draft 2021 IASR consultation: 11 December 2020 to 1 February 2021

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

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

These parameters are updated annually to reflect the current trends and estimates of future cost and performance data of new technologies. For 2021-22 modelling, AEMO has updated these parameters where they have been provided by Aurecon as part of the GenCost project. For any data not available from this source, AEMO has used data as per the 2020 ISP.

For new entrant 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 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.

Matters for consultation

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

4.6.5 Storage modelling

Input vintage	• Updated since ISP 2020. • Last update in May 2020.
Source	• Aurecon: 2020-21 Costs and Technical Parameters Review • CSIRO: GenCost 2020-21: Scenarios and Assumptions • Entura: 2018 Pumped Hydro Cost Modelling
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR.
Get involved	Draft 2021 IASR consultation: 11 December 2020 to 1 February 2021

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

AEMO has captured the location of storage developments considering the regional build limits presented in the Draft 2021-22 Inputs and Assumptions Workbook, and for pumped hydro technologies, the sub-regional limits within the 2018 Entura report, which AEMO has modified to reflect the latest information and generator interest while still observing the regional limits. Exact storage locations have been 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.

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[111], and adjusted as considered appropriate from feedback received after the release of the draft ISP in 2019. Based on the feedback received, AEMO applied a 50% increase to pumped hydro cost estimates provided by Entura for the 2020 ISP.

AEMO is proposing to use the same cost assumptions for pumped hydro costs in the 2022 ISP.

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 2020-21 GenCost report. These are provided in detail in the Draft 2021-22 Inputs and Assumptions Workbook.

For clarification, the capital cost increases assumed for PHES projects only apply to future uncommitted PHES projects. This does not apply to the Snowy 2.0 project, as it is considered a committed project and is therefore included in all scenarios.

As with other new entrant technologies, locational cost factors have been applied to PHES options, to distinguish those regions with natural resource and cost advantages. These values are also sourced from the same Entura report.

Tasmania, for example, has been assumed to have materially lower development costs for PHES than the mainland, for most PHES options. As shown in Table 27, Tasmanian PHES facilities are at least approximately

[111] 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.

24% lower cost than Victorian alternatives, and the cost advantages of pumped hydro in Tasmania increases for deeper storage sizes.

Table 27 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 1-hour, 2-hour, 4-hour, and 8 hour duration depths are available for 2021-22 modelling, based on data provided by Aurecon. Battery round-trip efficiency is assumed to be 84%, 84%, 85% and 83% respectively for 1-hour, 2-hour, 4-hour, and 8-hour duration depths. Battery storage degradation, which Aurecon indicates is 2.8% annually is not able to be modelled explicitly due to computational complexity (particularly in capacity outlook models). AEMO proposes that to account for this degradation, the storage capacity of all battery storage will be reduced by 12% which is an estimate of the average storage capacity over the battery life.

Like all technologies, a battery will retire at the end of its technical life, which is set to 20 years for batteries. This assumes a replacement of the battery component after 10 years, which represents a significant proportion of the total cost (approximately 60 – 85%). To incorporate this effect, AEMO is proposing to set the economic life to 20-years, and to include the discounted additional cost of replacement into the up-front cost such that all costs over the 20-year life are accounted for. The mid-life replacement cost will reflect the +10 years capital cost of the battery component to be installed, as per the battery build cost trajectory for each scenario.

AEMO does not have appropriate data sets for battery disposal costs, and therefore these costs are not considered. 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.

Matters for consultation

- As Entura pumped hydro cost estimates are location- and resource limit-specific, should AEMO modelling consider an expansion of PHES limits at higher cost?
- Are the cost assumptions for pumped hydro reasonable?
- Is the proposed approach to modelling battery storage technologies appropriate, particularly with regards to the end-of-life assumptions?
- Is the proposed approach to accounting for storage degradation appropriate, or would an alternative approach be more effective in representing battery storage degradation?

4.7 Fuel assumptions

4.7.1 Fuel prices

Gas prices

Input vintage	• Updated since ISP 2020. • Last update in December 2020.
Source	Lewis Grey Advisory
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR.
Get involved	Draft 2021 IASR consultation: 11 December 2020 to 1 February 2021

AEMO has sourced natural gas prices from external consultant Lewis Grey Advisory. These prices were recently updated and finalised for the 2021 GSOO.

The methodology is based on a game theory model that simulates competitive pricing outcomes suitable to understand contract pricing[112]. Gas production costs, reserves, infrastructure and pipelines are fundamental inputs into this model that also considers international liquid natural gas prices, oil prices, and measures of the domestic economy. This methodology was consulted on at FRG meeting 35 in September 2020[113].

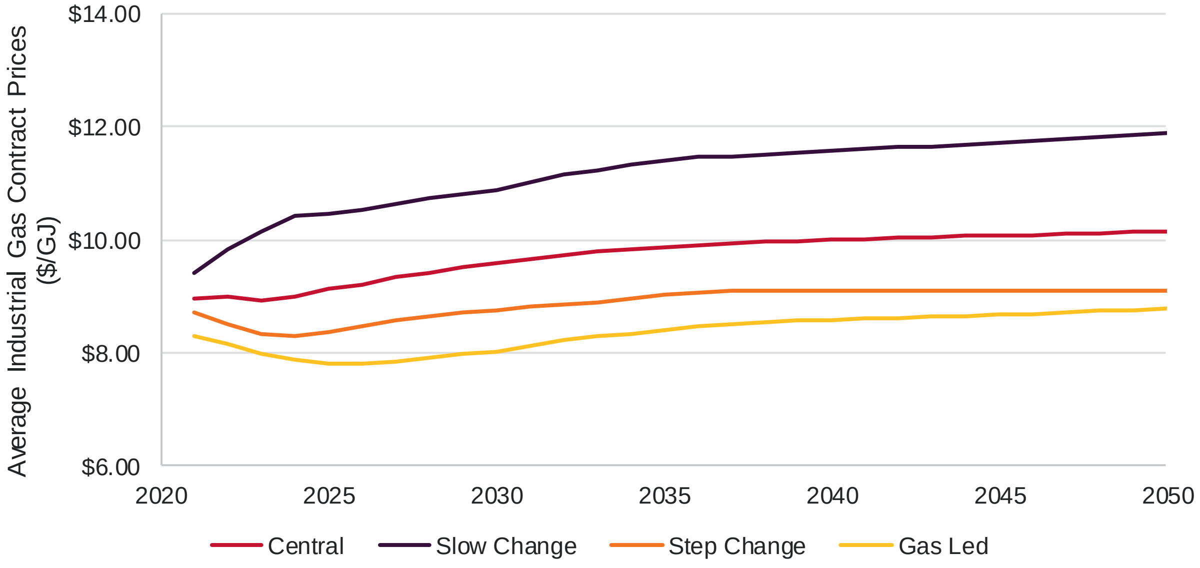
Four scenarios were forecast, based on assumptions about international pricing, Australian infrastructure, fields and the local level of competition. No explicit reservation policy was considered, although the "Gas Led" scenario did assume increased competition in addition to opening new fields and new pipelines.

A comparison of average industrial prices across the four major demand centres (excluding LNG export facilities) is shown in Figure 29.

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

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

Figure 29 Average industrial gas price forecast for the major eastern demand centres (averaged across Brisbane, Sydney, Adelaide, Melbourne)



The proposed mapping of the prices to the proposed scenarios outlined in this Draft 2021 IASR is shown in Table 28. These price mappings are selected because:

- Lower gas demand in the Export Superpower and Sustainable Growth, due to decarbonisation objectives, should loosen the tightness of supply and demand, lowering prices.
- Lower gas developments and slower VRE development in the Slow Growth scenario should tighten the supply and demand balance, increasing prices.
- Assumed developments and policy support/intervention in the gas market enables the lowest price in the Diversified Technology scenario.

Table 28 Mapping of the gas prices trajectories to the proposed scenarios

	Gas price scenario to apply	Relative price comparison
Central	Central	Mid price
Export Superpower	Step Change	Low price
Sustainable Growth	Step Change	Low price
Slow Growth	Slow Change	High price
Diversified Technology	Gas Led	Lowest price

Coal prices

Input vintage	• Updated since ISP 2020. • Last update in December 2020
Source	Wood Mackenzie
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR.
Get involved	Draft 2021 IASR consultation: 11 December 2020 to 1 February 2021

AEMO is currently engaging with external consultant Wood Mackenzie to provide updated coal price forecasts. These forecasts are shown in Figure 30 and Figure 31, and are provided in greater detail for all scenarios in the accompanying Draft 2021-22 Inputs and Assumptions Workbook.

Figure 30 Coal price forecast for existing coal-fired power stations in the Central scenario

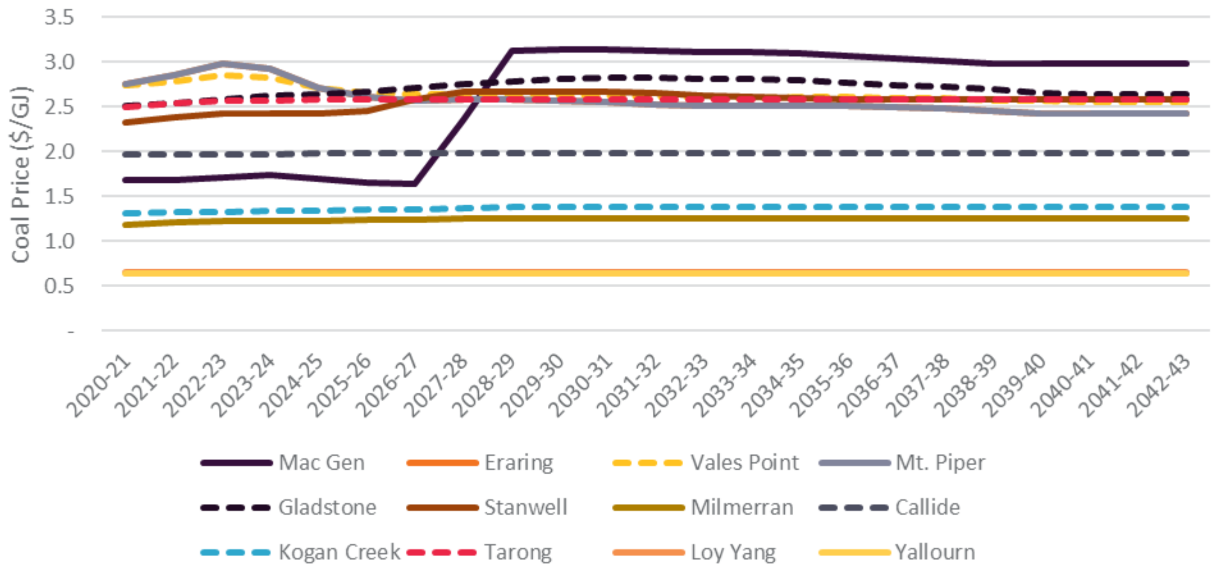
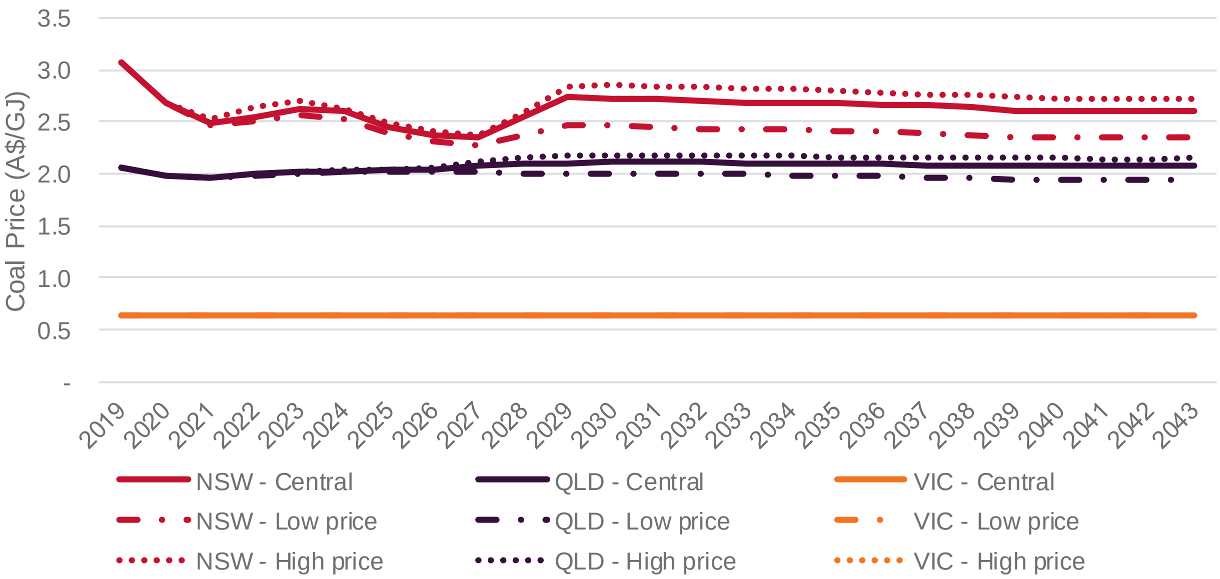


Figure 31 Region-averaged coal price forecast for existing coal-fired power stations across all scenarios



Three coal price scenarios were selected to align with plausible global coal demand with varying renewable energy uptake and global temperature pathways. The proposed mapping of the prices to the new scenarios is shown in Table 29.

Table 29 Mapping of the coal prices to the new scenarios

Scenario	Coal price scenario to apply
Central	Central
Export Superpower	Low
Sustainable Growth	Low
Slow Growth	High
Diversified Technology	Central

Biomass and liquid fuel prices

Input vintage	Unchanged from 2020 ISP.
Source	• Biomass prices – AEMO assumption • Liquid fuel prices – ACIL Allen 2014
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR.
Get involved	Draft 2021 IASR consultation: 11 December 2020 to 1 February 2021

The price trajectory for liquid fuels has been sourced from ACIL Allen[114], while biomass prices were assumed static and based on an AEMO assumption in the absence of better information. To date, AEMO has not received any feedback on the biomass price assumption in any of its consultations.

Matters for consultation

- Do you have any feedback on the assumed coal and gas price trajectories?
- Do you consider the continued use of biomass and liquid fuel prices from the 2020 ISP appropriate, updated for CPI? If not, do you have more specific and up-to-date data on these prices?

4.7.2 Renewable resources

Input vintage	Updated for 2020 ESOO.
Source	• DNV-GL • Solcast • Bureau of Meteorology • AEMO SCADA data
Update process	To be updated to reflect the 2020-21 reference year
Get involved	N/A

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

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

- Wind speed reanalysis data at hub heights of 100 m and 150 m from DNV-GL.
- Solar irradiance data from Solcast.
- Temperature and ground-level wind speed data from the BoM.
- Historical generation and weather measurements from SCADA data provided by participants.

These are updated annually to include the most recent reference years used in the modelling, based on the inputs described above. Further detail on how AEMO estimates half-hourly renewable generation profiles based on weather inputs is provided in the Market Modelling Methodology Paper[115].

4.8 Financial parameters

4.8.1 Discount rate

Input vintage	Updated from 2020 ISP value, originally sourced from Energy Networks Australia.
Source	• Energy Networks Australia: RIT-T handbook • Updated cost of debt.
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR.
Get involved	Draft 2021 IASR consultation: 11 December 2020 to 1 February 2021

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

In the 2020 ISP, AEMO applied a discount rate of 5.90% (real, pre-tax) for all financial discounting calculations, consistent with the RIT-T guidelines and sourced from Energy Networks Australia's RIT-T handbook[116]. AEMO has applied the same methodology in calculating a proposed update to the discount rate, although has changed a number of parameters to reflect current settings, updating the risk-free rate, forecasting inflation and cost of debt to reflect the values provided in the AER's December 2020 Rate of return Annual Update[117].

Holding other parameters constant, this yields a real, pre-tax discount rate of 4.8%. AEMO is seeking feedback on the appropriateness of this rate.

The Slow Growth scenario's settings are associated with lesser economic stimulation, lesser returns on equities, and therefore greater tolerance for lower margins on investments. AEMO proposes to use a lower discount rate of 3.8% as a simple way to account for these issues in the decision-making process.

AEMO adopts this discount rate as the Weighted Average Cost of Capital (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, and may introduce bias from an otherwise technology-neutral approach.

[115] 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.

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

[117] At https://www.aer.gov.au/system/files/AER%20-%20Rate%20of%20return%20annual%20update%20-%202%20December%202020%20FINAL%28117 39206.2%29.pdf.

Matters for consultation

- Do you have specific feedback and data on alternative sources for WACC and discount rate?
- Is the proposed approach to applying a lower discount rate in the Slow Growth scenario appropriate?

4.8.2 Value of customer reliability

Input vintage	Unchanged from 2020 ISP, using AER Values of Customer Reliability from December 2019.
Source	AER: 2019 Values of Customer Reliability Review
Update process	AEMO is required to use the AER's most recent VCRs at the time of publishing the ISP timetable
Get involved	N/A

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

In accordance with the AER's Cost Benefit Analysis Guidelines, AEMO is required to use the AER's most recent VCRs at the time of publishing the ISP Timetable. The AER released its final report on its review of VCRs in December 2019[118], which represents the most recent calculation as of October 2020 when the ISP Timetable was published[119].

For cost-benefit analysis in the 2022 ISP, AEMO is proposing to use the residential state VCRs provided in the AER's report, which are set out in Table 30 below. Residential VCR is proposed as it represents the most relevant VCR for load associated with unplanned electricity outages and is consistent with what ENA has suggested for non-ISP RIT-Ts in its RIT-T Economic Assessment Handbook[120].

Table 30 AER Values of Customer Reliability by state (real 2020 $)

Region	VCR ($ / MWh)
New South Wales	25,760
Victoria	21,355
Queensland	23,677
South Australia	30,204
Tasmania	16,901

Matters for consultation

- Is the proposed application of volume-weighted regional VCRs appropriate?

[118] AER Values of Customer Reliability Review, December 2019, at https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf.

[119] AEMO. 2022 ISP Timetable, available at https://www.aemo.com.au/-/media/files/major-publications/isp/2022/2022-isp-timetable.pdf.

[120] At https://www.energynetworks.com.au/resources/fact-sheets/ena-rit-t-handbook-2020/.

4.9 Renewable energy zones

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

- 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.

REZ candidates were initially developed in consultation with stakeholders for the 2018 ISP and used as inputs to the ISP model. To connect renewable projects beyond the current transmission capacity, additional transmission infrastructure will be required (for example, increasing thermal capacity, system strength, and developing robust control schemes). After the 2018 ISP, the REZ candidates were further refined as outlined in the 2020 ISP. AEMO now proposes another iteration of refinements to the candidate REZs.

This section describes the parameters around REZ for further refinement for the 2022 ISP. These parameters are:

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

4.9.1 REZ geographic boundaries

Input vintage	Updated since 2020 ISP to include new Banana REZ (Q9), removal of the Southern NSW Tablelands candidate REZ, redefined Wagga Wagga REZ (N6) boundaries and renaming of T3 REZ.
Source	AEMO – based on 2018 DNV-GL report, ISP workshops and written feedback to 2018 ISP and 2020 ISP.
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR.
Get involved	Draft 2021 IASR consultation: 11 December 2020 to 1 February 2021

REZ candidates are based on geographic definitions that are indications of where new renewable energy generation can be grouped to best utilise resources. These were initially developed through consultation to the 2018 and 2020 ISP. The process for identification of REZs is described in the ISP itself[121].

Geographic Information Systems (GIS) data

GIS data defining the candidate REZ boundaries is available on the 2022 ISP website[122]. When accessing this data, please note:

- Only candidate REZ boundaries have been provided, not any GPS data for assets owned by third parties (for example, generation and network data).

[121] AEMO. 2020 ISP Appendix 5, at https://www.aemo.com.au/-/media/files/major-publications/isp/2020/appendix--5.pdf?la=en.

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

- The GIS data for these candidate REZs is approximate in nature. The polygons were derived by replicating the candidate REZ illustration (see Figure 32).
- As the REZ polygons are approximate in nature, they should not be used to determine whether a project is within or outside of a candidate REZ.

Candidate REZ identification

AEMO engaged consultants DNV-GL to provide information on the resource quality for potential REZs in the 2018 ISP[123]. The wind resource quality assessment was based on mesoscale wind flow modelling at a height of 150 m above ground level (typical wind turbine height). Solar resource quality was assessed using Global Horizontal Irradiance (GHI) and Direct Normal Irradiance (DNI) data from the BoM. The work undertaken for the ISP is not intended in any way to replace any site-specific assessment of potential wind and solar farm sites by developers.

These 10 development criteria were used to identify candidate REZs:

- Wind resource – a measure of high wind speeds (above 6 m/s).
- Solar resource – a measure of high solar irradiation (above 1,600 kW/m^2).
- Demand matching – the degree to which the local resources correlate with demand.
- Electrical network – the distance to the nearest transmission line.
- Cadastral parcel density – an estimate of the average property size.
- Land cover – a measure of the vegetation, waterbodies, and urbanisation of areas.
- Roads – the distance to the nearest road.
- Terrain complexity – a measure of terrain slope.
- Population density – the population within the area.
- Protected areas – exclusion areas where development is restricted.

Using the resource quality and the development criteria together with feedback received throughout the 2020 ISP consultation, AEMO proposes 35 candidate REZs for inclusion in the 2022 ISP.

Proposed changes since the 2020 ISP

Based on AEMO analysis and recent feedback from existing and intending TNSPs, the following changes to the 2020 ISP REZ zones have been proposed:

- N4 (Southern NSW Tablelands) to be removed based on strong feedback of unsuitability of this area for REZ development. This REZ was not identified as part of the optimal development path in the 2020 ISP.
- N6 (Wagga Wagga) land area to be shifted to include land to the west of Wagga Wagga, and not the south, to better reflect land use availability.
- T3 to be renamed Central Highlands, and the REZ boundary reduced to exclude coastal areas on the east coast of Tasmania.
- T1 (North East Tasmania) and T3 (Central Highlands) to have increased solar resource limits due to developer interest and review of resource quality in these REZs.
- A new candidate zone in the vicinity of the Gladstone area (Q9 – Banana) to be added to assess the potential benefits of new zones near to a potential hydrogen port.
- The New South Wales Electricity Infrastructure Roadmap (see Section 4.1) proposes two new REZs named “Hunter-Central Coast” and “Illawarra”. AEMO will continue to engage with the New South Wales Government in the coming months to determine appropriate modelling information for these REZs.

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

AEMO intends to provide this information for consultation in a Draft Transmission Cost report in May 2021 (see Section 4.11.6).

Modelling renewable energy without REZs

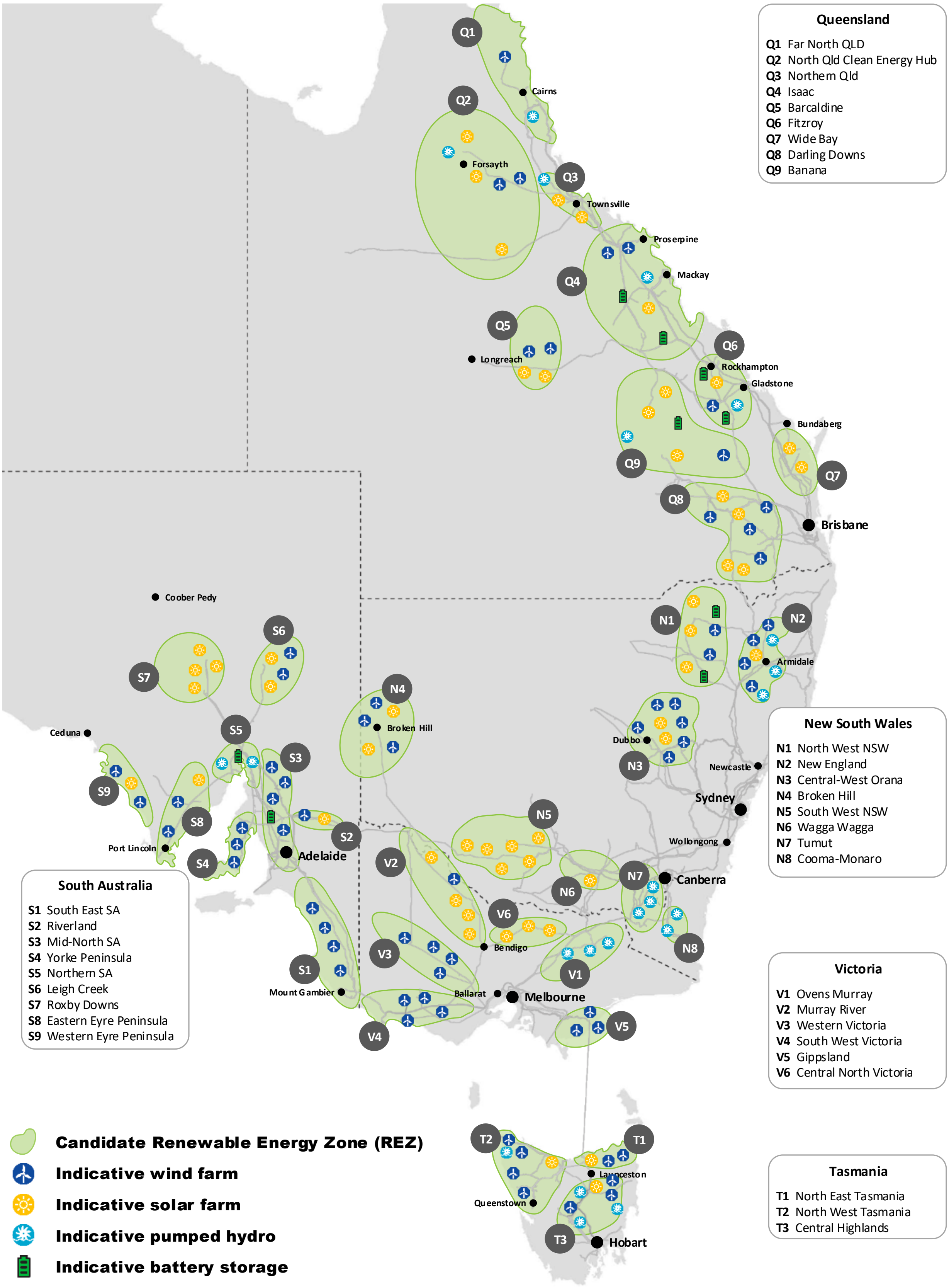
When determining the economic benefits of a development path, AEMO must compare system costs against a counter-factual where no transmission is built. In this counter-factual, transmission to connect REZs will generally not be allowed. To conduct this analysis, it will become necessary to model renewable generation connecting to areas with low quality resources. This process will be subject to consultation through the ISP Methodology.

Proposed candidate REZ geographic boundaries

Figure 32 shows the geographic locations of the Draft 2021 IASR REZ candidates as proposed. Generation symbols represent resource availability, and do not necessarily reflect locations of actual projects.

AEMO welcomes feedback on the REZ geographic boundaries/development criteria to better inform inputs to the ISP.

Figure 32 Renewable Energy Zone map – with proposed changes from 2020 ISP



† The New South Wales Electricity Infrastructure Roadmap (see section 4.1) proposes two new REZs named “Hunter-Central Coast” and “Illawarra”. AEMO will continue to engage with the New South Wales Government in the coming months to determine appropriate modelling information for these REZs.

Matters for consultation

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

Implications on REZ definitions for the Export Superpower scenario

Significant generation investment will be required under a hydrogen export scenario to meet the projected increase in electricity demand. This will challenge the existing candidate REZs, and it is possible that further refinements will be needed to candidate REZ areas. As an example, a new REZ has been defined near to the Gladstone area in this Draft 2021 IASR (Q9 – Banana) as this area may provide additional resources that may be advantageous to complement electrolyser loads.

In this scenario, there will be a need to supply power from REZs to new loads for the production of Hydrogen. The proposed approach to connecting REZs with potential hydrogen ports is outlined in Section 4.14.

Matters for consultation

- Do you have specific feedback on whether REZ definitions should change further in the Export Superpower scenario?

4.9.2 REZ resource limits

Input vintage	• Updated since 2020 ISP to account for committed generation as of November 2020. • New penalty factor to allow expansion of land use and REZ resource limits.
Source	AEMO. Resource limits were derived based on 2018 DNV-GL report, ISP workshops and written feedback to the 2018 ISP and the 2020 ISP.
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR.
Get involved	Draft 2021 IASR consultation: 11 December 2020 to 1 February 2021

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

Wind generation limits

Maximum REZ wind generation resource limits have initially been calculated based on a DNV-GL estimate of:

- Typical wind generation land area requirements.
- Land available that has a resource quality of high (in the top 10% of sites assessed), and medium (in the top 30% of sites assessed, excluding high quality sites).
- An assumption that only 20% of this land area will be able to be utilised for wind generation.

For the 2020 ISP these initial resource limits were adjusted to incorporate input from TNSPs, changes to REZ geographic boundaries, and increased connection interest, and to include existing and committed generation in each REZ.

Updated resource limits are now shown in Figure 33 and include the latest updates[124] to the committed and anticipated generation within each REZ. The resource limits are further detailed in the Draft 2021-22 Inputs and Assumptions Workbook.

The ISP Methodology will further detail the process and data behind these resource limits for further consultation prior to finalising the 2021 IASR for use in the 2022 ISP.

Solar PV plus solar thermal limits (MW)

Maximum REZ solar generation resource limits (both CST and PV) have initially been calculated based on:

- Typical land area requirements for solar PV.
- An assumed 0.25% of the approximate land area of the REZs. This allocation is significantly lower than wind availability, as solar farms have a much larger impact on alternative land use than wind farms, which require reasonable distance between wind turbines.

For the 2020 ISP these initial resource limits were adjusted to include input from TNSPs, changes to REZ geographic boundaries, and increased connection interest, and to include existing and committed generation in each REZ.

Updated resource limits are now shown in Figure 33 and include the latest updates to the committed and anticipated generation within each REZ. The resource limits are further detailed in the Draft 2021-22 Inputs and Assumptions Workbook.

The ISP Methodology document will further detail the process and data behind these limits for further consultation prior to finalising the 2021 IASR for use in the 2022 ISP.

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

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

To assess the outcomes if REZ resource limits are allowed to increase, but still take into account the likely increase in land costs or difficulties in obtaining land, AEMO proposes applying an additional land use penalty factor of $0.25 million/MW to all new VRE build costs in a REZs, which applies only if generation is required above the original REZ total resource limits.

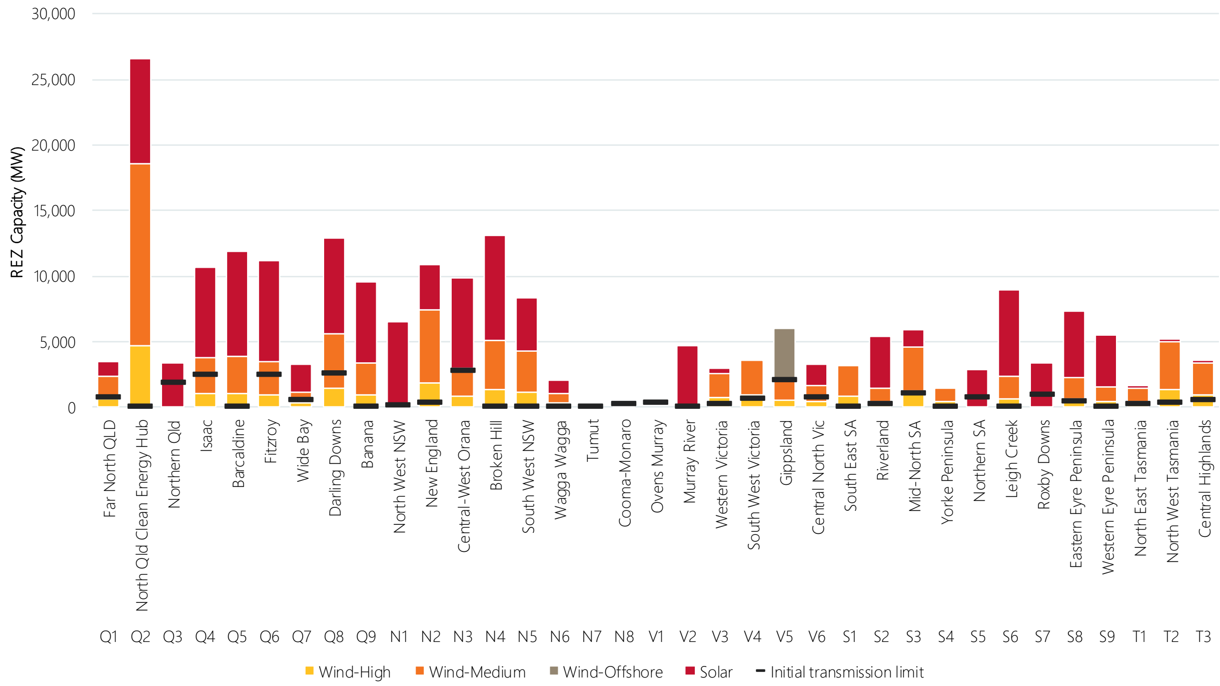
The additional REZ land use penalty factor is most likely to be utilised for the Export Superpower scenario, although it will be applied consistently to all studied scenarios. The required increase in REZ capacity to support the Export Superpower scenario is expected to expand the renewable generation footprint significantly. By using the REZ land-use penalty factor, AEMO can model a staged increase in land costs, reflecting more complicated arrangements required for planning approvals and engagement with community and traditional landowners as more renewable generation goes into a REZ.

It is vital that developers and TNSPs identify key stakeholders and commence engagement on land and access as early as possible for AEMO's assessments of future REZ potential. This includes engagement with communities, title holders, and traditional owners. Early indications of sensitivities in proposed future REZ areas will assist in the assessment of potential expansion opportunities or limits, thereby improving the projections of future potential in the ISP candidate paths.

An overview of the REZ resource limits, as well as the respective REZ transmission limited total build amounts are also shown in Figure 33. The REZ transmission limits are further discussed in Section 4.9.3, and detailed in the Draft 2021-22 Inputs and Assumptions Workbook.

[124] AEMO. Committed generation information, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2020/nem-generation-information-november-2020.xlsx?la=en.

Figure 33 REZ resource and transmission limits



Pumped hydro energy storage

Pumped hydro regional build limits are based on estimates detailed by Entura[125]. The Entura report provides a sub-regional breakdown of these limits, which AEMO has adjusted in some regions considering proposed projects across NEM regions. These have been applied as regional build limits in the capacity outlook market models, splitting capacities into depth of storages (6-hr, 12-hr, 24-hr, 48-hr). To minimise transmission build, the time-sequential phase of the 2020 ISP allocated pumped hydro to specific locations within the region while observing these limits, considering the locations of generator interest.

Proposed pumped hydro regional limits are shown in Table 31.

Table 31 Pumped hydro regional limits

Region	6 hour storage	12 hour storage	24 hour storage	48 hour storage
New South Wales	7,000†			
Queensland	1,800	1,500	1,100	500
South Australia	1,130	452	452	0
Tasmania	966	600	1,200	371
Victoria	1,200	1,200	700	500

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

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

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

- New South Wales pump hydro limits are based on 24 energy projects shortlisted for potential development as part of the New South Wales Government Pumped Hydro Roadmap[126].
- South Australian PHES limits have been adjusted to reflect Generation Information submissions, applying the project size ratios as specified in the Entura report.
- Tasmanian PHES storage limits have been informed by underlying analysis of the detailed project information within the Entura report, provided by contributors to the Entura report (but not published). This data avoids misinterpretation of projects that may not be mutually exclusive and is aligned reasonably with Tasmanian PHES Generation Information submissions.

Matters for consultation

- Do you have specific feedback on the proposed REZ resource limits?
- Is the addition of a resource limit land use penalty factor reasonable? Is the value proposed for the penalty factor reasonable, and should it be applied equally to all REZs?

4.9.3 REZ transmission limits

Input vintage	Based on 2020 ISP. REZ expansion costs for Export Superpower scenario are new. One new REZ added and minor changes to others.
Source	AEMO internal
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR and may be further updated through the ISP Methodology consultation processes.
Get involved	Draft 2021 IASR consultation and ISP Methodology

Individual REZ transmission limits

Network studies were undertaken to identify transmission limits to the amount of additional generation which can be accommodated within the existing network. The limits can change due to either:

- Interconnector developments, which can improve a REZ's access to the shared transmission network, or
- Explicit transmission developments that increase, at an efficient cost, transmission access between the NEM shared transmission network and the REZ.

Through power system analysis, REZ transmission limits and opportunities to relax these limits were assessed by:

- Determining the amount of additional generation which can be added within the existing transmission network capability.
- Determining the amount of additional generation which can be added with inter-regional network upgrade options.
- Identifying network expansion to connect REZs to the major transmission network and amount of generation which can be accommodated.

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

- Estimating the cost of transmission network expansion to connect REZs and converting the cost estimate to an annualised cost per MW equivalent.

These REZ transmission limits have been updated since the 2020 ISP to include newly committed generation[127] in the REZs (which reduces the remaining hosting capacity within the existing transmission network) and are shown in Figure 33. REZ transmission limits include the capacity gained by the network development of the Central-West Orana REZ Transmission Pilot project, and the Western Victoria RIT-T augmentation.

REZ transmission limits and augmentations are an outcome of applying analysis to a power system model. These REZ transmission limits will therefore be updated based on the Draft ISP Methodology that will further detail the process and data behind these limits for further consultation before finalising inputs for the 2022 ISP.

The cost per MW for each REZ is used as a linear penalty cost imposed on development of REZs beyond existing transmission connection capabilities. In this way, each REZ may provide 'free' connection capacity up to existing assumed transmission capabilities. Using this approach, the ISP model can assess the cost of building more intra-regional transmission to access additional capacity in excess of these limits against building new (potentially slightly lower but still good quality) generation in locations where spare transmission capacity exists.

Indicative transmission cost is a measure of the network expansion cost required to connect the REZ to the nearest major load centre and is shown in the table below. These costs have not yet considered recent experiences in increasing estimates for transmission, and will be reviewed as part of the major engagement planned with stakeholders on transmission cost estimation (see Section 4.11.6).

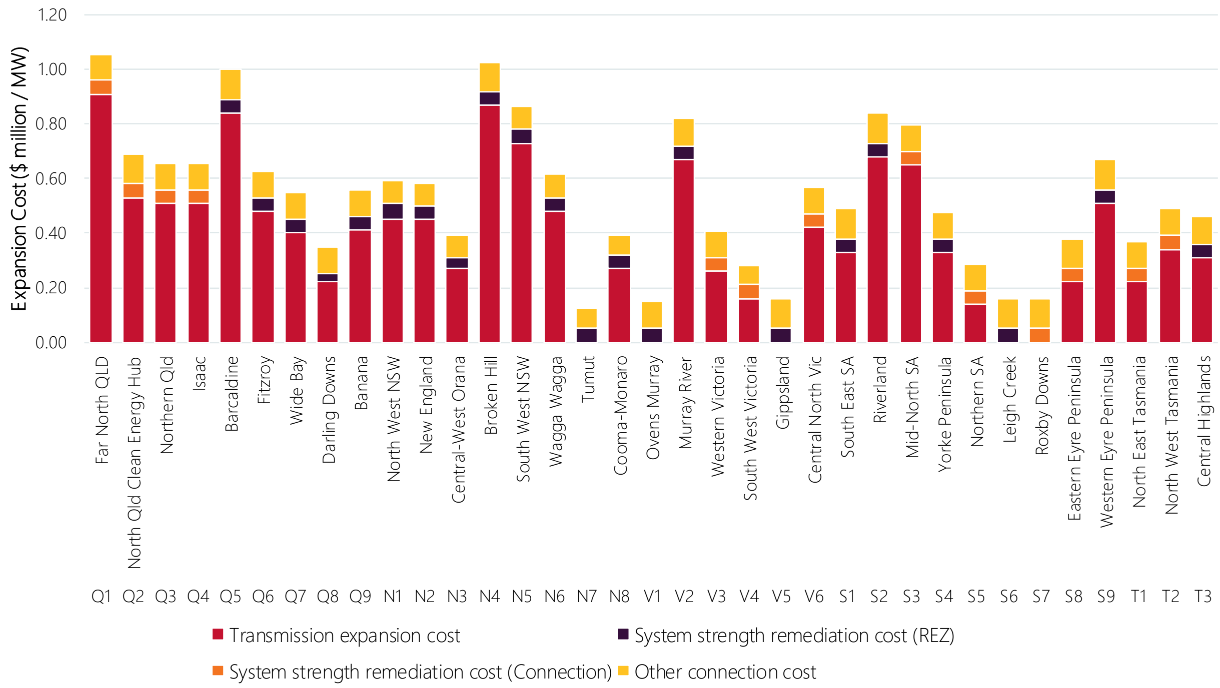
System strength remediation costs have been estimated from the system strength remediation cost outcomes assessed in the 2020 ISP studies[128] – these are in the range of $0.03 million to $0.06 million per MW.REZs that are already at system strength limits but do still have network capacity include additional system strength remediation costs as connection costs, so that this cost is imposed on new generation straight away. Where a REZ still has some available fault level but is likely to reach limits as the network needs to expand, system strength remediation costs are included as part of the REZ expansion costs instead.

A comparison of costs associated with REZs is shown in Figure 34, and detailed in the Draft 2021-22 Inputs and Assumptions Workbook.

[127] AEMO. Generation information, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2020/nem-generation-information-november-2020.xlsx?la=en.

[128] Based on available fault level calculations. AEMO 2020 ISP Appendix 5 REZ scorecards, at https://www.aemo.com.au/-/media/files/major-publications/isp/2020/appendix--5.pdf?la=en.

Figure 34 Summary of REZ-based expansion costs



Matters for consultation

- AEMO seeks stakeholders' views on the approach to REZ transmission limits for future build of REZs.
- AEMO requests stakeholders' views on the proposed approach to explicit incorporation of system strength remediation cost estimates in the analysis.

REZ expansion costs under the Export Superpower scenario

For the Export Superpower scenario, load centres may emerge near ports (to provide access to export facilities), rather than within the city centres (see Figure 52), which may require different network upgrades. In this scenario, REZ expansion cost assumptions need to be updated to take this into account.

To allow optimal determination of REZ expansion to power hydrogen facilities, REZ expansion options will be determined for each zone based on the distance from the zone to each nearby port. The current value proposed for REZ expansion to ports is $1,500/MW/km. This cost will be reviewed as part of the major engagement planned with stakeholders on transmission cost estimation (see Section 4.11.6).

REZ transmission limits and augmentations are an outcome of applying analysis to a power system model. These REZ transmission limits and expansion costs will therefore be updated based on:

- The Draft ISP Methodology, that will further detail the process and data behind these limits for further consultation prior to finalising inputs for the 2022 ISP.
- Updated transmission component costs (see Section 4.11.6).

Matters for consultation

- Do you have specific feedback on the proposed transmission expansion costs for use in the Export Superpower scenario, noting the different objective of connecting to ports rather than city centres?

Group constraints

The transmission system is a highly meshed system, and transmission flows are influenced by the generation and system services across multiple locations. Within AEMO's capacity outlook model, simplifications are needed to the power system to keep the optimisation problem tractable, which may rely on flow limits being influenced by single REZ outcomes.

To address this need, "group constraints" are proposed that combine the generation from more than one REZ, to reflect network limits that apply to multiple areas of the power system. The table below shows the group constraints that apply in the capacity outlook model. These have been developed by considering the limits observed from power system analysis, and in consultation with TNSPs.

Table 32 REZ group transmission constraints

REZ ID	REZ name	Group constraint name	Transmission-limited total build (MW)	Indicative transmission expansion cost ($M/MW)
Q1	Far North QLD	NQ1	1,800	0.42
Q2	North Qld Clean Energy Hub			
Q3	Northern Qld			
Q1	Far North QLD	NQ2	2,500	0.51
Q2	North Qld Clean Energy Hub			
Q3	Northern Qld			
Q4	Isaac			
Q5	Barcaldine			
Q1	Far North QLD	NQ3	2,500	0.48
Q2	North Qld Clean Energy Hub			
Q3	Northern Qld			
Q4	Isaac			
Q5	Barcaldine			
Q6	Fitzroy			
Q9	Banana			
S3	Mid-North SA	MN1	1,000	0.65
0.5 x S4 †	Yorke Peninsula			
S5	Northern SA			
S6	Leigh Creek			
S7	Roxby Downs			
S8	Eastern Eyre Peninsula			
S9	Western Eyre Peninsula			

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

Matters for consultation

- Do stakeholders have any other suggestions for representation of inter-related constraints across REZ?

Modifiers due to interconnectors and inter-zonal augmentations

If network augmentations such as interconnectors are developed close to a REZ, or if they traverse a REZ, the increase in network capacity has to be reflected in the REZ transmission limits.

Revised transmission expansion costs are then applied to the REZ to take into account the change in network upgrades required for further capacity.

Assessment of all new or augmented interconnector options therefore includes re-assessment of transmission limits and expansion costs for impacted REZ. The impact of interconnectors on REZ limits and expansion costs are considered in the ISP models when determining the optimal development path.

Results for all the REZs are shown in the tables below. These tables refer to inter-zonal augmentation options (for example, NNS-SQ Option 7) that are described in more detail in Section 4.11.5.

Table 33 REZ transmission limit modifiers due to Northern New South Wales – South Queensland upgrades (MW)

REZ ID	REZ name	NNS-SQ Option 7	NNS-SQ Option 5	NNS-SQ Option 6
Q8	Darling Downs	2,000	1,000	2,000

Table 34 REZ transmission limit modifiers due to Central New South Wales – Northern New South Wales (MW)

REZ ID	REZ name	CNSW-NNSW Option 1	CNSW-NNSW Option 2	CNSW-NNSW Option 3	CNSW-NNSW Option 4	CNSW-NNSW Option 5	CNSW-NNSW Option 6	CNSW-NNSW Option 7	CNSW-NNSW Option 8
N1	North West NSW	-	-	-	1,000	1,000	-	1,000	2,000
N2	New England	1,200	2,000	2,000	-	2,000	2,000	1,000	-
N3	Central West-Orana	-	-	-	-	500	-	1,000	-

Table 35 REZ transmission limit modifiers due to Southern New South Wales – Central New South Wales (MW)

REZ ID	REZ name	HumeLink	SNSW-CNSW Option 1	SNSW-CNSW Option 2
N6	Wagga Wagga	1,000	1,000	1,000

Table 36 REZ transmission limit modifiers due to Victoria – Southern New South Wales (MW)

REZ ID	REZ Name	VNI West (Shepparton)	VNI West (Kerang)	VNI Option 1	VNI Option 2	VNI Option 3†	VNI Option 3‡	VNI Option 4
N5	South West NSW	-	1,000	-	-	-	-	-
V1	Ovens Murray	-	-	1,000	1,000	-	-	-
V2	Murray River	-	2,000	-	-	-	1,000	-
V3	Western Victoria	-	1,000	-	-	-	-	-
V6	Central North Vic	2,000	-	-	-	1,000	-	2,000

† This limit is applied when Victoria – New South Wales Interconnector (VNI) Option 3 is developed after VNI West (Shepparton).
‡ This limit is applied when VNI Option 3 is developed after VNI West (Kerang).

Table 37 REZ transmission limit modifiers due to South Australia – South-West New South Wales upgrades (MW)

REZ ID	REZ name	Project EnergyConnect
N5	South West NSW	600
V2	Murray River	380
S2	Riverland	800

Table 38 REZ transmission limit modifiers due to Victoria – Tasmania upgrades (MW)

REZ ID	REZ Name	VIC-TAS Option 1 (1x750 MW)	VIC-TAS Option 1 (2x750 MW)
T2	North West Tasmania	-	600
T3	Central Highlands	540	540

Following development of VIC-TAS option 1 or option 3, REZ expansion costs for T2 reduce to $0.122 million/MW. The draft ISP Methodology will further detail the process and data behind these limits for further consultation prior to finalising inputs for the 2022 ISP.

Matters for consultation

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

4.9.4 Connection costs

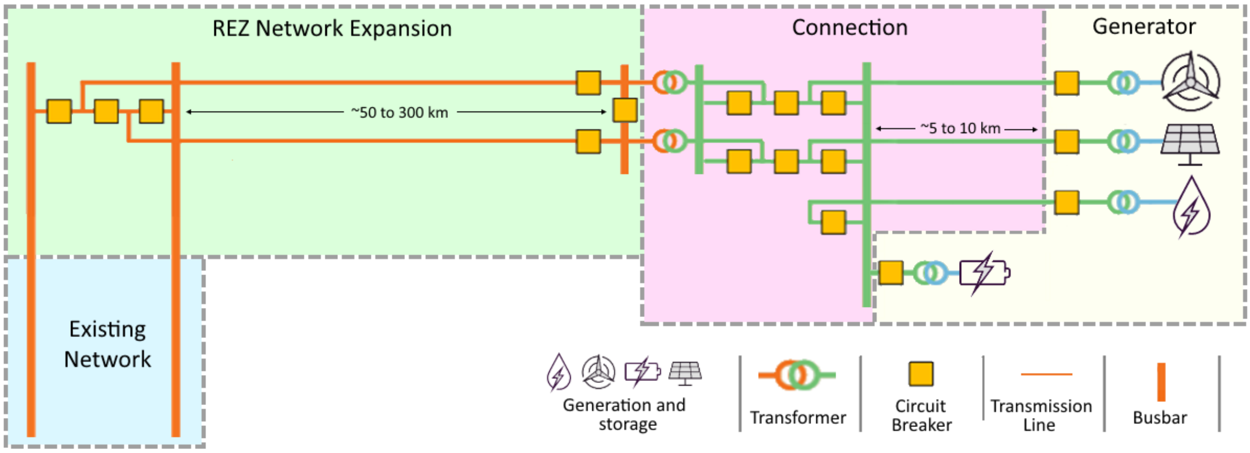
Input vintage	Unchanged since 2020 ISP.
Source	AEMO internal
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR and may be further updated through the ISP Methodology consultation processes.
Get involved	Draft 2021 IASR consultation and ISP Methodology

Connection costs are the cost of connecting a generator to the hub of the REZ (that is, the local high-voltage network). These also include provision of local system strength via plant such as synchronous condensers where required.

Connection costs increase the build costs of new technologies to cater for transmission infrastructure to connect to the grid and varies depending on the proximity to transmission assets. The connection cost of battery storage is lower than other storage and generation options because battery storage has more flexibility in its location and can leverage the connection assets used in connecting VRE. Due to resource location, wind, solar, and PHES projects will often be located 5-10 km from the existing network.

An example of how these costs are proposed to be allocated in relation to overall costs is shown in Figure 35.

Figure 35 Connection cost allocation



The draft ISP Methodology will further detail the process and data behind these costs for further consultation prior to finalising inputs for the 2022 ISP.

A comparison of connection costs associated with REZs is shown in Table 39, and detailed in the Draft 2021-22 Inputs and Assumptions Workbook. These costs are presented alongside other REZ-based expansion costs in Figure 34.

REZs that are already at system strength limits[129] but do still have network capacity include additional system strength costs of $50/kW[130] as connection costs so that this cost is imposed on new generation straight away. Where a REZ still has some available fault level, but likely to reach limits as the network needs to expand, then system strength remediation costs are included as part of the REZ expansion costs instead.

Regional-based connection costs for all generator and storage technologies are presented in the Draft 2021-22 Inputs and Assumptions Workbook.

[129] Based on available fault level calculations detailed in the 2020 ISP Appendix 5 REZ scorecards, at https://www.aemo.com.au/-/media/files/major-publications/isp/2020/appendix--5.pdf?la=en.

[130] AEMO's system strength remediation costs are based on an in-house transmission cost database which has been updated periodically by expert consultants. This value will be updated through the transmission cost review process (see section 4.11.6), which will include the release of a public transmission cost database.

Table 39 Regional-based connection costs ($/kW)

Region	CCGT	OCGT or reciprocating engines	Black coal (supercritical PC)	Biomass	Battery storage (2hrs storage)	Battery storage (4hrs storage)
Queensland	80.83	80.83	42.02	96.40	9.97	9.97
New South Wales	85.13	85.13	52.99	84.11	9.97	9.97
Victoria	72.25	72.25	0.00	98.41	9.97	9.97
South Australia	80.83	80.83	0.00	96.40	9.97	9.97
Tasmania	72.25	72.25	0.00	98.41	9.97	9.97

† Note: CCS technology is not expected to change the connection cost of coal-fired generation.

Pumped hydro connection costs are included in the capital costs provided by Entura. If required for inverter-based resources (IBR), a system strength remediation cost of $50/kW of installed capacity is added[131]. It will only be applied when the location selected for connection has insufficient system strength or the technology doesn't provide system strength.

Matters for consultation

- Do you have any specific feedback on proposed connection costs for individual REZs, including the specific system strength remediation costs when applicable?
- Do you have any specific feedback on proposed regional-based connection costs?

4.10 Climate change factors

The changing climate has an impact on a number of aspects of the power system, from consumer demand response to changing temperature conditions, to generation and network availability impacts. The following sections describe the various impacts across the spectrum of inputs.

4.10.1 Climate data within consumption and demand forecasting

Input vintage	Accessed Jan-2019 (CMIP5)
Source	BoM, CSIRO, ClimateChangeInAustralia.gov.au
Update process	Subject to the infrequent provision of appropriately tailored climate science.
Current accuracy	N/A
Get involved	N/A

AEMO incorporates climate change in its demand forecasts, and adjusts historical weather outcomes to apply in future years based on the outcomes projected by forecast climate models. Climate data is collected from

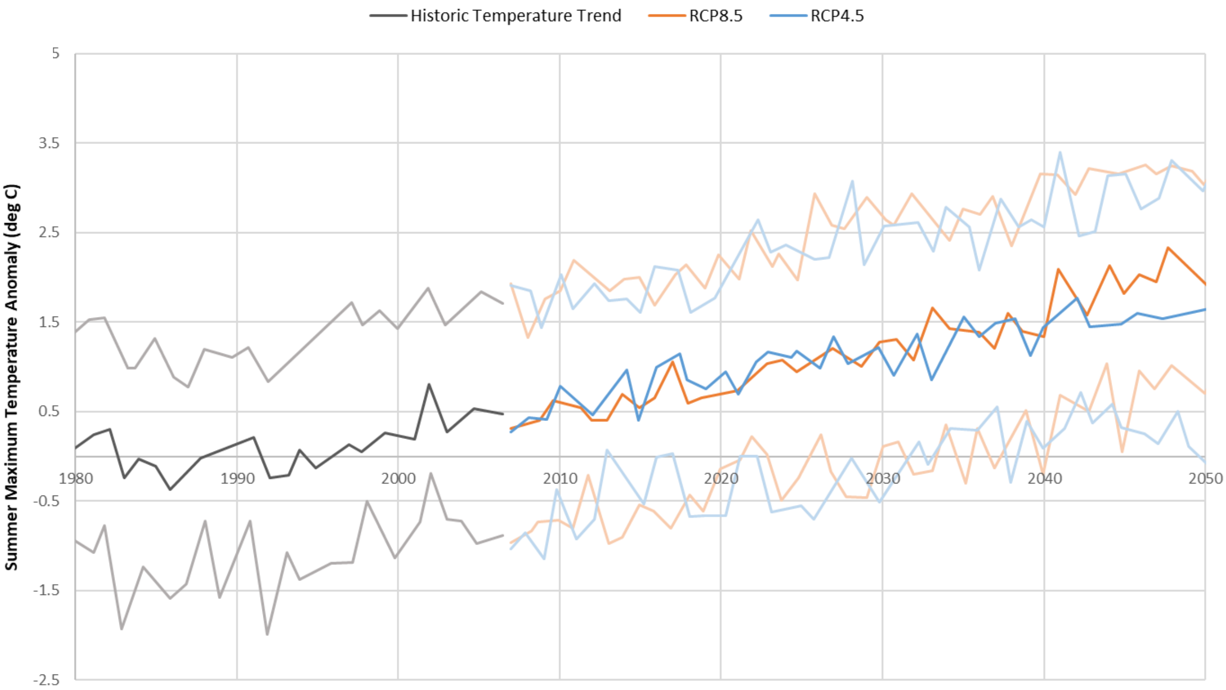
[131] AEMO's system strength remediation costs are based on an in-house transmission cost database which has been updated periodically by expert consultants. This value will be updated through the transmission cost review process (see Section 4.11.6), which will include the release of a public transmission cost database.

the CSIRO and BoM's website Climate Change in Australia[132]. For more information on this, see Appendix A.2.3 of the Electricity Demand Forecasting Methodology Information Paper.

Climate Change in Australia projects gridded daily minimum and maximum temperatures for each global climate model (GCM) for each of the RCP pathways. Data is selected for the closest available RCP to the scenario specification. Warming over the medium term is largely locked in and does not vary substantially between emissions trajectories.

Figure 36 shows the change to summer maximum temperature anomaly ranges expected for Southern Australia under two atmospheric greenhouse gas concentrations (RCP4.5 - RCP8.5) applied across the scenarios[133].

Figure 36 Southern Australia summer maximum temperature anomaly



Matters for consultation

- Are the assumptions above considered appropriate?

4.10.2 Climate effect on network modelling

Input vintage	New
Source	Climate factors – CSIRO and BoM
Update process	Variable transmission line constraints and outage rates to be adjusted based on the best available climate science.
Get involved	FRG: May 2021

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

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

Australian-specific climate information on regional changes in long-term average rainfall over time has been estimated through close collaboration with CSIRO and the BoM as part of the ESCI project sponsored by the Federal Government[134]. This includes provision of factors for expected temperature impacts on transmission line ratings, and the provision of factors for bushfire and wind impacts on transmission failure rates. All climate factors relevant to network performance will be consulted on the May 2021 FRG.

4.11 Network modelling

This section describes inputs and assumptions relating to the transmission network. The inputs and assumptions are grouped into the following categories:

- **ISP zones** – the power system is modelled in different ways depending on the analysis being performed. A 10-zone structure is proposed to improve the granularity of optimisations that were previously assessed across five regions.
- **Existing network capacity** – this section summarises the existing capacity of the transmission network.
- **Committed transmission projects** – these projects are included in all scenarios. Once a project meets five criteria, the projects are classified as committed and will be modelled in all scenarios.
- **Anticipated transmission projects** – major transmission projects that are in the process of meeting three of the five commitment criteria are classified as anticipated. The treatment of anticipated transmission projects can vary depending on the type of modelling being performed (see Section 4.11.4).
- **Augmentation options** – this includes transmission upgrades that are not committed or anticipated and will be assessed in the ISP.
- **Transmission augmentation costs** – the costs of transmission augmentation options and the building blocks used to estimate new augmentations as the need may arise.
- **Preparatory activities** – the 2020 ISP triggered preparatory activities for six future ISP projects. By 30 June 2021, the relevant TNSPs will provide the costs and preliminary designs for these projects.
- **Non-network options** – AEMO considers potential non-network options alongside network solutions to develop an efficient power system strategy.
- **Inter-regional loss flow equations** – these equations are used to reflect the energy lost when transferring energy between regions.
- **Network losses and MLFs** – these values are used to reflect network losses and the marginal pricing impact of bids from a connection point to the regional reference node.
- **Transmission line failure rates** – forced outage rates of inter-regional transmission elements are critical inputs for AEMO's reliability assessments.

4.11.1 ISP zones

Input vintage	Based on 2020 ISP with additional zones added to enable better modelling of projects where AEMO triggered preparatory activities.
Source	AEMO internal
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR and may be further updated through the ISP Methodology consultation processes.
Get involved	Draft 2021 IASR consultation and ISP Methodology

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

Depending on the purpose and the stage of the modelling, AEMO represents the network topology and reference nodes in different ways. The network can be represented as either a regional or zonal topology:

- In the regional topology, each of the five NEM regions are represented by a single reference node. In this topology, all regional loads are placed at the regional reference nodes, with generation represented across the power system considering the REZ transmission limits and group constraints described previously.
- The zonal topology breaks down some of the NEM regions into smaller zones. As outlined in the following section, the proposed zonal structure will enable better information for projects that were actionable or where AEMO triggered preparatory activities in the 2020 ISP. In this topology the regional load and generation resources are appropriately split between the different zones. Inter-zonal transmission constraints are added to reflect the capability of the network.

The following table list all the regions and the proposed zones to be used in AEMO studies (and their corresponding reference nodes). The nodes in **bold** are those used as reference nodes in the regional topology.

Table 40 NEM regions, ISP zones, reference nodes and REZs

NEM Region	ISP Zone	Reference Node	REZs
Queensland	Central and North Queensland (CNQ)	Ross 275 kilovolts (kV)	Q1, Q2, Q3 , Q4, Q5 and Q6
	Gladstone Grid (GG)	Calliope River 275 kV	-
	South Queensland (SQ)	**South Pine 275 kV**	Q7, Q8 and Q9
New South Wales	Northern New South Wales (NNSW)	Armidale 330 kV	N1 and N2
	Central New South Wales (CNSW)	Wellington 330 kV	N3
	South NSW (SNSW)	Canberra 330 kV	N4, N5, N6, N7 and N8
	Sydney, New Castle, Wollongong (SNW)	**Sydney West 330 kV**	-
Victoria	Victoria (VIC)	**Thomastown 66 kV**	V1, V2, V3, V4, V5 and V6
South Australia	South Australia (SA)	**Torrens Island 66 kV**	S1, S2, S3, S4, S5, S6, S7, S8 and S9
Tasmania	Tasmania (TAS)	**Georgetown 220 kV**	T1, T2 and T3

*Bold reference nodes are those used for whole of region modelling, for example in the ESOO. In such studies, all regional loads are represented at the regional reference nodes.

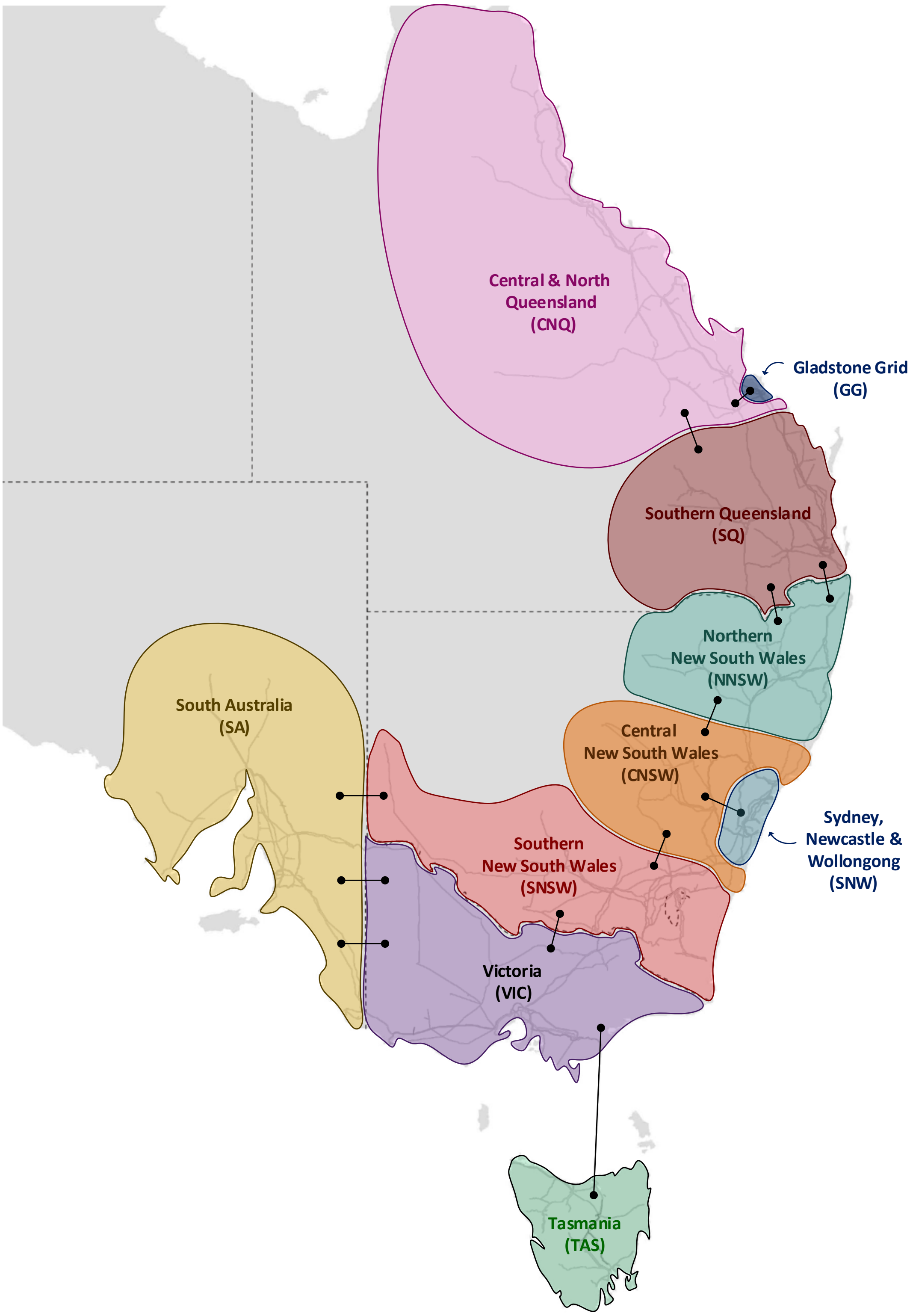
Capacity outlook model representation:

For the purposes of ISP modelling, AEMO is exploring expanding the capacity outlook modelling from a five-state regional model to a zonal model. This provides more granular information on key intra-regional transmission limitations and augmentations which are not well approximated by REZ limits alone. There is a trade-off when adding zones to this model. While additional zones provide more information, they increase the computational complexity of the PLEXOS model. The proposed zonal structure will enable better information for projects that were actionable or where AEMO triggered preparatory activities in the 2020 ISP.

The zonal representation presented and described in Figure 37 and Table 41 is an initial proposal under development. AEMO includes information on this proposed implementation within this Draft 2021 IASR to provide context for the draft inputs described in the remaining sections. It also provides an opportunity for stakeholders to provide early input into the proposed model improvement.

AEMO is currently undertaking analysis which may alter the topology presented or feasibility of this approach. If the analysis shows that this zonal representation of the physical system has merit, the approach will be consulted on extensively as part of the draft ISP methodology consultation in 2021.

Figure 37 ISP zonal model



‡ The possible "Central with CopperString" risk scenario (see Section 2.5) may require the addition of a new zone near Mt Isa.

Table 41 Cut-set representation between regions or zones

Inter-zonal definition	Inter-zonal cut-sets (forward direction of power flow)
CNQ – GG	Bouldercombe – Calliope River 275 kV (1 circuit) Raglan – Larcom Creek 275 kV (1 circuit) Calvale – Wurdong 275 kV (1 circuit) Gin – Calliope River (2 circuits) Teebar Creek – Wurdong (1 circuit) Callide A – Gladstone South 132 kV (2 circuits)
SQ – CNQ	Woolooga – Teebar Creek 275 kV (1 circuit) Woolooga – Gin 275 kV (2 circuits) Halys – Calvale 275 kV (2 circuits)
NNSW – SQ (Queensland – New South Wales interconnector, or QNI)	Dumaresq – Bulli Creek 330 kV (2 circuits)
NNSW – SQ (Terranora)	Terranora – Mudgeeraba 110 kV (2 circuits)
CNSW – NNSW	Muswellbrook – Tamworth 330 kV (1 circuit) Liddell – Tamworth 330 kV (1 circuit) Hawks Nest tee – Taree 132 kV line (1 circuit) Stroud – Taree 132 kV line (1 circuit)
SNSW – CNSW	Crookwell – Bannaby 330 kV (1 circuit) Yass – Marulan 330 kV (2 circuits) Capital – Kangaroo Valley 330 kV (1 circuit) Yass – Cowra 132 kV (2 circuits)
CNSW – SNW	Wallerawang – Ingleburn 330 kV (1 circuit) Wallerawang – Sydney South 330 kV (1 circuit) Bayswater – Sydney West 330 kV (1 circuit) Bayswater – Regentville 330 kV (1 circuit) Liddell – Newcastle 330 kV (1 circuit) Liddell – Tomago 330 kV (1 circuit) Bannaby – Sydney West 330 kV (1 circuit) Marulan – Avon 330 kV (1 circuit) Marulan – Dapto 330 kV (1 circuit) Kangaroo Valley – Dapto 330 kV (1 circuit) Stroud – Brandy Hill 132 kV (1 circuit) Stroud – Tomago 132 kV (1 circuit) Hawks Nest tee – Tomago 132 kV (1 circuit)
VIC – SNSW	Murray – Upper Tumut 330 kV (1 circuit) Murray – Lower Tumut 330 kV (1 circuit) Wodonga – Jindera 330 kV (1 circuit) Red Cliffs – Buronga 220 kV line (circuit) 132 kV bus tie at Guthega (1 circuit which is normally open)
SNSW – SA	Buronga 330 kV – Robertstown (2 circuits)

Inter-zonal definition	Inter-zonal cut-sets (forward direction of power flow)
VIC – SA (Heywood)	Heywood – South East 275 kV (2 circuits)
VIC – SA (Murraylink)	Red Cliffs – Monash HVDC cable
TAS – VIC	George Town – Loy Yang HVDC cable

Representation of load and generation within each of the zones is presented in the table below. Zonal loads are to be represented at the Zonal Reference Node. The Zonal Reference Node for each zone is located close to the zone's major load centre. Initial views on this representation are welcome as part of this consultation.

Table 42 Load and generation representation within the zonal model

Zone	Reference Node	Load and generation representation
Gladstone grid (GG)	Calliope River 275 kV	All load and generation at Calliope River, Boyne Island, Larcom Creek, Raglan, Wurdong, Gin and Teebar Creek substations.
Central/North Queensland (CNQ)	Ross 275 kV	All load and generation including and north of Calvale, Calliope River and Wurdong substations, except load and generation in GG zone.
South Queensland (SQ)	South Pine 275 kV	All Queensland load and generation except load and generation in CNQ zone.
Northern New South Wales (NNSW)	Armidale 330 kV	Within NSW, all load and generation including and north of Tamworth substation.
Central New South Wales (CNSW)	Wellington 330 kV	Within NSW, all load and generation including and west of Wallerawang and Wollar substations. Load and generation at Bayswater, Liddell and Muswellbrook substations. Load and generation at Bannaby, Avon and Dapto substations.
South NSW (SNSW)	Canberra 330 kV	Within NSW, all load and generation including and south of Gullen Range, Marulan and Kangaroo Valley substations. All load and generation in South West NSW.
Sydney, Newcastle and Wollongong (SNW)	Sydney West 330 kV	All NSW region load and generation except CNSW and SNSW zone load and generation.
Victoria (VIC)	Thomastown 66 kV	All load and generation within Victoria
South Australia (SA)	Torrens Island 66 kV	All load and generation within South Australia
Tasmania (TAS)	Georgetown 220 kV	All load and generation within Tasmania

Matters for consultation

- Is the proposed zonal model a reasonable representation of the network, focusing on the most critical cut-sets? Are there any additional zones which should be considered (and why)?
- For each ISP zone, is the nominated Zonal Reference Node appropriate?

Detailed time-sequential model representation

The time-sequential models used in the ISP and ESOO use a regional topology. The NEM transmission network is represented using detailed transmission constraint equations, similar to what is used in the NEM Dispatch Engine (NEMDE).

These constraints:

- Consider the NEM's network at 220 kilovolts (kV) or above, and other transmission lines under this voltage level that run parallel to the network at 220 kV or above.
- Calculate the network flow capability (intra- and inter-regional) and the available generator output capacity in every dispatch interval of the model.
- Are constantly updated to reflect changing power system conditions and outages.
- Are modified to cater for different transmission development pathways and scenarios assessed in an ISP.

4.11.2 Existing transmission capability

Input vintage	Based on 2020 ISP with additional limits added to reflect the updated ISP zones.
Source	AEMO internal and TNSPs
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR, and success of the zonal model development.
Get involved	Draft 2021 IASR consultation: December 2020 – February 2021

Transfer capability across the transmission network is determined by thermal capacity, voltage stability, transient stability, small signal stability and system strength. It varies throughout the day with generation dispatch, load and weather conditions. In time-sequential market modelling, limits are represented through network constraint equations. For capacity outlook modelling, notional transfer limits between the zones are represented at the time of maximum demand in the importing zone.

These proposed notional transfer limits are presented in the table below, noting that these reflect current assessments and may change based on the outcome of the ISP Methodology consultation, and as further power system analysis is undertaken, or as the zonal representation is refined. Interconnector transfer capabilities are a subset of this information, and are listed in the Draft 2021-22 Inputs and Assumptions Workbook.

Table 43 Notional transfer capabilities between the zones

Cut-sets (forward power flow direction)	Forward direction capability (MW)	Reverse direction capability (MW)
CNQ – GG	615	615
SQ – CNQ	2,100	2,100
NNSW – SQ ("QNI")	545 835 (after QNI Minor)	1,120 1,310 (after QNI Minor)
NNSW – SQ ("Terranora")	50	150
CNSW – NNSW	245 400 (after QNI Minor)	1,120 1,310 (after QNI Minor)
SNSW – CNSW	2,700 2,870 (after VNI minor)	2,700 2,870 (after VNI minor)

Cut-sets (forward power flow direction)	Forward direction capability (MW)	Reverse direction capability (MW)
CNSW – SNW	5,600	5,600
VIC – SNSW	700 870 (after VNI minor)	400
SNSW – SA	800 (after Project EnergyConnect)	800 (after Project EnergyConnect)
VIC – SA ("Heywood")	650 750 (after Project EnergyConnect)	650 750 (after Project EnergyConnect)
SNSW – SA & VIC – SA (Heywood) combined	1,300 (after Project EnergyConnect)	1,450 (after Project EnergyConnect)
VIC – SA (Murraylink)	220	200
TAS – VIC	478	478

Matters for consultation

- Do you have any specific feedback on the existing inter-zonal transfer capabilities? For capacity outlook modelling, if notional transfer limits between the zones were represented for several different demand conditions (rather than just maximum demand), what would the most relevant demand conditions be?

4.11.3 Committed transmission projects

Input vintage	Updated from 2020 ISP using latest available AER and TNSP information.
Source	AER/TNSP – approval of Contingent Project Application or other approval as appropriate
Update process	As projects receive committed status, these are updated in the Input and Assumptions.
Get involved	Draft 2021 IASR consultation: December 2020 – February 2021

AEMO proposes applying the same five criteria definition of committed project as the RIT-T guidelines[135]; specifically, a committed transmission project must meet all the following criteria:

- The proponent has obtained all required planning consents, construction approvals and licenses, including completion and acceptance of any necessary environmental impact statement.
- Construction has either commenced or a firm commencement date has been set.
- The proponent has purchased/settled/acquired land (or commenced legal proceedings to acquire land) for the purposes of construction.
- Contracts for supply and construction of the major components of the necessary plant and equipment (such as transmission towers, conductors, terminal station equipment) have been finalised and executed, including any provisions for cancellation payments.
- Necessary financing arrangements, including any debt plans, have been finalised and contracts executed.

[135] AER, RIT application Guidelines, at https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20-%20RIT%20application%20guidelines%20-%2014%20December%202018.pdf.

The following projects are classified as committed transmission projects. Some projects currently categorised as anticipated (see Section 4.11.4) may become committed before ISP modelling commences (this includes Victoria – New South Wales Interconnector [VNI] Minor, Western Victoria Transmission Network Project, Project EnergyConnect and the VNI System Integrity Protection Scheme). AEMO intends to update this list of committed projects if a project becomes committed during the development of the ISP.

Table 44 Committed transmission projects

Project	Description	Expected in service date
South Australia system strength remediation	This project includes installation of: • Two high inertia synchronous condensers at Davenport 275 kV substation. • Two high inertia synchronous condensers at Robertstown 275 kV substation. • Each of the four synchronous condensers provide 575 MVA nominal fault current and 1,100 MWs of inertia.	Davenport synchronous condensers energised in Q1 2021 and Robertstown energised in Q2 2021.
QNI minor **(Queensland – New South Wales interconnector)**	The committed upgrade involves: • Uprating of following transmission lines from the existing design operating temperature of 85°C to 120°C. • Liddell–Tamworth 330 kV line. • Liddell–Muswellbrook 330 kV line. • Muswellbrook–Tamworth 330 kV line. • Installation of shunt capacitor banks at Armidale, Dumaresq, and Tamworth substations. • Installation of dynamic reactive plant at Tamworth and Dumaresq.	Equipment are expected to be in service in Q4 2021 with inter-network testing to be completed within 9 to 15 months. AEMO assumes full capacity will be available from Feb 2023.
VNI Minor (Victorian Works)	In combination with the NSW works associated with this project (currently classified as "anticipated" – see Section 4.11.4), this project increase thermal capacity of VIC-NSW interconnector by approximately 170 MW from Victoria to New South Wales. Victorian works involves: • Uprate South Morang–Dederang 330 kV line; and • An additional new 500/330 kV transformer at South Morang.	Service date: Late 2022 To allow time for inter-network testing, AEMO will model this augmentation at full capacity from Jan 2024.

Note: Some committed transmission projects are not included in this list because they are unlikely to impact AEMO's modelling.

4.11.4 Anticipated transmission projects

Input vintage	Updated from 2020 ISP using latest available AER and TNSP information.
Source	–
Update process	As projects receive anticipated status, these are updated in the Input and Assumptions.
Get involved	Draft 2021 IASR consultation: December 2020 – February 2021

Anticipated transmission projects are transmission augmentations that are not yet committed but are highly likely to proceed and could become committed soon. AEMO applies the criteria set out in the AER RIT-T guidelines to determine anticipated projects. These projects must be in the process of meeting three out of the five committed project criteria (as described in Section 4.11.3). Such projects could be network or non-network augmentations and could be regulated or non-regulated assets.

The Reliability Forecasting Methodology[136] defines which categories of transmission projects are included (considered to be committed) in reliability assessments. This may include anticipated projects that have received regulatory approval and minor upgrades that are not subject to the RIT-T but judged to be committed for reliability assessment purposes. For ISP modelling, anticipated projects will be included in all scenarios.

The following table outlines the projects that are currently classified as anticipated transmission projects. Generally, transmission projects will be classified as anticipated once they have passed a contingent project application or ISP feedback loop. Because Project EnergyConnect has not yet passed the contingent project application stage, it will be removed from this list and modelled as an inter-zonal augmentation option if it does not receive regulatory approval. AEMO intends to update this list of anticipated projects if any other project becomes anticipated during the development of the ISP.

Table 45 Anticipated projects

Project name	Project description	Timing
Western Victoria renewable integration	Stage 1 augmentation includes: The installation of wind monitoring equipment and the upgrade of station limiting transmission plant on the: • Red Cliffs–Wemen 220 kV line. • Wemen–Kerang 220 kV line. • Kerang–Bendigo 220 kV line. • Moorabool–Terang 220 kV line. • Ballarat–Terang 220 kV line. Stage 2 augmentation includes: • A new terminal station at north of Ballarat. • A new 500 kV double-circuit transmission line from Sydenham to the new terminal station north of Ballarat. • A new 220 kV double-circuit transmission line from the new terminal station North of Ballarat to Bulgana (via Waubra). • 2 x 500/220 kV transformers at the new terminal station north of Ballarat. • Cut-in the existing Ballarat–Bendigo 220 kV line at the new terminal station north of Ballarat. • Moving the Waubra Terminal Station connection from the existing Ballarat–Ararat 220 kV line to one of the new terminal stations north of Ballarat–Bulgana 220 kV lines. • Cut-in the existing Moorabool–Ballarat No. 2 220 kV line at Elaine Terminal Station.	Stage 1 completed by 2021. Stage 2 commissioned by 2025.
VNI System Integrity Protection Scheme* (Non-network solution)	Allow the existing VIC-NSW interconnector (VNI) to operate at 5-minute thermal rating. This involves procurement of 250 MW System Integrity Protection Scheme (SIPS) in Victoria to rapidly respond by injecting power after a contingency event on VNI.	Service date: Summer 2021-22

[136] AEMO. Reliability Forecasting Methodology, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines/forecasting-and-planning-guidelines.

Project name	Project description	Timing
VNI Minor† **(NSW Works)**	In combination with the Victorian works associated with this project (currently classified as "committed" – see section 4.11.3), this project increase thermal capacity of VIC-NSW interconnector by approximately 170 MW from Victoria to New South Wales. Increase thermal capacity of VIC-NSW interconnector by approximately 170 MW from Victoria to New South Wales. NSW works involves: • Power flow controllers on Upper Tumut-Yass and Upper Tumut-Canberra 330 kV lines.	Service date: Late 2022 To allow time for inter-network testing, AEMO will model this augmentation at full capacity from Jan 2024.
Project EnergyConnect **(If contingent project application is approved)‡**	Project EnergyConnect is a new double-circuit 330 kV transmission line between Wagga Wagga in New South Wales and Robertstown in South Australia via Buronga. This includes: • A new 330 kV double-circuit line from Wagga Wagga to Dinawan to Buronga to Robertstown. • A new 330 kV substation at Bundey near Robertstown including 275/330 kV transformers. • A new 275 kV line between Bundey and Robertstown. • A new 330 kV switching station at Dinawan. • New 330 kV phase shifting transformers at Buronga. • New 330/220 kV transformers at Buronga. • Rebuild of the existing 220 kV line from Red Cliffs to Buronga as a double-circuit 220 kV line. • Turning the existing 275 kV line between Para and Robertstown into Tungkillo. • Augmentation works at Robertstown, Buronga, Red Cliffs and Wagga Wagga substations. • Static and dynamic reactive plant at Bundey, Robertstown, Buronga, Dinawan. • A special protection scheme to detect and manage the loss of either of the AC interconnectors connecting to South Australia.	Service date: Mid-2024 To allow time for inter-network testing, AEMO will model this augmentation at full capacity from July 2025.

* AEMO. Victorian Annual Planning Report, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/vapr/2020/2020-vapr.pdf?la=en.
† In November 2020, AEMO published an ISP feedback notice confirming that the VNI Minor project meets the identified need and remains aligned with the optimal development path set out in the 2020 ISP. AEMO now considers the NSW works for this project to be anticipated. The notice is available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/integrated-system-plan-feedback-loop-notices. This project requires AER approval of a Contingent Project Application and final investment decision (FID) prior to being classified as committed.
‡ If the Contingent Project Applications for Project EnergyConnect[137] are not approved, or FID not made, AEMO will model this project as an inter-zonal augmentation option rather than a "committed" or "anticipated" project.

Matters for consultation

- Do you have any specific feedback on the treatment of anticipated transmission projects in the ISP?

[137] AER. TransGrid and ElectraNet – Project EnergyConnect contingent project, at https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/transgrid-and-electranet-–-project-energyconnect-contingent-project.

4.11.5 Inter-zonal augmentation options

Input vintage	Updated for Draft 2021 IASR
Source	AEMO, 2020 ISP, TNSPs
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR and further TNSP engagement.
Get involved	Draft 2021 IASR consultation: December 2020 – February 2021

Inter-zonal augmentation options represent new network and non-network options to increases the transfer capability between ISP zones. Each option is a candidate to be built during capacity expansion modelling[138]. While many inter-zonal augmentation options increase REZ network capacities, distinct options to expand the network capacity within individual REZs are modelled through a separate process, outlined in Section 4.9.3.

AEMO identified development options across ISP zones to connect renewable energy zones and pumped hydro storage. Credible options along the development paths include:

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

The options presented in this section were sourced from the past ISP consultation, AEMO's engagement with stakeholders, Transmission Annual Planning Reports (TAPRs), and the 2020 ISP.

Augmentation options

The augmentation options described in the following sections have been modified to suit the zonal representation proposed for the capacity outlook model (described in Section 4.11.1). This means some of the interconnector augmentation options used in the 2020 ISP are now separated into multiple components. For clarity, AEMO describes how new inter-zonal augmentations relate to the previous concept of interconnector augmentation. This is particularly relevant for the Queensland – New South Wales interconnector (QNI).

Augmentation details of each of the options are provided in Draft 2021-22 Inputs and Assumptions Workbook tab "augmentation options". AEMO welcomes feedback on the development paths and credible augmentation options in order to better inform inputs to the ISP.

The augmentation options are aligned with the modelled network topology (see Figure 37) and increase the transfer between zones. These augmentations or new lines, can be categorised as follows:

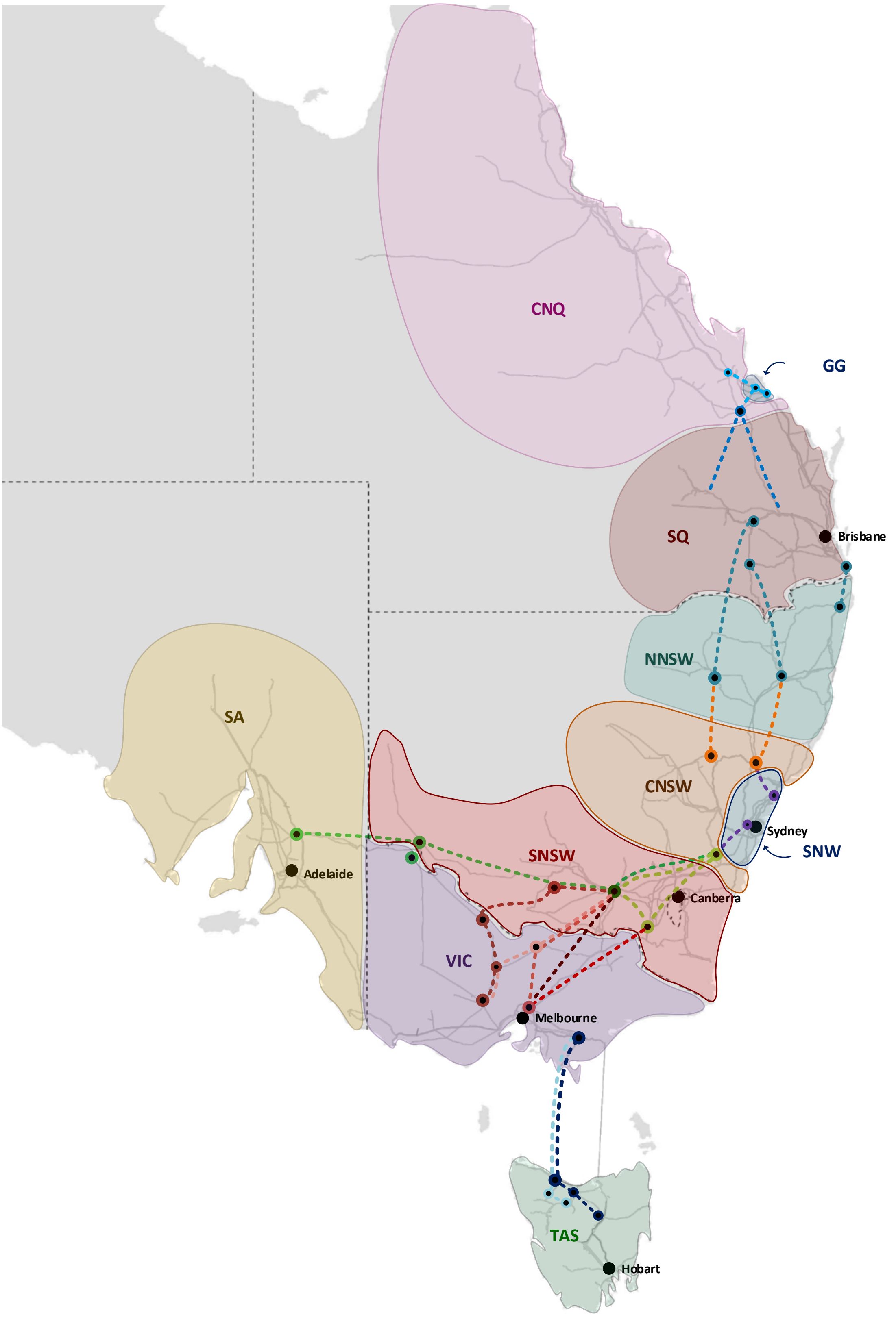
- **Gladstone Grid (GG) Reinforcement** – an option to increase transfer capacity between the CNQ and Gladstone ISP zones.
- **Central to Southern Queensland** – options to increase transfer capacity between the Central/North Queensland (CNQ) and Southern Queensland (SQ) ISP zones, including the Central to Southern Queensland Transmission Link for which AEMO triggered preparatory activities (see Section 4.11.7).
- **Northern New South Wales (NNSW) – Southern Queensland** – options to increase the transfer capability between NNSW and SQ. This includes components of the QNI Medium and Large project for which AEMO triggered preparatory activities (see Section 4.11.7).
- **Central New South Wales – Northern New South Wales** – options to increase the transfer capability between CNSW and NNSW. This includes components of the QNI Medium and Large project for which AEMO triggered preparatory activities (see Section 4.11.7).

[138] See AEMO Market Methodology Report for further details, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Market-Modelling-Methodology-Paper.pdf.

- **Central New South Wales – Sydney, Newcastle and Wollongong** – options to reinforce supply to Sydney, Newcastle and Wollongong load centres following retirement of coal power generators in New South Wales. This includes the Reinforcing Sydney, Newcastle and Wollongong Supply project for which AEMO triggered preparatory activities (see Section 4.11.7).
- **South New South Wales (SNSW) – Central New South Wales** – options to increase the transfer capability between SNSW and CNSW, which is currently proposed to be increased via the HumeLink project.
- **Victoria – South New South Wales** – options to increase the transfer capability between Victoria and SNSW. This includes augmentation options considered as part of the VNI such as VNI Minor (see sections 4.11.3 and 4.11.4) and VNI West.
- **Tasmania – Victoria** – this includes Project MarinusLink, the proposed new interconnector increase the transfer capability between Tasmania and Victoria.

The different corridors associated with these options are illustrated in Figure 38 and described in more detail in the following sections.

Figure 38 Proposed inter-zonal augmentation corridors



Augmentation capability and costs

Notional transfer capability for each of the options are indicative only. Cost estimates are particularly preliminary and indicative – AEMO will continue to engage with stakeholders on cost estimates (see

Section 4.11.6).
TNSPs are reviewing these values for the actionable ISP projects and for projects where AEMO has triggered preparatory activities.

AEMO is currently engaging with TNSPs to review and update these values before the IASR is published in July 2021. For all other projects, AEMO will update notional transfer limits as further power system analysis is undertaken.

Expected service dates

Expected service dates for projects identified as actionable in the 2020 ISP have been sourced from TNSPs. For all other augmentations, expected lead times represent the likely minimum time for service from the date of publication of the final 2022 ISP. The lead time includes regulatory justification, AER approval, relevant community engagement and planning approvals, procurement, construction, commissioning, and inter-network testing.

Each augmentation presented in this section is considered to be a 'standalone' option. Where options are built subsequent to a previous option (that is, if there is a pre-requisite upgrade), it is explicitly stated. The application of a single nominal transfer limit is required in AEMO's capacity outlook models to represent the limit ranges for each of the augmentation options. This single nominal transfer limit is calculated as the maximum capability during peak demand conditions in the importing region. In time-sequential modelling, separate constraint equations are used to identify complex network limit equations. These limit equations may invalidate the single nominal transfer limits, and if necessary, result in changes to the simplified representation during the modelling period in an iterative approach.

Gladstone grid (GG) reinforcement

With retirement or reduced generation from Gladstone Power Station and increased generation in North Queensland, the Boyne Island, Calliope River, Larcom Creek and Raglan substations cannot be supplied. The following figure and table present a network option to ensure supply reliability in this area. AEMO will consider alternatives to network upgrades – including local generation or storage in the Gladstone area.

In the 2020 ISP, AEMO recommended that Powerlink complete preparatory activities for the Gladstone Grid reinforcement project (see Section 4.11.7). Alternative proposals flagged in Powerlink's assessment may also be considered.

Figure 39 Gladstone grid section development corridors

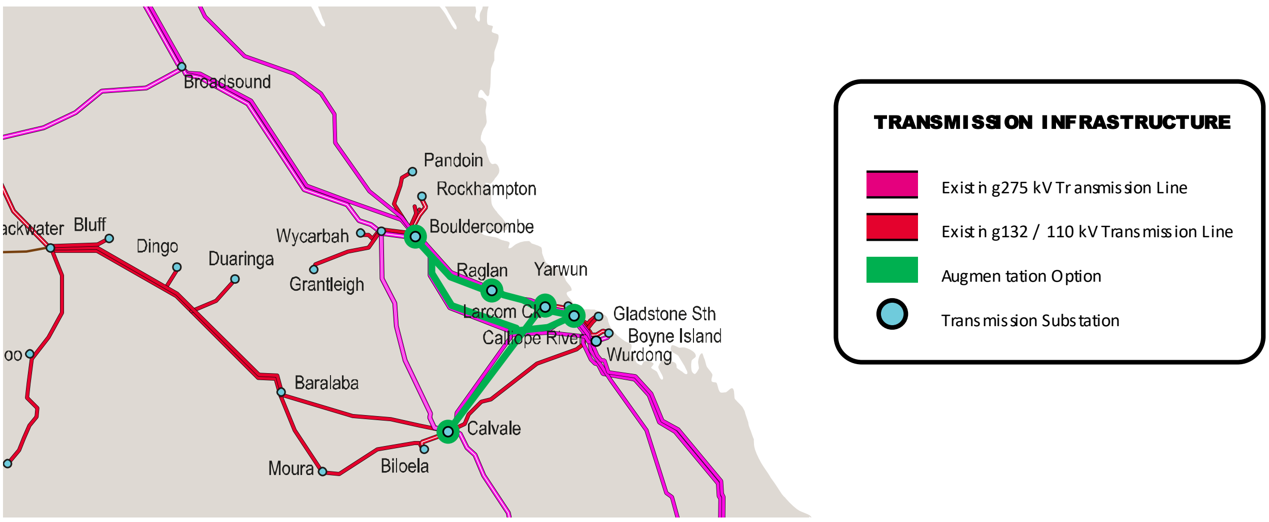


Table 46 Development options for CNQ–GG

Development path	Development driver	Option Name	Description	Notional transfer limit increase (MW)	Indicative cost estimates ($ million in real June 2019 dollars)	Indicative lead time for service
Existing CNQ–GG path	To increase thermal capability of transmission lines to supply Boyne Island load and load supplied from Calliope River, Larcom Creek and Raglan substation following retirement of Gladstone power station.	GG Option 1	Rebuild Bouldercombe–Raglan–Larcom Creek–Calliope River and the Bouldercombe–Calliope River 275 kV lines as a high capacity double-circuit lines. Turn Bouldercombe–Calliope River 275 kV line into Larcom Creek. New double-circuit Calvale–Larcom Creek 275 kV line. Third Calliope River 275/132 kV transformer.	700 MW from CNQ to GG	$300-560 million (2020 ISP) AEMO will apply the cost provided by Powerlink via preparatory activities (see section 4.11.7).	5 years

South Queensland to Central and North Queensland (SQ–CNQ)

At present, increased net generation from Central and North Queensland needs to pass through the central to southern Queensland grid section to reach major load centres. The maximum power transfer from central to southern Queensland is limited by transient or voltage stability following a Calvale to Halys 275 kV single-circuit contingency. In the longer term, the development of large loads for hydrogen production (for example, the Export Superpower scenario) or the connection to the NEM of Mt Isa (the potential "Central with CopperString" risk scenario – see Section 2.5) could materially change the energy needs in Central and North Queensland.

Figure 40 and Table 47 present network options to increase transfer capability between central and southern Queensland. A grid-scale battery option is included in addition to network options. In the 2020 ISP, AEMO recommended that Powerlink complete preparatory activities for the Central to Southern Queensland transmission link (see Section 4.11.7). Alternative proposals flagged in Powerlink's assessment may also be considered.

Figure 40 SQ–CNQ development corridors

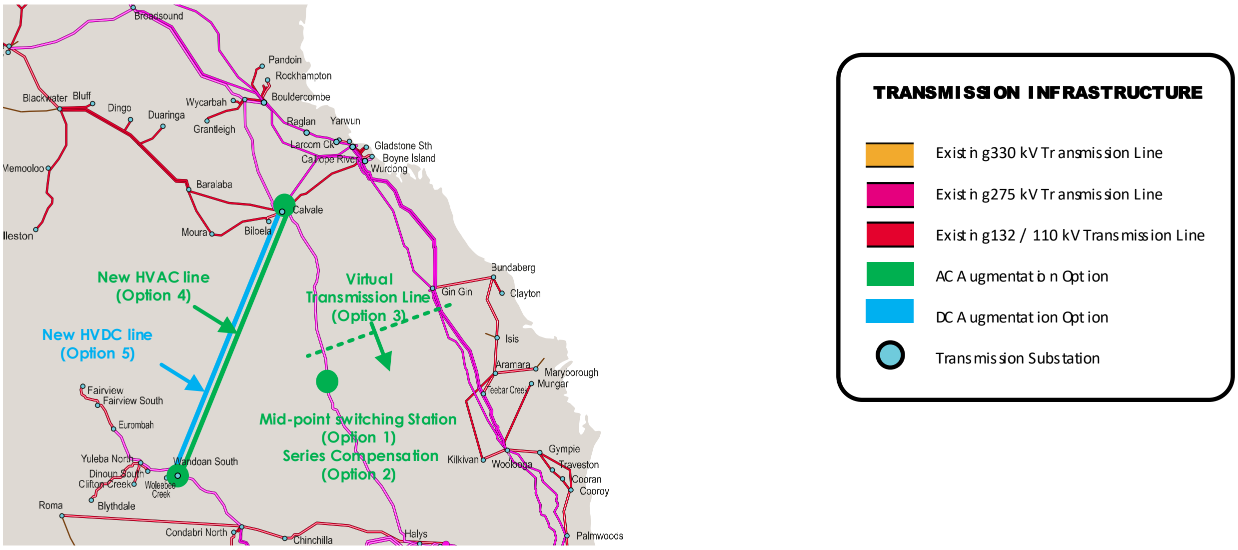


Table 47 Development options for SQ–CNQ

Development path	Development driver	Option Name	Description	Notional transfer limit increase (MW)	Indicative cost estimates ($ million in real June 2019 dollars)†	Indicative lead time for service
Existing SQ–CNQ (SQ–CQ) path	To increase voltage and transient capability of the SQ–CQ corridor for an outage of Calvale-Halys 275 kV circuit.	SQ–CNQ Option 1	Mid-point switching substation on the Calvale – Halys 275 kV double-circuit line.	300 MW In both directions	$50-90 million	3 years
		SQ–CNQ Option 2	Reduce the series impedance of the Calvale – Halys 275 kV double-circuit line.	450 MW In both directions	To be updated via "Preparatory Activities" (see section 4.11.7).	3 years
		SQ–CNQ Option 3	A Virtual Transmission Line option with a 300 MW battery storage system in CQ and SQ.	300 MW In both directions	$910-1,690 million	3 years
West of existing SQ–CNQ path	As above and to provide route diversity to the existing SQ–CQ path	SQ–CNQ Option 4	A new 275 kV double-circuit line between Calvale and Wandoan South.	900 MW In both directions	$300-560 million	7 years
		SQ–CNQ Option 5	A HVDC 2,000 MW bi-pole between Calvale and SWQ.	1,750 MW In both directions	$1,200-2,225 million	7 years

† AEMO will apply the cost provided by Powerlink via preparatory activities (see section 4.11.7).

Northern New South Wales to South Queensland (NNSW–SQ)

The NNSW–SQ corridor represents a portion of the network which forms part of the QNI. Development options on this corridor include the northern sections of proposed QNI upgrades.

NNSW–SQ transfer capability is limited in both directions by thermal and voltage and transient stability limits. Development options include candidates along the existing QNI path or via a westerly path which provides route diversity and access to the North West NSW REZ.

AEMO considers the QNI minor project to be committed (see Section 4.11.3) and assumes it is completed prior to the development options listed below. The figure and table below present credible network options to expand transmission capacity across this corridor. A large grid scale battery option is also included.

In the 2020 ISP, AEMO recommended that Powerlink and TransGrid complete preparatory activities for QNI Medium and Large interconnector upgrades (see Section 4.11.7). Alternative proposals flagged in Powerlink or TransGrid's assessments may also be considered.

Figure 41 NNSW–SQ development corridors

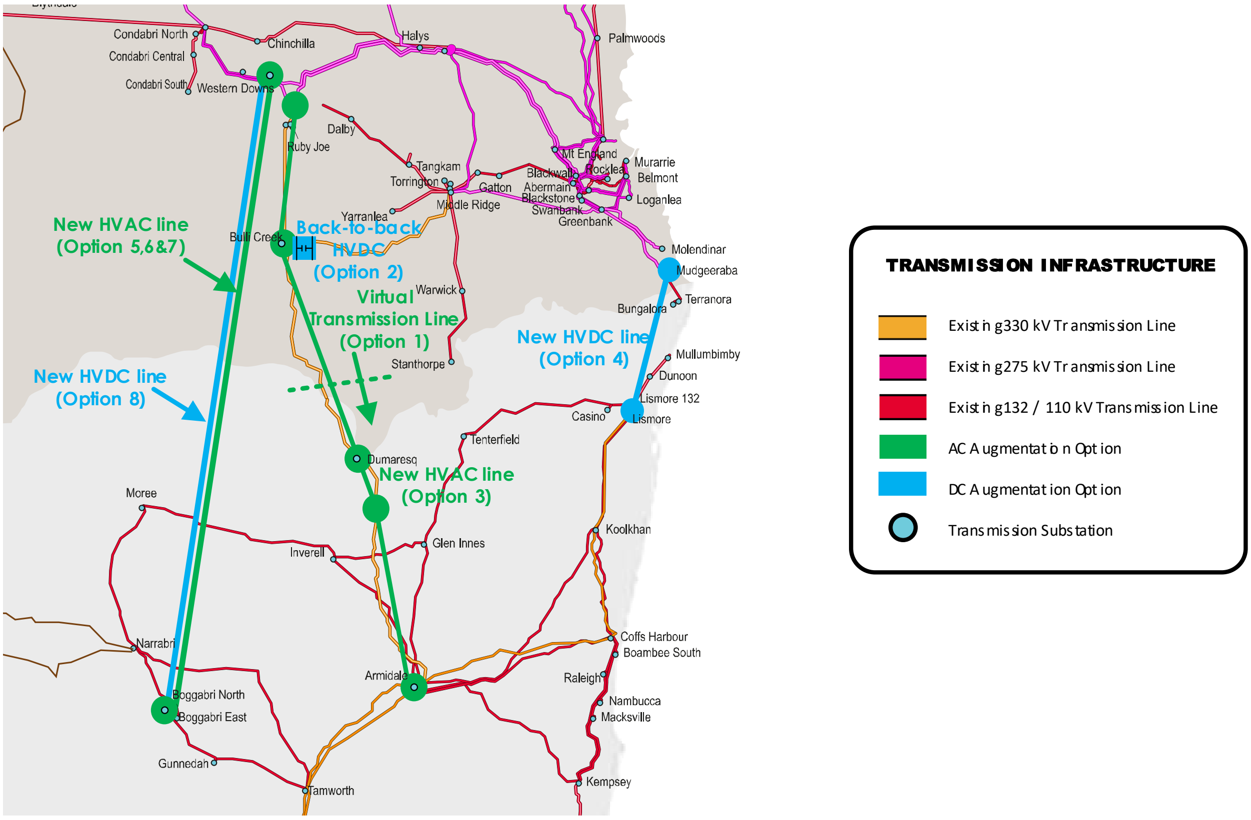


Table 48 NNSW–SQ development options

Development path	Development driver	Option Name	Description	Notional transfer limit increase (MW)	Indicative cost estimates ($ million in real June 2019 dollars)†	Indicative lead time for service
QNI corridor	To increase thermal capacity and, voltage and transient stability limits of 330 kV and 275 kV lines between Armidale and South West QLD.	NNSW–SQ Option 1	A Virtual Transmission Line option with a 300 MW grid-scale battery storage located south of Liddell and north of Western Downs.	300 MW in both directions	\$910 – 1,690 million	3 years
		NNSW–SQ Option 2	HVDC back-to-back converter station at Bulli Creek	890 MW CNSW to SQ 630 MW SQ to CNSW	\$749 – 1,391 million	4 years
		NNSW–SQ Option 3	A new 330 kV double-circuit line from Uralla to Sapphire to Dumaresq to Bulli Creek to Braemar.	1,145 MW NNSW to SQ 1,115 MW SQ to NNSW	\$990 – 1,835 million	7 years

Development path	Development driver	Option Name	Description	Notional transfer limit increase (MW)	Indicative cost estimates ($ million in real June 2019 dollars)†	Indicative lead time for service
Directlink corridor	To increase transfer capacity along the Terranora interconnector	NNSW–SQ Option 4	Replace Directlink with a new 600 MW HVDC interconnector from Lismore to Mudgeeraba.	550 MW NNSW to SQ 450 MW SQ to NNSW	$546 – 1,014 million	7 years
West of QNI corridor	To increase thermal capacity and, voltage and transient stability limits of 330 kV and 275 kV lines between Armidale and South West Queensland.	NNSW–SQ Option 5	A new single 500 kV line in a double-circuit tower construction from a new substation in NWNSW REZ (say near Boggabri) to west of Dumaresq to Bulli Creek to Western Downs.	830 MW NNSW to SQ. 760 MW SQ to NNSW.	$1,045 – 1,945 million	7 years
	To provide route diversity to existing QNI corridor	NNSW–SQ Option 6	An additional new 500 kV circuit (second circuit) strung on NNSW–SQ Option 5 from the new substation in NWNSW REZ to west of Dumaresq to Bulli Creek to Western Downs.	Capacity increase in addition to NNSW–SQ Option 5: 1,540 MW NNSW to SQ. 1,370 MW SQ to NNSW.	$580 – 1,080 million	2-3 years after NNSW–SQ option 5.
		NNSW–SQ Option 7	A new double-circuit 500 kV line from a new substation in NWNSW REZ (say near Boggabri) to west of Dumaresq to Bulli Creek to Western Downs.	2,370 MW NNSW to SQ. 2,130 MW SQ to NNSW.	$1,550 – 2,875 million	7 years
		NNSW–SQ Option 8	A new HVDC 2000 MW bi-pole interconnector between a new substation in NWNSW REZ and Western Downs.	1,750 MW in both directions.	$1,600 – 2,970 million	7 years

† AEMO will apply the cost provided by Powerlink and TransGrid via preparatory activities (see section 4.11.7).

Central New South Wales to Northern New South Wales (CNSW–NNSW)

The CNSW–NNSW corridor represents a portion of the network which forms part of the QNI. Development options on this corridor include the southern sections of proposed QNI upgrades.

Transfer capability on CNSW–NNSW is limited in both directions by thermal, voltage and transient stability limits. Development options can be close to the existing QNI path which can provide access to the New England REZ or west of the existing QNI path which can provide a route diversity to the QNI path and access to the North West NSW REZ.

AEMO considers the QNI Minor project to be committed (see Section 4.11.3) and assumes it is completed prior to the development options listed below. The following figure and table present credible network and non-network options. In the 2020 ISP, AEMO recommended that Powerlink and TransGrid complete preparatory activities for QNI Medium and Large interconnector upgrades and New England and North West New South Wales REZ expansion. Alternative proposals flagged in TransGrid's assessment may also be considered.

Figure 42 CNSW–NNSW development corridors

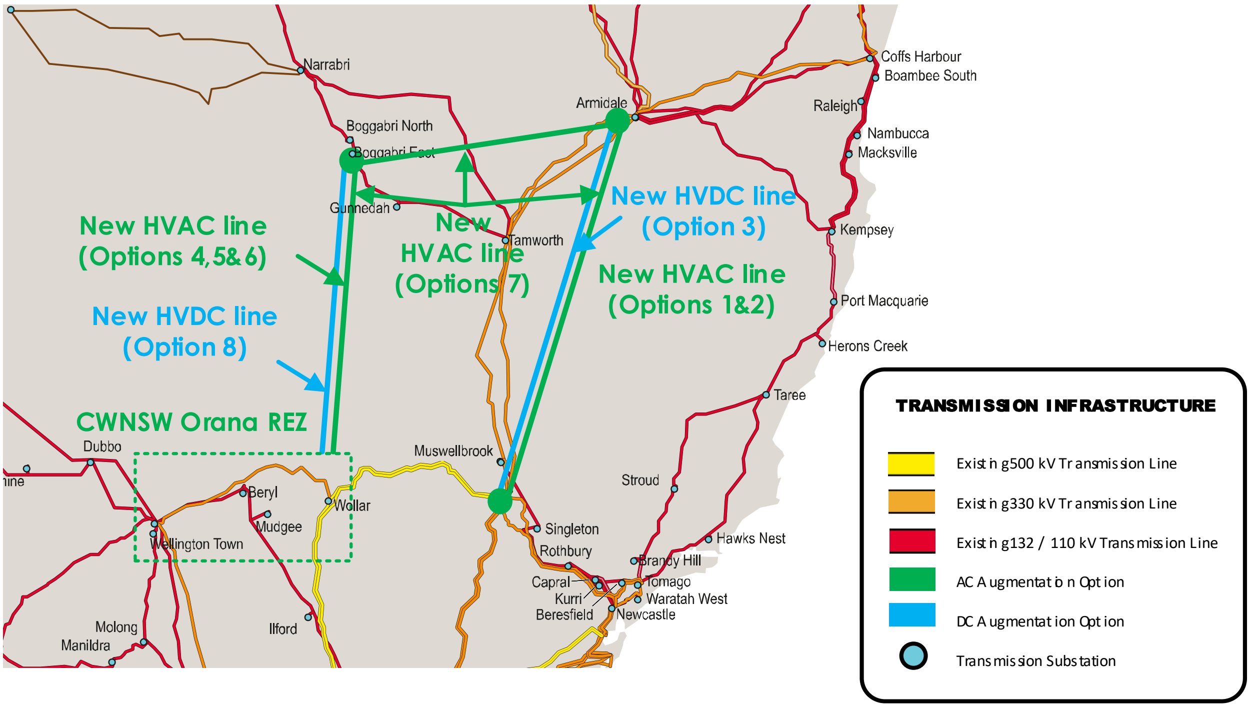


Table 49 CNSW–NNSW development options

Development path	Development driver	Option Name	Description	Notional transfer limit increase (MW)	Indicative cost estimates ($ million in real June 2019 dollars)†	Indicative lead time for service
Existing QNI corridor	To increase thermal capacity and, voltage and transient stability limits of 330 kV lines between Liddell and Uralla.	CNSW–NNSW Option 1	A new 330 kV double-circuit line from Liddell to Uralla.	1,145 MW CNSW to SNSW 1,115 MW SNSW to CNSW	$385 – 715 million	7 years
		CNSW–NNSW Option 2	A new 500 kV double-circuit line from Bayswater to Uralla	2,370 MW CNSW to NNSW 2,130 MW NNSW to CNSW	$730 – 1,350 million	7 years

Development path	Development driver	Option Name	Description	Notional transfer limit increase (MW)	Indicative cost estimates ($ million in real June 2019 dollars)†	Indicative lead time for service
		CNSW–NNSW Option 3	A 2000 MW bi-pole HVDC transmission system between Bayswater and Uralla	1,750 MW in both directions	1,180 – 2,190	7 years
West of QNI corridor	As above and to provide route diversity to the existing QNI path.	CNSW–NNSW Option 4	A new single 500 kV line in a double-circuit tower construction from new substations in CWNSW Orana and NWNSW REZ.	830 MW CNSW to NNSW 760 MW NNSW to CNSW	$435 - 807 million	7 years
		CNSW–NNSW Option 5	CNSW–NNSW Option 3 plus, An additional new single 500 kV circuit (second circuit) strung between new substations in CWNSW Orana and NWNSW REZ.	Capacity increase in addition to CNSW–NNSW Option 4: 1,540 MW CNSW to NNSW 1,370 MW NNSW to CNSW	$220 – 407 million	2-3 years after CNSW–NNSW option 3.
		CNSW–NNSW Option 6	A new 500 kV double-circuit line from new substations in CWNSW Orana and NWNSW REZ.	2,370 MW CNSW to NNSW 2,130 MW NNSW to CNSW	$630 – 1,168 million	7 years
		CNSW–NNSW Option 7	A new 500 kV single circuit line from a new substation in CWNSW Orana and NWNSW REZ (Boggabri); and A new 500 kV single circuit from Bayswater to Uralla to Boggabri	2,370 MW CNSW to NNSW 2,130 MW NNSW to CNSW	$995 – 1,852 million	7 years
		CNSW-NNSW Option 8	A 2000 MW bi-pole HVDC transmission system between a new substation in CWNSW Orana and NWNSW REZ (Boggabri)	1,750 MW in both directions	$1,140 – 2,120 million	7 years

† AEMO will apply the cost provided by Powerlink and TransGrid via preparatory activities (see section 4.11.7).

Central New South Wales to Sydney, Newcastle and Wollongong (CNSW–SNW)

The transmission network in the Sydney, Newcastle and Wollongong (SNW) area was originally designed to connect large coal-fired generators in the Hunter Valley to supply the SNW load centres. When these coal-fired generators retire, the network has insufficient capability to supply SNW load centres from generators located outside of the Hunter Valley. Additional transmission network augmentation will be needed to access renewable generation outside the SNW area and/or non-network services would be needed to supply the load centre.

The location of network augmentation or non-network services will depend on the sequence of coal-fired generation retirement and the location of renewable generation developments. The table and figure below present two transmission network options – one for increased renewable generation from the northern side and the other for increased generation in the southern side of the SNW area. In the 2020 ISP, AEMO recommended that TransGrid complete preparatory activities for reinforcing Sydney, Newcastle and Wollongong supply. Alternative proposals flagged in TransGrid's assessment may also be considered.

Figure 43 CNSW–SNW development corridors

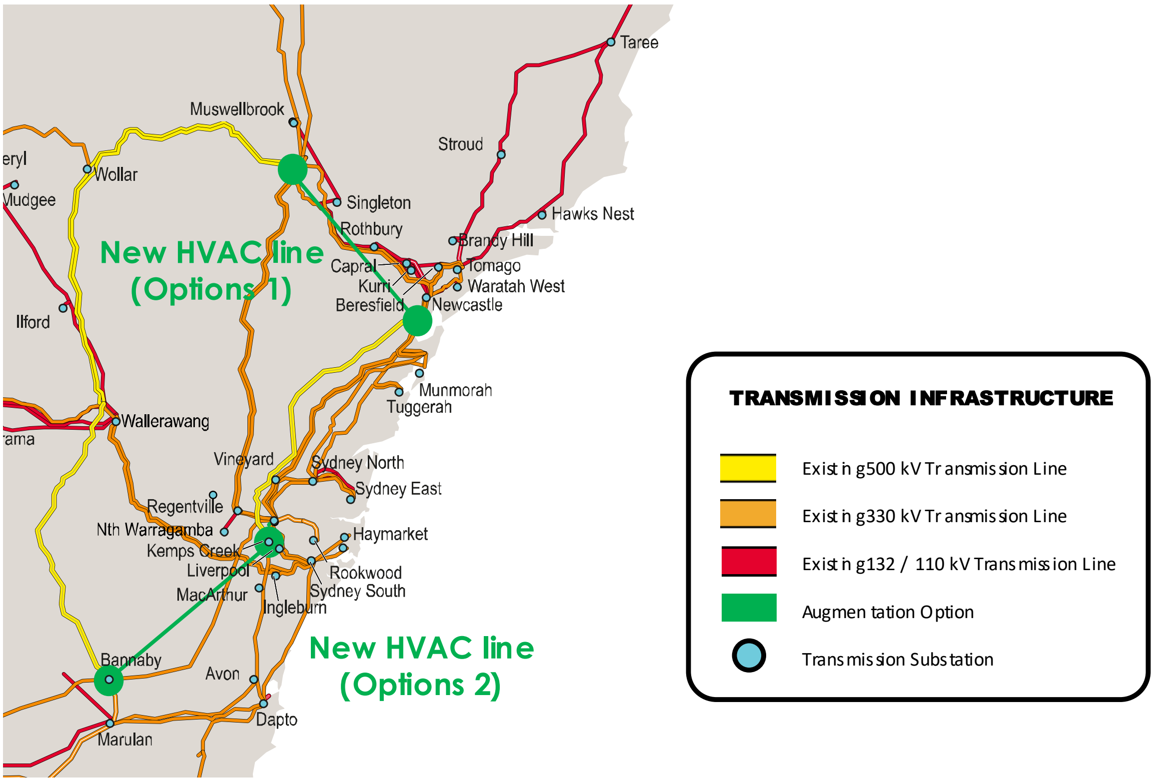


Table 50 Development options for CNSW–SNW

Development path	Development driver	Option Name	Description	Notional transfer limit increase (MW)	Indicative cost estimates ($ million in real June 2019 dollars)	Indicative lead time for service
Northern Side of Sydney	Retirement of coal-powered generation in New South Wales. The sequence of works and the optimal timing highly influenced by load distribution, battery storage locations, and potential line uprating's within Greater Sydney load centre.	CNSW–SNW Option 1	Two 500 kV lines between Eraring and Bayswater (Northern loop)	Between 5,000 MW and 6,000 Mw (with both northern and southern developments in service)	AEMO will apply the cost provided by TransGrid via preparatory activities (see section 4.11.7).	8 years
Southern Side of Sydney		CNSW–SNW Option 2	Two 500 kV lines from Bannaby to a new substation between Eraring and Kemps Creek (Southern loop)			8 years

South New South Wales to Central New South Wales (SNSW–CNSW)

HumeLink is a proposed transmission network augmentation that reinforces the New South Wales southern shared network to increase transfer capacity to the region's demand centre. This is an actionable 2020 ISP project. TransGrid is currently undertaking a RIT-T for this network augmentation. The Project Assessment Draft Report (PADR), the second report of the RIT-T, was published in January 2020[139].

Figure 44 SNSW–CNSW development corridors

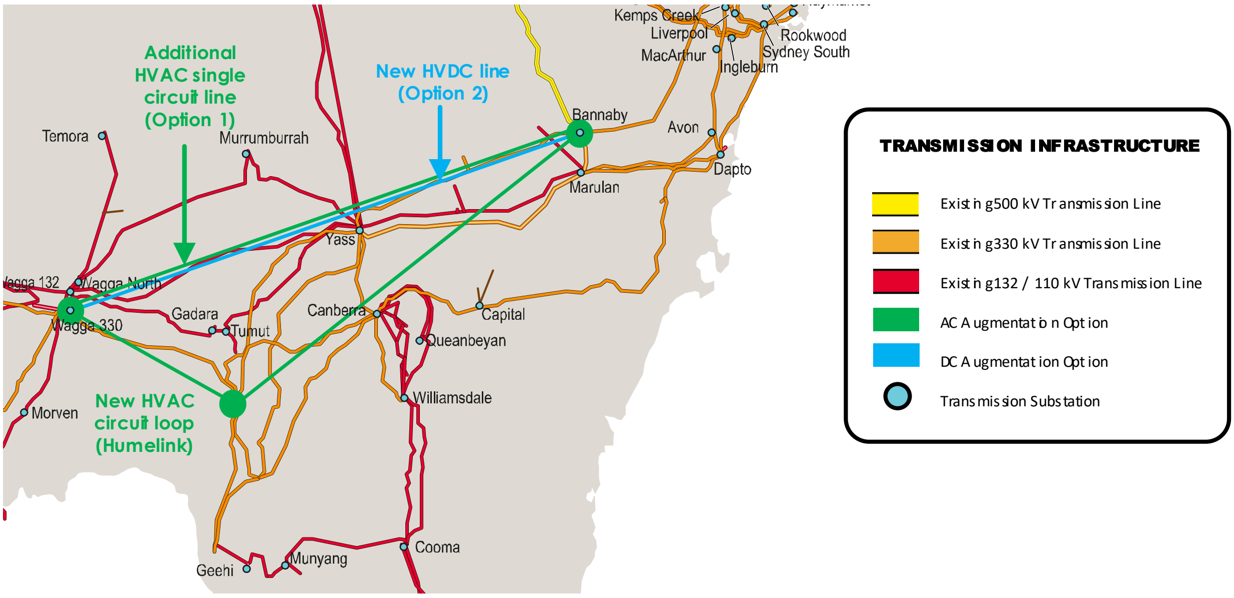


Table 51 Development options for SNSW–CNSW

Development path	Development driver	Option Name	Description	Notional transfer limit increase (MW)	Indicative cost estimates ($ million in real June 2019 dollars)	Indicative lead time for service
HumeLink	Without HumeLink, the capacity from Snowy 2.0 and other generation in southern New South Wales will not be able to reach major load centres.	HumeLink	500 kV transmission line from Maragle to Bannaby to Wagga Wagga and back to Maragle.	2,230 MW to 2,570 MW	The latest cost information from the HumeLink RIT-T will be applied.	The latest timing information from the HumeLink RIT-T will be applied.
Wagga Wagga to Bannaby (After HumeLink)	Increased import from Victoria and South Australia with high existing and Snowy 2.0 hydro generation	SNSW–CNSW Option 1	An additional 500 kV line from Wagga Wagga to Bannaby.	2,000 MW in both directions	$700 – 1,300 million	7 years
		SNSW–CNSW Option 2	A 2,000 MW HVDC bi-pole transmission system between Wagga Wagga and Bannaby	1,750 MW in both directions	$1,270 – 2,360 million	7 years

[139] TransGrid. HumeLink – delivering safe, reliable and affordable electricity, at https://www.transgrid.com.au/humelink.

Victoria to South New South Wales (VIC–SNSW)

The 2020 ISP recommended two actionable ISP projects to increase transfer capability between Victoria and New South Wales. These are:

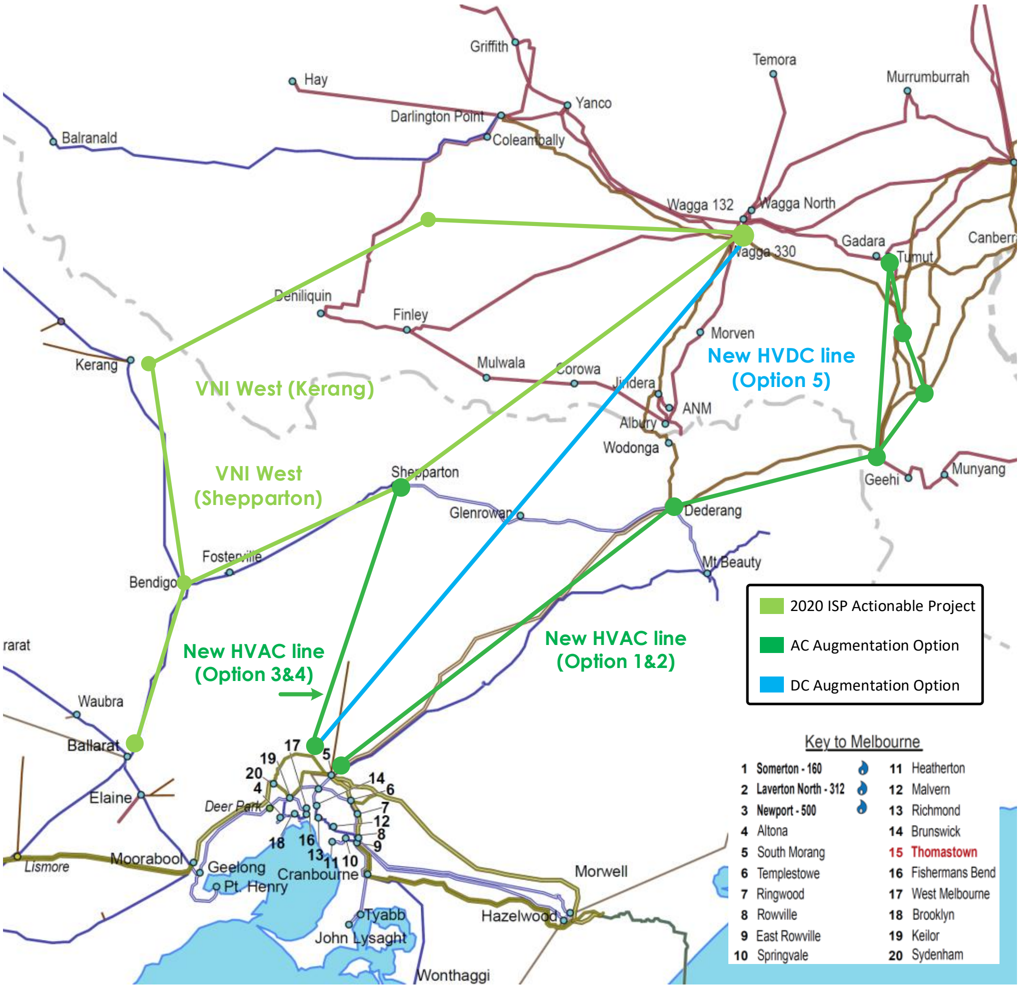
- **VNI Minor** – an incremental capacity increase from Victoria to New South Wales. TransGrid and AEMO completed the RIT-T for VNI Minor in February 2020[140] (see Section 4.11.4).
- **VNI West** – a large capacity increase in both directions currently being assessed by TransGrid and AEMO through the VNI West RIT-T[141].

Options to increase transfer capacity

More renewable generation is expected to be connected across the Victorian transmission network to meet the VRET. Without network augmentation, the Victorian transmission network will become constrained. The figure and table below present:

- Two network options (pale green) being assessed to increase Victoria – New South Wales power transfer capacity and increase the VRE hosting capacity of REZs (VNI West via Kerang or Shepparton).
- Additional network options (dark green and blue) to further increase transfer between Victoria and New South Wales after VNI West is delivered.

Figure 45 VIC–SNSW development corridors



[140] AEMO. Victoria to New South Wales interconnector upgrade regulatory investment test for transmission, at https://aemo.com.au/initiatives/major-programs/victoria-to-new-south-wales-interconnector-upgrade-regulatory-investment-test-for-transmission.

[141] AEMO. Victoria to New South Wales Interconnector West (VNI West) regulatory investment test for transmission (RIT-T), at https://aemo.com.au/initiatives/major-programs/victoria-to-new-south-wales-interconnector-west-regulatory-investment-test-for-transmission.

Table 52 Development options for VIC–SNSW

Development path	Development driver	Option Name	Description	Notional transfer limit increase (MW)	Indicative cost estimates ($ million in real June 2019 dollars)	Indicative lead time for service
West of VNI 330 kV path (VNI West) †	Increase thermal capacity and, voltage and stability limit of VNI. Provide route diversity of existing VNI 330 kV corridor	VNI West (Shepparton path)	A new 500 kV double-circuit line from north of Ballarat to near Shepparton to Wagga Wagga.	1,930 MW VIC to SNSW 1,800 MW SNSW to VIC	The latest cost information from the VNI West RIT-T will be applied.	Service date 2028
		VNI West (Kerang path)	A new 500 kV double-circuit line from north of Ballarat to near Bendigo to near Kerang to Dinawan to Wagga Wagga.	1,930 MW VIC to SNSW 1,800 MW SNSW to VIC	The latest cost information from the VNI West RIT-T will be applied.	Service date 2028
Existing VNI 330 kV path (Post VNI West)	Increase thermal capacity and, voltage and stability limit of existing VNI and VNI West	VNI Option 1	A new double-circuit 330 kV transmission line from South Morang to Dederang to Murray.	1,500 MW in both directions	$742 – 1,378 million	3 years after VNI West
		VNI Option 2	Convert South Morang-Dederang-Murray-Upper Tumut-Lower Tumut 330 kV lines to 500 kV design and operation.	1,500 MW in both directions	$2,020 – 3,755 million	3 years after VNI West
Additional Path from Melbourne to Shepparton (Post VNI West)	Increase thermal capacity and, voltage and stability limit of existing VIC-NSW interconnector and VNI West	VNI Option 3	A new 500 kV double-circuit line from north of Melbourne to near Shepparton.	1,000 MW in both directions	$555 – 1,030 million	3 years after VNI West
Additional Path from Melbourne to Kerang (Post VNI West)		VNI Option 4	A new 500 kV double-circuit line from north of Melbourne to near Shepparton to Wagga Wagga.	2,000 MW in both directions	$1,330 – 2,470 million	3 years after VNI West
Donnybrook to Wagga Wagga (Post VNI West)		VNI Option 5	A 2,000 MW HVDC bi-pole transmission system between north of Melbourne and Wagga Wagga	1,750 MW in both directions	$1,570 – 2,915 million	3 years after VNI West

† The latest values from the VNI West RIT-T will be adopted following the release of the Project Assessment Draft Report.

Tasmania to Victoria (TAS–VIC)

Marinus Link consists of two new high voltage direct current (HVDC) cables connecting Victoria to Tasmania, each with 750 MW transfer capacity and associated high voltage alternating current (HVAC) transmission. TasNetworks is currently undertaking a RIT-T to identify the preferred option and net market benefits for the project. The PADR, the second report of the RIT-T, was published in December 2019[142].

In November 2020, TasNetworks published a supplementary analysis report[143], with updated cost benefit analysis using the 2020 ISP assumptions. Marinus Link is now in the Design and Approvals phase of the project and was recognised by the Federal Government as a priority project for economic recovery from COVID-19. Accordingly, it received enhanced environmental approvals assessment resourcing, meaning if an investment decision is made in 2024, it could be delivered by 2027, earlier than assumed in the 2020 ISP.

Figure 46 TAS–VIC development corridors

[142] TasNetworks. RIT-T Process, available at https://www.marinuslink.com.au/rit-t-process/.

[143] TasNetworks, https://www.marinuslink.com.au/wp-content/uploads/2020/11/Marinus-Link-Supplementary-Analysis-Report.pdf.

Table 53 Development options for TAS–VIC

Development path	Development driver	Credible alternative options	Description	Notional transfer limit	Indicative cost estimates ($ million in real June 2019 dollars)	Indicative service date
Proposed Marinus Link path **(Path between Burnie area and Latrobe Valley area)**	Increase transfer capacity between Victoria and Tasmania	TAS–VIC Option 1	A 750 MW monopole high voltage direct current (HVDC link) between Burnie area in Tasmania and Latrobe Valley in Victoria. A 220 kV double-circuit AC line from Palmerston to Sheffield to the Burnie area.	TAS to VIC 750 MW in both directions Marinus Link and Basslink combined TAS to VIC 1,228 MW. VIC to TAS 978 MW	$1,292 – 2,399 million The latest cost information from the Marinus Link RIT-T will be applied.	Service date: October 2027 To allow time for inter-network testing, AEMO will model this augmentation at full capacity from mid-2028.
		TAS–VIC Option 2	A 2x750 MW HVDC link between Burnie area in Tasmania and Latrobe Valley in Victoria. A 220 kV double-circuit ac line from Palmerston to Sheffield to the Burnie area. A 220 kV double-circuit ac line from Staverton to Hampshire to the Burnie area.	TAS to VIC 1,500 MW in both directions Marinus Link and Basslink combined TAS to VIC 1,928 MW. VIC to TAS 1,728 MW	$2,209 – 4,102 million The latest cost information from the Marinus Link RIT-T will be applied.	2nd link service date: October 2029 To allow time for inter-network testing, AEMO will model this augmentation at full capacity from mid-2030.

Matters for consultation

- Do the augmentation options for the inter-zonal model listed above capture a good spread of credible options?
- Is the evolution into inter-zonal augmentation options from inter-regional options appropriately defined?

4.11.6 Transmission augmentation costs

Input vintage	Costs developed for 2020 ISP.
Source	• Actionable projects: RIT-T data with factors applied. • Future projects: AEMO in-house data.
Update process	A new Transmission Cost Database will be produced primarily for AEMO to estimate the cost of network augmentation options. This process will exclude projects that are currently being assessed by TNSPs under the RIT-T or where AEMO has triggered Preparatory Activities (see Section 4.11.7).. The Transmission Cost Database will be used to review and provide an independent cross-check of estimates provided by the TNSPs. Costs for other network augmentations will be produced using the new database and consulted on from May to June 2021.
Get involved	• Draft 2021 IASR consultation: December 2020 – February 2021 • Transmission cost database webinar: January 2021 (to be advised; engagement updates will be provided to the ISP mailing list and at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/opportunities-for-engagement.) • Draft Transmission Cost consultation: May to June 2021

This section outlines the cost estimates used for transmission projects in AEMO's modelling activities. In the NEM, transmission is typically a regulated asset, and for a new transmission project to be approved, the relevant TNSP is required to go through the RIT-T, administered by the AER. Information on the stages of the RIT-T can be found on the AER website[144].

As part of the RIT-T process, TNSPs progress the design of proposed projects in collaboration with AEMO and develop cost estimates. As a project progresses further through the RIT-T stages, and the level of design increases, the accuracy of the cost estimate is also expected to improve.

Following feedback from stakeholders on the transmission costs assumed for the 2020 ISP, AEMO has begun an initiative to improve the accuracy and transparency of costs used for the 2022 ISP. This section outlines the planned process for improvement activities and covers the following:

- Current cost estimates (as used in the 2020 ISP):
  - Early stage projects.
  - Later stage projects.
  - Cost components.
- Forward program.
- Consultation on transmission costs.

Current cost estimates

AEMO has not finalised a set transmission cost estimates for the 2022 ISP for this IASR; rather, AEMO intends to develop a more sophisticated approach in collaboration with stakeholders for the treatment of cost inputs for transmission projects. In recognition of stakeholder feedback and views in this area, AEMO considers it more appropriate to comprehensively engage with stakeholders in the preparation of both the approach to transmission cost estimation and the final estimates to be applied for the 2022 ISP in early 2021 (see the next section on the forward program).

For reference, the approach used to estimating costs for the 2020 ISP is described below and listed in sections 4.11.4 and 4.11.5 for each project.

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

Early stage projects

For the 2020 ISP, AEMO used an in-house database to estimate costs for early stage transmission projects, before and during the Project Specification Consultation Report (PSCR) stage of the RIT-T. Capital cost estimates of transmission network projects are indicative and are prepared from desktop studies based on the latest cost data available within AEMO[145]. These cost estimates include planning estimates of the following components:

- Preliminaries – site survey, geotechnical and location services.
- Design and engineering.
- Primary plant (towers, conductors, transformers, switchgears, static/dynamic reactive plant).
- Secondary systems including control and protection.
- Civil works including clearing, excavation, earthworks, foundation, support structure.
- Building for secondary equipment.
- Testing and commissioning of plant.
- Project management.

AEMO's unit cost estimates for transmission assets are provided in the Draft 2021-22 Inputs and Assumptions Workbook.

Cost estimates of transmission lines are based on 110% of the straight-line distance between two connection points. A 5% of overall capital cost is allowed for land and easement. The specific route will only be confirmed during detailed preparation of a RIT-T. An extensive range of factors may affect the project cost including (but not limited to) environmental factors affecting line route, biodiversity considerations, land acquisition or easement cost, construction cost implications arising from route dynamics, currency fluctuations and construction contractor costs in the proposed construction period.

Later stage projects

For the 2020 ISP, cost estimates of transmission network projects currently undergoing RIT-T by TNSPs were obtained from the RIT-T or latest information available[146].

Feedback received on the Draft 2020 ISP indicated that the estimates for the major interconnector projects were too low. In some cases, as projects progressed through the RIT-T and TNSPs were able to complete more detailed assessments, cost estimates were observed to increase approximately 30% from initial estimates. A key reason for this was that estimates in the RIT-Ts, in particular in the early stages of RIT-Ts, were based on preliminary information, without the benefit of full detailed assessments (such as land, planning, community engagements, and detailed technical designs). Another factor was that new transmission has not been built for some time in the NEM.

As a consequence, for the final modelling on the 2020 ISP, after collaborating with the responsible TNSPs, AEMO increased the capital cost estimates on all identified ISP transmission projects by approximately 30%. The Marinus Link cost was adjusted to reflect updated information on HVDC works and pre-construction activities. REZs included network designs which also incorporated a 30% increase on network costs within the REZ, and some projects had variations where better information was available.

All capital cost estimates are considered to be within ±30% tolerance. A 1% of capital cost per annum is generally assumed as operation and maintenance cost.

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[145] For the 2020 ISP, the latest cost data available is as at February 2020.

[146] For the 2020 ISP, cost estimates of transmission networks projects currently undergoing RIT-T by TNSPs were obtained from the RIT-T or latest information available in March 2020.

Cost components

Cost data for transmission components used in the 2020 ISP is included in the Draft 2021-22 Inputs and Assumptions Workbook. This data will be updated and expanded to include additional components such as HVDC lines and overhead and risk costs, as part of the forward program outlined below.

Forward program

Following feedback from stakeholders on the transmission costs assumed for the 2020 ISP, AEMO has commenced an initiative to improve the approach to and transparency of input cost estimation for transmission used for the 2022 ISP.

AEMO will collaborate with TNSPs and use an independent consultant to produce and publish an updated database of unit costs. The scoping phase is now complete, and the consultant report outlining the suggested framework for the transmission cost database is in the Transmission Cost Database Phase 1 Report[147].

This transmission cost database will provide a reference point of information, primarily for use in estimating the costs for candidate future ISP projects, with suitable risk margins to allow for the large amount of known but as yet unquantified potential additional costs at this stage of proposed projects. The database will also provide an independent reference for stakeholders when considering projects that are 'Future ISP projects with Preparatory Activities', or are undergoing the RIT-T process when ISP modelling begins.

The sources of cost estimates proposed for the 2022 ISP are outlined in the table below.

Table 54 ISP transmission projects – source of cost inputs for 2022 ISP

2020 ISP project category	Specific projects	Source of estimate to be used in ISP modelling	Form of estimate†	Role of Transmission Cost Database
Actionable (excluding anticipated transmission projects – see Section 4.11.4)	HumeLink Central-West Orana REZ Transmission Link	TNSP	Single $ figure with quoted accuracy range	Independent cross-check
Actionable – staged with decision rules	VNI West ‡ Marinus Link	TNSP	Single $ figure with quoted accuracy range	Independent cross-check
Future ISP Projects with Preparatory Activities	QNI Medium & Large Central to Southern QLD Gladstone Grid Reinforcement Reinforcing Sydney, Newcastle & Wollongong Supply New England REZ North West NSW REZ	TNSP	$ figure for each potential route option, with quoted accuracy range	Independent cross-check
Candidate ISP projects	All other network expansion and candidate REZ augmentations	AEMO's transmission cost database	$/MW for stated line length basis (for input to models)	Basis for estimate

† AEMO reserves the right to add offsets to prices advised by TNSPs to ensure that uncertainty and risks are applied consistently across investment options. This process will be consulted on via the ISP Methodology and Transmission Cost Database consultations.
‡ The project cost estimates for the VNI West options are currently being developed as part of the RIT-T being conducted by AEMO and TransGrid. Further information will be become available as the RIT-T progresses.

[147] MBB. AEMO Transmission Cost Database Report, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/Transmission-Cost-Database-Phase-1-Report.pdf.

The expected timeline for the transmission cost database project is shown in Table 55 below.

Table 55 Timeline for Transmission Cost Database Project

Step Description	Start	End
Scoping study	September 2020	October 2020
Build new cost database	December 2020	April 2021
Transmission Cost Database stakeholder workshop	January 2021	-
AEMO to develop estimates for candidate Future projects	April 2021	May 2021
Draft Transmission Cost Report (4 week consultation)	May 2021	June 2021
Webinar on overview of network augmentation costs for 2022 ISP	May 2021	-
TNSPs provide costs for future projects with preparatory activities and current actionable projects	-	June 2021
AEMO review of TNSP estimates	June 2021	July 2021
Publication of final 2021 IASR with updated transmission costs	July 2021	-

Consultation on transmission costs

The first stakeholder workshop is planned for January 2021, with the aim of obtaining feedback and eliciting views on the proposed process to preparing a Transmission Cost Database.

As shown in the timeline above, there will be a four-week consultation period starting in May 2021 on the cost estimates for the candidate Future ISP projects. This will include a published draft report, a workshop for collaboration with stakeholders in which AEMO will actively seek views on a range of matters in relation to these projects, and the opportunity for written feedback.

TNSPs are required to provide estimates of costs and initial designs for the projects that are 'Future ISP projects with Preparatory Activities' or are undergoing the RIT-T process by June 2021. This timing is needed to provide the information AEMO needs to commence modelling. Information provided by TNSPs will be cross-checked by AEMO and included in the final 2021 IASR. Following publication of the final 2021 IASR in July 2021, there will not be further opportunity to consult on these TNSP transmission costs prior to commencing the extensive modelling for the draft 2022 ISP.

Matters for consultation

- Do you wish to provide views on transmission cost estimation ahead of the planned engagement, or suggestions for these upcoming engagements?

4.11.7 Preparatory activities

Input vintage	New
Source	TNSPs
Update process	2021 IASR process
Get involved	These are specially for TNSPs to undertake. AEMO welcomes feedback on all augmentation options described in Section 4.11.5.

As part of the actionable ISP rules[148], AEMO can ask TNSPs to provide a report on preparatory activities for future ISP projects. These are typically projects which may become actionable ISP projects, but more detailed information is required, such as improved cost estimates, network designs, and initial appraisal of land considerations. This initial high-level design and costing in the preparatory activities report is necessarily approximate, as the detailed requirements for robust costings and plant design will not have been undertaken – this would require much more extensive work, including detailed Geotech land surveying along with engagement on the route and necessary planning approvals. Preparatory activities are not the same as early works leading to final investment decision (FID), as preparatory activities remain essentially a desktop exercise.

The projects for which preparatory activities are currently required to be performed by the TNSPs are outlined in the following table.

Table 56 Preparatory activities

Project	Timing	Preparatory activities required by	Responsible TNSP(s)
QNI Medium and Large	2032-33 to 2035-36	30 June 2021	Powerlink and TransGrid
Central to Southern Queensland Transmission Link	Early 2030s	30 June 2021	Powerlink
Gladstone Grid Reinforcement	2030s	30 June 2021	Powerlink
Reinforcing Sydney, Newcastle and Wollongong Supply	2026-27 to 2032-33	30 June 2021	TransGrid
New England REZ Network Expansion	2030s	30 June 2021	TransGrid
North West NSW REZ network expansion	2030s, based on connection interest	30 June 2021	TransGrid

Matters for consultation

- Is there any specific feedback on the treatment of costs and options developed via preparatory activities for inclusion in the ISP?

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

4.11.8 Non-network options

Input vintage	Unchanged since 2020 ISP
Source	Previous projects, stakeholder submissions
Update process	2021 IASR and progression of RIT-Ts.
Get involved	2021 IASR update process

AEMO seeks input on any non-network options for consideration in the 2022 ISP. Non-network options specifically to address the identified need for projects declared actionable in the 2020 ISP are being investigated through the RIT-T process.

In the ISP, AEMO considers potential non-network options alongside network solutions to develop an efficient power system strategy. Depending on their relative costs and benefits, the capital costs of large network augmentation could be deferred or avoided by delivering a non-network solution.

Non-network options include a range of technologies, for example:

- Generation investment (including embedded or large-scale).
- Storage technologies (such as battery storage and pumped hydro).
- Demand response.

As per item 27 (Table 13) of the AER CBA guidelines[149], prior to the draft ISP, AEMO is required to:

- Undertake early engagement with non-network proponents to gather information in relation to non-network options; and
- If there are any credible non-network options identified through early engagement and joint planning, but not included in a TAPR, include these in step one of its process for selecting development options.

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

Matters for consultation

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

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

4.11.9 Inter-regional loss flow equations and marginal loss factor (MLF) equations and loss proportion factors

Input vintage	Loss proportioning factors	Existing network: 2020 Loss factors and regional boundaries Augmentation Options: 2019 Draft ISP, not updated for 2020 Final ISP
	Inter-regional loss flow equations	Existing network: 2020 Loss factors and regional boundaries Augmentation Options: Included in Draft 2021-22 Inputs and Assumptions Workbook for first time – based on July 2020 Regions and Marginal Loss Factors Report.
Source	AEMO, Regions and Marginal Loss Factors Report.	
Update process	Updated in line with AEMO's annual Regions and Marginal Loss Factors Report.	
Get involved	2021 IASR and ISP Methodology Consultation	

This section describes the inter-regional loss flow equations, interconnector MLF equations, and interconnector loss proportioning factors for use in long-term planning studies such as the ISP and ESOO. While the zonal model does split some regions into zones, losses are initially proposed to continue to be modelled across regional boundaries. This section will therefore retain losses as defined between NEM regions. This treatment, and the zonal model, is still in early stages of development and this proposal may change based on feedback to the ISP Methodology consultation. AEMO welcomes feedback on these issues in the Draft 2021 IASR and the ISP Methodology consultation process that will commence early in 2021.

Inter-regional loss flow equations

Inter-regional loss flow equations are used to determine the amount of losses on an interconnector for any given transfer level. These are used to determine net losses for different levels of transfer between regions so NEMDE or PLEXOS can ensure the supply-demand balance includes losses between regions. Inter-regional loss flow equations are presented in the Interconnector loss parameters tab of the Draft 2021-22 Inputs and Assumptions Workbook.

Inter-regional loss flow equations describe the variation in loss factor at one regional reference node (RRN) with respect to an adjacent RRN. These equations are necessary to cater for the large variations in loss factors that may occur between RRNs as a result of different power flow patterns. This is important in minimising the distortion of economic dispatch of generating units. Inter-regional loss flow equations can be found on the Interconnector loss parameters tab of the Draft 2021-22 Inputs and Assumptions Workbook.

Interconnector loss proportioning factors

Inter-regional losses are proportioned to individual regions by NEMDE or PLEXOS. This dispatch process implements inter-regional loss factors by allocating the inter-regional losses to the two regions associated with a notional interconnector. The proportioning factors are used to portion the inter-regional losses to two regions by an increment of load at one RRN from the second RRN. The incremental changes to the inter-regional losses in each region are found from changes to interconnector flow and additional generation at the second RRN. The average proportion of inter-regional losses in each region constitutes a single static loss factor.

Loss proportion factors are out an outcome of applying the methodology described in AEMO's Forward-Looking Transmission Loss Factors[150]. Loss proportion factors are updated every financial year with

[150] AEMO. Forward Looking Loss Factor Methodology, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries.

the publication of AEMOs Regions and Marginal Loss factors Report[151]. Inter-regional loss flow equations are presented in the Interconnector loss parameters tab of the Draft 2021-22 Inputs and Assumptions Workbook.

Matters for consultation

- While AEMO will consult further on the approach to modelling loss factors in the ISP Methodology consultation, AEMO welcomes initial views on the approach that AEMO should take for loss factors, particularly as new transmission and generation is projected to be commissioned.

4.11.10 Network losses – marginal loss factors

Input vintage	July 2020
Source	AEMO, Regions and Marginal Loss Factors Report.
Update process	Updated in line with AEMO's annual Regions and Marginal Loss Factors Report.
Get involved	• For how these are incorporated into the ISP, the ISP Methodology Consultation. • AEMO is also presently consulting on forward-looking loss factors (see https://aemo.com.au/consultations/current-and-closed-consultations/forward-looking-transmission-loss-factors).

Network losses occur as power flows through transmission lines and transformers. Increasing the amount of renewable energy connected to the transmission network remote from load centres will increase network losses. As more generation connects in a remote location, the power flow over the connecting lines and on the AC system increases, and so do losses. In the NEM, transmission network losses are represented through marginal loss factors (MLFs).

MLFs are used to adjust the price of electricity in a NEM region, relative to the RRN, in a calculation that aims to recognise the difference between a generator's output and the energy that is actually delivered to consumers. In dispatch and settlement in the NEM, the local price of electricity at a connection point is equal to the regional price multiplied by the MLF. A renewable generator's revenue is directly scaled by its MLF, through both electricity market transactions and any revenue derived from large-scale renewable generation certificates (LGCs) created if accredited under the LRET.

MLFs are an outcome of applying the methodology described in AEMO's Forward-Looking Transmission Loss Factors. MLFs are updated every financial year with the publication of AEMO's Regions and Marginal Loss Factors Report. AEMO proposes to update the MLFs to reflect the latest available version of this report. Where a committed or anticipated generator does not have an MLF calculated in the Forward-Looking Transmission Loss Factor report, a 'shadow' generator is used. This is a generator which is located electrically close to the generator in question, and where possible, is the same technology. This same concept is applied to generic new entrant generators.

See the MLF tab in the Draft 2021-22 Inputs and Assumptions Workbook for values to be consulted on in Draft 2021 IASR.

Matters for consultation

- While AEMO will consult further on the approach for modelling MLFs in the ISP in its consultation on the ISP Methodology, AEMO welcomes initial views on the approach that AEMO should take for new generation.

[151] AEMO. Regions and Marginal Loss Factors, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries.

4.11.11 Transmission line failure rates

Input vintage	July 2020
Source	AEMO Network Outage Schedule and other AEMO sources.
Update process	To be updated as part of data collection process for 2021 ESOO.
Get involved	FRG: June 2021

Similar to generators, forced outage rates of inter-regional transmission elements are critical inputs for AEMO's reliability assessments. Information is collected on the timing, duration and severity of the transmission outages to inform transmission forced outage rate forecasts.

Where relevant, AEMO will implement time-varying outages rates based on meteorological parameters, such as wind gust and bushfire weather. Input meteorological trends will follow climate change projections consistent with the scenario specification. The use of meteorological variables ensures that forced outages are simulated consistent with the reference year, with regard for coincident power system impacts. This improvement is subject to consultation as outlined in AEMO's Forecast Accuracy Report and associated improvement plan, and is not part of this Draft 2021 IASR consultation

The following table shows the inputs used in the 2020 ESOO, which will be subject to revision and FRG consultation for use in future publications.

Table 57 Transmission line failure rates

Transmission Flow Path	Unplanned outage rate (%)	Mean time to repair (hours)
New South Wales – Victoria	0.53	25.65
Victoria-South Australia (Heywood)	2.64	80.87
Victoria-Tasmania (Basslink)	0.07	1.87

4.12 Other power system security inputs

Planning studies focus on the reliability and security of the future power system under system normal conditions and following the first credible contingency, including the continued availability of various system services to be able to restore the power system to a secure operating state within 30 minutes following a contingency. As such, planning studies focus not only on energy and reliability, but also on system services and system security.

New generation and transmission investments may change the scale and location of these required services, and a changing mix of technologies from synchronous units and new IBR developments create both key challenges and key opportunities for planning the future power system. This is especially so for voltage-related system services such as reactive reserve levels, voltage control, and system strength, which are localised and impacted by changes in local area infrastructure.

The sections which follow describe the security services AEMO incorporates into its planning assessments.

4.12.1 Power system security services

Input vintage	2020 ISP
Source	AEMO internal
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR and may be further updated through the ISP Methodology consultation processes.
Get involved	Draft 2021 IASR consultation and ISP Methodology

To operate the power system in a secure and reliable manner, a number of power system security services are required. AEMO's Power System Requirements document[152] describes the services in more detail, and the capabilities of various technologies to supply these services.

Many power system requirements are often not modelled when forecasting the economic market dispatch. Therefore, AEMO post-processes market modelling outcomes to assess the capability of the future power system with respect to:

- **System strength** – including fault current and short-circuit ratio.
- **Frequency control** – including inertia, fast frequency control and frequency control ancillary services (i.e. primary and secondary frequency response).
- **Non-credible contingencies** – including the trip of double-circuit interconnectors.

High-level planning assumptions are applied when developing the ISP, given the uncertainty regarding the future operation of synchronous generating units, emerging technology and new innovations for that enable IBR to provide sought-after system services, demand levels, regulatory change, operational measures, and other emerging security issues. As the system evolves, and once detailed models are available, comprehensive studies will be required to improve the accuracy of operating requirements and limits advice.

The tables in the following sections highlight the source of power system services now and into the future for each region. The following notation is used in the tables:

- **Orange outline** indicates the expected primary service provider for the service.
- **Green shading** indicates the services can be provided by the corresponding source.
- **Shaded green** indicating low or partial levels of service can be provided.
- **Numbers** are used to indicate an approximate unit requirement (when multiple sources are required).

New South Wales

Because the New South Wales power system has multiple large AC interconnectors to other regions, the likelihood of electrical islanding is low. For this reason, it is assumed that inertia and frequency control services can be transferred to New South Wales through the AC interconnectors.

As IBR penetration increases, the number of large synchronous generating units online is reducing and encroaching on the system strength limits. Within AEMO's market modelling, manual constraints are not typically used to enforce these outcomes because the required plant is typically dispatched for energy market outcomes. In future years as coal retires, system strength shortfalls may be declared to ensure delivery of the service. For the purpose of this modelling, AEMO assumes that system strength requirements in New South Wales will be met by services that do not impact on the energy market dispatch, such as synchronous condensers. In practice, a wider range of options could be considered.

The following table outlines the planning assumptions for the current New South Wales power system.

[152] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/power-system-requirements.pdf?la=en.

Table 58 Planning assumptions for the current New South Wales power system

Power System Requirement	Number of required synchronous generating units			IBR	HVDC inter-connection	AC inter-connection		Synchronous condensers	Demand side response	Distributed PV
	Gas	Coal	Hydro (inc PHES)		Directlink	QNI	VNI			
Bulk Energy										
Energy Balance										
Operating Reserve-ramping										
Inertial response and RoCoF										
Primary Frequency Control										
Secondary Frequency Control										
Fast voltage control										
Slow voltage control										
System Strength		≥ 7						Note †		

Notation: Primary service provider | Service provider | Partial service provider | No service provision

† Generation proponents are already installing synchronous condensers to meet localised system strength needs.

As thermal power stations retire (or reduce in operation), the system strength services currently being provided will need to be replaced by other sources such as synchronous condensers or from other synchronous generators (for example, pumped hydro generation). Proposals to increase interconnection to New South Wales will further reduce the likelihood of requiring local services under islanding conditions.

The following table outlines the planning assumptions for the future New South Wales power system (from 2025-26 onward). Due to increased interconnection, increased presence of pumped hydro generators, and expected levels of synchronous condensers being installed for system strength remediation, AEMO assumes that the requirement to maintain a minimum dispatch of coal-fired generators will end[153]. In practice, the pace at which unit commitment requirements reduce will depend on the pace of the energy transition and the delivery of services such as system strength remediation.

[153] Long-term power system security assumptions are used for the purpose of assessing reliability and the economics of development plans. Detailed limits advice is required before changing operational practices.

Table 59 Planning assumptions for the future New South Wales power system

Power System Requirement	Number of required synchronous generating units: Gas	Coal	Hydro (inc PHES)	IBR	HVDC inter-connection: Directlink	AC inter-connection: QNI, QNI 2	VNI, VNI West	SA-NSW	Synchronous condensers	Demand side response	Distributed PV	BESS
Bulk Energy	Service provider	Service provider	Primary service provider	Service provider	Partial service provider	Primary service provider	Primary service provider	Primary service provider	No service provision	Partial service provider	No service provision	Partial service provider
Energy Balance	Service provider	Service provider	Primary service provider	Partial service provider	Service provider	Primary service provider	Primary service provider	Primary service provider	No service provision	Service provider	Partial service provider	Service provider
Operating Reserve-ramping	Service provider	Service provider	Primary service provider	Partial service provider	Partial service provider	Primary service provider	Primary service provider	Primary service provider	No service provision	Partial service provider	Partial service provider	Partial service provider
Inertial response and RoCoF	Service provider	Service provider	Primary service provider	No service provision	No service provision	Primary service provider	Primary service provider	Primary service provider	Primary service provider (Note †)	No service provision	No service provision	No service provision
Primary Frequency Control	Service provider	Service provider	Primary service provider	No service provision	No service provision	Primary service provider	Primary service provider	Primary service provider	No service provision	No service provision	No service provision	Service provider
Secondary Frequency Control	Service provider	Service provider	Primary service provider	No service provision	No service provision	Primary service provider	Primary service provider	Primary service provider	No service provision	Service provider	No service provision	Service provider
Fast voltage control	Service provider	Service provider	Primary service provider	Service provider	Service provider	No service provision	No service provision	No service provision	Primary service provider	No service provision	No service provision	Service provider
Slow voltage control	Service provider	Service provider	Primary service provider	Service provider	Service provider	No service provision	No service provision	No service provision	Primary service provider	No service provision	No service provision	Service provider
System Strength	Service provider	Service provider	Primary service provider	No service provision	No service provision	Partial service provider	Partial service provider	Partial service provider	Primary service provider	No service provision	No service provision	No service provision

Notation: Primary service provider | Service provider | Partial service provider | No service provision

† Even though AC interconnectors assists in resolving local inertia requirements, NEM regions cannot all rely on other regions for inertia at the same time. Fitting high inertia flywheels to new synchronous condensers will efficiently maintain the NEM-wide inertia need.

Queensland

Queensland currently has a number of large coal power stations which provide the essential power system requirements. With IBR (utility and DER) increasingly supplying the energy needed, the reliance on thermal synchronous generation for energy and capacity will reduce. AEMO expects this will lead to changes in the commercial operation of the thermal power stations, including decommitments and partial availability of synchronous units. The power system services that the synchronous units provide will need to be sourced elsewhere if replaced in daily dispatch by cheap energy from IBR to the point where units are decommitted. If too many units are offline in a particular area, then system strength issues may begin to arise. Further, when the QNI interconnector is at risk of tripping (for example, during maintenance or if a double-circuit trip is declared credible) local inertia requirements will become increasingly important.

Within AEMO's market modelling there are initially no need for manual constraint equations to enforce provision of these system services because the required plant is typically dispatched for energy market outcomes. In future years, as plant operation changes, system strength shortfalls may arise. As a long-term planning assumption, AEMO considers that system strength requirements will be met by services that do not impact on the energy market dispatch, such as synchronous condensers or generators running in synchronous converter mode.

The following table outlines the planning assumptions for the current Queensland power system.

Table 60 Planning assumptions for the current Queensland power system

Power System Requirement	Number of required synchronous generating units			IBR	HVDC inter-connection	AC inter-connection	Demand side response	Distributed PV
	Gas	Coal	Hydro (inc. PHES)		Directlink	QNI		
Bulk Energy								
Energy Balance		≥ 2						
Operating Reserve-ramping		≥ 2						
Inertial response and RoCoF		≥ 2 †						
Primary Frequency Control		≥ 1						
Secondary Frequency Control		≥ 4						
Fast voltage control								
Slow voltage control								
System Strength		≥ 11	≥ 2					

Notation: Primary service provider | Service provider | Partial service provider | No service provision

† On the assumption that if high RoCoF for a non-credible separation were to become an issue, interconnector constraints, like used for South Australia, could be implemented.

As coal-fired generation retires, the system strength services currently being provided will need to be replaced by other sources such as synchronous condensers or from additional pumped hydro generation. If an additional New South Wales to Queensland interconnector is delivered, local inertia requirements will no longer be required in the event of one of the AC interconnectors being out of service.

The following table outlines the planning assumptions for the future Queensland power system (from 2025-26 onward). Due to increased interconnection, increased utilisation of pumped hydro generators, and expected levels of synchronous condensers being installed for system strength remediation, AEMO assumes that the requirement to maintain a minimum dispatch of coal-fired generators will end[154]. In practice, the pace at which unit commitment requirements reduce will depend on the pace of the energy transition and the delivery of services such as system strength remediation.

[154] Long-term power system security assumptions are used for the purpose of assessing reliability and the economics of development plans. Detailed limits advice is required before changing operational practices.

Table 61 Planning assumptions for the future Queensland power system

Power System Requirement	Number of required synchronous generating units			IBR	HVDC inter-connection	AC inter-connection		Synchronous condensers	Demand side response	Distributed PV	BESS
	Gas	Coal	Hydro (inc. PHES)		Directlink	QNI	QNI 2				
Bulk Energy											
Energy Balance											
Operating Reserve-ramping											
Inertial response and RoCoF								Note †			
Primary Frequency Control											
Secondary Frequency Control											
Fast voltage control											
Slow voltage control											
System Strength											

Notation: Primary service provider | Service provider | Partial service provider | No service provision

† Even though a second AC interconnector assists resolving local inertia requirements, NEM regions cannot all rely on other regions for inertia at the same time. Fitting high inertia flywheels to new synchronous condensers will prevent NEM wide inertia levels reducing too far.

South Australia

The South Australian power system does not currently have any synchronous hydroelectric or coal-fired generators, so currently, a minimum number of gas-powered generating units are required online at all times in order to meet all service requirements. For planning studies, this operational requirement is modelled with constraint equations that reflect the impact on the economic dispatch.

At present, the requirement for a minimum unit commitment is primarily for system strength, and a minimum of at least four synchronous units are required online[155]. ElectraNet is currently in the process of installing synchronous condensers (see Section 4.11.3), which are expected to reduce the need for synchronous generation to remain online to *at least* two units – noting that during outages, or under certain operational conditions, the need may be higher. For example, to ensure that following a non-credible contingency of the Heywood interconnector[156] the South Australia region is still able to operate in a secure manner, there will likely be remaining requirements only able to be met by synchronous units until a second AC interconnector is in place.

Consistent with ElectraNet's economic evaluation[157] that was used to justify the synchronous condensers, AEMO assumes that two large generating units will be required to remain online following the commissioning

[155] AEMO. Transfer Limit Advice – South Australia and Victoria, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf.

[156] A "non-credible" separation event has occurred approximately once every two to three years since NEM start. With Energy Connect, the separation risk would be reduced.

[157] ElectraNet. Addressing the system strength gap in SA – Economic evaluation report (see section 5.1), at https://www.aer.gov.au/system/files/ElectraNet%20-%20System%20Strength%20Economic%20Evaluation%20Report%20-%2018%20February%202018.PDF.

of synchronous condensers, and that this requirement is eliminated following the commissioning of Project EnergyConnect (see Section 4.11.4).

The following table outlines the planning assumptions for the current South Australia power system.

Table 62 Planning assumptions for the current South Australia power system

Power System Requirement	Number of required Synchronous generating units (Gas)	IBR	HVDC inter-connection (Murraylink)	AC inter-connection (Heywood)	Demand side response	Distributed PV	BESS
Bulk Energy							
Energy Balance	≥ 2						
Operating Reserve-ramping	≥ 2						
Inertial response and RoCoF	≥ 1			Note †			Note ‡
Primary Frequency Control	≥ 1						
Secondary Frequency Control	≥ 2						
Fast voltage control							
Slow voltage control							
System Strength	≥ 4						

Notation: Primary service provider | Service provider | Partial service provider | No service provision

† RoCoF risk is currently managed with a 3 Hz/s RoCoF constraint on the Heywood interconnector.
‡ Fast Frequency Response is currently utilised to reduce synchronous inertia requirements

With Project EnergyConnect and the four large ElectraNet synchronous condensers in place, for the ISP modelling, AEMO assumes there is no longer a minimum requirement for synchronous units to always remain online, even when considering a non-credible trip of one of the AC interconnectors.

The following table outlines the planning assumptions for the future South Australia power system (from 2025-26 onward).

Table 63 Planning assumptions for the future South Australia power system

Power System Requirement	Number of required Synchronous generating units	IBR	HVDC inter-connection	AC inter-connection		Synchronous condensers	Demand side response	DPV	BESS
	Gas		Murraylink	VIC-SA	Energy Connect				
Bulk Energy	Service provider	Service provider	Partial service provider	Service provider	Primary service provider	No service provision	Partial service provider	No service provision	Partial service provider
Energy Balance	Service provider	Partial service provider	Service provider	Service provider	Primary service provider	No service provision	Service provider	Partial service provider	Service provider
Operating Reserve-ramping	Service provider	Partial service provider	Partial service provider	Service provider	Primary service provider	No service provision	Partial service provider	Partial service provider	Partial service provider
Inertial response and RoCoF	Service provider	No service provision	No service provision	Service provider	Primary service provider	Service provider	No service provision	No service provision	No service provision
Primary Frequency Control	Service provider	No service provision	No service provision	Service provider	Primary service provider	No service provision	No service provision	No service provision	Service provider
Secondary Frequency Control	Service provider	No service provision	No service provision	Service provider	Primary service provider	No service provision	Service provider	No service provision	Service provider
Fast voltage control	Service provider	Service provider	Service provider	No service provision	No service provision	Primary service provider	No service provision	No service provision	Service provider
Slow voltage control	Service provider	Service provider	Service provider	No service provision	No service provision	Primary service provider	No service provision	No service provision	Service provider
System Strength	Service provider	No service provision	No service provision	Partial service provider	Partial service provider	Primary service provider	No service provision	No service provision	No service provision

Notation: Primary service provider | Service provider | Partial service provider | No service provision

Tasmania

Tasmania's generation has historically been predominantly hydro-based, and Tasmania has historically relied on this synchronous generation to provide the bulk of Tasmania's needs for power system services, when generating. A key requirement in Tasmania is services to cater for the credible trip of the Basslink interconnector, as with this single contingency Tasmania continues to be exposed to islanding. As more IBR connects to the system, hydroelectric units may be needed to be placed into synchronous condenser mode in order to continue to supply voltage control, inertia and system strength services.

Due to the large number of small distributed hydroelectric generators, Tasmania does not have a strict minimum number of units required to be online, but instead has a large number of combinations that can be utilised.

No manual constraints are applied within market modelling because operation of synchronous condensers when needed does not materially influence the energy market outcomes.

The following table outlines the planning assumptions for the current Tasmania power system.

Table 64 Planning assumptions for the current Tasmania power system

Power System Requirement	Synchronous generating units		IBR	HVDC inter-connection	Synchronous condensers ‡	Demand side response	Distributed PV
	Gas	Hydro		Basslink			
Bulk Energy							
Energy Balance		≥ 2					
Operating Reserve-ramping		≥ 2					
Inertial response and RoCoF							
Primary Frequency Control		≥ 1					
Secondary Frequency Control		≥ 2		Note †			
Fast voltage control							
Slow voltage control							
System Strength							

Notation: Primary service provider | Service provider | Partial service provider | No service provision

† Noting Basslink has a Frequency Controller that enables transfer of FCAS.
‡ A number of hydro generating units can be placed into synchronous condenser mode in the Tasmanian region.

The proposed Marinus Link project (see Table 53) will relax the reliance on hydro generation for all the services. Services are predominantly expected to be met with hydro generation (generating, pumping or synchronous condenser mode), or via one of the HVDC links.

The following table outlines the planning assumptions for the future Tasmania power system (from approximately 2028-29 onward). Due to increased interconnection and increased development of VRE with system strength remediation, AEMO assumes that the requirement to maintain a minimum dispatch of hydro generators will end once Marinus Link is commissioned[158]. In practice, the pace at which unit commitment requirements reduce will depend on the pace of the energy transition and the delivery of services such as system strength remediation.

[158] Long-term power system security assumptions are used for the purpose of assessing reliability and the economics of development plans. Detailed limits advice is required before changing operational practices.

Table 65 Planning assumptions for the future Tasmania power system

Power System Requirement	Synchronous generating units		IBR	HVDC inter-connection		Synchronous condensers	Demand side response	Distributed PV
	Gas	Hydro (inc. PHES)		Basslink	Project Marinus			
Bulk Energy	Service provider	Primary service provider	Service provider	Primary service provider	Primary service provider	No service provision	Partial service provider	No service provision
Energy Balance	Service provider	Primary service provider	Partial service provider	Primary service provider	Primary service provider	No service provision	Service provider	Partial service provider
Operating Reserve-ramping	Service provider	Primary service provider	Partial service provider	Primary service provider	Primary service provider	No service provision	Partial service provider	Partial service provider
Inertial response and RoCoF	Service provider	Primary service provider	No service provision	No service provision	Partial service provider	Primary service provider	No service provision	No service provision
Primary Frequency Control	Service provider	Primary service provider ≥ 1	No service provision	No service provision	Partial service provider	No service provision	No service provision	No service provision
Secondary Frequency Control	Service provider	Primary service provider	No service provision	Service provider	Service provider	No service provision	Service provider	No service provision
Fast voltage control	Service provider	Primary service provider	Service provider	No service provision	Service provider	Primary service provider	No service provision	No service provision
Slow voltage control	Service provider	Primary service provider	Service provider	Partial service provider	Service provider	Primary service provider	No service provision	No service provision
System Strength	Service provider	Primary service provider	No service provision	No service provision	Partial service provider	Primary service provider	No service provision	No service provision

Notation: Primary service provider | Service provider | Partial service provider | No service provision

Victoria

Due to the Victorian region already having two AC interconnectors, the likelihood of islanding is low, resulting in the ability for inertia and frequency control services to be met by the interconnectors.

As IBR penetration increases, the number of large coal units online is reducing and encroaching on the system strength limits.

Within the market modelling there are not any manual constraints to enforce provision of these system services as the required plant is dispatched for the energy market outcomes. In future years as coal retires, system strength shortfalls may be declared to ensure delivery of the service. As a long-term planning assumption AEMO considers that system strength requirements will be met by services that do not impact on the energy market dispatch, such as synchronous condensers or generators running in synchronous converter mode.

The following table outlines the planning assumptions for the current Victoria power system.

Table 66 Planning assumptions for the current Victoria power system

Power System Requirement	Synchronous generating units			IBR	HVDC inter-connection		AC inter-connection		Synchronous condensers	Demand side response	Distributed PV	BESS
	Gas	Coal	Hydro		Murray Link	Basslink	VIC-SA	VNI				
Bulk Energy												
Energy Balance												
Operating Reserve-ramping												
Inertial response and RoCoF												
Primary Frequency Control												
Secondary Frequency Control												
Fast voltage control												
Slow voltage control												
System Strength		≥ 5							Note †			

Notation: Primary service provider | Service provider | Partial service provider | No service provision

† Generation proponents are already installing synchronous condensers to meet localised system strength needs.

As coal-fired generation retires, the system strength services currently being provided will need to be replaced by other sources including synchronous condensers or from additional pumped hydro generation.

The proposed increase in interconnection will even further reduce the likelihood of requiring local services under islanding conditions.

The following table outlines the planning assumptions for the future Victoria power system (from 2025-26 onward). Due to increased interconnection, increased utilisation of pumped hydro generators, and expected levels of synchronous condensers being installed for system strength remediation, AEMO assumes that the requirement to maintain a minimum dispatch of coal-fired generators will end[159]. In practice, the pace at which unit commitment requirements reduce will depend on the pace of the energy transition and the delivery of services such as system strength remediation.

[159] Long-term power system security assumptions are used for the purpose of assessing reliability and the economics of development plans. Detailed limits advice is required before changing operational practices.

Table 67 Planning assumptions for the future Victoria power system

Power System Requirement	Synchronous generating units		IBR	HVDC inter-connection			AC inter-connection	Synchronous condensers	Demand side response	Distributed PV	BESS
	Gas / Coal	Hydro (inc PHES)		Murraylink	Basslink	Project Marinus	VIC-SA VNI, VNI West				
Bulk Energy	Service provider	Primary service provider	Service provider	Partial service provider	Service provider	Primary service provider	Primary service provider	No service provision	Partial service provider	No service provision	Partial service provider
Energy Balance	Service provider	Primary service provider	Partial service provider	Service provider	Service provider	Primary service provider	Primary service provider	No service provision	Service provider	Partial service provider	Service provider
Operating Reserve-ramping	Service provider	Primary service provider	Partial service provider	Partial service provider	Service provider	Primary service provider	Primary service provider	No service provision	Partial service provider	Partial service provider	Partial service provider
Inertial response and RoCoF	Service provider	Primary service provider	No service provision	No service provision	No service provision	Partial service provider	Primary service provider	Primary service provider	No service provision	No service provision	No service provision
Primary Frequency Control	Service provider	Primary service provider	No service provision	No service provision	No service provision	Partial service provider	Primary service provider	No service provision	No service provision	No service provision	No service provision
Secondary Frequency Control	Service provider	Primary service provider	No service provision	No service provision	Service provider	Primary service provider	Primary service provider	No service provision	Service provider	No service provision	Service provider
Fast voltage control	Service provider	Primary service provider	Service provider	Service provider	No service provision	Service provider	No service provision	Primary service provider	No service provision	No service provision	Service provider
Slow voltage control	Service provider	Primary service provider	Service provider	Service provider	Partial service provider	Service provider	No service provision	Primary service provider	No service provision	No service provision	Service provider
System Strength	Service provider	Primary service provider	No service provision	No service provision	No service provision	Partial service provider	Partial service provider	Primary service provider	No service provision	No service provision	No service provision

Notation: Primary service provider | Service provider | Partial service provider | No service provision

4.12.2 System strength

Input vintage	2020 ISP
Source	AEMO internal
Update process	Updates (provided at www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability) will depend on feedback to this Draft 2021 IASR, and may be further updated following the release of AEMO's report on system strength and inertia (or subsequent updates to requirements in response to changing circumstances in the next six months).
Get involved	Draft 2021 IASR consultation, and ISP Methodology.

The increasing integration of IBR across the NEM has implications for the engineering design of the future power system. As clusters of IBR connect in close proximity, generators will need to offset their impact on system strength, and TNSPs will need to ensure a basic level of fault current across their networks.

Key areas of system strength (discussed in AEMO's white paper System Strength Explained[160]) include steady state voltage management, voltage dips, fault ride-through, power quality and operation of protection.

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

AEMO is required to determine the fault level requirements across the NEM and identify whether a fault level shortfall is likely to exist now or in the future. The System Strength Requirements Methodology[161] defines the process AEMO must apply to determine the system strength requirement at each node. Updates are made to the requirements periodically and published on AEMO's website[162]. AEMO intends to use the requirements in the documents and updates above as inputs into the 2022 ISP. Any updates to these requirements will be reflected in the 2022 ISP. The present values are shown in Table 68.

Table 68 Minimum three phase fault levels for 2020

Region	Fault level node	2020 minimum three phase fault level (MVA)	
		Pre-contingency	Post-contingency
New South Wales	Armidale 330 kV	3,300	2,800
	Darlington Point 330 kV	1,500	600
	Newcastle 330 kV	8,150	7,100
	Sydney West 330 kV	8,450	8,050
	Wellington 330 kV	2,900	1,800
Queensland	Greenbank 275 kV	4,350	3,750
	Gin Gin 275 kV	2,800	2,250
	Lilyvale 132 kV	1,400	1,150
	Ross 275 kV	1,350	1,175
	Western Downs 275 kV	4,000	2,550
South Australia	Davenport 275 kV	2,400	1,800
	Para 275 kV	2,250	2,000
	Robertstown 275 kV	2,550	2,000
Tasmania	Burnie 110 kV	850	560
	George Town 220 kV	1,450	1,450
	Risdon 110 kV	1,330	1,330
	Waddamana 220 kV	1,400	1,400
Victoria	Dederang 220 kV	3,500	3,300
	Hazelwood 500 kV	7,700	7,150
	Moorabool 220 kV	4,600	4,050
	Red Cliffs 220 kV	1,700	1,000
	Thomastown 220 kV	4,700	4,500

[161] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/%E2%80%8C System_Strength_Requirements_Methodology_PUBLISHED.pdf.

[162] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/system-security-market-frameworks-review.

4.12.3 Inertia

Input vintage	2020 ISP
Source	AEMO internal
Update process	Updates will be dependent on the feedback received to this Draft 2021 IASR, and may be further updated following the release of AEMO's annual report on system strength and inertia (or any subsequent ad hoc updates to those requirements in response to changing circumstances in the next six months. Updates will be provided at www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.
Get involved	Draft 2021 IASR consultation, and ISP Methodology.

Maintaining an appropriate level of synchronous inertia, or its equivalent, is crucial for ensuring overall power system security. AEMO is required under the NER to calculate (in accordance with the published methodology) and publish the satisfactory and secure requirements for synchronous inertia for each NEM region when it is islanded. These are outlined in AEMO's Inertia Requirements Methodology and individual updates found on AEMOs website[163].

AEMO intends to use the requirements outlined in this process and document as inputs into the 2022 ISP. Any updates to these requirements will be reflected in the ISP. The present values are shown in Table 69.

Table 69 Inertia requirements for 2020

Region	2020 inertia requirements	
	Secure (MWs)	Minimum (MWs)
Queensland	14,800	11,900
Victoria	13,900	9,500
New South Wales	12,500	10,000
South Australia	Combination of synchronous inertia and fast frequency response	4,400
Tasmania	3,800	3,200

4.12.4 Other system security settings

In NEMDE, a series of network constraint equations control dispatch solutions to ensure that intra-regional network limitations are accounted for. The time-sequential model used in long-term planning studies contains a subset of the NEMDE network constraint equations to achieve the same purpose. This subset of network constraint equations is included in the ISP model to reflect power system operation within security limits. These include:

- **Voltage stability** – for managing transmission voltages so that they remain at acceptable levels after a credible contingency.
- **Transient stability** – for managing continued synchronism of all generators on the power system following a credible contingency.

[163] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/system-security-market-frameworks-review.

- **Oscillatory stability** – for managing damping of power system oscillations following a credible contingency.
- **Rate of change of frequency (RoCoF)** – for managing the rate of change of frequency following a credible contingency.

The effect of committed transmission and generation projects on the network is implemented as modifications to the network constraint equations that control flow. The methodology for formulating these constraints is in AEMO's Constraint Formulation Guidelines[164].

Matters for consultation

- AEMO's proposed assumptions generally reflect a projected decline over time in commitment of synchronous generator units (typically in thermal power stations) as alternative energy sources are introduced in the NEM. Do you have any specific feedback on this approach?
- Do you have any specific feedback on the regional security assumptions?
- Do you have any feedback on using the inertia and system strength requirements as described on AEMOs website as inputs to the ISP?

4.13 Gas modelling

AEMO recognises the high degree of coupling between the gas and electricity sectors and therefore also considers the eastern and south-eastern Australian gas markets when optimising decisions for the development of the NEM.

Given the strongly integrated nature of these systems, any development or shortfalls in the gas market would have direct implications for the operation of gas-powered generation (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.

When forecasting the future operation and development of the gas and electricity markets, consistency in assumptions, processes and scenarios is critical to create forecasts that are broadly applicable and comparable.

This Draft 2021 IASR focuses on elements of gas modelling that are modelled in tandem with the electricity system, as part of co-optimised capacity outlook modelling. When modelling the gas system in isolation, AEMO uses the same inputs and scenarios as much as practical, although bespoke inputs regarding the gas transmission system may also be used that are not included in this Draft 2021 IASR, but would accompany the publication of the GSOO.

As part of the ISP Methodology, AEMO uses an integrated gas and electricity model to project developments considering gas, hydrogen and electricity systems simultaneously.

The gas portion of the integrated model will use the model topology, input assumptions, and settings under development for the 2021 GSOO[165]. New gas supply options will be implemented as expansion options in this integrated model, using build costs derived from publicly available information for the chosen projects. New gas supply options considered include:

- LNG import terminals.

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

[165] 2021 GSOO report, modelling methodology, and supplementary materials will all be available by March 2021, at http://aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

- New field developments.
- New gas processing plants.
- Pipelines.
- Storage facilities.

Assumptions relevant to the gas market are provided in the Draft 2021-22 Inputs and Assumptions Workbook, and outlined in Table 70 below.

Table 70 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
Reserves and resources estimates by resource category (2P, 2C and prospective)	GSOO stakeholder surveys and information sourced from Wood Mackenzie
Gas field production costs	Information sourced from Wood Mackenzie
Gas expansion candidate build costs	Information sourced from public data and reports
Wholesale gas prices, as described in Section 4.7.1	Information sourced from Lewis Grey Advisory

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[166].

Matters for consultation

- Do you have any specific feedback on the inputs and assumptions documented for gas modelling in the Draft 2021-22 Inputs and Assumptions Workbook?

4.14 Hydrogen modelling

Input vintage	New content
Source	AEMO engaged with stakeholders in a Hydrogen Workshop in September 2020 to assist in defining the assumptions for the Export Superpower scenario.
Update process	Updates will be dependent on feedback received on this Draft 2021 IASR and may be further updated through the ISP Methodology consultation process.
Get involved	Draft 2021 IASR consultation and ISP Methodology

[166] 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.

Hydrogen production was discussed qualitatively in the 2020 ISP, and feedback was received from stakeholders that it should be incorporated in more detail for the 2022 ISP.

Including hydrogen production as a driver within the scenario collection reflects the significant increase in interest and activity from industry and direct funding support from governments in Australia and internationally. As described in the scenario narratives presented in Section 2.3, NEM-connected hydrogen will only be modelled in the Export Superpower scenario. Other scenarios assume negligible impact from grid-connected electrolysers on the NEM. Accordingly, the assumptions and inputs discussed in this section are only applicable to the Export Superpower scenario.

To manage the modelling scale and complexity, a range of hydrogen variables are assumed as inputs to the model. The initial estimates and assumptions are outlined below, and AEMO invites feedback on these items as part of the Draft 2021 IASR consultation.

4.14.1 Hydrogen demand

Hydrogen demand assumed in the Export Superpower scenario includes both domestic applications and hydrogen exports, with a strong, emerging export economy assumed to start from 2030. Australia's Technology Investment Roadmap[167] has identified that energy export is of strategic importance to Australia and hydrogen is one of the priority low emissions technologies. Australia's National Hydrogen Strategy[168] recognises that a strong domestic sector will be required to successfully compete internationally. Consequently, this scenario assumes early domestic uptake facilitates export growth, allowing for a large and rapid development of hydrogen for export as the international market develops.

Multiple domestic applications for hydrogen are assumed:

- Hydrogen is used for fuel switching from natural gas to hydrogen by both residential and industrial consumers, with domestic use of natural gas phased out by 2045. Distribution blending of hydrogen into the gas grid enables domestic consumption. It is possible to blend up to 10% hydrogen (by volume) into the existing distribution gas network without any changes in gas rules or appliances. Over time the distribution network may be segmented into physically separated sections of network with different gas compositions. In the event of this segmentation, the distribution pipeline network would be able to incrementally transition to 100% hydrogen.
- Hydrogen is expected to have a strong role in replacing diesel-fuelled heavy vehicles, and this scenario increases the competitiveness of hydrogen fuel-cell vehicles to compete with BEVs.
- Increased availability of hydrogen may enable its use in power generation as an alternative to peaking gas and non-transport diesel.

This section outlines the assumptions and inputs proposed for hydrogen demand.

Total demand (including export)

Through stakeholder collaboration, AEMO defined the assumed scale of annual NEM-connected electrolyser production in the NEM regions of approximately 8 megatonnes (Mt) by 2040, growing to over 20 Mt by 2050[169] (excluding hydrogen produced in Western Australia, the Northern Territory, and off-grid in NEM regions), shown in Figure 47. Production is assumed to start in 2023, supported by various state government policies and hydrogen ambitions.

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

[168] See https://www.industry.gov.au/sites/default/files/2019-11/australias-national-hydrogen-strategy.pdf.

[169] The export growth rate targets were based on combining and averaging the estimates for hydrogen scenarios from IRENA, Hydrogen Council, ACIL Allen and Deloitte. The numbers were taken from the summary in Deloitte's report and direct reference to the ACIL Allen report for more scenario information. Australia was assumed to supply a percentage of global demand in line with stakeholder feedback in the workshops. Deloitte: https://www2.deloitte.com/content/dam/Deloitte/au/Documents/future-of-cities/deloitte-au-australian-global-hydrogen-demand-growth-scenario-analysis-091219.pdf. ACIL Allen: https://www.acilallen.com.au/uploads/files/projects/227/ACILAllen_OpportunitiesHydrogenExports_2018pdf-1534907204.pdf.

Figure 47 NEM-connected hydrogen production (Mt)

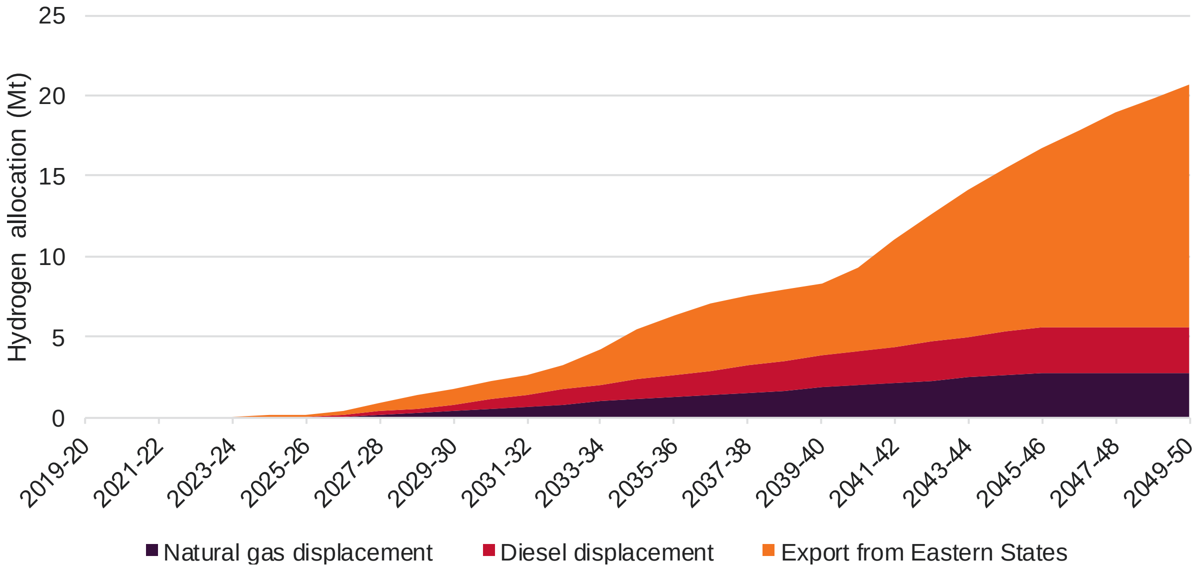
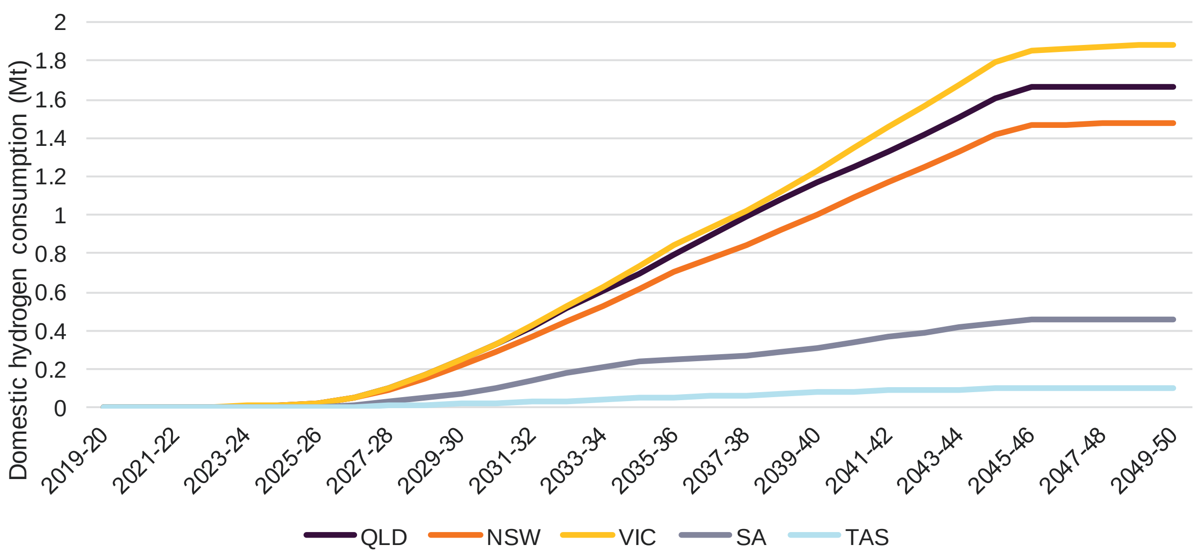


Figure 48 shows an indicative representation of projected hydrogen consumption based on gradual displacement of diesel and natural gas consumption of each region, coupled with export opportunities. These interim assumptions will be updated as part of AEMO's forecasting of distributed energy resources, particularly understanding the future projection of both battery electric and fuel cell electric vehicles.

Figure 48 Indicative domestic hydrogen consumption (Mt, based on diesel and gas displacement)



Residential and commercial demand

AEMO assumes existing gas distribution networks can accept up to 10% hydrogen blending (by volume) without any pipeline changes and without exceeding energy content standards for existing appliances. It is assumed that by segmenting the gas distribution grid (as described at the start of this section) the total amount of gas blending within the distribution grid can increase.

Large industrial demand

Currently large industry uses approximately 180 petajoules (PJ) a year of natural gas in Australia's eastern and south-eastern gas markets. Consistent with Australia's National Hydrogen Strategy, it is assumed that industrial hydrogen hubs are established in the Export Superpower scenario, allowing industrial customers to switch from natural gas to hydrogen, and supporting potential new industrial customers. At this stage a net increase in industrial load is not assumed, although some industries may be replaced with new ones.

Transportation demand

In the Export Superpower scenario, on-grid hydrogen is assumed to gradually replace diesel for long distance heavy transport (trucking and trains)[170]. Passenger vehicles are assumed to be mainly BEVs initially, although FCVs become available and grow over time. The balance of battery and hydrogen vehicle growth is requiring update for this scenario, and will be consulted through the February, March and April FRG meetings, as appropriate.

The Sustainable Growth scenario also is expected to feature relatively strong uptake of BEV and FCV fleets, although this scenario would not feature material transmission connected hydrogen production facilities. This reduces the relative ease for FCV adoption in this scenario.

4.14.2 Hydrogen supply

Hydrogen production technologies

There are three primary technology options to produce hydrogen:

- **Electrolysis** – uses electricity to split water molecules into hydrogen and oxygen. If this electricity is sourced from renewable electricity it can create "green hydrogen".
- **Steam methane reformation (SMR)** – reacts methane (natural gas) with steam under pressure to produce hydrogen and carbon dioxide.
- **Coal gasification** – reacts pulverised coal with oxygen and steam to produce hydrogen and carbon dioxide. Different quality coal can result in different processes and chemical compositions.

In the Export Superpower scenario, hydrogen production via electrolysis of water powered by VRE is assumed to be the primary hydrogen production technology, given the decarbonisation ambition of the scenario.

There are three electrolyser technology options:

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

AEMO proposes the use of PEM electrolysis to be the primary hydrogen production technology, reflecting the current technology development trends.

PEM characteristics

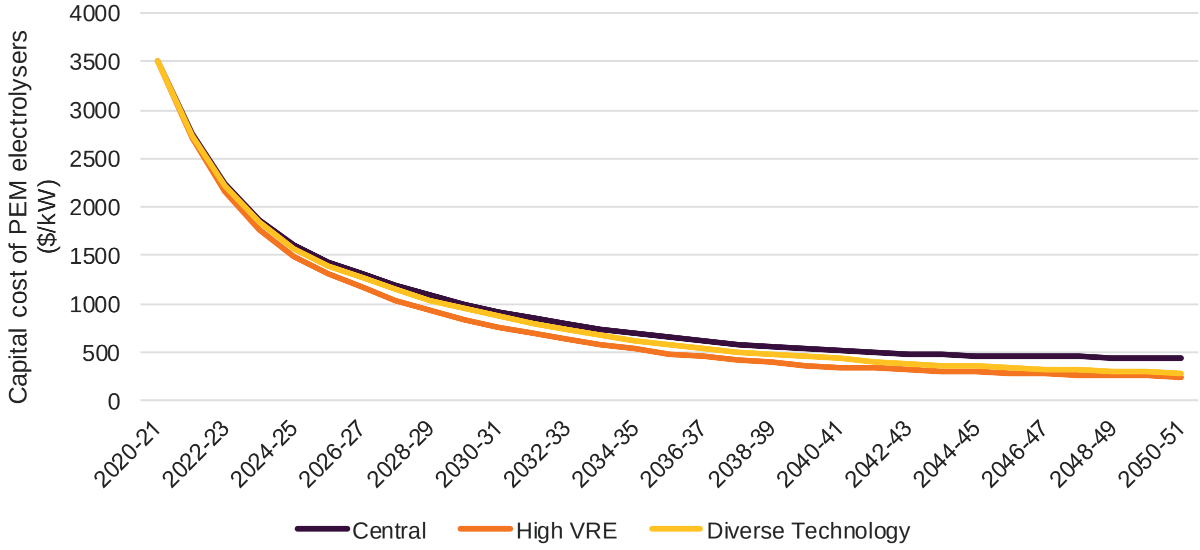
Assumptions around key PEM characteristics are outlined in the following section.

Capital costs

The GenCost report released with this Draft 2021 IASR contains estimates for the current capital cost of a PEM electrolyser, at \$3,510/kW, with equipment and construction costs accounting for 70% and 30% of total capex respectively. By 2030 the cost of PEM electrolysers is projected to be less than \$1000/kW in all scenarios. The cost trajectory projected in GenCost 2021 is shown in Figure 49.

[170] The details of this transition are being sourced through consultants.

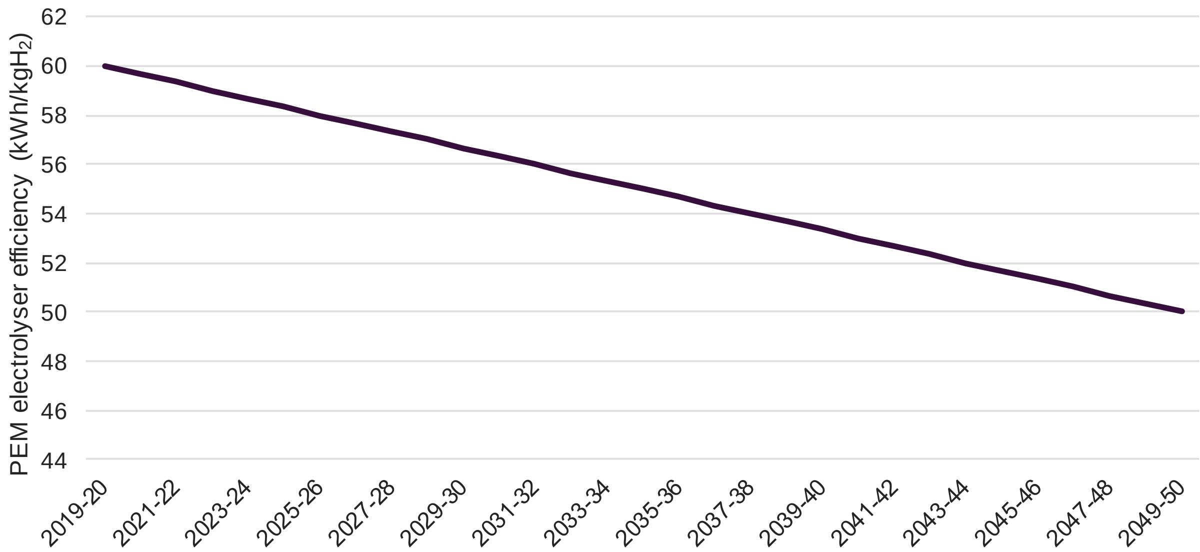
Figure 49 CSIRO GenCost 2021 capital cost projections for PEM electrolysers



Flexibility

The actual electrolyser itself can be ramped up and down rapidly, potentially even providing fast frequency response similar to electrochemical batteries. AEMO proposes to model PEM electrolysers as fully flexible, although there is an associated baseload component (as described below). The degree of actual flexibility offered in the market will depend strongly on the commercial arrangements in relation to the plant and its contracts for supply of hydrogen, relative to the effectiveness of the markets in the NEM and the opportunities to efficiently arbitrage between contract arrangements and the NEM. The efficiency of the electrolyser is projected to improve over time, as shown in Figure 50[171].

Figure 50 Efficiency projections for PEM electrolysers



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

Modularity

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

Baseload/auxiliary load of the electrolyser

While the electrolyser stack is fully flexible, an electrolysis plant has a range of components which respond at different rates. Such components include dryers, compressors/pumps and cooling. Discussion with various industry experts have placed the baseload demand consumed by the electrolyser at somewhere up to 10% of the total demand, even when the electrolyser is not producing hydrogen.

The best available information that could be sourced from an operating unit comes from Energiepark Mainz[172] and shows the operating characteristics of a 4 MW electrolyser plant comprised of three modular electrolysers. The baseload reported is 175 kW (~4.5%).

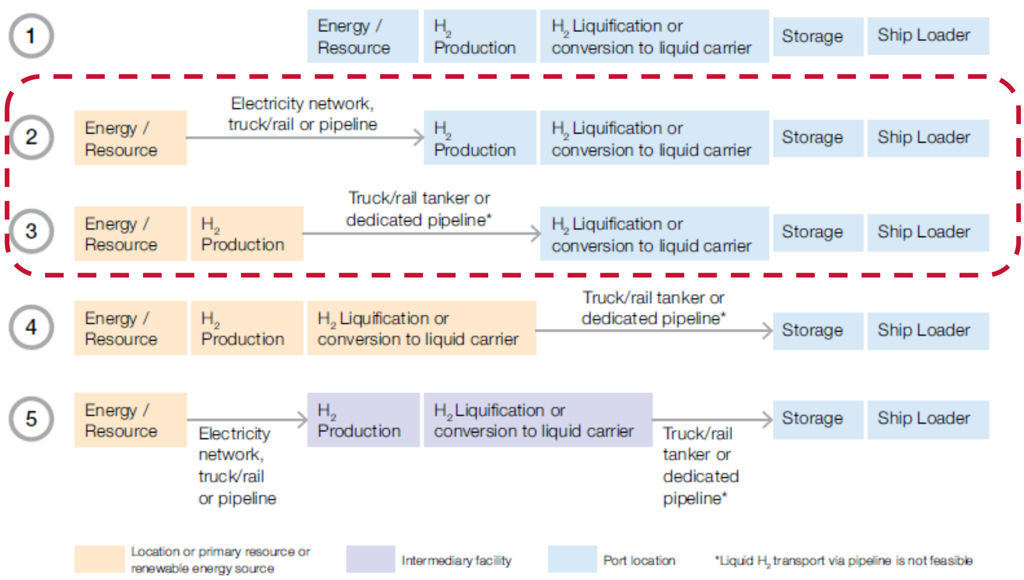
At this stage it is difficult to be sure how this will scale up with increase in capacity of electrolysers, yet discussions with equipment suppliers and international research organisations indicate that this is approximately the right magnitude and would likely scale fairly linearly. There is also opinion that the whole plant should be able to be shut down quickly. In the absence of better information, AEMO proposes to assume a baseload of 4.5%.

As noted previously, the actual operation of electrolyser plants will depend strongly on commercial arrangements in place for supply of hydrogen, relative to opportunities in the NEM.

4.14.3 Hydrogen infrastructure needs

ARUP's Australian Hydrogen Hubs report to the COAG Energy Council identified the potential hydrogen export pathways[173] in Figure 51. A hydrogen export pathway describes the supply chain from the energy source to the export location, and includes the method and form of energy transport; the location of the electrolysers; and the location of the hydrogen liquefaction or conversion facilities.

Figure 51 Hydrogen export pathways, highlighting those proposed to apply in AEMO's current and future forecasting and planning



Source: Arup, 2019, Australian Hydrogen Hubs Study

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

[173] At http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/nhs-australian-hydrogen-hubs-study-report-2019.pdf.

In the 2022 ISP, AEMO proposes to consider transmission developments that are designed around the principles of pathway 2, which transports the energy for hydrogen production via electrical transmission lines. Pathway 3, which transports the energy via hydrogen transmission pipelines, may be considered as an alternative in future ISPs.

Electrolyser location

The export-focused electrolysers are proposed to be associated with nearby REZs. The selection of combined port/REZ candidates will be optimised to minimise the cost to produce the hydrogen. This will be constrained by the available resources (such as VRE and water), considering the deliverability of VRE in REZs to hydrogen hubs at regional ports (accounting for transmission augmentations as described in Section 4.9.3).

The proposed export ports were selected from 30 hydrogen hubs identified in ARUP's Australian Hydrogen Hubs report to the COAG Energy Council[174]. The following table outlines 10 proposed candidate hydrogen export ports (shown geographically in Figure 52) that provides a geographic spread with access to REZ and port infrastructure.

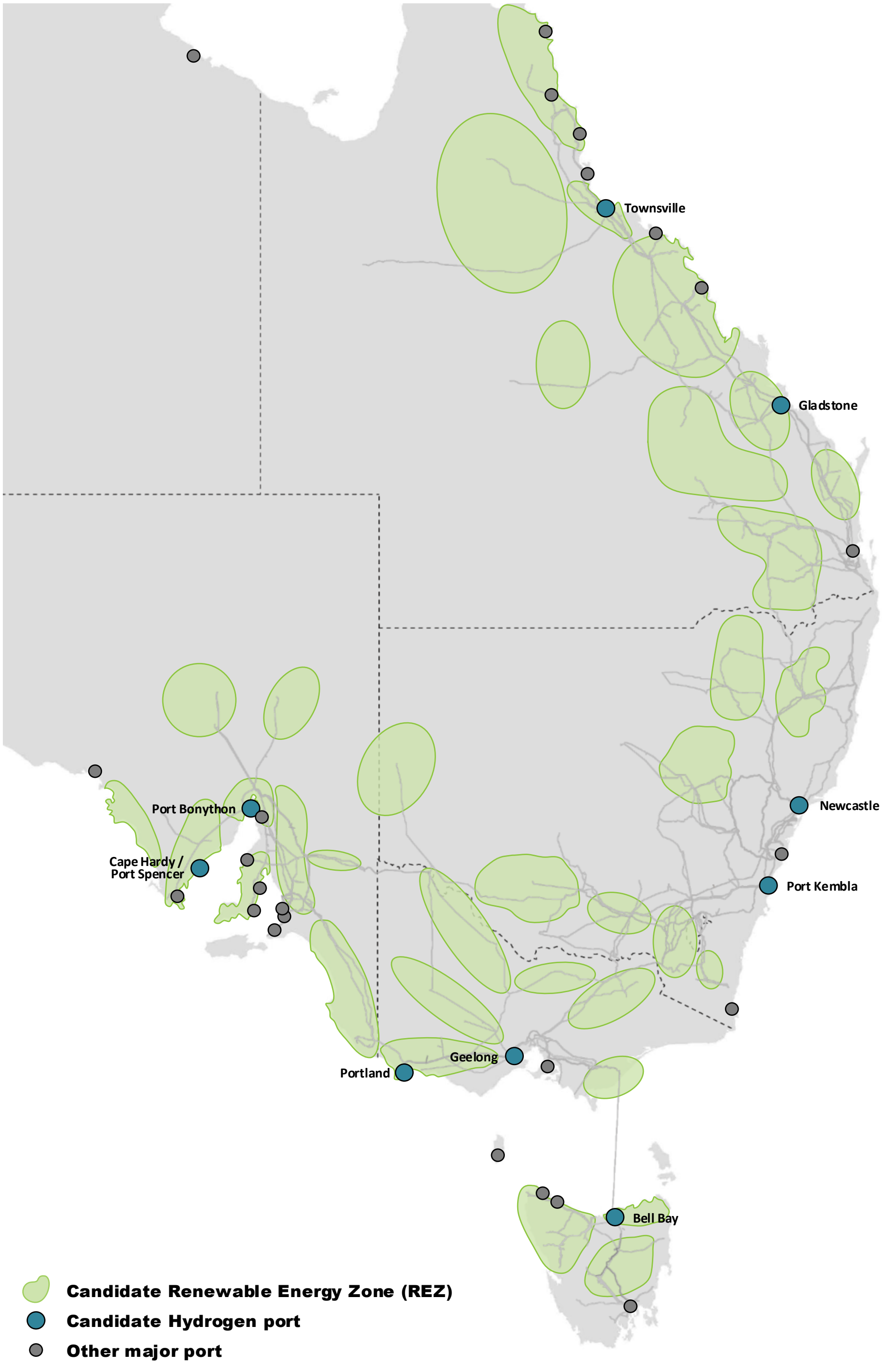
Table 71 Candidate hydrogen export ports

NEM Region	Potential port location
New South Wales	Newcastle, Port Kembla
Queensland	Gladstone, Townsville
South Australia	Port Bonython, Cape Hardy/Port Spencer
Tasmania	Bell Bay
Victoria	Geelong, Portland

There is also notable domestic consumption of hydrogen proposed in the Export Superpower scenario. The demand for each region's domestic load is assumed to be delivered from centralised electrolysis plants located near the regional load centre. Where possible, each state's domestic hydrogen will be produced in that state with electrolysers placed at the edge of the industrial zones near to the regional reference node.

[174] At http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/nhs-australian-hydrogen-hubs-study-report-2019.pdf.

Figure 52 Candidate hydrogen export ports



Storage

For export purposes, pathway 2 has limited inherent storage, since the hydrogen is generated close to the port, with minimal pipeline needed. In this situation it will be assumed that storage is included in the hydrogen production facilities near the ports. Pathway 3 has an inherent advantage of large amounts of line pack in the new hydrogen transmission pipelines, which would provide firm hydrogen supply to the liquefaction or processing facilities; this pathway may be explored in future ISPs. Given the simplified modelling approach, the cost of hydrogen storage is implicit in the assumed price of hydrogen; it is assumed that hydrogen will be readily available in this scenario. Any hydrogen consumed for electricity generation purposes will need to be replaced, at cost, in the model.

For domestic hydrogen use, as stated above, the distribution pipelines will provide inherent storage through line pack. For power generation, hydrogen GPG may be useful for peaking gas and potentially seasonal storage. Information from Aurecon's 2020-21 Cost and Technical Parameter Review showed no capital cost difference between hydrogen combustion peaking plant and gas combustion peaking plant; this was based on interviews with manufacturers.

Water supply

Hydrogen production from electrolysis, coal gasification or steam methane reforming of natural gas all require water as a main feedstock. Electrolysis requires at least 9 litres/kg of hydrogen, possibly more depending on the quality and the pre-treatment required.

It is estimated that production of 8 Mt/year of hydrogen would require approximately 72 gigalitres (GL) of water per year, which is around 1 % of the 7,200 GL of water that was applied to crops and pastures in Australia in 2018-19[175]. It is important that careful consideration is given to siting of hydrogen production facilities, to ensure demand for water does not impact other local uses such as town water supplies or agriculture. Relying on alternative sources of water, such as desalinated seawater, would marginally increase the cost and complexity of producing hydrogen.

For the 2022 ISP, water availability is not proposed to be a significant limitation to siting options. Initial screening of water sources near the major ports indicates the potential water availability shown in Table 72. Detailed information and proposals for the approach to incorporation of water limitations will be part of AEMO's engagements on the ISP Methodology. AEMO welcomes stakeholder feedback on the appropriateness of the ports proposed for hydrogen production and export, as discussed above.

Table 72 Potential water availability at export ports – screening level only

Port	Potential water availability
Townsville	
Gladstone	
Newcastle	
Port Kembla	
Geelong	
Portland	
Bell Bay	
Port Bonython	
Cape Hardy / Port Spencer	

Legend:

	Fresh water likely to be available
	Desalination required
	Uncertain fresh water availability - further review required to determine if desalination will be required

[175] ABS, https://www.abs.gov.au/statistics/industry/agriculture/water-use-australian-farms/latest-release, accessed 25 November 2020.

It is assumed that adequate water would be available either using treated local freshwater sources or desalination of seawater at the port. If desalination is required, the cost of desalination is assumed to be $0.05 per kilogram of hydrogen produced, in line with Australia's National Hydrogen Strategy[176].

Matters for consultation

- Grid-connected hydrogen is proposed to only be modelled in the Export Superpower scenario; in other scenarios any hydrogen is expected to either be insignificant or produced off-grid. Does this give sufficient coverage?
- In the Export Superpower scenario, decarbonisation ambitions lead to transitioning gas distribution networks to 100% hydrogen by 2045. Do you have any feedback on this approach?
- In the Export Superpower scenario, domestic hydrogen consumption is approximately equal to export until 2040, at which point domestic demand is largely saturated and export becomes the dominant cause of growth in demand. Do you have any feedback on the suitability of this trajectory?
- Do you have feedback on the penetration of battery and fuel-cell electric vehicles in the scenario collection?
- AEMO has selected PEM electrolysers as the preferred technology in this scenario, due to decarbonisation targets (preferencing green hydrogen), higher levels of flexibility in the operation of the assets, and notable investment activity in the market. Do you have any information that may indicate this assumption should be changed?
- Do you have any feedback on the cost of electrolysers, the efficiency of electrolysers, or the rate of cost reductions projected into the future?
- The electrolysers are assumed to have a fixed minimum baseload of 4.5% of their total capacity, even when they are not producing hydrogen. Do you have information that may indicate this assumption should be changed?
- Nine ports are proposed as candidates for the 2022 ISP expansion to produce export hydrogen. Do you have feedback on these candidates and their suitability over other options for hydrogen hubs?
- Water availability near the candidate export ports has been screened. Do you have any feedback on the assumed classification of fresh water being likely to be available or unavailable or desalination being required? Information that could help resolve the water availability at ports would be highly appreciated.
- The cost of desalination is assumed to be $0.05 per kilogram of hydrogen based on Australia's National Hydrogen Strategy. This is a small contribution to overall cost, and it is proposed that the electricity demand would likely be immaterial in the scale of the Export Superpower scenario (when compared with electrolyser demand). Do you think this is an acceptable simplification?
- It is assumed that only a small amount of hydrogen storage will be required at the ports for operational uses, and as such, the cost associated with this storage is immaterial. Do you agree with this approach?

[176] At https://www.industry.gov.au/data-and-publications/australias-national-hydrogen-strategy.