AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Draft 2020 Integrated System Plan Appendices

12 December 2019

Important notice

PURPOSE

AEMO publishes the Draft 2020 Integrated System Plan (Draft ISP), which includes these Appendices, pursuant to its functions under section 49(2) of the National Electricity Law (which defines AEMO's functions as National Transmission Planner) and its broader functions to maintain and improve power system security. In addition, AEMO has had regard to both the requirements of rule 5.20 of the National Electricity Rules and to the Draft ISP Rules published by the Energy Security Board.

DISCLAIMER

These Appendices form part of the Draft ISP, and contain data provided by or collected from third parties, and conclusions, opinions, assumptions or forecasts that are based on that data. AEMO has made every reasonable effort to ensure the quality of the information in this Draft ISP but cannot guarantee that the information, forecasts and assumptions in it are accurate, complete or appropriate for your circumstances. These Appendices do not include all of the information that an investor, participant or potential participant in the national electricity market might require, and do not amount to a recommendation of any investment.

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These Appendices and the information in this document will be subsequently changed or updated for the Final 2020 ISP. The Appendices do not constitute legal or business advice, and should not be relied on as a substitute for obtaining detailed advice about the National Electricity Law, the National Electricity Rules, or any other applicable laws, procedures or policies.

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VERSION CONTROL

Version	Release date	Changes
1	12/12/2019	Initial release

Contents

Tables

Figures

Appendix 1. ISP Database

A large quantity of information and data relevant to the ISP is available in previously published reports and on the AEMO website. This section summarises the data and provides links to enable ease of access.

Table 1 Published AEMO reports and information

Name	Date	Link
Reports		
2018 ISP	Jul 2018	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Integrated-System-Plan-2018_final.pdf
2018 ISP appendices	Jul 2018	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/ISP-Appendices_final.pdf
2019 Planning and Forecasting Consultation paper	Feb 2019	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Planning-and-Forecasting-Consultation-Paper.pdf
Building Power System Resilience with Pumped Hydro Energy Storage – ISP Insights	Jul 2019	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2019/ISP-Insights---Building-power-system-resilience-with-pumped-hydro-energy-storage.pdf
2019 Planning and Forecasting Consultation response on Scenarios, Inputs, Assumptions and Methodology – Final Report	Aug 2019	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Planning-and-Forecasting-Consultation-Responses.pdf
2019 Forecasting and Planning Scenarios, Inputs and Assumptions	Aug 2019	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-20-Forecasting-and-Planning-Scenarios-Inputs-and-Assumptions-Report.pdf
AEMO web pages for more information related to ISP		
2018 ISP Database (Information and further documents used to create the 2018 ISP)		https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2018-Integrated-System-Plan/ISP-database
Scenarios, Inputs, Assumptions and Methodologies for Planning and Forecasting (used in 2020 ISP)		https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies

Name	Date	Link
2019 ISP (timeline and opportunities for engagement)		https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan
2019 ISP Database (Information and further documents used to create the 2020 ISP)		https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan/ISP-database
Data files		
2019 Inputs and Assumptions Workbook		https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Input-and-Assumptions-workbook-Sept-19.xlsx
Other media		
2019 ISP Interactive Map	2018	http://www.aemo.com.au/aemo/apps/visualisations/map.html

Table 2 Published third-party reports

Name	Date	Link
Aurora Energy Research analysis of AEMO's ISP Part 1: benefits of interconnection	May 2019	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2019/20190526-AEMO-Phase-1-report-summary.pdf
Aurora Energy Research analysis of AEMO's ISP Part 2: economics of coal closures	May 2019	https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2019/20190526-AEMO-Phase-2-report-summary.pdf

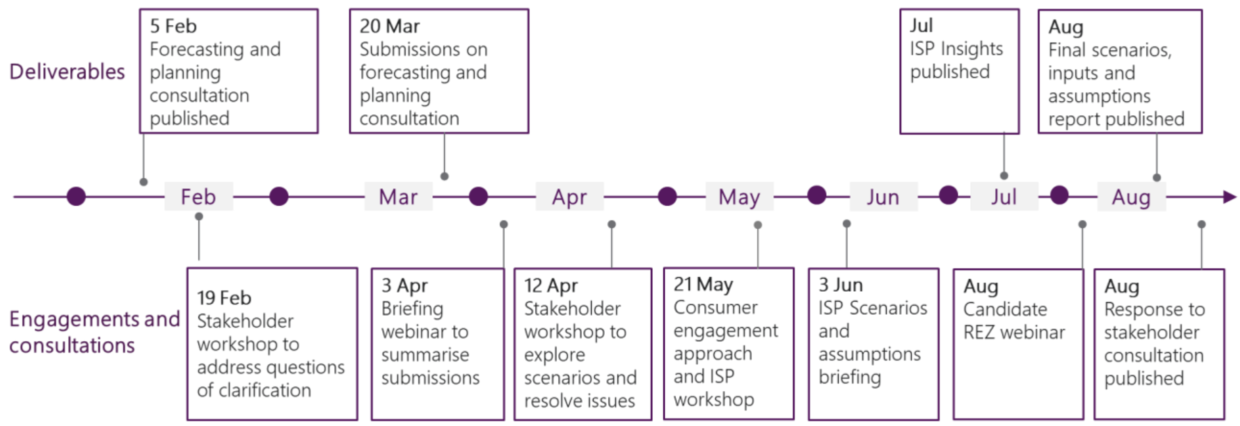
Appendix 2. Stakeholder engagement for the ISP

2.1 Stakeholder engagement plan and timelines

A comprehensive stakeholder engagement plan has been undertaken for the 2020 ISP with workshops scheduled at various stages throughout the ISP process, and two formal consultations included. The timeline of engagements is summarised in the figures below. Forecasting and Planning consultation on the scenarios, inputs, assumptions, and methodologies ran from February to March 2019, with the final report published in August after a series of workshops. The second consultation on the Draft ISP outcomes will run from December 2019 to March 2020 (see Part E of the main report)[1].

AEMO will establish an ISP Consumer Reference Group (ISP CRG) in early 2020, to support and facilitate productive engagement between AEMO and consumer representatives throughout the ISP development and publication cycle. The ISP CRG will have the opportunity to consider all aspects of the plan, including modelling inputs and interpretation, as well as any other issues of concern to members or AEMO. AEMO will seek nominations and publishing guidance on how members will be selected, and ISP CRG members and AEMO will then collaboratively design and formalise the group before the end of Q1 2020.

Figure 1 ISP engagement timeline, February to August 2019



[1] In parallel, AEMO is consulting on any changes to Inputs and Assumptions to apply for its forecasting and planning activities in 2020. For the 2020 ISP, any changes in assumptions will only be incorporated between this Draft and Final if expected to materially change the outcomes.

Figure 2 ISP engagement timeline, October 2019 to February 2020

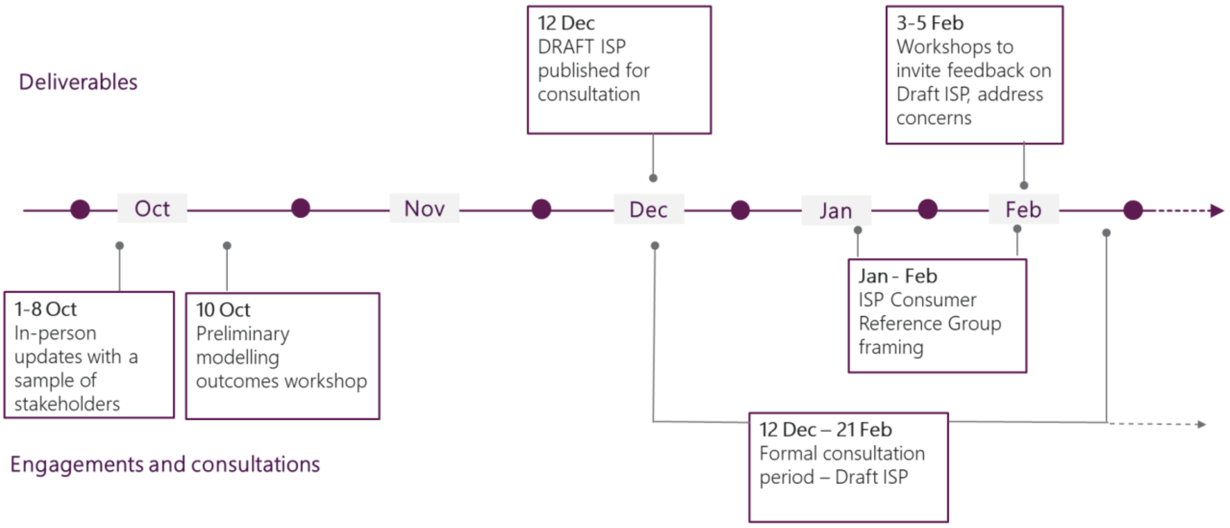
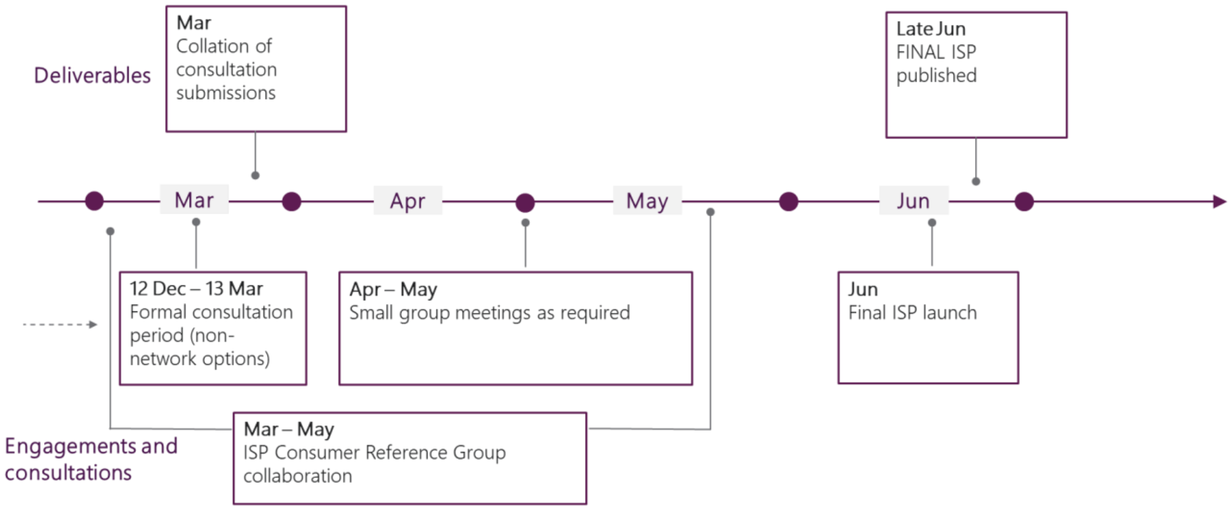


Figure 3 ISP engagement timeline, March to June 2020



2.1.1 Stakeholder engagement outcomes

Consultation on the inputs, assumptions, and methodologies included multiple opportunities for engagement (in-person and via webinar) and resulted in many modifications to the original inputs. The most significant change was that a fifth (Step Change) scenario was added to the modelling brief, reflecting the actions needed to meet the long-term goal of the Paris Agreement. Changes were also made in the following areas:

- Increasing transparency.
- Increasing internal consistency.
- Refining renewable energy zone (REZ) representation.
- Capturing physical symptoms of climate change.
- Updating key inputs.

The results of this consultation were captured in the final report[2], and other relevant publications including considered response to feedback are available on AEMO's website[3].

A series of meetings with a sample of stakeholders was held in early October to provide early feedback on the broader stakeholder engagement plan, and to plan the Preliminary Outcomes workshop. The feedback received included:

1. It is important to present the results relative to the 2018 ISP – what's changed and why?
2. Illustrate intra-day behaviour of storage usage, charging/discharging patterns.
3. Some perceived the 2018 ISP to be very transmission-centric and suggested greater prominence to storage, REZs, and DER.
4. There is a desire to show timing of the projects in the 2020 ISP, or a range of timings across the scenarios.
5. A separate summary for policy-makers would be welcomed.
6. The ISP development process can seem to some like a 'black box' and is not always well understood.

Point 1 was incorporated in the Preliminary Outcomes Workshop in October[4]. The Draft ISP has sought to address points 2, 3, 4 and 6, with greater focus on the methodology used to apply the 'least regret' approach, and more prominence on non-network solutions. The separate summary for policy-makers will be considered for the Final ISP release and more training to make the approach easier to understand is planned for 2020.

The Preliminary Outcomes workshop held on 10 October 2019 was attended by over 100 stakeholders, and was held as a collaborative workshop. Questions were posed to attendees across a range of areas covering both technical outcomes and format and content of the ISP document itself, and a large amount of feedback was captured. A synopsis of the feedback was released following the workshop[5], and the overall themes are shown in the table below. A rigorous process has been put in place to review and, where relevant, action the feedback received from both the stakeholder meetings and the Preliminary Outcomes workshop. Appropriate actions will be fed into the ISP process at the relevant stages. Where possible, feedback has been incorporated into this Draft ISP. Some items will be incorporated into the Final ISP (in June 2020, see Next Steps in Section 10), while other broader commentary on methodology will be considered for inclusion in the 2022 ISP.

Table 3 Overall themes of feedback received at ISP Preliminary Outcomes workshop (Oct 19)

Theme	Description	Items addressed in Draft ISP
ISP document content	More detail was requested for inclusion in the ISP in a number of areas, particularly around financial information, Marginal Loss Factors (MLFs) and system strength assessments. Traceability of the data to the relevant assumptions was also highlighted.	MLFs and System strength assessments have been incorporated in the relevant sections of this report.
ISP document format	It was noted that a high-level summary for policy makers would be useful, and some requested a simple front-end focus to the document.	

[2] AEMO. 2019. *2019 Planning and Forecasting Consultation Responses on Scenarios, Inputs, Assumptions and Methodology – Final Report*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Planning-and-Forecasting-Consultation-Responses.pdf.

[3] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan.

[4] AEMO ISP Preliminary Outcomes Workshop slides, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2019/ISP-Prelim-Outcomes-presentation-10-Oct-2019.pdf.

[5] AEMO ISP Workshop Synopsis, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2019/ISP-workshop-synopsis-10-Oct-2019.pdf.

Theme	Description	Items addressed in Draft ISP
Methodology	More explanation was requested on the modelling methodology, including criteria for project commitment and least regrets approach. Inclusion of social license aspects such as competing land uses was suggested.	Increased discussion on methodology has been included, along with a description of the development of the least worst regret optimal development path.
Results commentary	The representation of the projected changing energy mix was well received, and considered reflective of future thinking. Expansion of this approach was requested, along with more detail on future storage requirements. Consideration of the potential impact of hydrogen was recommended. Further suggestions were provided for assessment of the quality of Renewable Energy Zones (REZs), including the need to consider how these criteria may change over time. The grid outcomes were noted to be broadly aligned with TNSP positions, and a need for more emphasis on non-network alternatives was noted. Further risk factors were identified for consideration, including stranded assets, timing of project commitment, and inter-play with regulatory processes.	The description of the projected energy mix has been expanded, including the need for storages to provide dispatchability. REZ assessment methods have been updated, along with the REZ scorecards. Non-network solutions have been discussed where applicable. The process now explicitly calls for non-network options as part of the notice of consultation. Timing of project commitment has been illustrated using a new graphical approach.
Engagement	The use of interactive sessions such as this workshop was encouraged, and further workshops would be useful after the Draft ISP. More focused meetings such as with TNSPs, generators and consumer groups were also suggested, with incorporation of discussions on risk and least cost approach. Clearer communication of the registration process and the overall consultation process was requested.	Workshops have been scheduled for February, and discussions have been initiated with consumer groups on risk and least cost approaches – these will continue in 2020. The registration process has been clarified on the AEMO website, to complement the invitee register. The overall consultation process has been described in detail in this report.
Review/critiques	The preliminary outcomes were noted to be broadly consistent with the 2018 ISP and the increased transparency of the early workshop approach was welcomed. The need for the ISP to remain independent was stated and clarity was requested on what is driven by policy vs economics.	

The next opportunity for engagement will be at the workshops to be run in three locations in early February 2020, along with the consultation on the Draft ISP – see details in Part E of the Draft ISP report.

Appendix 3. The energy mix of tomorrow's power system

3.1 Common themes and technologies

The ISP forecasts the NEM evolving from a generation mix dominated by coal-fired generation, to a generation mix dominated by renewable generation supported by energy storage, transmission, GPG, and DER.

The most efficient replacement portfolio for aging power stations is projected to be a combination of:

- **Renewable energy** – a mixture of diversely located variable renewable energy (VRE) (solar and wind) and DER, firmed by storage, GPG and supported by network augmentations.
- **Energy storage** – to firm the production of renewable generation and provide backup supply and peaking support (up to storage capacity), as well as a range of essential power system security services including fast frequency response and frequency control ancillary services (FCAS).
- **Gas-powered generation (GPG)** – to provide backup supply and peaking support.
- **Increased transmission, including interconnection** – to support the integration of significant quantities of dispersed VRE across the grid and DER, and facilitate the efficient sharing of renewable energy, storage, and backup and firming services.

The generation mix is expected to be technologically and geographically diverse. This technology mix may diversify further in the future than current projections, if forecast technology cost reductions in emerging and maturing technologies occur more rapidly than current expectations.

This projected resource portfolio provides a lower overall cost to deliver the energy and peak capacity needed than developing new replacement thermal generation and supports large reductions in emissions.

The magnitude and depth[6] of storage required will depend on the mix and location of renewable technologies and the flexibility that remains in the existing generation fleet. The pace of transformation will hasten the need for the development of flexible supplies that can firm and support a renewable energy mix. Furthermore, the prospects of a highly decentralised energy mix will not replace the need for grid-scale, controllable supplies to maintain grid reliability and security.

This Appendix details the development opportunities identified as part of the optimal development path outlined in the Draft ISP, which are enabled through the Group 1, 2, and 3 grid projects.

[6] Storage technologies can be referred to as either 'shallow' or 'deep', reflecting the size of the storage and the role that they may play.

3.2 Resource developments using the ISP optimal development path, by scenario

3.2.1 Central scenario

The Central scenario demonstrates a moderate pace of change, with new developments required to replace aging assets in the next 20 years across the NEM, and to support existing national and state policies.

The Central scenario forecasts some regional concentration of large-scale renewable generation development over the near term, with renewable energy targets in Queensland and Victoria driving developments in those regions. New transmission capacity to increase the connectivity of South Australia and New South Wales to their respective neighbouring regions will increase the capability of energy sharing, reducing the need for significant local resources in the near term.

This section describes the ISP development opportunities that are forecast to maximise market benefits in the Central scenario (assuming VNI West is accelerated, consistent with the optimal development path).

For the 2020 ISP, the introduction of multiple reference years to capture the variable operation of wind, solar, and hydro generation has resulted in an enhanced representation of the value these complementary technologies provide to the system, aided by transmission augmentations. With these modelling enhancements, the forecasts for the 2020 ISP scenarios tend to present a more even distribution of solar, wind, and storage installations on a capacity basis than the 2018 ISP.

This outcome suggests that the least cost outcome for the system will consist of a complementary suite of VRE, storage, DER, and transmission to address the transitional requirements of the NEM over the next 20 years.

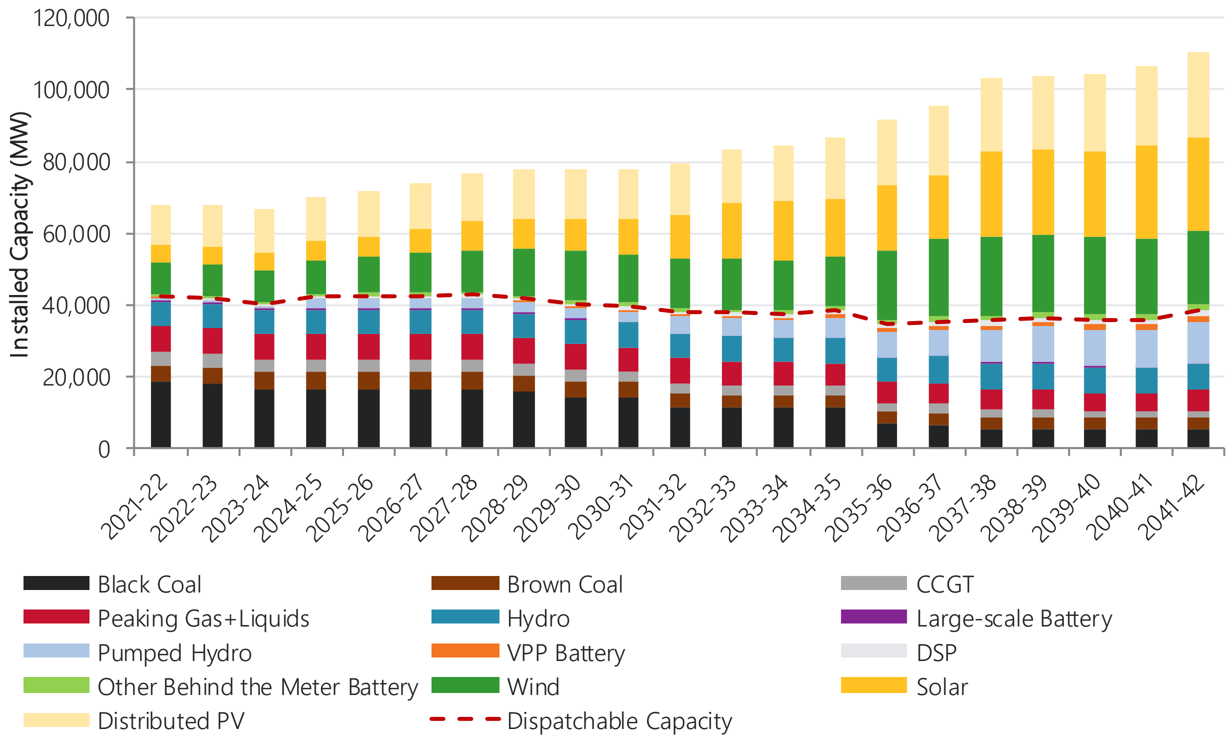
The generation capacity forecast projects that:

- To 2030:
  - Renewable energy policies in Victoria and Queensland will drive development of VRE in those regions[7].
  - The commissioning of the Snowy 2.0 project, and Group 1 and Group 2 grid projects, will reduce the need for new dispatchable investments beyond existing commitments to meet the current reliability standard.
- By 2040:
  - The expected closure of coal capacity across the NEM will require significant replacement capacity. Aging assets are forecast to be progressively replaced by VRE, complemented by energy storages. Generation retirements also drive relatively strong value in transmission augmentations, reducing the need for local capacity and, in particular, maximising the operational efficiency of renewable developments and the remaining thermal fleet.
  - The development of increased transmission infrastructure and DER operating as virtual power plants (VPPs) will allow a marginal reduction in overall dispatchable capacity.

Figure 4 presents the forecast large-scale capacity mix for the NEM across the outlook period to 2042.

[7] Information on the New South Wales Electricity Strategy was received too late to be incorporated in this draft ISP.

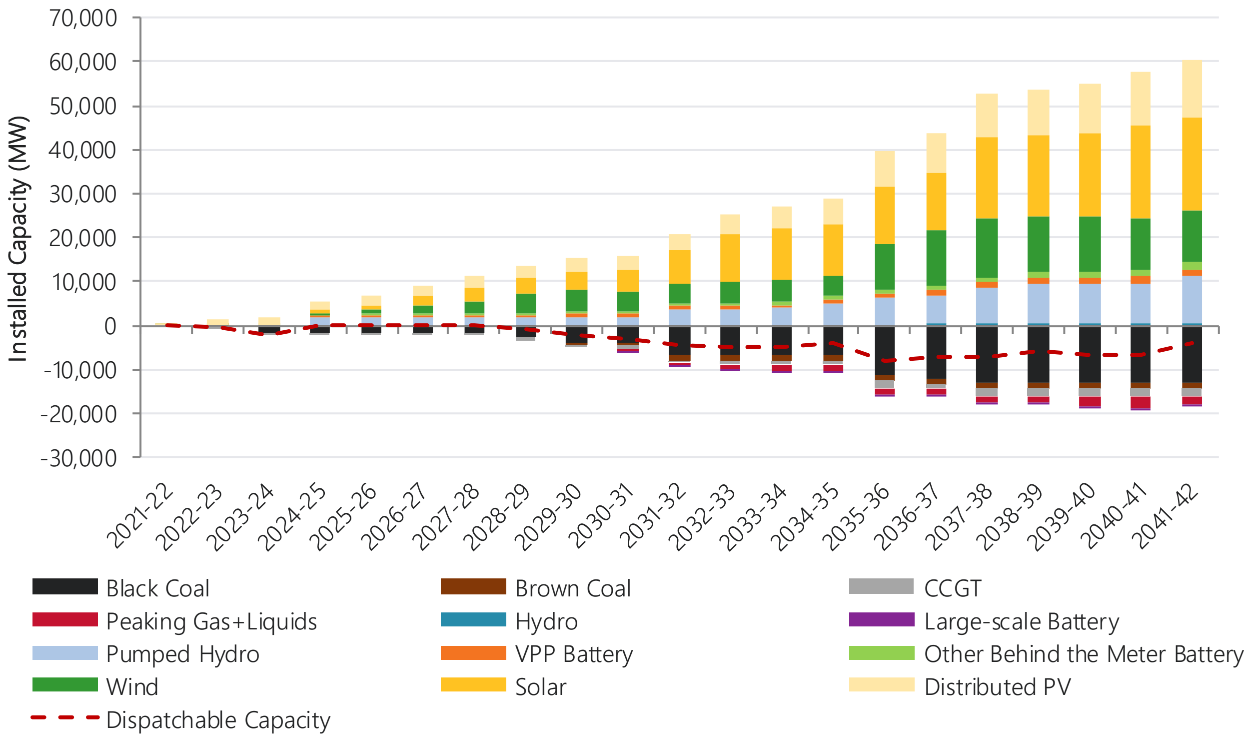
Figure 4 Forecast NEM generation capacity 2041-42, Central scenario



In Figure 5, a positive value in the chart indicates a net addition in installed capacity, while a negative value indicates a net deduction due to retirement or end of technical life. It shows that, under the Central scenario:

- Initial developments of renewable generation occur in the period before 2030, driven by existing policies. As retirements accelerate after 2030, a significant new entrant generation response is observed, consisting of a complementary suite of VRE, storage, and DER.
- By 2040, in addition to the assumed 22 GW of DER (primarily rooftop PV), the NEM needs an additional 34 GW of VRE by 2040 to replace major coal plant exits, over and above existing and committed VRE. This is complemented by approximately 10 GW of grid-scale energy storage.
- Overall, dispatchable capacity (coal generation, hydro generation, GPG, energy storages, DSP, and behind-the-meter VPP batteries) reduces, but dispatchability is maintained in all hours through greater interconnection, and therefore sharing of geographically and technologically diverse resources. Intra-day operability is discussed in more detail in Appendix 4.

Figure 5 Forecast relative change in installed capacity to 2041-42, Central scenario

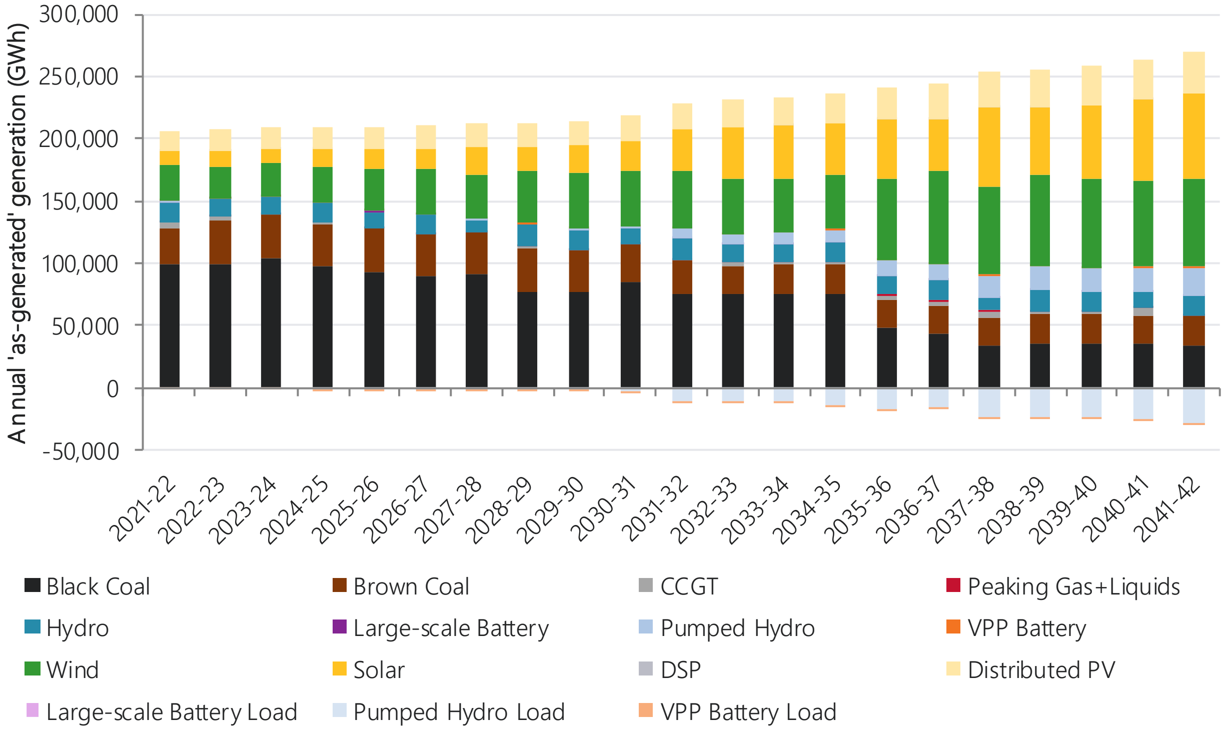


The Central scenario applies the expected closure dates provided by market participants. These retirements provide incentives for the introduction of new generation and transmission developments.

In terms of energy production, Figure 6 demonstrates the forecast change in the energy mix from coal generation to VRE. It also demonstrates the scale of energy required to operate energy storages, through the pumped hydro load beneath the x-axis. Renewable energy is forecast to expand from approximately 35% of energy generated to approximately 74% of energy generated by 2040. The projected mix of grid-scale wind and solar generation is relatively evenly split (46% wind and 54% solar). This is a more even mix of renewable technologies than forecast in the 2018 ISP, which forecast[8] a stronger role for grid-scale solar generation at 61% of renewable energy, and less wind generation at 39%.

[8] As per the 2018 ISP, "Neutral with Storage Initiatives" scenario.

Figure 6 Forecast annual generation to 2041-42, Central Scenario



Across the NEM, the forecast evolution of the supply mix in regions varies, in terms of size and timing. Generation developments in NEM regions will depend on a number of factors including the scale of retirements, the quality of local wind and solar resources, the potential for storage capacity to complement VRE, and access to transmission to share energy. Figure 7 shows forecast regional evolution to 2041-42.

By 2040, all regions are projected to have new VRE capacity (9-15 GW each in Queensland and New South Wales, and 4 GW in Victoria, over and above what is already committed, to replace retiring assets. South Australia is forecast to feature the highest share of renewable energy of all NEM regions. Tasmania is also forecast to continue to rely heavily on hydro generation, complemented by increased wind and rooftop PV.

Figure 7 Forecast annual 'as-generated' generation for each NEM region to 2041-42, Central scenario

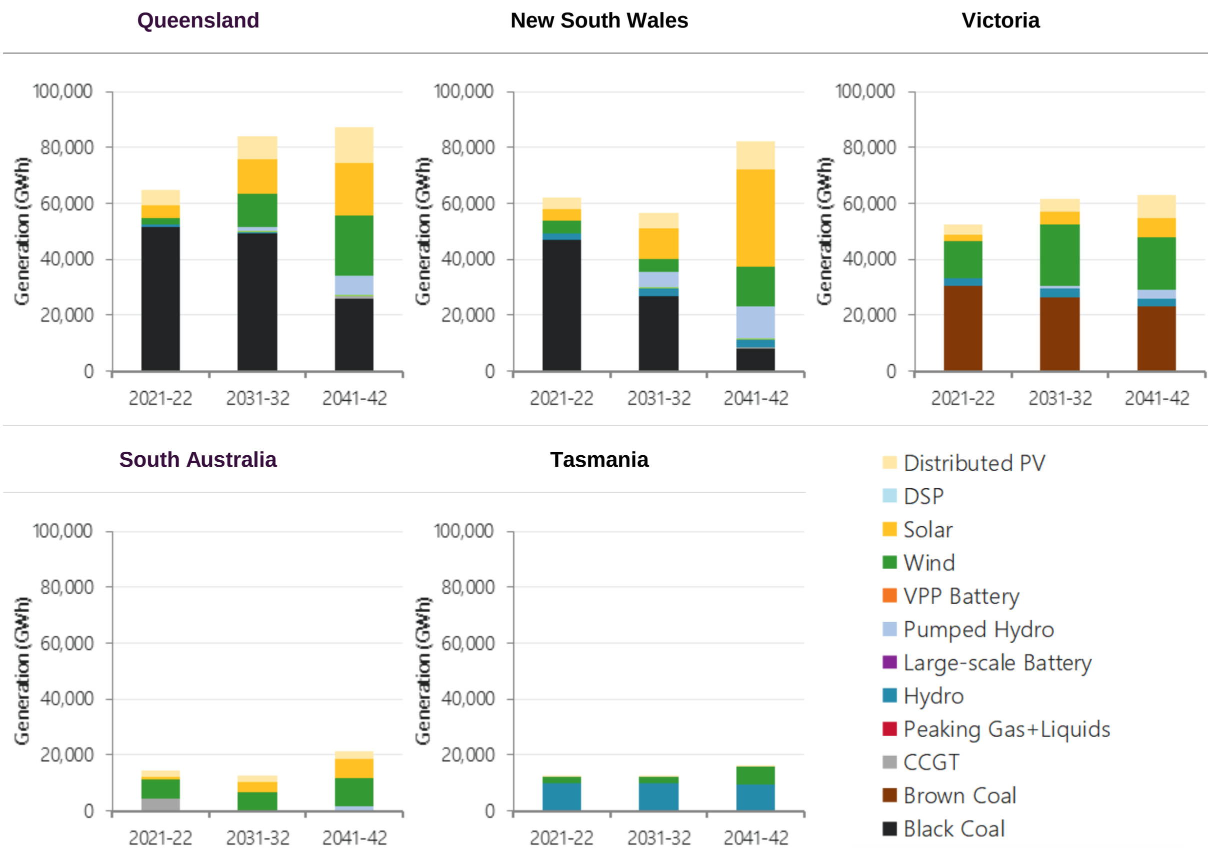
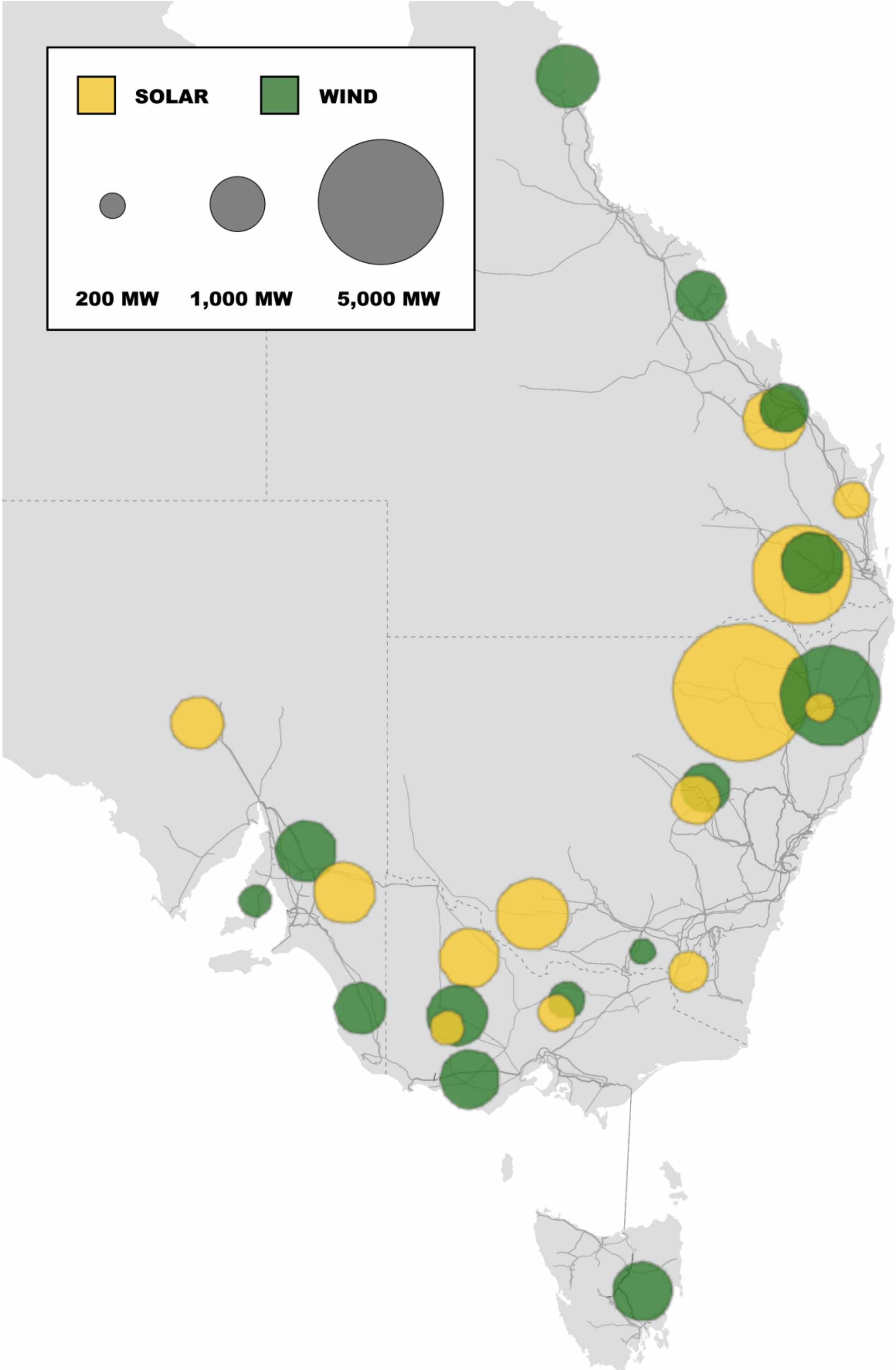


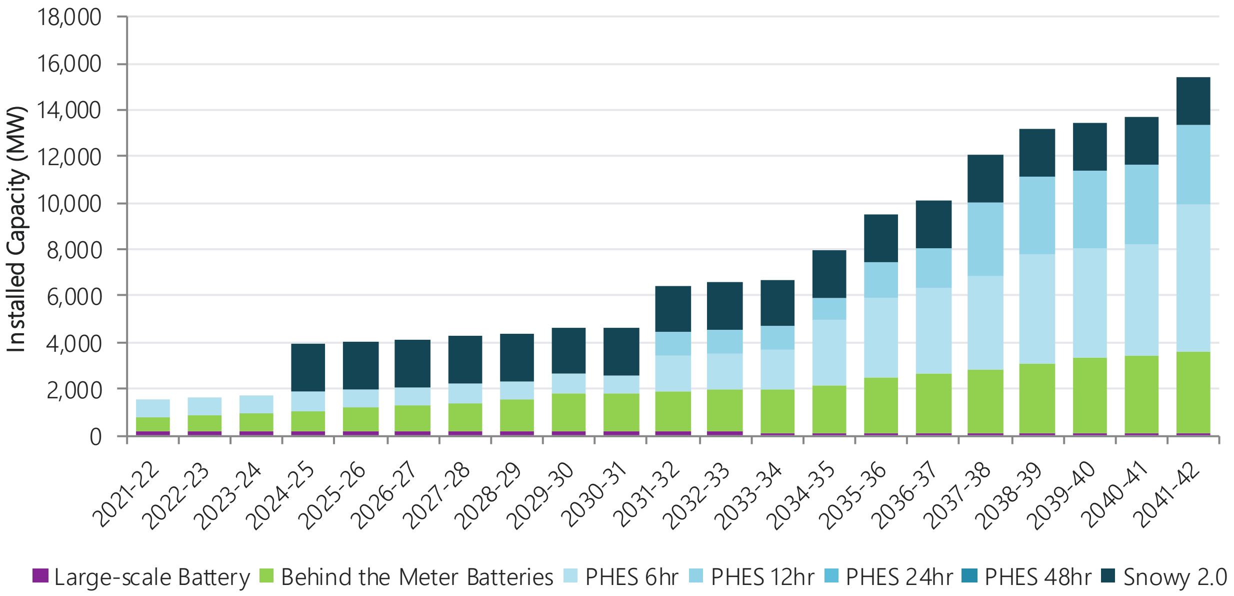
Figure 8 shows the forecast diversity of renewable generation across the NEM, including existing and committed capacity. Geographic and technical diversity will be important to maximise resilience and fuel security associated with weather events, and bushfire risks in a future energy system with high VRE.

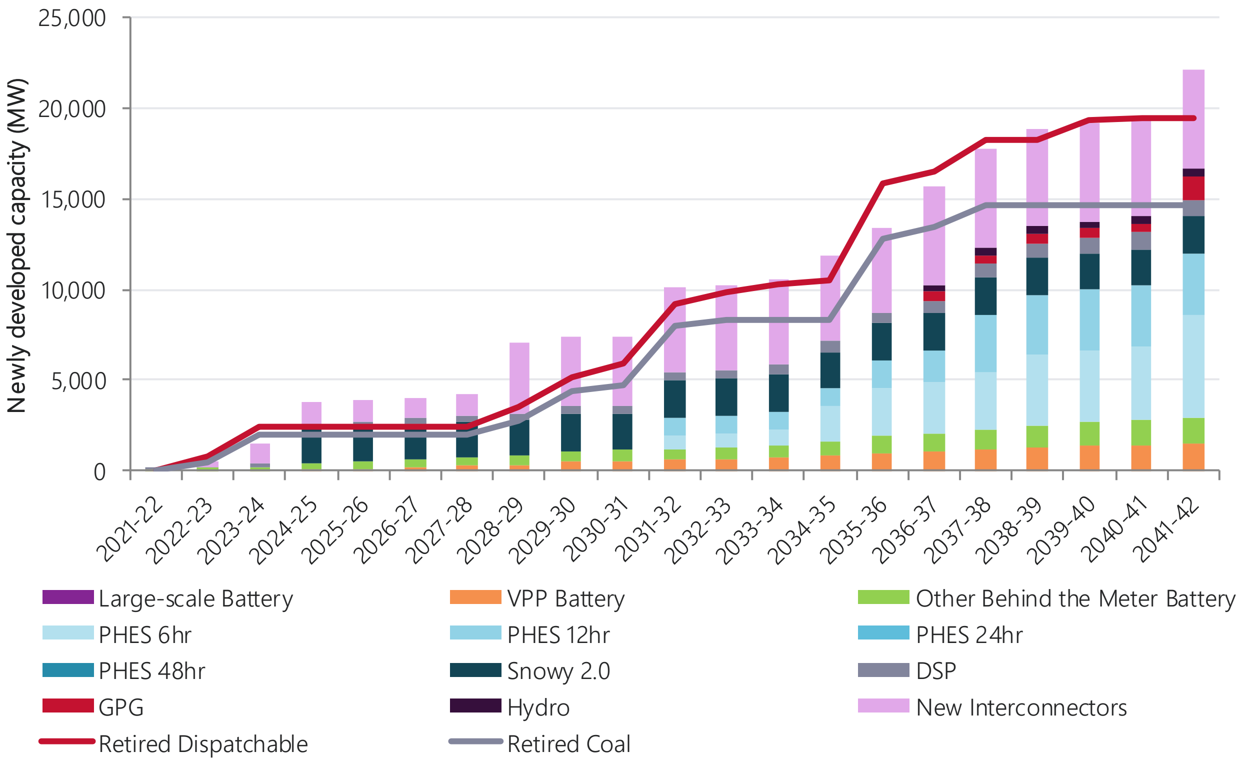
Figure 8 Forecast geographic and technological dispersion of new developments by 2040, Central scenario



To complement the development of renewable energy, small and large-scale energy storage development, DSP and dispatchable generation is necessary. With the introduction of Snowy 2.0 and a number of Group 1 and Group 2 grid projects, the need for significant additional storage developments is not observed in the forecast until 2030 (Figure 9). After 2030, the schedule of expected retirements drives the projected development need for storages across the NEM.

Figure 9 Forecast storage and dispatchable capacity development to 2041-42, Central scenario

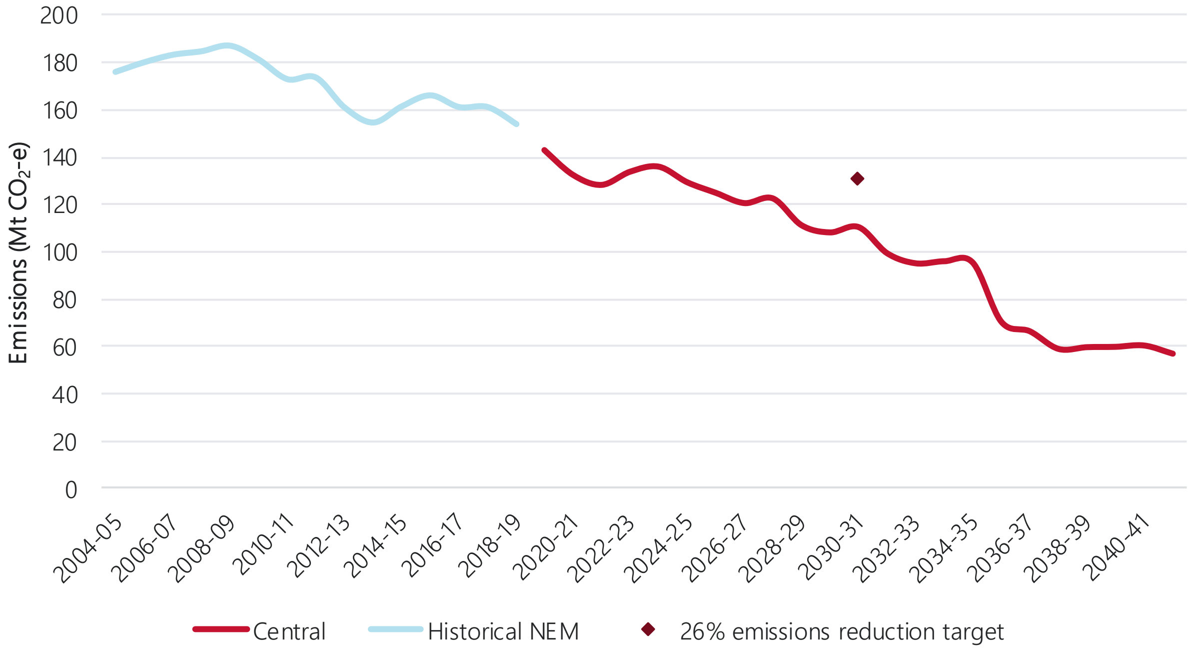




The emissions intensity of the NEM is forecast to reduce with the uptake of renewable energy, particularly as incumbent emissions-intensive thermal generators retire or reduce operation. Figure 10 below[9] demonstrates the reduction in emissions forecast to 2042. Emissions will vary depending on VRE resource availability. Years where this is an increased availability of hydro inflows or greater wind and solar production would rely less on alternative generation, keeping emissions lower than in years where VRE resources are lower. Renewable energy diversity can limit the year-on-year resource variability.

On average by 2030, NEM emissions are projected to reduce 30% from current levels, to 108 MT CO_2-e, exceeding the 26% Federal emissions reduction target.

Figure 10 Forecast NEM emissions to 2040-41, Central Scenario

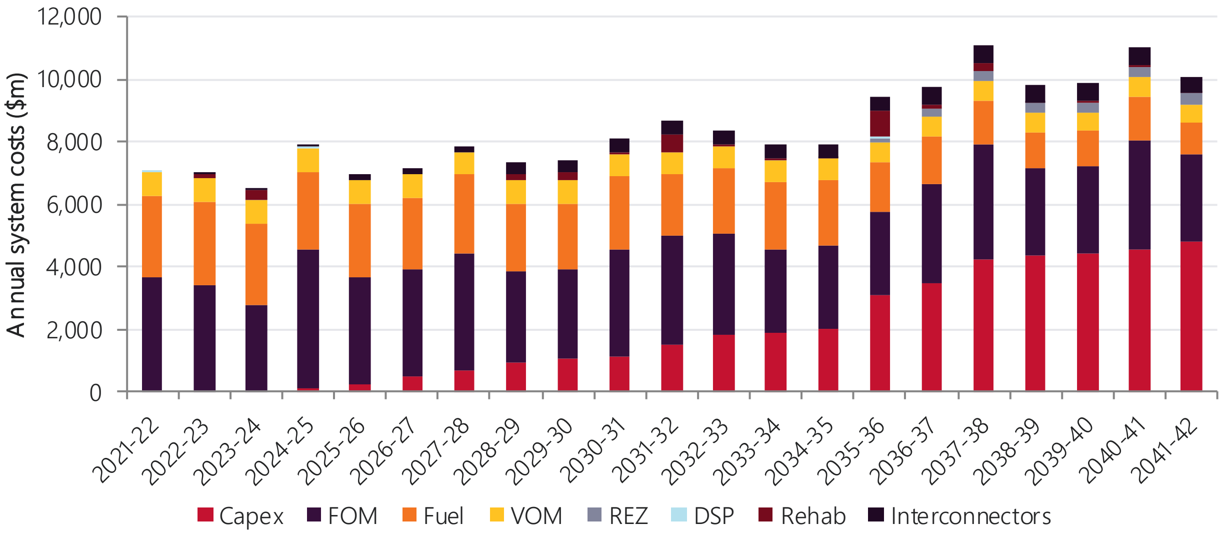


Data from Department of the Environment and Energy, Australia's emissions projections 2018.

Over the forecast period, system costs (Figure 11) are projected to increase, despite grid consumption remaining relatively flat, due to the capital-intensive requirements to develop both new VRE and transmission. Operating costs, such as maintenance expenditure, are forecast to continue being a large cost for the system despite the shift to a greater renewable energy mix, while fuel costs are projected to reduce significantly as thermal plant retire.

[9] Department of the Environment and Energy, Australia's emissions projections 2018, accessed December 2019, at http://www.environment.gov.au/system/files/resources/128ae060-ac07-4874-857e-dced2ca22347/files/aust-emissions-projects-chart-data-2018.xlsx.

Figure 11 Forecast total aggregate system costs to 2041-42, Central scenario



The cost categories considered in modelling and presented in Figure 11, and all other total aggregate system costs figures referred to in this Appendix, are defined in Table 4. The costs of DER and distribution-level investment are not included in the total system costs, because they are beyond the scope of this Draft ISP.

Table 4 System cost categories

Cost category	Description
Capex	Capital expenditure for new generators.
FOM	Fixed operation and maintenance cost (including life extension costs where applicable). These life extension refurbishment costs can result in a material increase in total system FOM costs year to year.
Fuel	Fuel cost for thermal generation plant.
VOM	Variable operation and maintenance cost.
Rehab	Rehabilitation costs of generator retirements.
USE+DSP	Cost of unserved energy and demand side participation.
REZ	Cost of grid development directly associated with REZ expansions.
Interconnectors	Expenditure for new or augmented transmission projects.

3.2.2 High DER

The High DER scenario considers a future where there is stronger growth in distributed rooftop PV generation, embedded battery storages, and other demand-based resources installed by consumers and industry. Other key scenario settings are broadly consistent with the Central scenario, leading to a development outlook that has an increased share of the transformation borne by consumers and industry as they develop resources behind-the-meter to meet their energy needs.

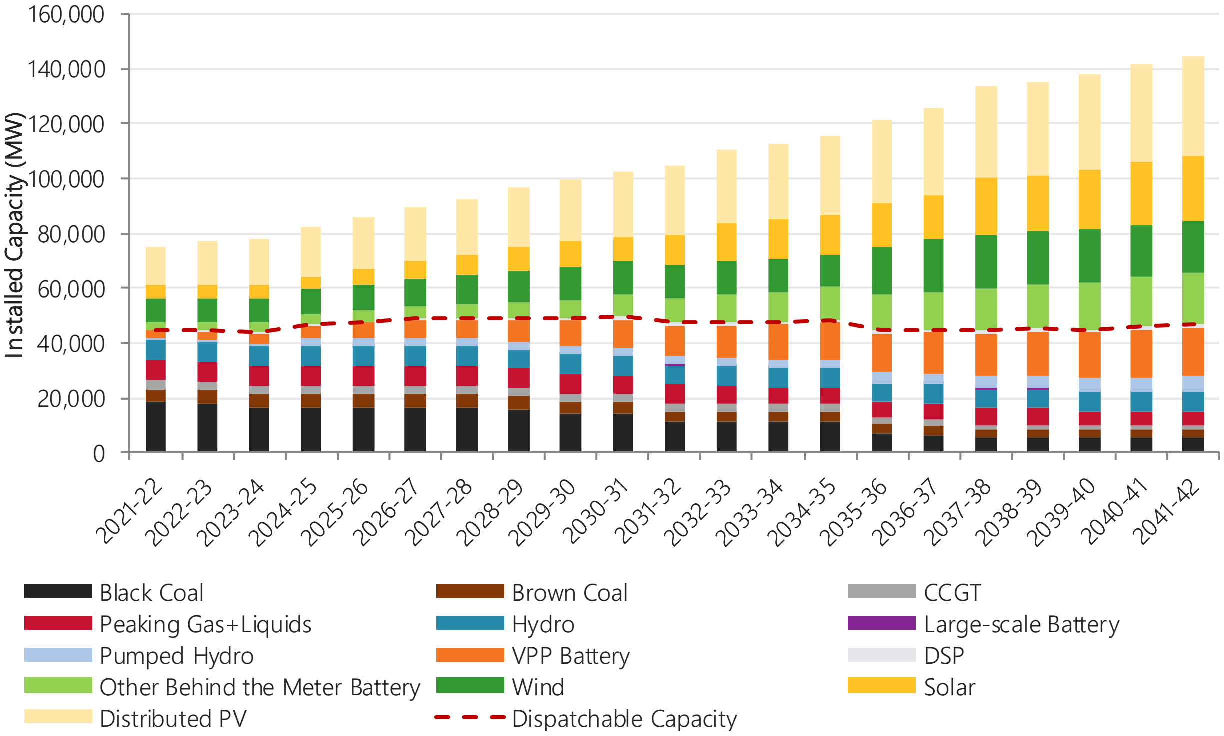
DER uptake – particularly if controllable through VPP technologies – reduces the need for grid-scale capacity, as the energy needs of consumers and industry are met at the point of consumption. For this development outlook to be effective, technological and communication development is necessary to ensure coordination of DER efficiently lowers total system costs.

The generation capacity forecast projects that:

- To 2030:
  - Similar to the Central scenario, new capacity developments will consist of a portfolio of wind and solar developments, particularly in Victoria and Queensland. However, due to the decreased utilisation factor of DER compared to efficiently located large-scale VRE, there will be a greater number of generation assets in the NEM on an installed capacity basis.
  - The proportion of large-scale renewable developments across the NEM will be lower than in the Central scenario forecast, as DER plays a much greater role in energy production and management, resulting in a more even distribution of energy resources near load centres throughout the NEM.
  - Accelerated uptake of behind the meter battery storages, particularly the deployment of aggregated VPP, will limit requirements for further dispatchable capacity across the NEM in addition to the Snowy 2.0 project.
- By 2040:
  - Generator retirements will drive continued development in VRE, complemented by deeper pumped hydro storages.
  - Overall capacity expansion in the High DER scenario in both VRE and energy storages will be lower when compared to other scenarios except Slow Change, as a result of the increased development of DER deferring the requirement of generation and storage.

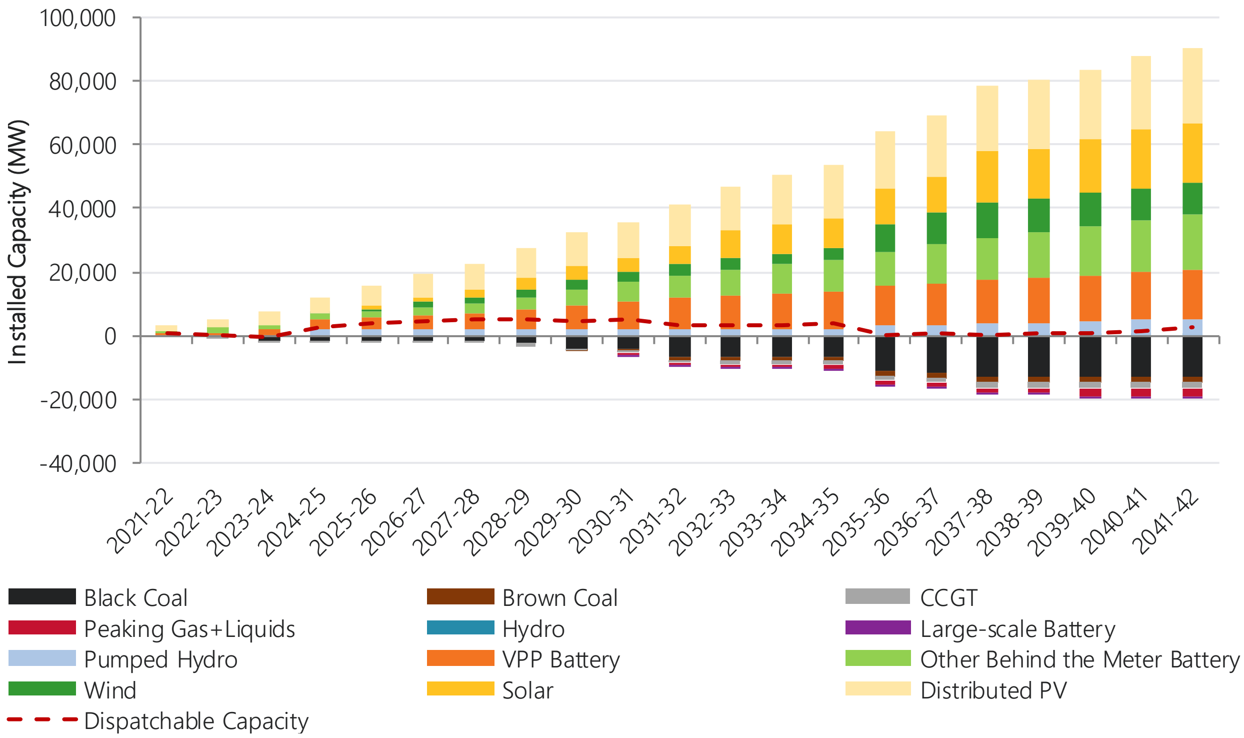
Figure 12 presents the forecast capacity mix for the NEM across the outlook period to 2041-42 for the High DER scenario. Of note is the material development of behind-the-meter batteries, providing a significant proportion of the NEM's firming requirements. As these storages are at the point of consumption, the need for transmission and large-scale energy storage to provide energy sharing and firming of peak demands is reduced, but nonetheless they still have a vital role in effectively managing, and delivering, the inherently variable VRE to the load centres.

Figure 12 Forecast NEM generation capacity to 2041-42, High DER scenario



As shown in Figure 13, the uptake of DER solutions in this scenario is significant, reducing the need for grid-connected generation and storage assets compared to the Central scenario. By 2040, allowing for the stronger growth in DER, the NEM will need 30 GW of new VRE over and above what is already committed, to replace retiring assets. This is approximately 4 GW less than in the Central scenario. This is complemented by approximately 5 GW of grid-scale energy storage. Large-scale storages, such as pumped hydro energy systems, are also much lower in this scenario. Additionally, with the assumption of a greater uptake in DER, specifically in the form of VVP, the High DER scenario is able to sustain a stable level of installed dispatchable capacity.

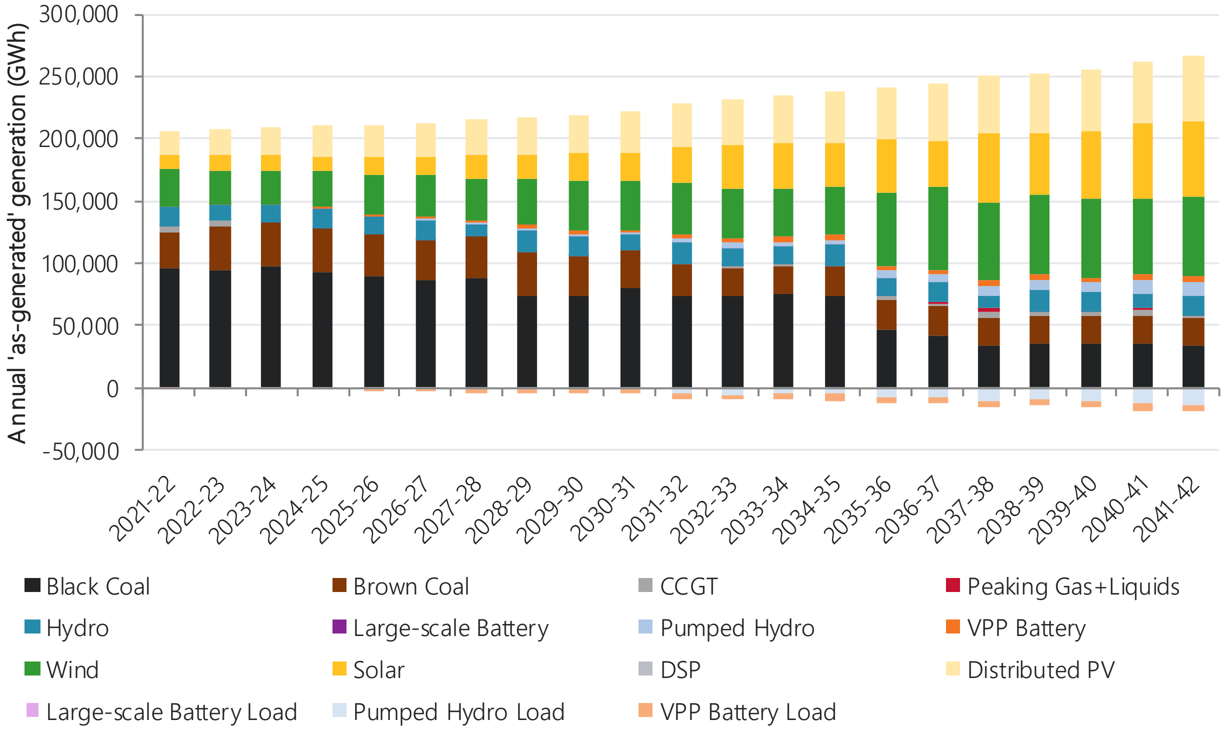
Figure 13 Forecast relative change in installed capacity to 2041-42, High DER scenario



Compared to the Central scenario, the forecast level of dispatchable capacity over time is relatively static in the High DER scenario, due to the greater proportion of behind-the-meter battery operating as VPPs in this scenario. By 2040, 12% of total installed capacity (16 GW), is assumed to be operated as VPPs (nearly 50% of behind-the-meter battery storage).

DER is also assumed to play a greater role in contributing to overall electricity generation, approximately doubling in energy contribution from 9% of generation in 2021-22 to 18% in 2039-40. The contribution from all renewable energy sources – VRE and DER – is expected to be approximately 74% of total energy production by 2040. The forecast mix of grid-scale wind and solar generation at that time is relatively evenly split (approximately 40% wind and 60% solar).

Figure 14 Forecast annual generation to 2041-42, High DER scenario



Across NEM regions, the forecast evolution of the supply mix varies in a similar manner to the Central scenario, particularly with regards to the timing and therefore urgency of the transformation (Figure 15). Large-scale VRE developments both in Queensland and Victoria are forecast to be lower than in the Central scenario, with the increased role of DER assisting in achieving state-based targets, and also increasing behind-the-meter solar generation in regions without renewable energy targets. In New South Wales, this increased contribution of rooftop PV in the generation mix subsequently reduces the projected interconnection requirement between New South Wales and Queensland, leading to the preference for a smaller QNI augmentation in the optimal development path.

By 2040, all regions are projected to have new VRE capacity (10-11 GW each in Queensland and New South Wales, and 4 GW in Victoria), over and above what is already committed, to replace retiring assets.

Figure 15 Forecast annual 'as-generated' generation for each region in the NEM for the High DER scenario

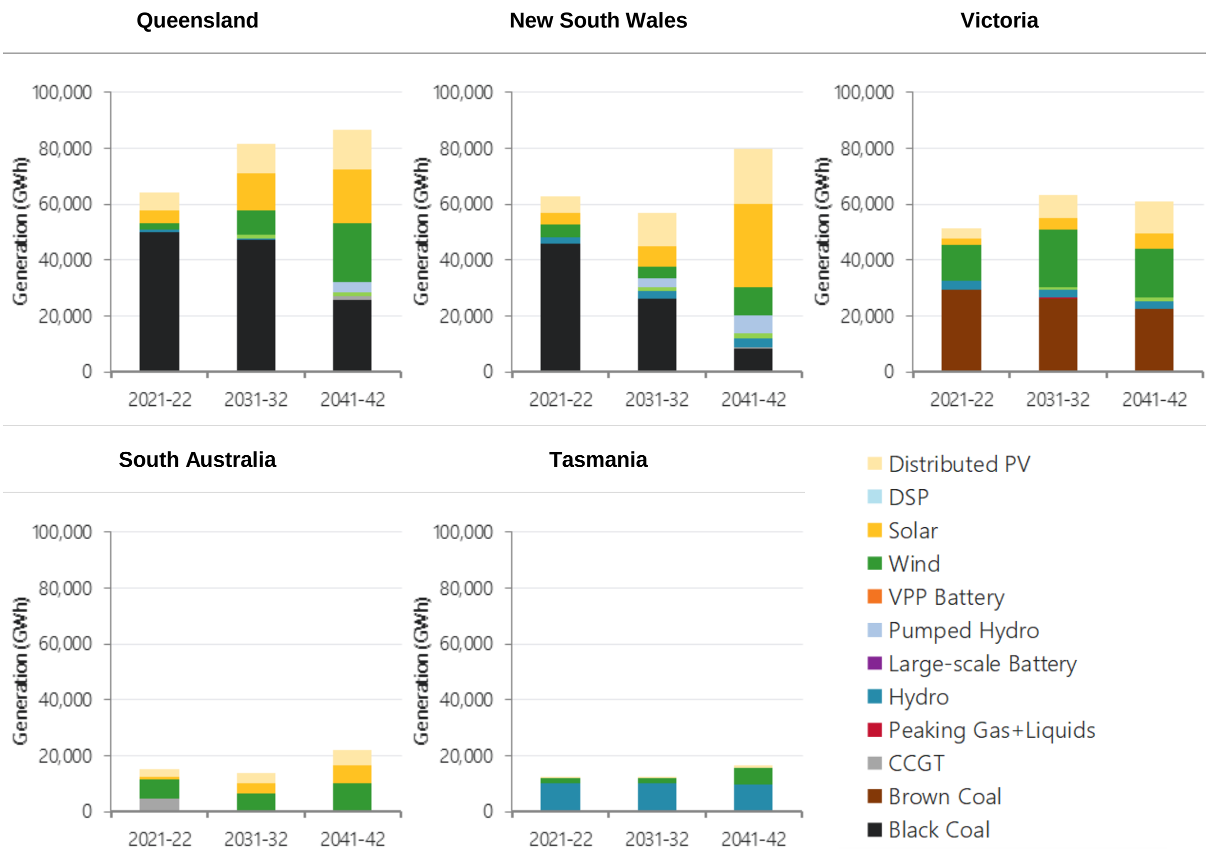
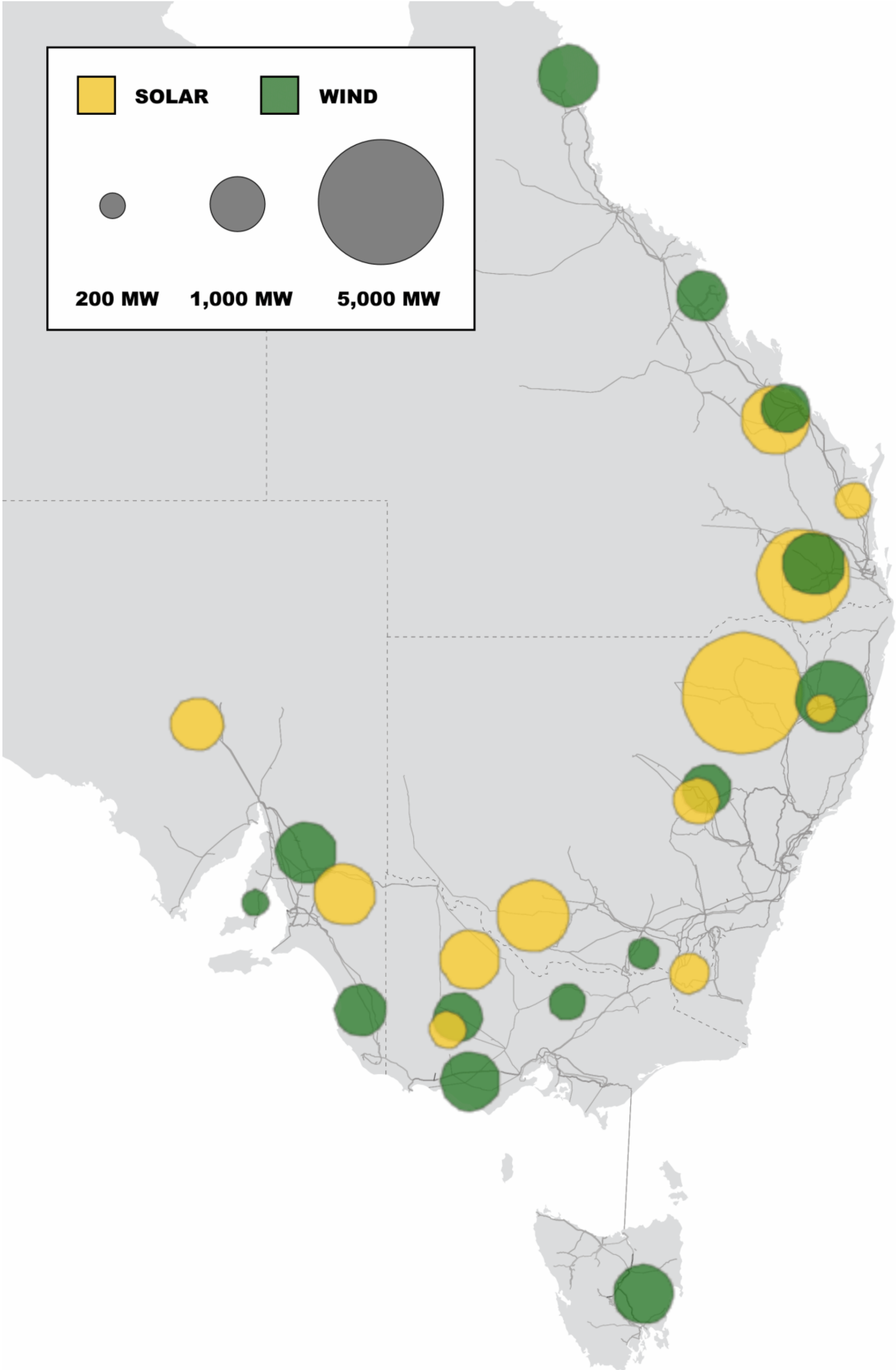


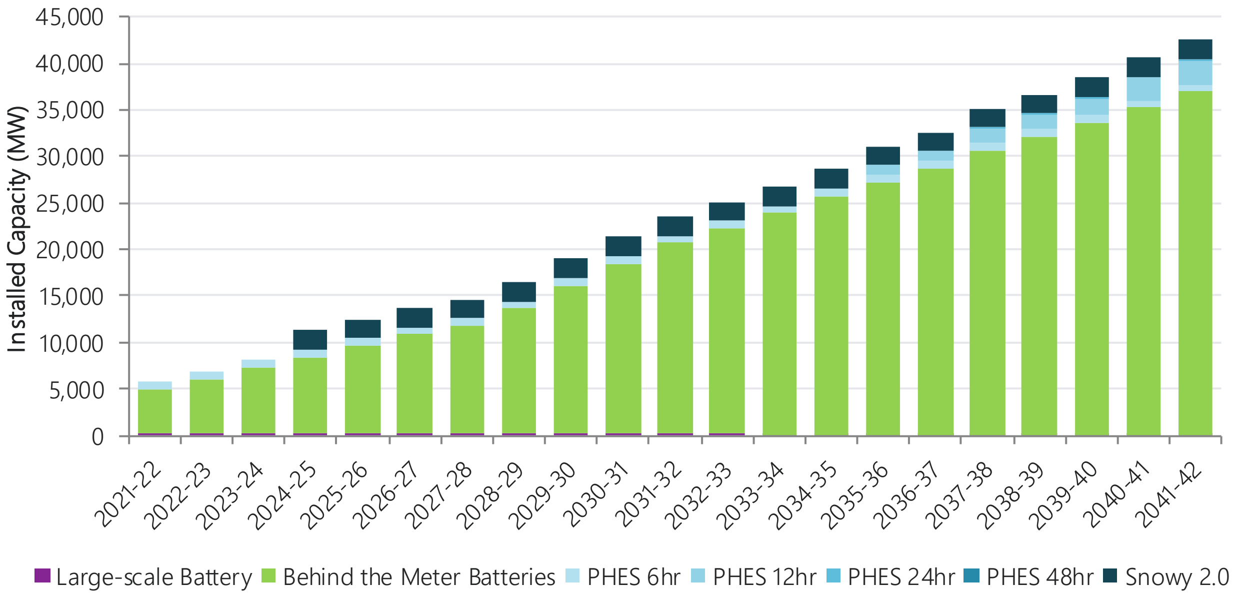
Figure 16 shows the forecast VRE diversity across the NEM. Given the scale of DER developments, this scenario represents reduced diversity of large-scale generation, although the nature of DER is that it will be naturally diversified, with distribution across each region's population centres.

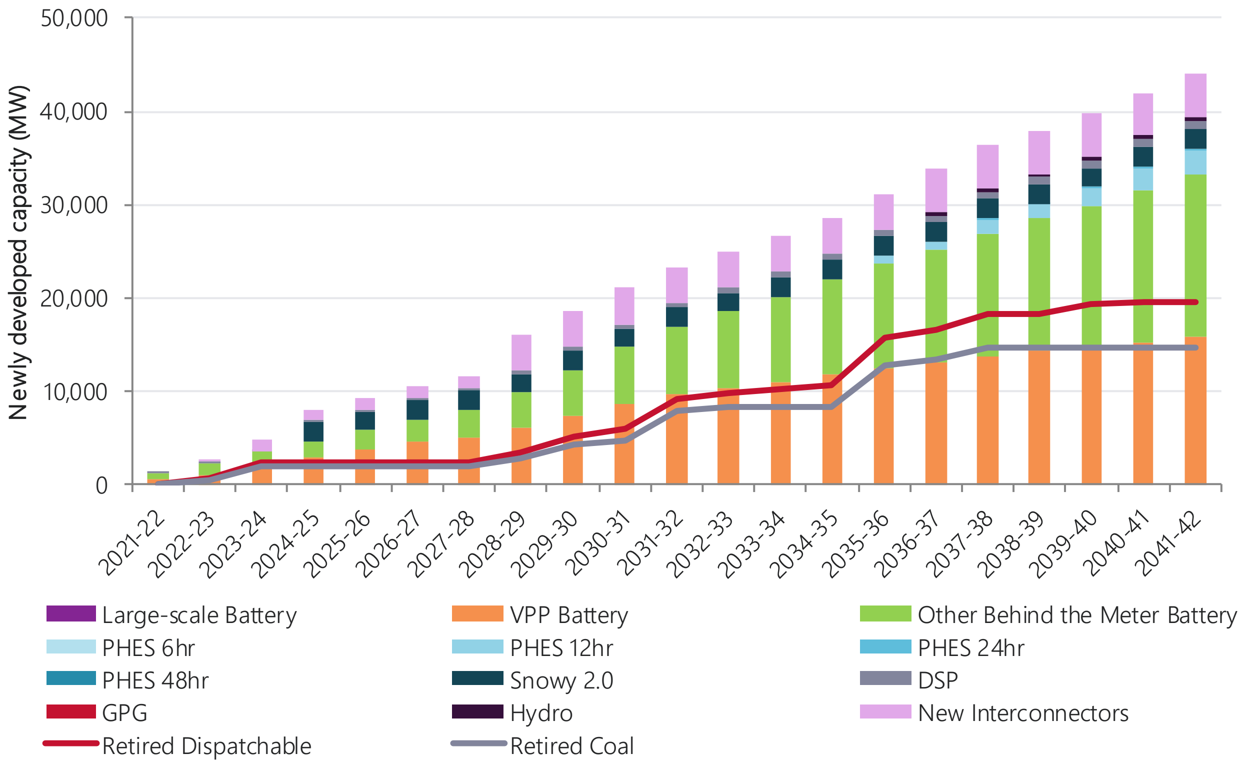
Figure 16 Forecast geographic and technological dispersion of new developments by 2040, High DER Scenario



In this scenario, distributed battery storages largely fulfil the requirement for daily peak storage management, shifting rooftop PV generation to assist in covering the evening peak demand periods. When required in the 2030s, medium-depth pumped hydro storages are projected to be developed in New South Wales and Queensland to complement the shallow batteries, particularly after coal retirements lead to an increased need for flexibility and peaking support.

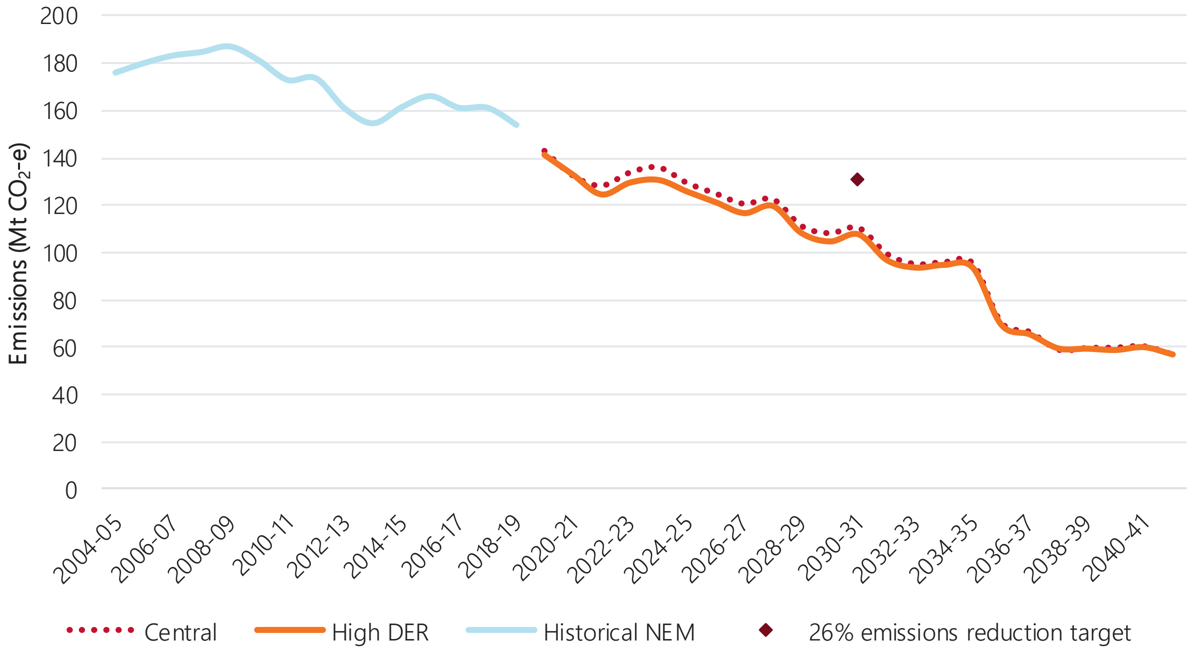
Figure 17 Forecast storage and dispatchable capacity development to 2041-42, High DER Scenario





As in the Central Scenario, emissions are forecast to reduce given the expected schedule of generator retirements, as shown in Figure 18 below[10]. Higher DER production does offset some emissions-intensive generation, but on the whole the emissions forecast in the High DER scenario is not significantly different to the Central scenario.

Figure 18 Forecast NEM emissions to 2040-41, High DER scenario, relative to the Central scenario

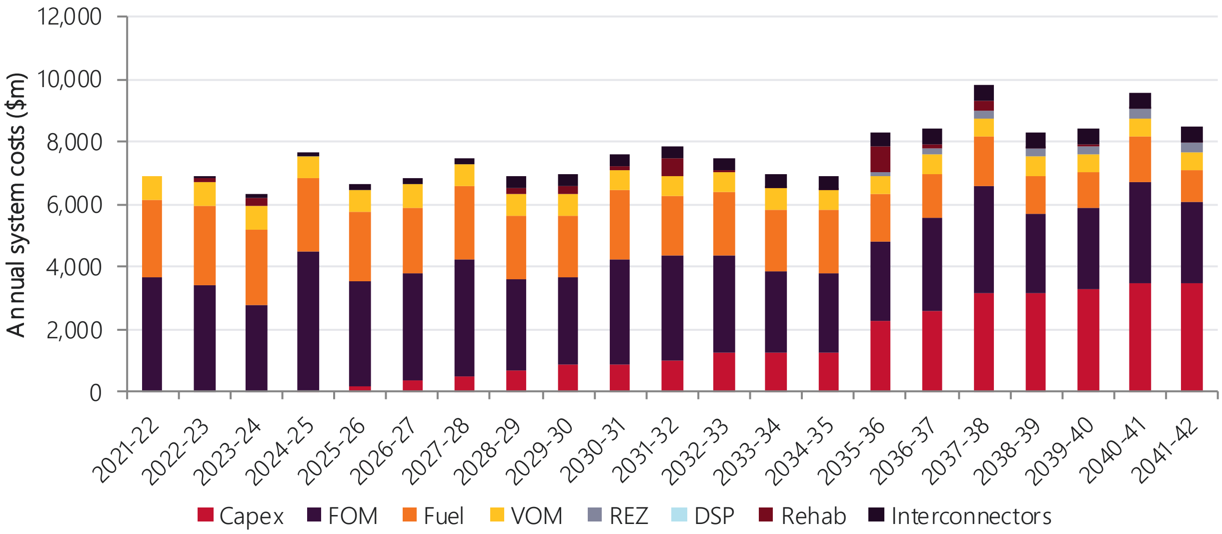


Data from Department of the Environment and Energy, Australia's emissions projections 2018.

As seen in Figure 19, total system costs in the High DER scenario are forecast to be lower than in the Central scenario, as total system costs do not capture the cost of DER or any necessary distribution-level investments. Capital expenditure is projected to increase as large-scale VRE and transmission to accompany DER is developed, while fuel costs are forecast to decrease over time with the shift towards renewable energy generation sources.

[10] Department of the Environment and Energy, Australia's emissions projections 2018, accessed December 2019, at http://www.environment.gov.au/system/files/resources/128ae060-ac07-4874-857e-dced2ca22347/files/aust-emissions-projects-chart-data-2018.xlsx.

Figure 19 Forecast total aggregate system costs to 2041-42, High DER scenario



3.2.3 Step Change

The Step Change scenario considers stronger growth with aggressive action to address climate risks. In this scenario, commitment to aggressive decarbonisation is forecast to lead to accelerated exits of existing thermal generation.

This scenario includes faster technological improvements leading to a greater electrification of the transport sector, energy digitalisation, and consumer-led innovation.

Key differences to the Central Scenario include:

- Higher population and economic growth.
- Most aggressive decarbonisation goals.
- Technology innovation and increased DER uptake.
- Greater EV uptake and stronger role for energy management solutions, including vehicle-to-home opportunities.
- Stronger role for energy efficiency measures.

The generation capacity forecast projects that:

- To 2030:
  - Similar to the Central scenario, VRE developments will be expected to locate in Victoria and Queensland. However, due to the higher requirement for VRE development NSW experiences an increase in VRE development.
  - With a more aggressive emissions abatement target, retirements of both black and brown coal across the NEM will be accelerated. This reduction in generation production will be primarily addressed by a combination of VRE, DER, storage and transmission.
  - Large volumes of VRE are forecast to be required to achieve the aggressive carbon budgets to address climate risks, additionally Snowy 2.0, is forecast to be needed, with deeper pumped hydro to complement the increased VPP in this scenario.
  - With such rapid transformation, there is a greater need for transmission development – both intra- and inter-regional – to improve access to REZs and share energy and capacity between regions.
- By 2040:

– Generator retirements will continue to partially drive developments in VRE, complemented by deeper pumped hydro storages.
– The total installed capacity of coal fired power stations in the NEM is expected to be less than 6 GW. Leading to the need of low emission firming technologies such as storage complemented by VRE.

Figure 20 presents the large-scale capacity outlook for the NEM across the outlook period for the Step Change scenario. Of note is the accelerated retirements of black and brown coal generators to meet this scenario's carbon budget. There is an influx of new VRE capacity, both large-scale technologies and DER. Providing firm capacity are new builds of pumped hydro storages and behind the meter VPPs.

Figure 20 Forecast NEM generation capacity to 2041-42, Step Change scenario

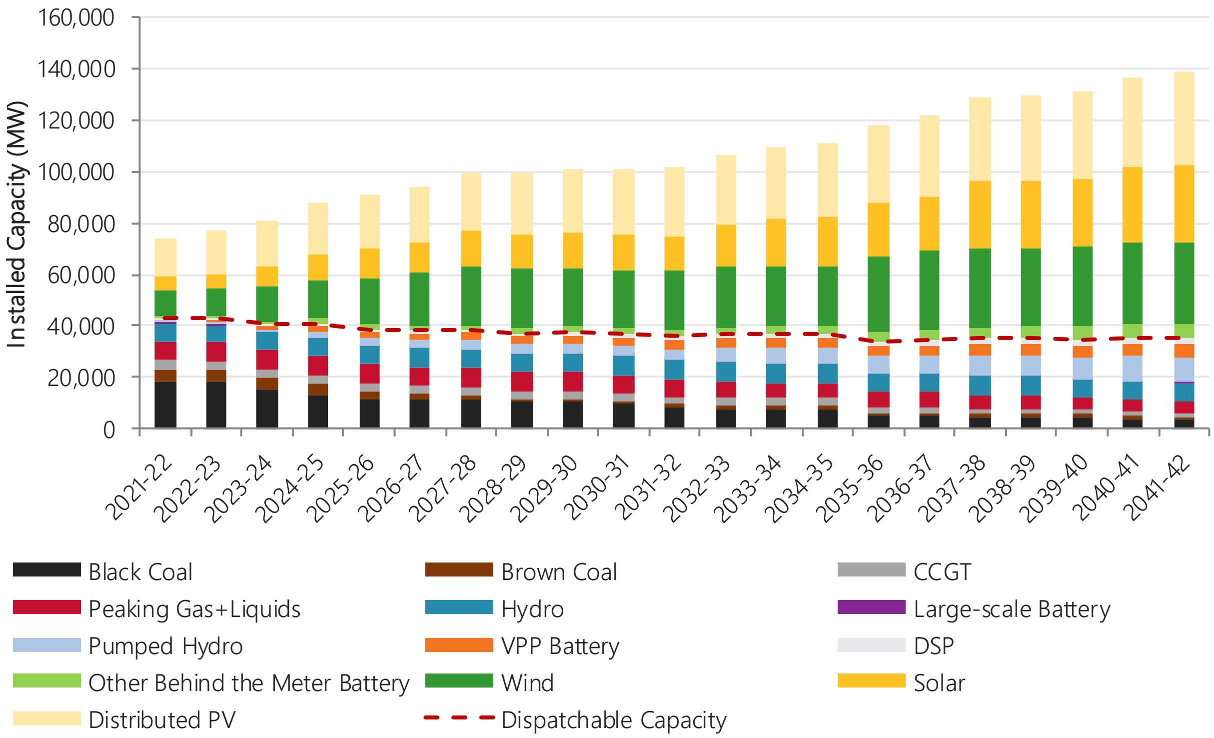
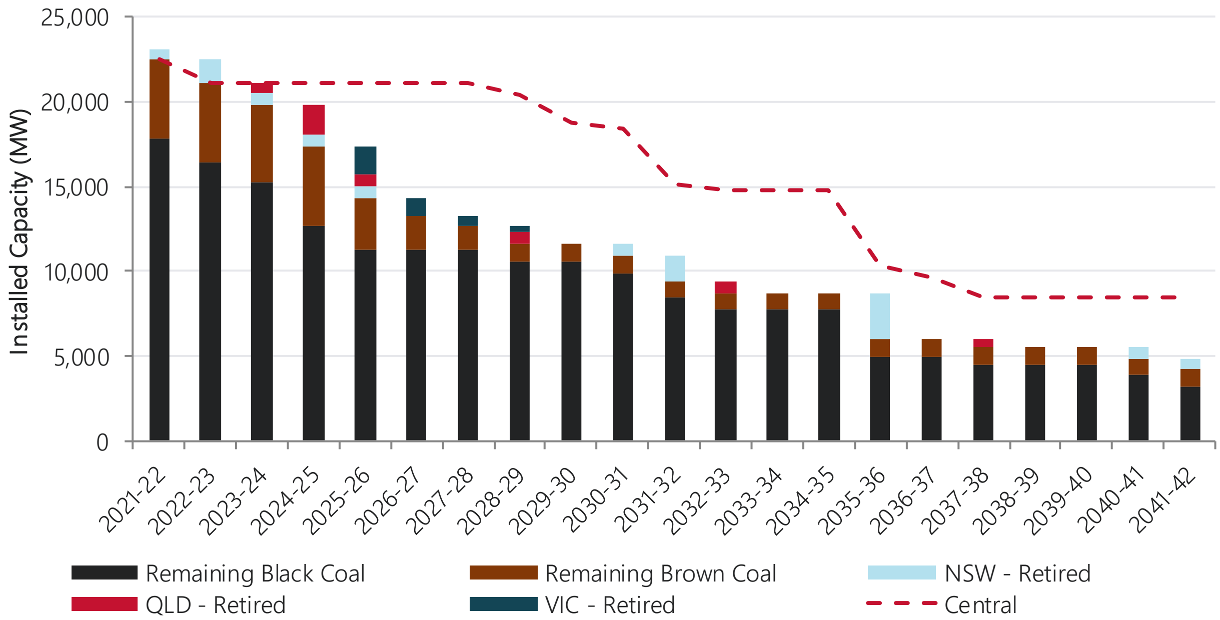


Figure 21 shows the rapid retirements, relative to the current expected closure years, that are assumed in this scenario to meet emissions reductions requirements. The greatest period of thermal capacity withdrawal occurs during the mid-2020s, effectively advancing retirements as a system by 6 to 7 years. During this period the system is more able at an efficient cost, to materially reduce emissions over the forecast horizon. By delaying retirements to post 2030, a significant proportion of the emissions budget would be eroded in the 2020s, causing significant challenge and increased costs under a retirement schedule that attempts to catch-up at a later date.

Figure 21 Forecast coal retirements to 2041-42, Step Change scenario

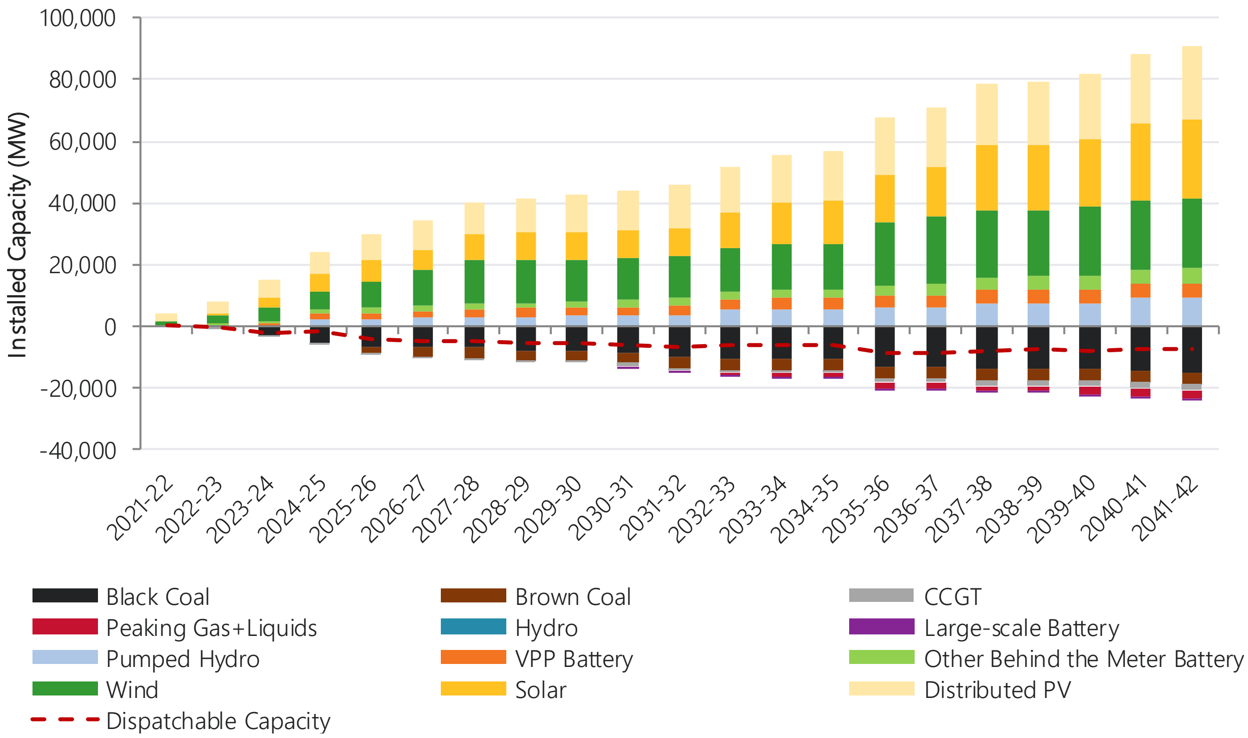


By 2040, in addition to the assumed 43 GW of DER, primarily rooftop PV, the NEM needs an additional 47 GW of VRE to replace major coal plant exits. This is complemented by approximately 7 GW of grid-scale energy storage.

As shown in Figure 22, the development of VRE is earlier in this scenario than all others, with the accelerated retirements in the late 2020s of several thermal generators replaced by large-scale solar and wind generators. Aggregated VPPs in this scenario provide a significant proportion of new firm capacity. Pumped hydro predominately in NSW and Qld supplemented by Vic and Tas, is built to provide longer-term energy storage and replace retired assets.

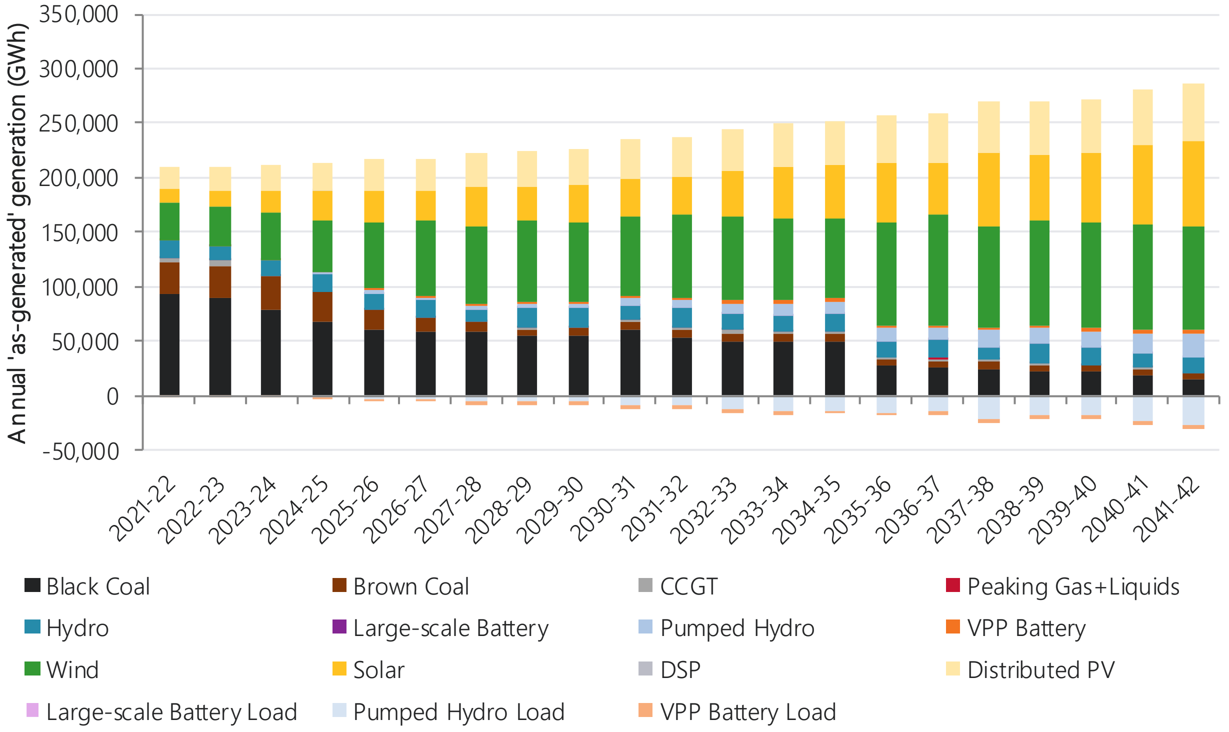
Figure 22 below shows the relative forecast change in installed capacity in the Step Change scenario, demonstrating the shift from coal to renewable energy, that requires a much larger capacity footprint. Total dispatchable capacity declines in this scenario, and dispatchability is maintained in all hours through greater storage flexibility and sharing of resources across the NEM.

Figure 22 Forecast relative change in installed capacity to 2041-42, Step Change scenario



In terms of energy production, Figure 23 highlights the projected change in the energy mix from coal generation to VRE. It also demonstrates the scale of energy required to operate energy storages, through the pumped hydro load beneath the x-axis. Renewable energy is forecast to expand from approximately 39% of generation in 2021-22 to approximately 70% by 2030 and 89% of energy generated by 2040, and the pace of this transformation is more rapid than in any other scenario considered. The mix of grid-scale wind and solar generation by 2040 is relatively evenly split (48% wind and 52% solar).

Figure 23 Forecast annual generation to 2041-42, Step Change scenario

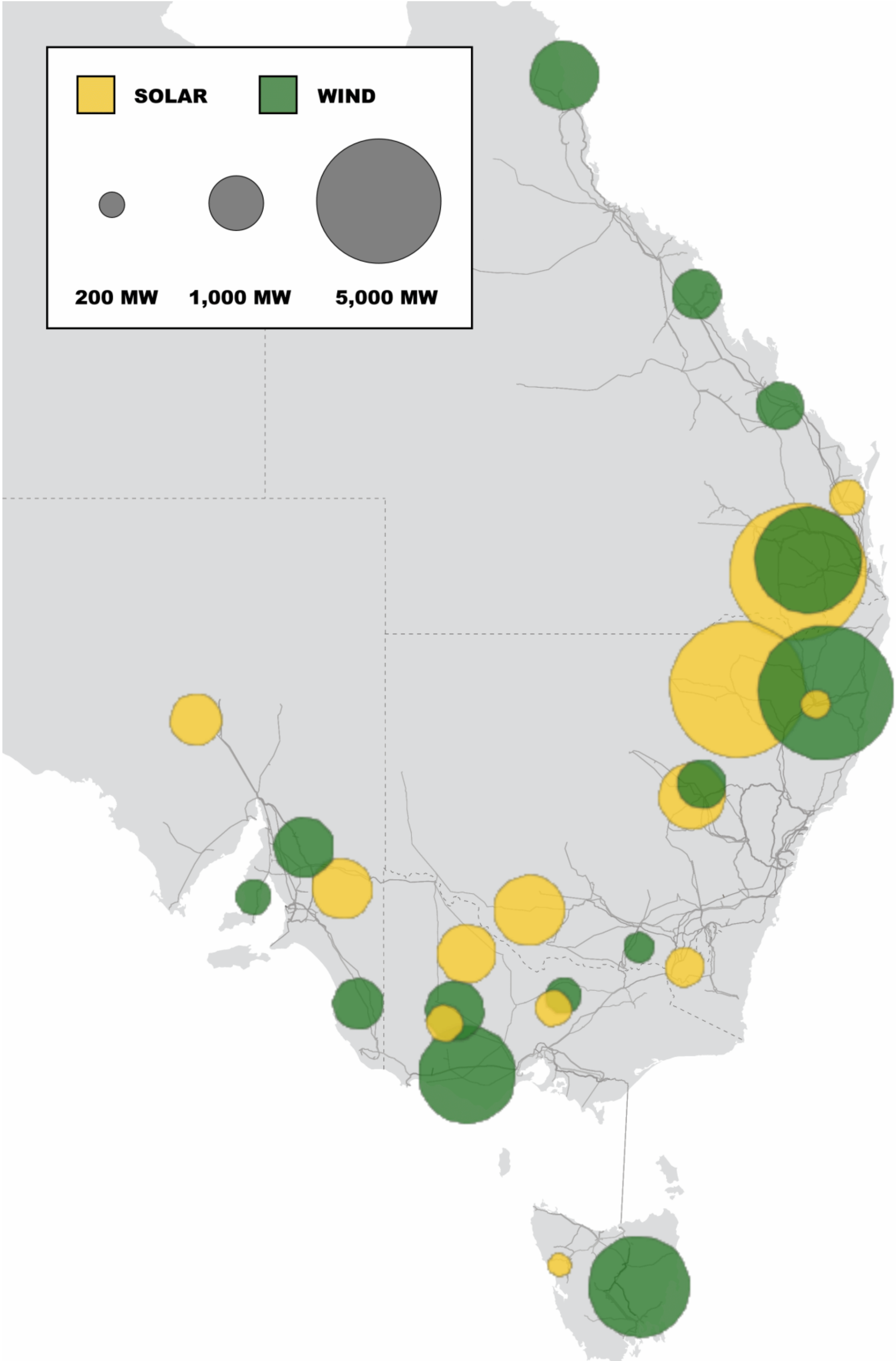


The figures below demonstrate the regional transformation of the NEM, with the projected distribution of VRE across NEM regions. By 2040, all regions are projected to have new VRE capacity 15-28 GW each in Queensland and New South Wales, and 3-6 GW in Victoria, South Australia and Tasmania, over and above what is already committed, to replace retiring assets, particularly South Australia which is forecast to feature the highest share of renewable energy amongst all NEM regions. Significantly, in this scenario, all coal capacity in New South Wales is forecast to have retired by 2041-42, but local generation production is still expected to grow, with stronger VRE penetration to compensate complemented by over 21 GW of storage and DSP technologies. Greater geographic and technological diversity is expected to increase power system resilience to weather events.

Figure 24 Forecast annual 'as-generated' generation for each NEM region to 2041-42, Step Change scenario

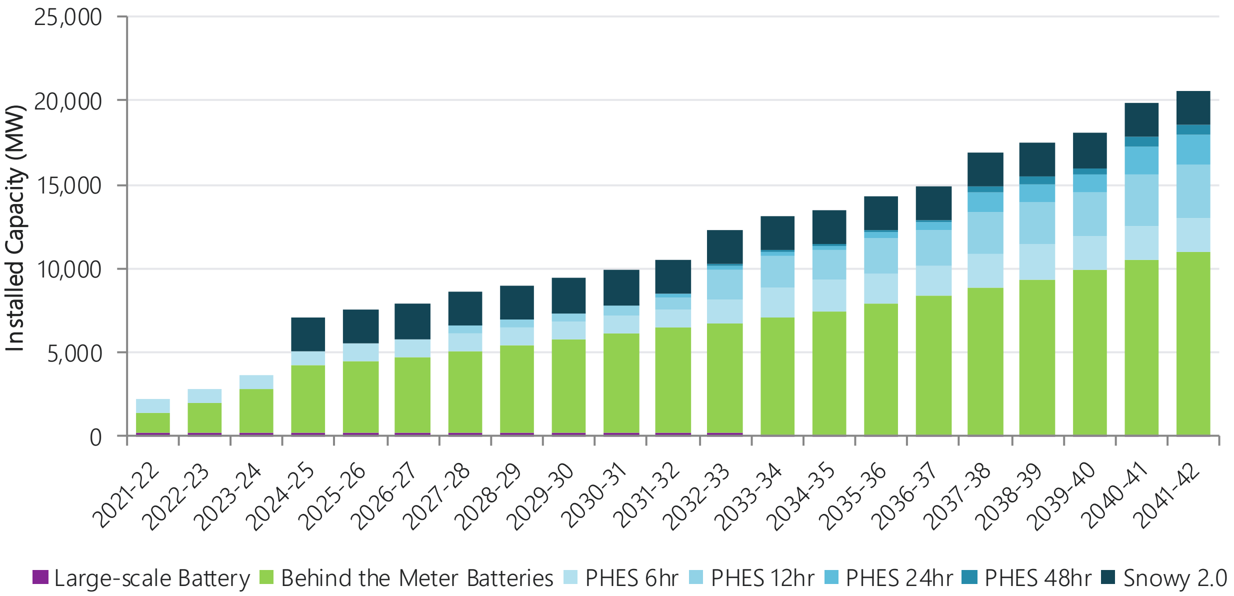
Figure 25 shows the projected diversity of renewable generation across the NEM, including existing and committed capacity.

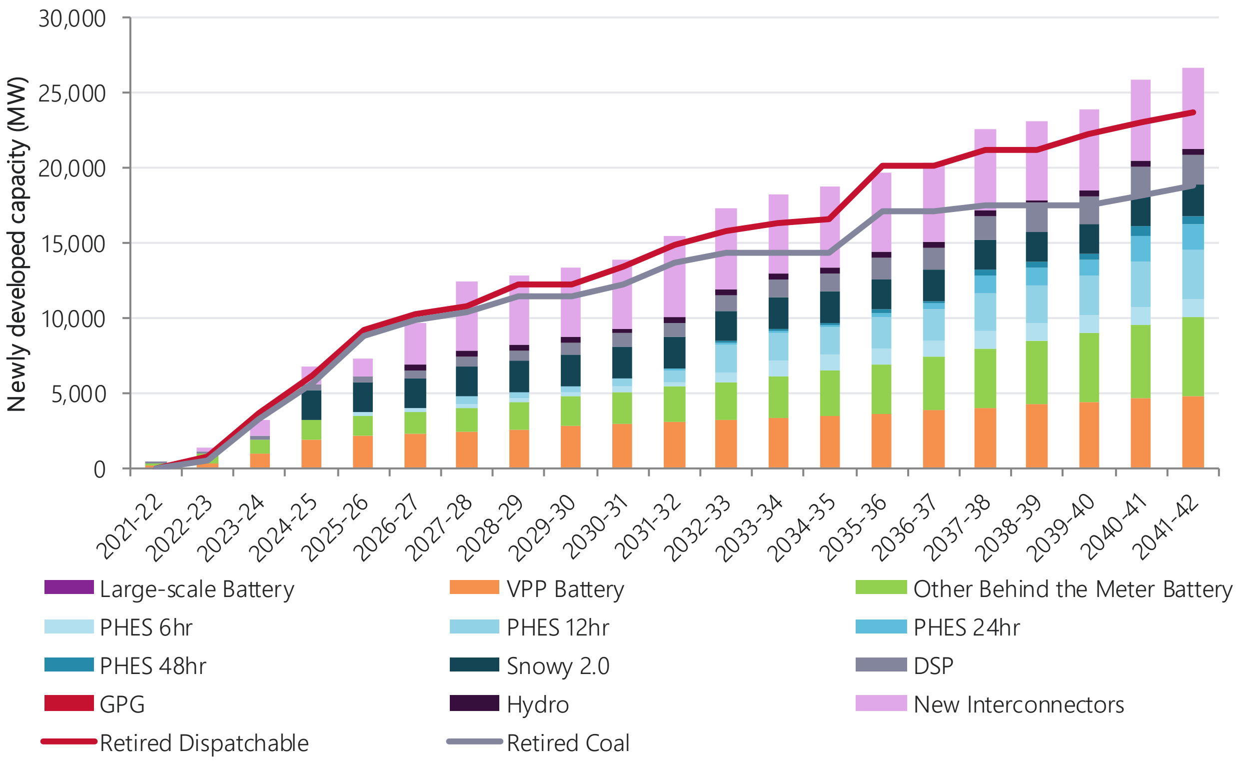
Figure 25 Forecast geographic and technological dispersion of new developments by 2040, Step Change scenario



To complement the development of renewable energy, energy storage development is necessary. Figure 26 shows the projected development of new storage capacity in the NEM for the Step Change scenario. Deeper storages are required to replace the accelerated retirements of dispatchable capacity, and are forecast for development from the early 2030s. Shallow depth storage needs are mostly filled by the growth of VPP, leading to less pumped hydro storage that can hold only six hours of energy storage.

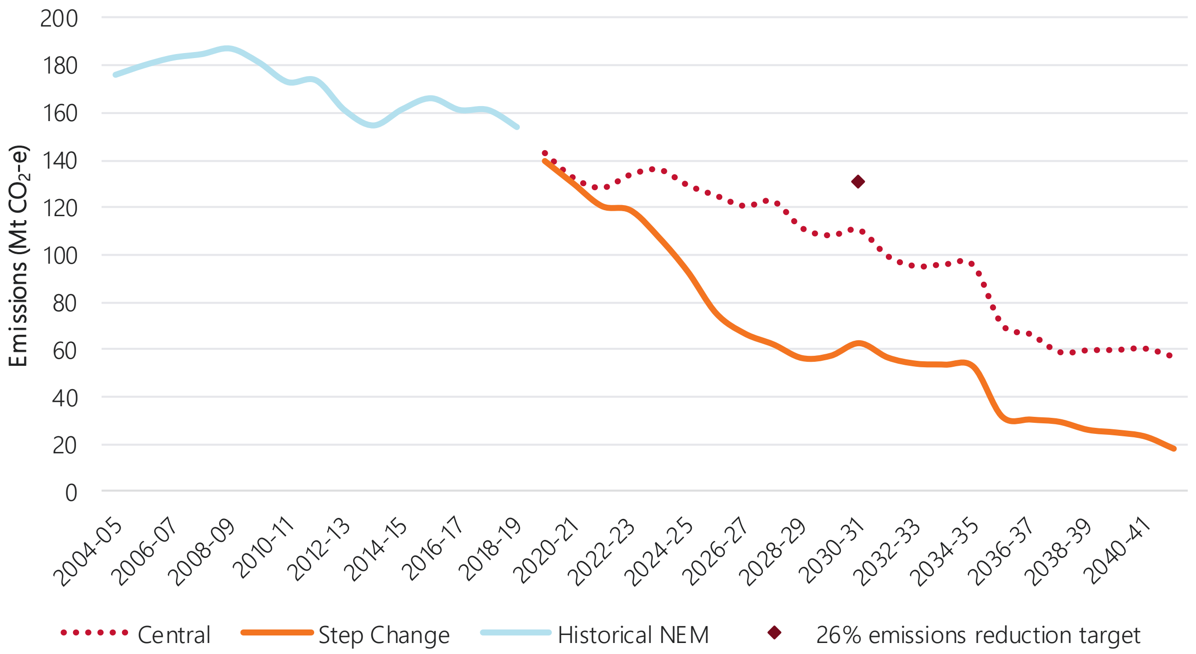
Figure 26 Forecast storage and dispatchable capacity development to 2041-42, Step Change scenario





Deep emissions reductions are forecast in this scenario, given the accelerated coal retirements and rapid transformation of the NEM's generation mix. These deep cuts early in the horizon are essential for meeting the aggressive carbon reduction budget. Figure 27 shows the forecast outcome of this approach to reducing emissions[11], in comparison to the Central scenario.

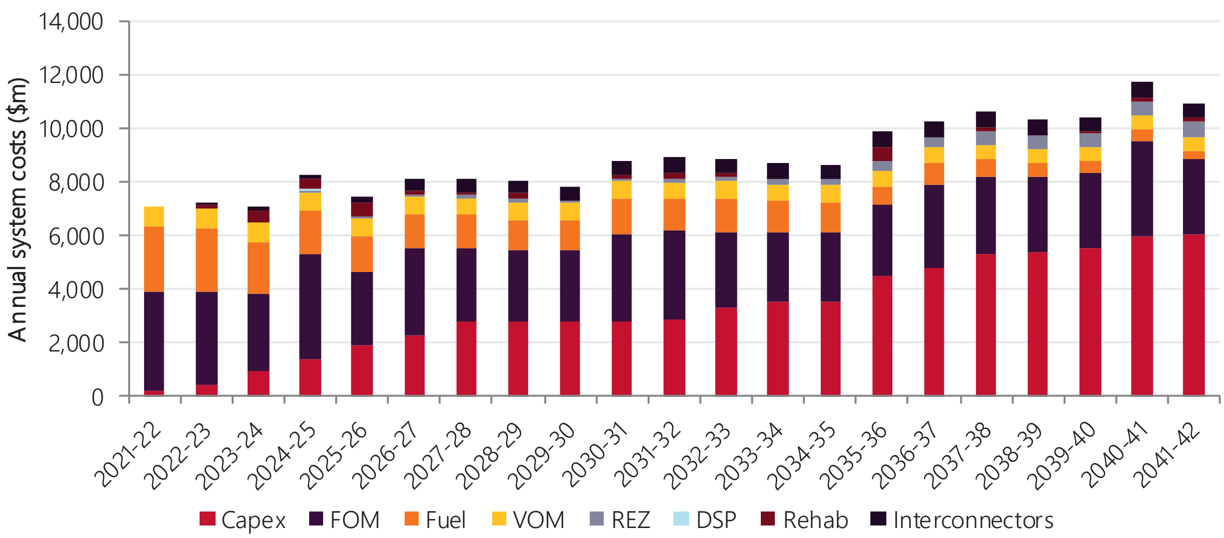
Figure 27 Forecast NEM emissions to 2040-41, Step Change scenario



Data from Department of the Environment and Energy, Australia's emissions projections 2018.

Figure 28 displays the annual system costs of the NEM that are forecast in the Step Change scenario. Expenditure on fuel costs associated with the existing thermal fleet is forecast to reduce due to retirements and instead be redirected towards capital investment in new generation and transmission. This is projected to create considerable savings on fuel and maintenance costs. Further assisting in reducing total system costs is the expectation for greater energy efficiency, and reductions in DER and generation development costs.

Figure 28 Forecast total aggregate system costs to 2041-42, Step Change scenario



[11] Department of the Environment and Energy, Australia's emissions projections 2018, accessed December 2019, at http://www.environment.gov.au/system/files/resources/128ae060-ac07-4874-857e-dced2ca22347/files/aust-emissions-projects-chart-data-2018.xlsx.

3.2.4 Fast Change

The Fast Change scenario considers a rapid technology-led transition, particularly at grid scale, where advancements in large-scale technology improvements support a reduction in the economic barriers of the energy transition.

Key differences to the Central scenario include:

- Accelerated decarbonisation of the stationary energy and transport sectors, which in turn may result in advanced retirements of existing generators, to achieve emissions abatement targets.
- Consolidation of regional renewable development schemes, allowing greater national diversity of large-scale VRE developments.

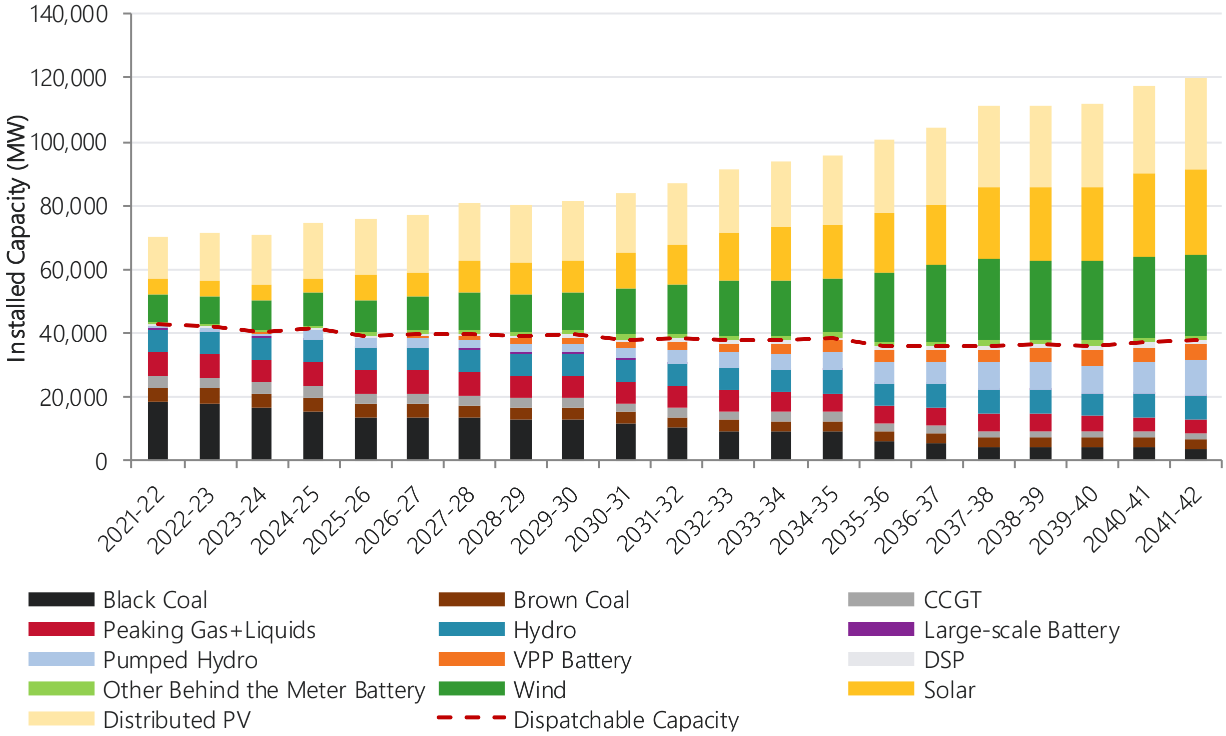
This section describes the ISP development opportunities that are forecast to maximise market benefits in the Fast Change scenario.

The generation capacity forecast projects that:

- To 2030:
  - The Fast Change scenario's carbon budget will advance coal power station retirements ahead of the current expected closure schedule. Although not as aggressive as the Step Change scenario, the forecast of coal retirements demonstrates the least cost approach to achieving emissions abatement is with advancement of retirements into the mid-2020s.
  - Renewable investments will be spread across most NEM regions, including in New South Wales, South Australia, and Tasmania from the mid-2020s. This is in contrast to the Central scenario, where Victoria and Queensland are projected to develop the most near-term renewable generation to meet policy objectives.
- By 2040:
  - Installed coal capacity will reduce to 7.4 GW, 68% lower than existing capacity. Fossil fuel generation will be progressively replaced by renewable energy complemented by additional energy storages.
  - Storage development will be needed in all mainland regions to support the renewable developments across each region in a future with less thermal generation available to smooth and firm VRE.

Figure 29 presents the large-scale capacity outlook for the NEM under the Fast Change scenario. With the accelerated rate of retirements from thermal generation to meet emissions requirements, the new entrant VRE and storage build materially increases throughout the horizon.

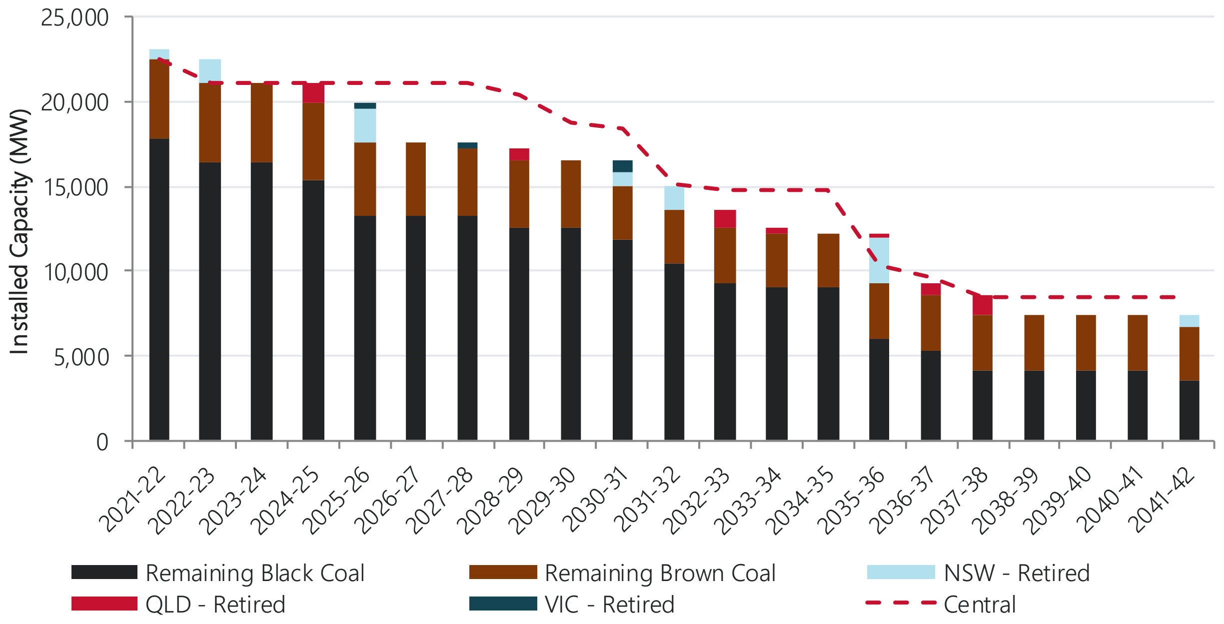
Figure 29 Forecast NEM installed capacity to 2041-42, Fast Change scenario



To meet the Fast Change scenario's carbon budget, coal retirements are forecast to be accelerated, relative to the expected closure timings used in the Central Scenario. Earlier retirements in the 2020s reduce the overall cost of achieving the emissions budget compared to later retirements (which would require deeper cuts in emissions by the end of the horizon). Black coal-fired generation in New South Wales and Queensland has higher marginal costs than brown coal-fired generation in Victoria, and is therefore more cost-efficient to retire within the objectives of the carbon budget, despite having a lower relative emission intensity. The cost advantage brown coal generation has over all other thermal generation forms means that these more emission-intensive generators are preferred in the modelling to continue to operate to end of life, but would present a means for deeper emissions abatement if retired earlier.

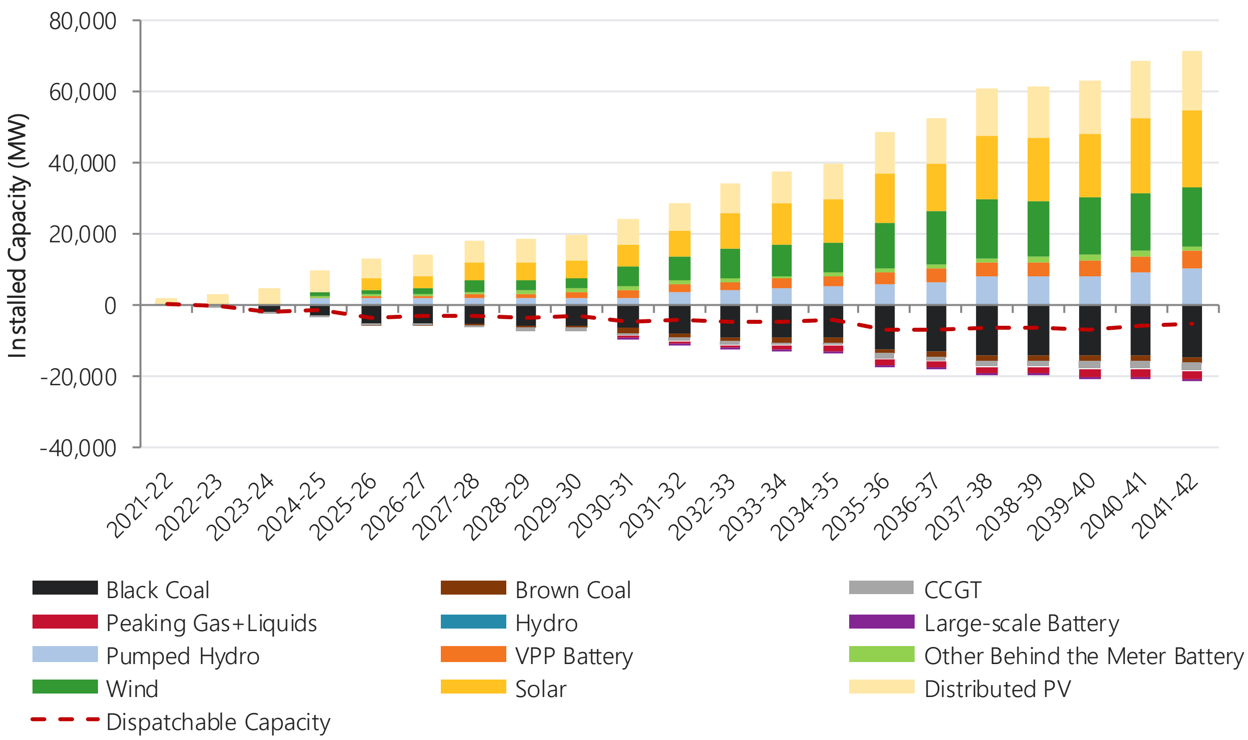
The Fast Change scenario retirements are presented in Figure 30.

Figure 30 Forecast coal retirements to 2041-42, Fast Change scenario



As shown in Figure 31, advanced thermal retirements in the Fast Change scenario are forecast to be offset by a combination of VRE, storages, and DER. By 2040, in addition to the assumed 30 GW of DER, primarily rooftop PV, the NEM needs an additional 37 GW of VRE to replace major coal plant exits. This is complemented by approximately 9 GW of grid-scale energy storage.

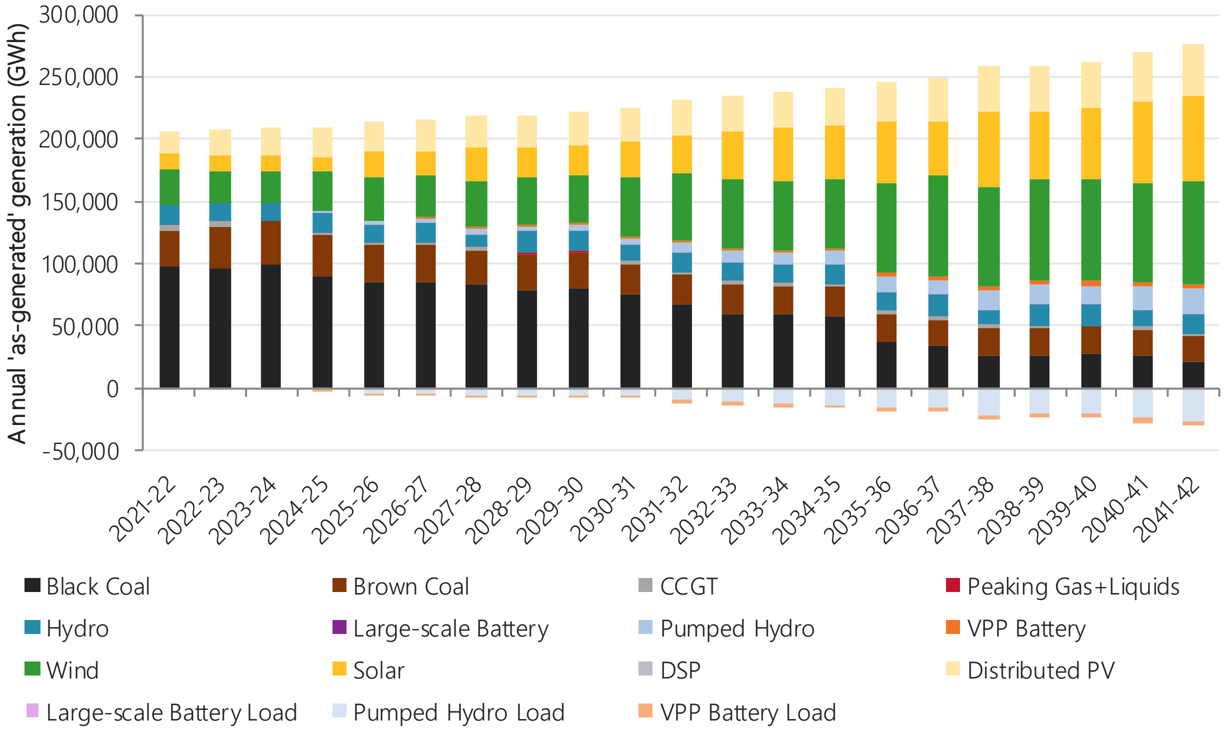
Figure 31 Forecast relative change in installed capacity to 2041-42, Fast change scenario



In the Fast Change scenario, the emissions budget impacts the NEM supply mix, promoting a shift from fossil fuel to renewable generation. Coal retirement in the Fast Change scenario is accelerated compared to the

Central scenario, especially between 2026 and 2031. In 2022, fossil fuel generators are projected to account for 64% of total generation, while in 2040 this decreases to 21% of the total generation, as shown in Figure 31. From Figure 32, this loss of thermal energy production will need to be replaced by investment in renewable generators, storages *and* transmission solutions, leading to a supply mix that is different both technologically and geographically to today's energy system. Renewable energy is forecast to expand from approximately 36% of generation to approximately 79% of energy generated by 2040. The projected mix of grid-scale wind and solar generation by 2040 is (48% wind and 52% solar).

Figure 32 Forecast annual generation to 2041-42, Fast Change scenario



Generation transformation in Queensland, New South Wales, and Victoria is forecast to be influenced by early coal retirements in each of those regions, as shown in Figure 33. New South Wales is forecast to have the most significant transformation with most coal-fired generation capacity forecast to be retired by 2040 under this scenario. This significant transformation in New South Wales is enabled by interconnector construction and energy storage technology development, which facilitates reliable and secure power supply to the region.

Without the 50% Queensland Renewable Energy Target (QRET) policy, forecast renewable generation in Queensland would be proportionally lower in the Fast Change scenario compared to the Central Scenario.

Due to the Fast Change scenario assuming no extended Victorian Renewable Energy Target (VRET) to 2030, VRE development in Victoria over the next decade is projected to be much slower in this scenario. Installation rates are, however, forecast to ramp up quickly after 2030, in preparation for the expected closure of Yallourn Power Station, and by 2031-32 similar levels of forecast installed VRE capacity are observed in Victoria as in the Central scenario.

By 2040, all regions are projected to have new VRE capacity (12-16 GW each in Queensland and New South Wales, and 4 GW in Victoria, over and above what is already committed, to replace retiring assets.

Figure 33 Forecast annual 'as-generated' generation for each NEM region to 2041-42, Fast Change scenario

Figure 34 demonstrates the forecast geographic diversity of new developments in the generation portfolio. Consistent with all scenarios with materially VRE development; northern Victoria, southern and northern NSW and south west Queensland continue to be key renewable development locations.

Figure 34 Forecast geographic and technological dispersion of new developments by 2040, Fast Change scenario

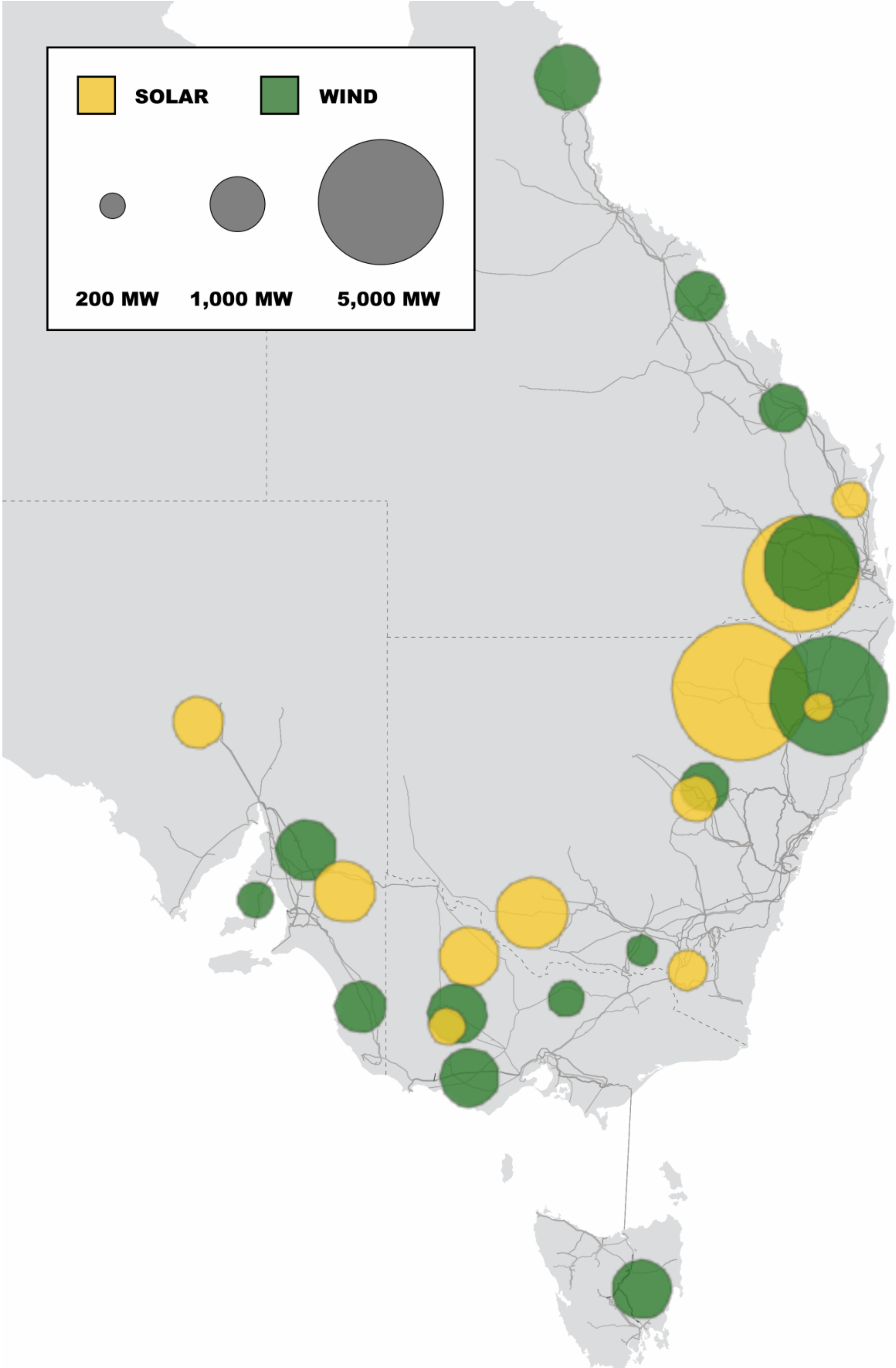
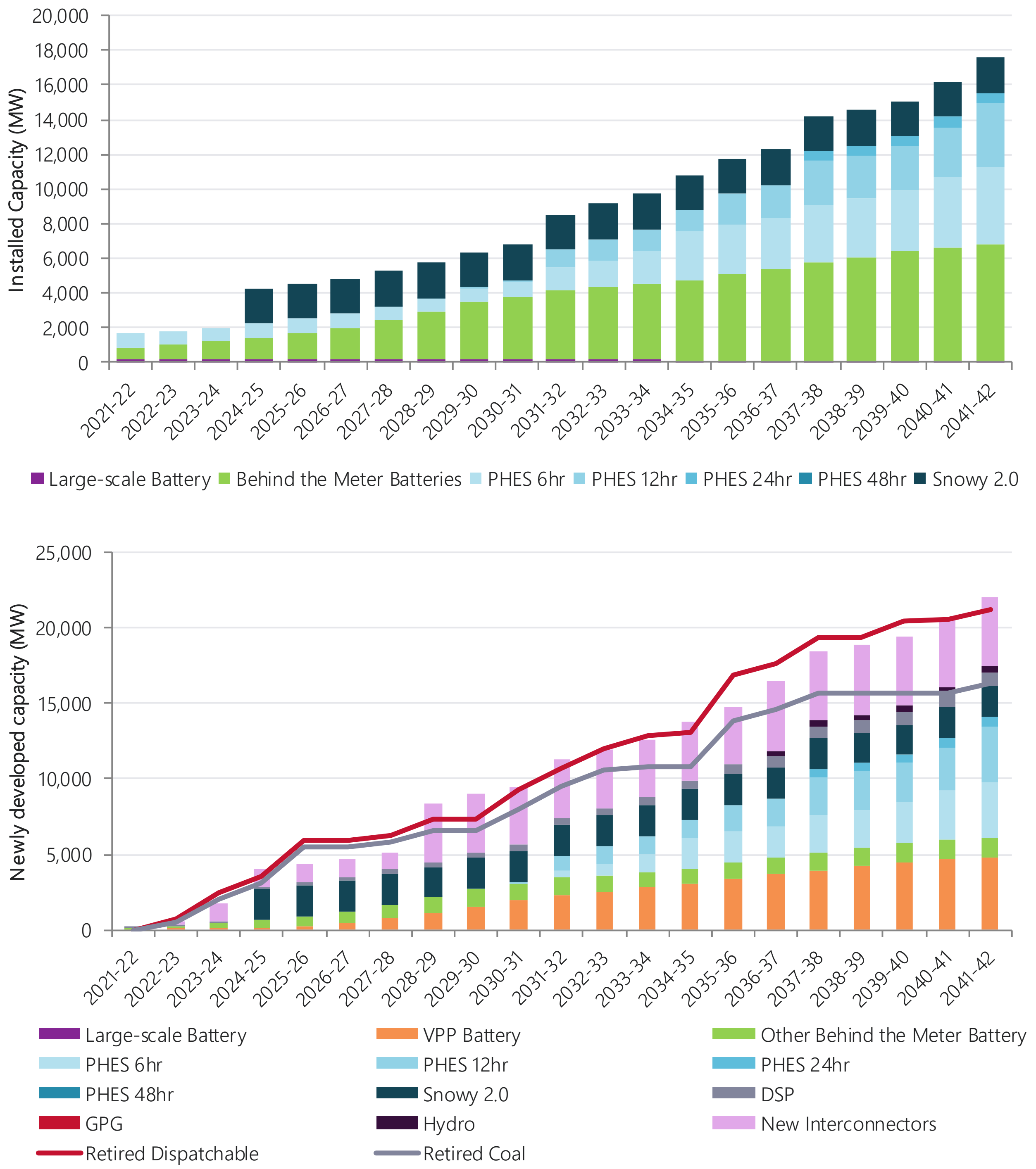


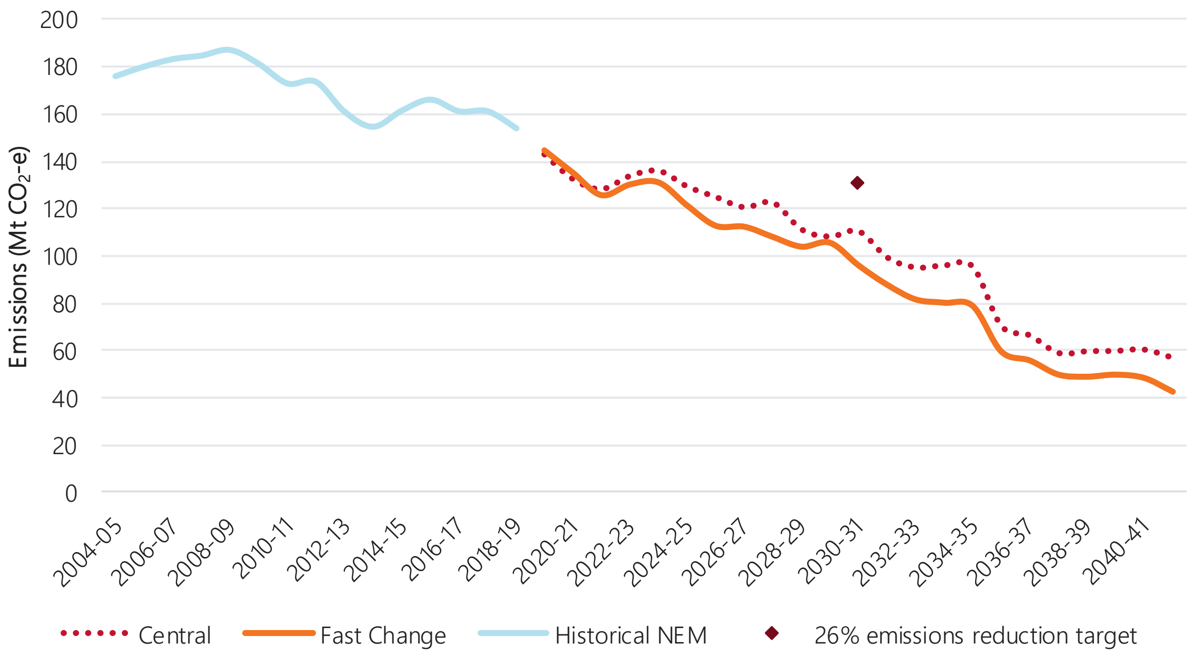
Figure 35 Forecast storage and dispatchable capacity development to 2041-42, Fast Change scenario



As shown in Figure 36[12], cumulative NEM emissions for the Fast Change scenario are forecast to be 10% lower than the Central scenario, declining progressively with coal retirements. To meet the carbon budget, emissions in the Fast Change scenario would have to decrease 60%, from 125 Mt CO_2-e in 2021-22 to just over 50 Mt CO_2-e by 2040, with most of the emissions cuts (relative to the Central Scenario) being made in the mid-2020s from advanced coal retirements, as indicated in Figure 36.

[12] Department of the Environment and Energy, Australia's emissions projections 2018, accessed December 2019, at http://www.environment.gov.au/system/files/resources/128ae060-ac07-4874-857e-dced2ca22347/files/aust-emissions-projects-chart-data-2018.xlsx.

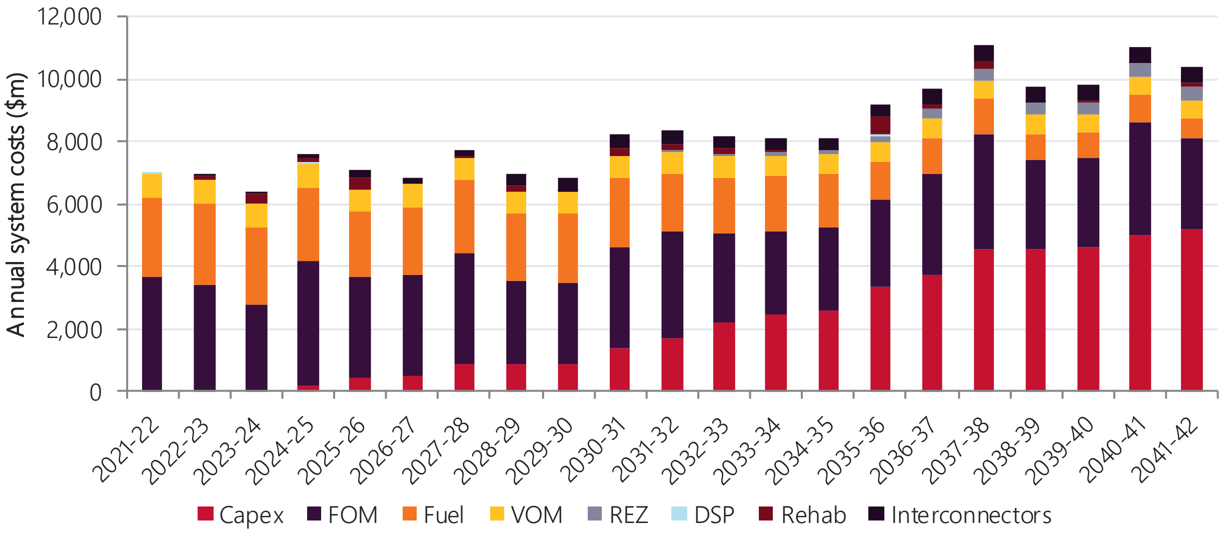
Figure 36 Forecast NEM emissions to 2040-41 in the Fast Change scenario



Data from Department of the Environment and Energy, Australia's emissions projections 2018.

Total system costs under the Fast Change scenario are forecast to increase, as the capital expenditure required to progressively transform the power system is greater than the fuel and operational cost savings, as shown in Figure 37. The long-term exposure of the power system to fuel costs is forecast to be significantly lower in the future energy system.

Figure 37 Forecast total aggregate system costs to 2041-42, Fast Change scenario



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3.2.5 Slow Change

The Slow Change scenario forecasts lower economic growth and lower overall grid consumption, with less DER and less ambition to decarbonise the energy sector, compared to the Central scenario. With reduced decarbonisation ambition, there is increased value in refurbishing aging coal-fired generators as they approach the end of technical life.

This section describes the resource mix that is forecast, in combination with transmission development, to optimally reduce total system costs, maximising market benefits of an efficiently operating power system.

The generation capacity forecast projects that:

- To 2030:
  - There will be little change in the near-term generation mix beyond committed project developments. Several coal-fired generators have life extensions for a period of 10 years (Bayswater in New South Wales, Callide B and Gladstone in Queensland, and Yallourn in Victoria) to minimise system costs.
  - In the near term, renewable developments also stall, with the Victorian VRET 2025 policy[13] providing most near-term development incentive.
- By 2040:
  - Generators that retire are replaced with small-scale and large-scale solar and pumped hydro storage, especially in New South Wales and South Australia.

Figure 38 presents the forecast NEM generation capacity in the Slow Change scenario. Coal is forecast to remain a significant part of the generation mix in this scenario, with solar and pumped hydro storage increasing slightly in the later years, particularly in the late 2030s. Dispatchable capacity softens over the forecast period in line with a reduction in energy consumption. By 2040, in addition to the assumed 14 GW of DER, primarily rooftop PV, the NEM needs an additional 4 GW of VRE to replace major coal plant exits. This is complemented by approximately 3 GW of grid-scale energy storage.

[13] On 30 October 2019, the VRET 2030 target was passed into legislation through an amendment. This target builds on the 2025 target increasing to a 50% target by 2030.

Figure 38 Forecast NEM generation capacity to 2041-42, Slow Change scenario

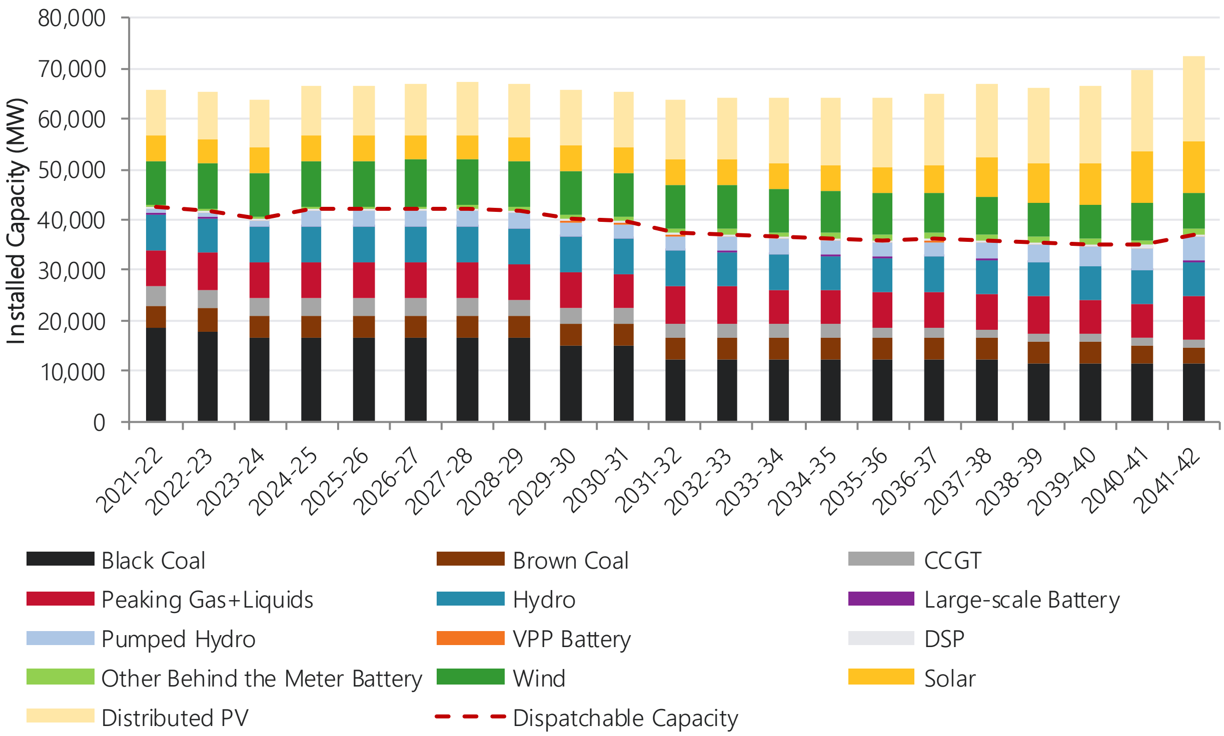
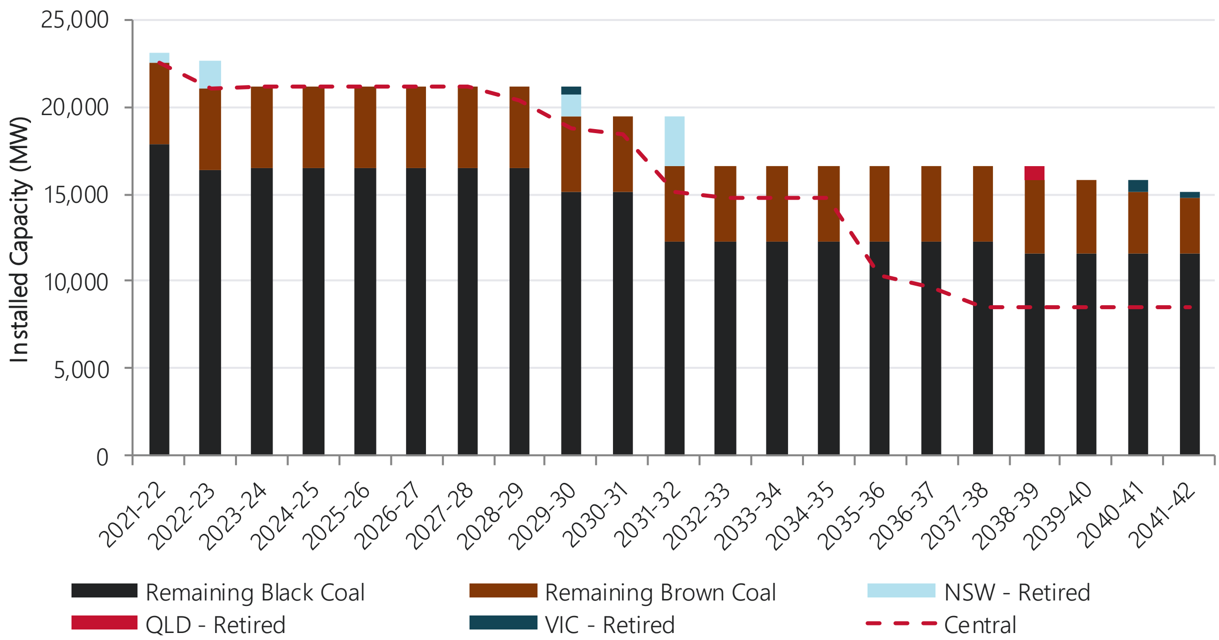


Figure 39 presents the difference in forecast coal retirements between the Slow Change scenario and the Central scenario, with the delayed retirements in the Slow Change scenario clearly evident beyond 2030.

Figure 39 Forecast coal retirements to 2041-42, Slow Change scenario relative to the Central scenario



In Figure 40, a positive value indicates an addition in installed capacity while a negative value indicates a deduction due to retirement or end of technical life. This figure shows the forecast relative change in installed capacity in the Slow Change scenario, where the shift from coal to renewable energy is slower than in the

Central scenario. In the Slow Change scenario, new renewable energy is forecast to be provided mainly by solar technologies, complemented with shallow storages in addition to the Snowy 2.0 project. There is minimal additional wind generation forecast beyond what has already been committed. It is also important to note that some wind generation is forecast to retire due to the end of the generators' technical life. These end of technical life retirements are considered in all scenarios, but are more pronounced in the Slow change scenario with minimal new VRE developments offsetting these closures.

Figure 40 Forecast relative change in installed capacity to 2041-42, Slow Change scenario

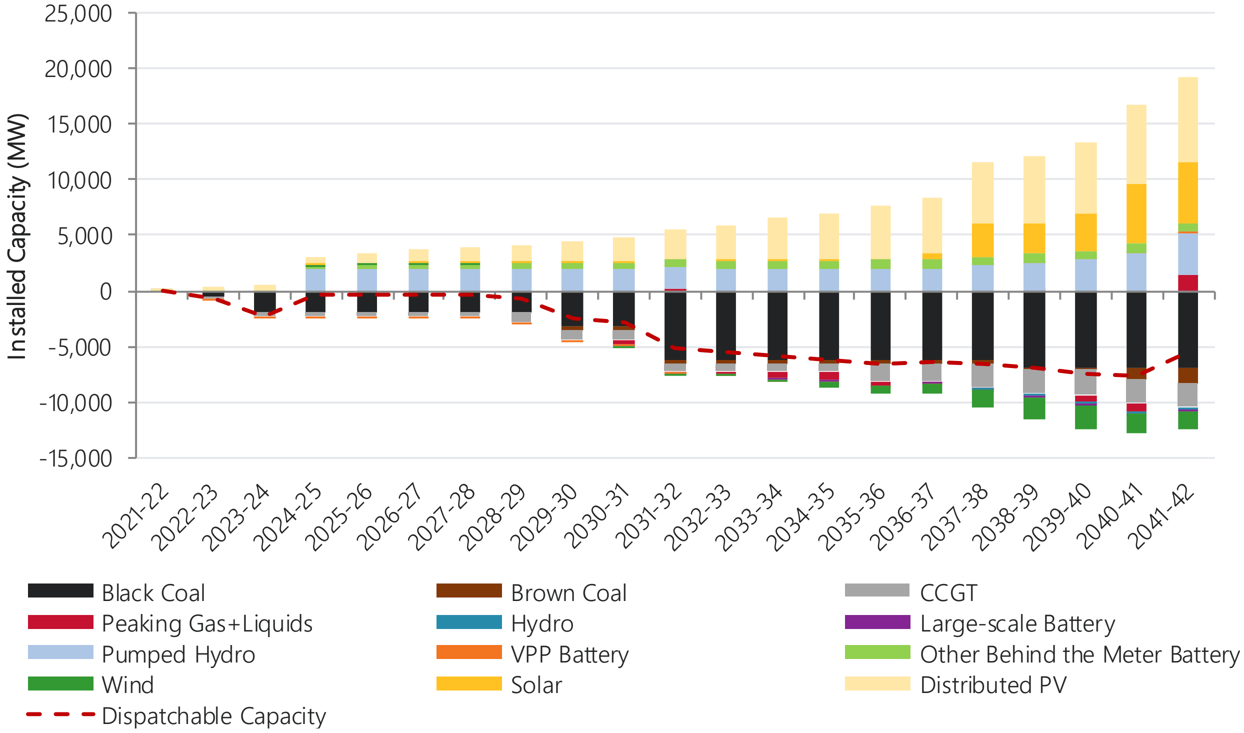
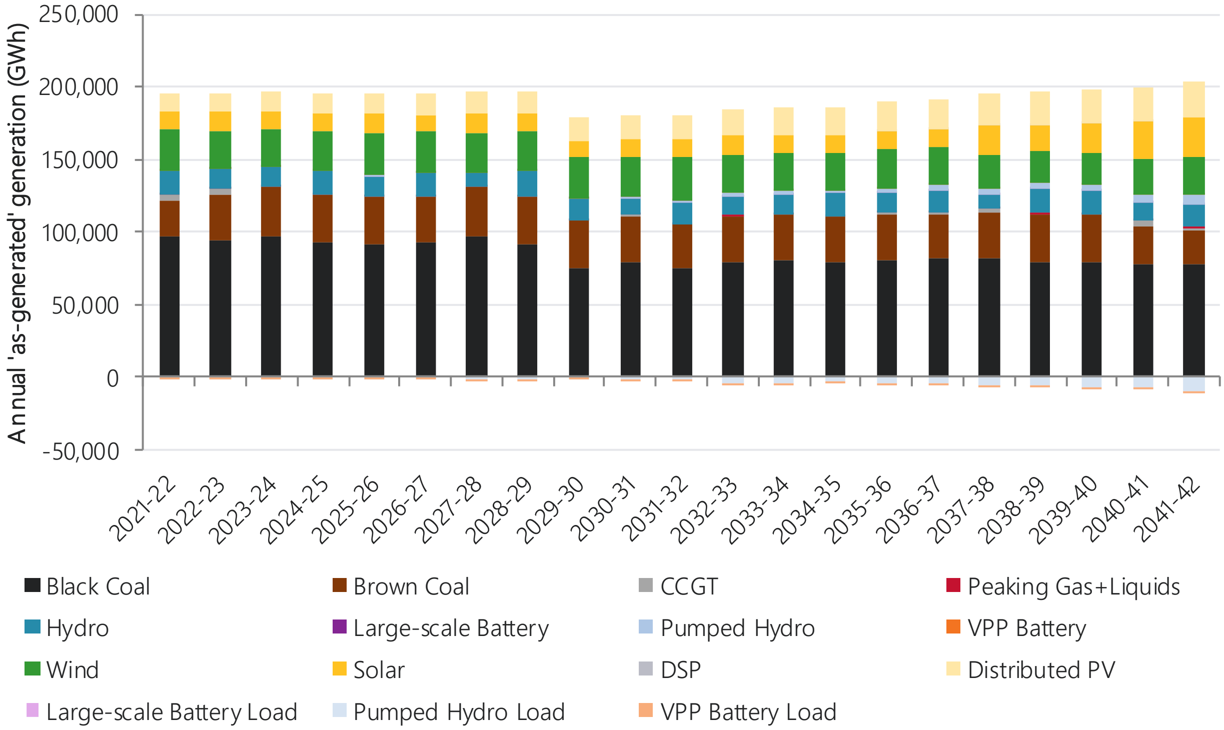


Figure 41 presents the slight change in the generation mix for energy production over time. In this scenario, energy production is forecast to be dominated by coal generation over the outlook period. Renewable energy is forecast to expand from approximately 36% of generation to 40% of energy generated by 2040. The projected mix of grid-scale wind and solar generation by 2040 is (37% wind and 63% solar).

Figure 41 Forecast annual generation to 2041-42, Slow Change scenario



Generation transformation is projected to be slow in all NEM regions across the forecast horizon in this scenario, as shown in Figure 42 and Figure 43, which present the generation in each region and the geographic and technological dispersion of new developments by 2040, respectively. By 2040, all regions except Tasmania are projected to have new VRE capacity totalling 4 GW.

Figure 42 Forecast annual 'as-generated' generation for each NEM region to 2041-42, Slow Change scenario

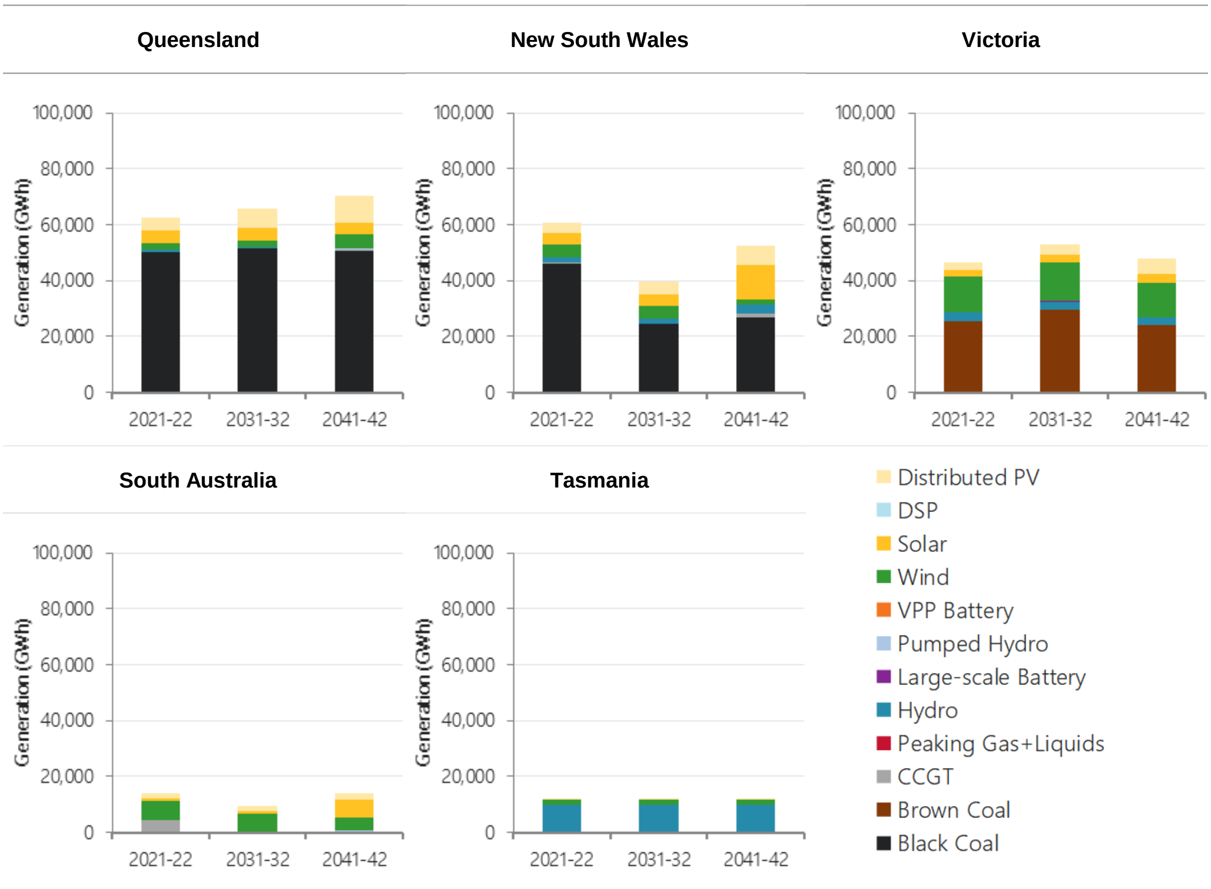
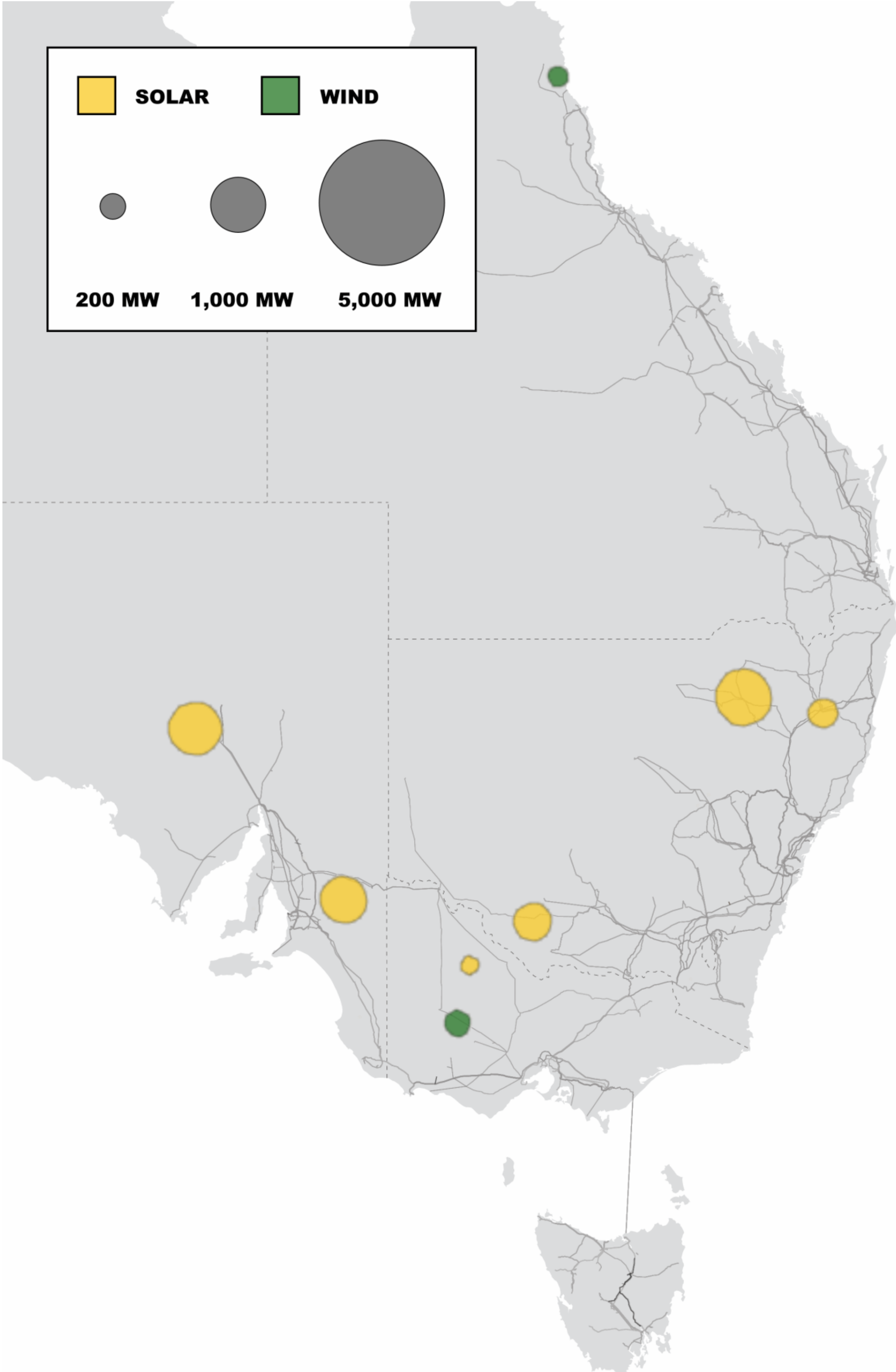
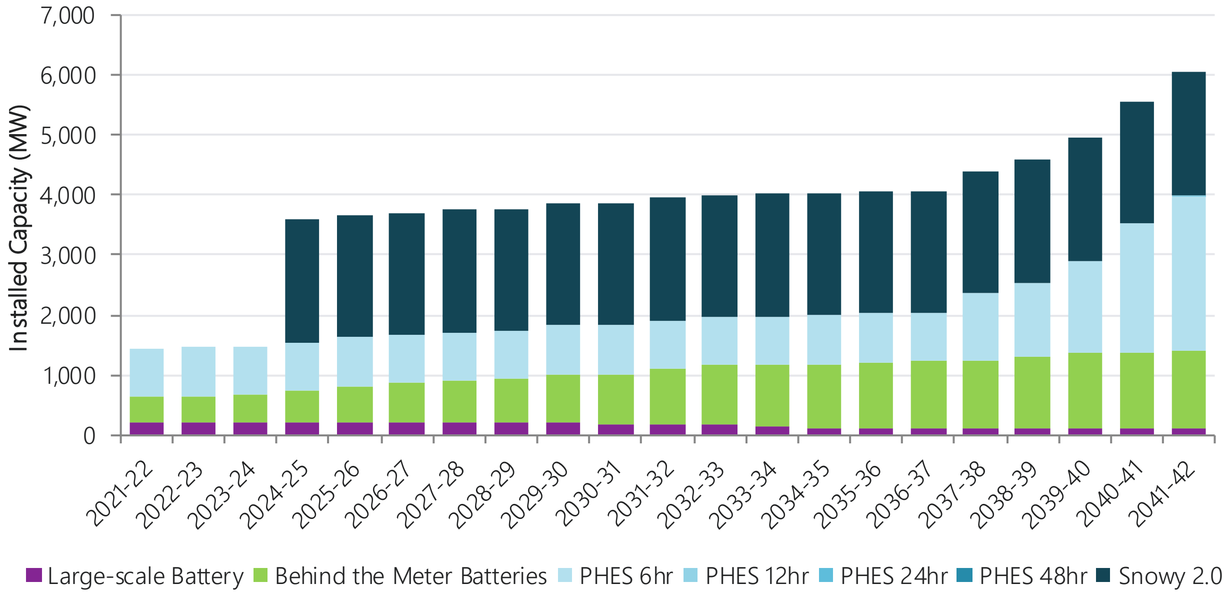


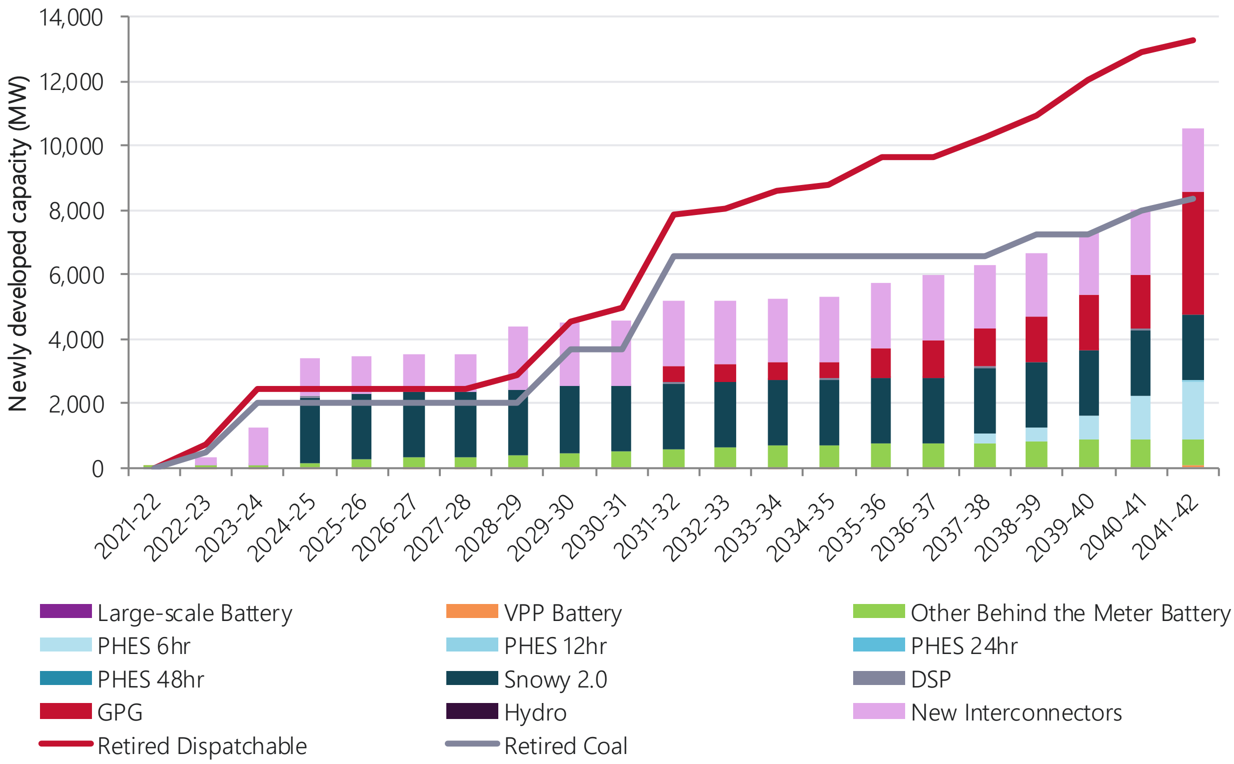
Figure 43 Forecast geographic and technological dispersion of renewable energy by 2040, Slow Change scenario



Given the lack of renewable generation in this scenario, storage developments are also projected to be limited. Where storages do develop, relatively shallow pumped hydro generation is preferred to smooth solar generation; there is no forecast need for additional deep storages beyond the Snowy 2.0 project, due to the low amount of VRE resources, as shown in Figure 44.

Figure 44 Forecast storage and dispatchable capacity development to 2041-42, Slow Change scenario





Emissions in the Slow Change scenario are forecast to be higher than in all other scenarios, and are presented in Figure 45[14] compared to the Central Scenario. As the transformation of the NEM is already underway,

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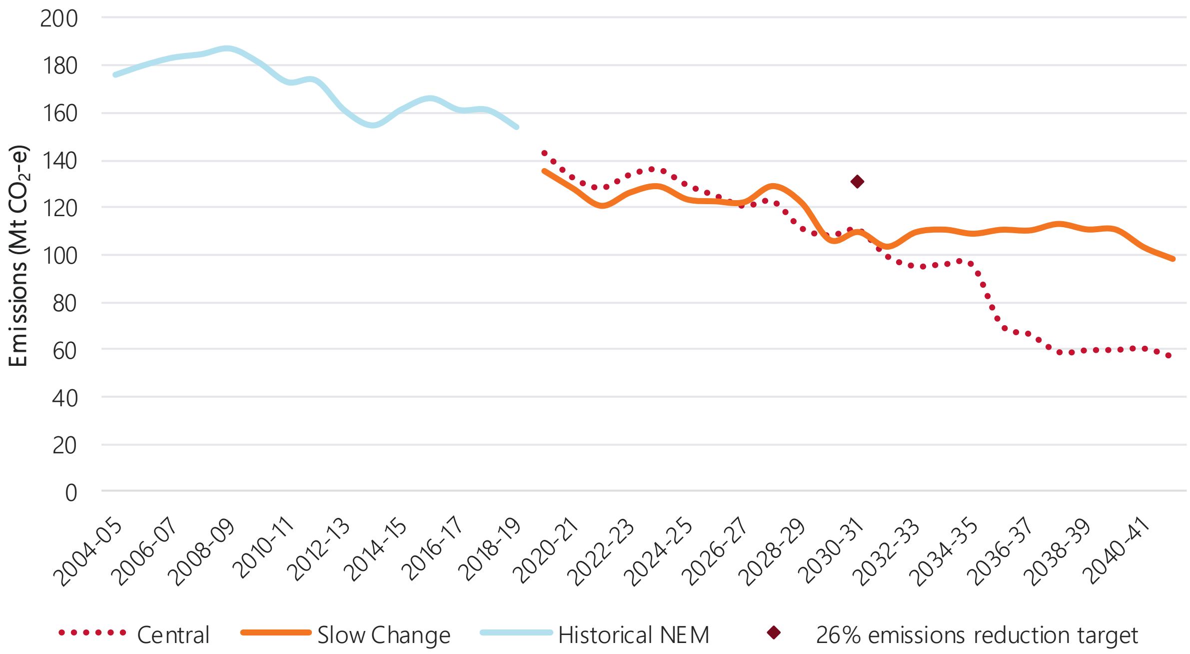
[14] Department of the Environment and Energy, Australia's emissions projections 2018, accessed December 2019, at http://www.environment.gov.au/system/files/resources/128ae060-ac07-4874-857e-dced2ca22347/files/aust-emissions-projects-chart-data-2018.xlsx.

emissions by 2030 are forecast to be below the 26% emissions reduction target, even in this Slow Change scenario. The assumed closures of some industrial loads in this scenario also reduce forecast emissions.

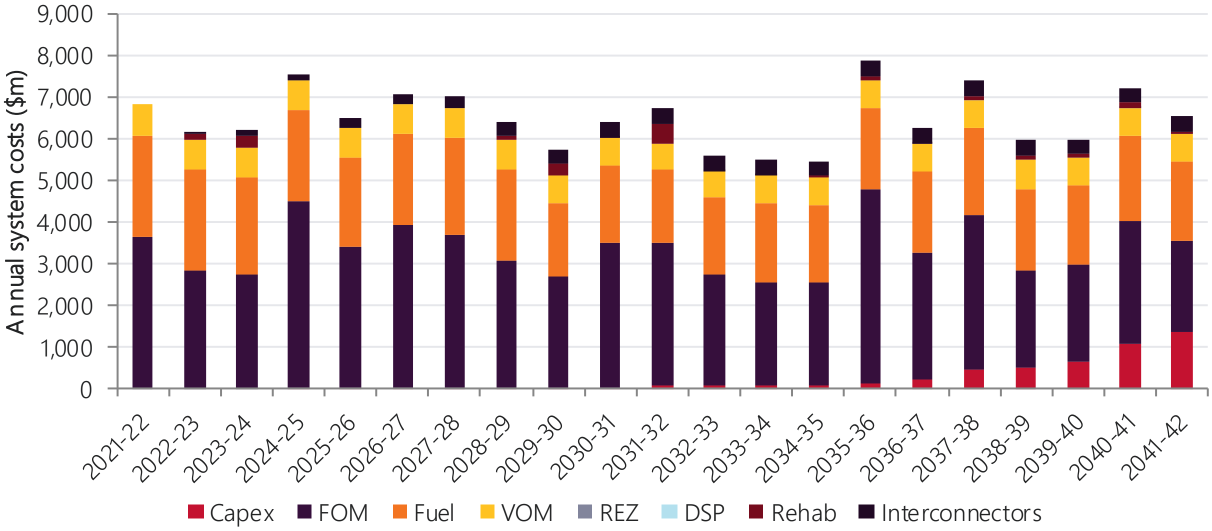
Figure 45 Forecast NEM emissions to 2040-41, Slow Change scenario relative to Central scenario



The total cost of transforming and operating the electricity system in the Slow Change scenario is projected to be significantly lower than in the other scenarios, because of the lower demand and reduced need for generation and transmission developments. This does not account for broader economic and societal costs associated with slow economic growth, lost productivity (industrial closures), and higher emissions.

With lower NEM consumption, and some refurbishment of aging thermal plant, less new generation needs to be built. Consequently, the projected build costs for new generators and REZ expansions are significantly lower than in all other scenarios, although the FOM costs are forecast to be higher due to the life extension of certain coal generators (Figure 46). In the long term, in this scenario, the NEM is forecast to continue to have a high relative spend in fuel costs, due to the low penetration of renewable energy.

Figure 46 Forecast total aggregate system costs to 2041-42, Slow Change scenario



Appendix 4. Intra-day operability and results validation

The Draft ISP outlines an optimal development path that is profoundly different to the power system today. Care is therefore needed to understand the impacts of this change on operability of the system to ensure that the power system needs are met in every half hour period.

Further, the cost benefit analysis in this draft is based on results from AEMO's Detailed Long Term (DLT) model, which necessarily makes temporal simplifications to manage computational burden, does not incorporate detailed transmission constraints, and also assumes perfect competition with short run marginal cost (SRMC) bidding to determine the least cost solution.

The results of the analysis therefore need to be validated through more detailed half-hourly simulations that include detailed transmission constraints to determine whether:

- The power system remains dispatchable in all hours.
- The existing coal-fired generators remain revenue sufficient.
- The DLT generation and total system costs relied upon in the cost benefit analysis are representative of total system costs when analysed with greater temporal detail.
- Gas demand from GPG does not deviate significantly from what is assumed in the DLT.

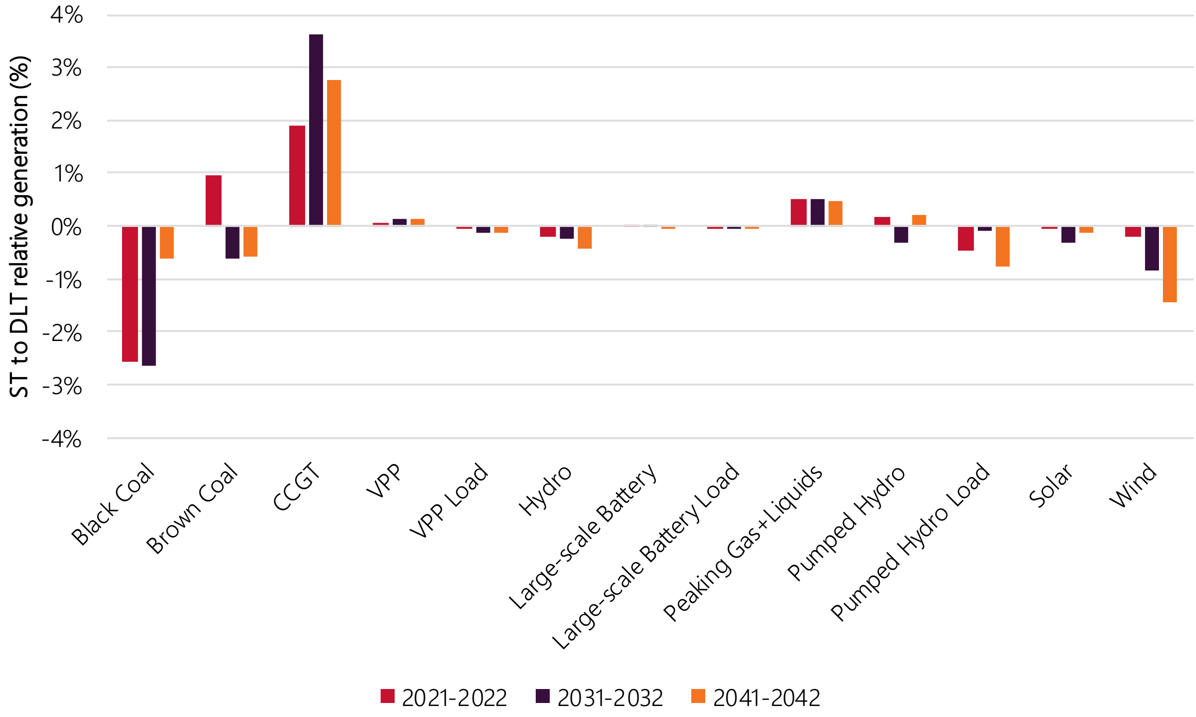
To perform these validations, AEMO has run two detailed Short Term (ST) models: one using SRMC bidding to confirm alignment with DLT outcomes, and test reliability; and one using game-theoretic bidding behaviour and unit commitment optimisation to assess revenue sufficiency and intra-day operability.

4.1 ST results validate the DLT outcomes

While AEMO did not run ST versions of all the DLT cases (and this will be done for the final ISP report), STs were used to validate the DLT outcomes in the Central and High DER scenarios. Generation levels across DLT and ST modelling are broadly consistent under SRMC operation and can confirm that the DLT outcomes are accurate.

Figure 47 below shows the generation levels of different technologies across 2021-22, 2031-32, and 2041-42 for the Central scenario.

Figure 47 Difference in share of energy mix – DLT compared to ST results, Central 2022, 2032, 2042



The ST outcomes, run on a half-hourly basis with more sophisticated storage optimisation show:

- Additional value from pumped hydro and battery storages.
- Slightly less reliance on coal (due to discrete outages).
- Marginally less value from wind and solar as local transmission constraints mean that some VRE is curtailed.
- Slightly greater reliance on gas.

From a cost perspective, this results in total system costs (mainly fuel costs) being around 5% higher than in the DLT. This difference is not considered material to the optimal development path as, if anything, it should increase the value of interconnection that allows more efficient sharing of low cost resources across the NEM and reduces VRE curtailment. For the Final ISP, the cost benefit analysis will be tested using these ST runs to confirm that these differences are not material.

Table 5 Comparison of NEM-wide cost differences between DLT and ST ($B), Central scenario

Cost Category	2021-22		2031-32		2041-42	
	DLT	ST	DLT	ST	DLT	ST
Total Capital Costs	0	0	2.49	2.49	5.71	5.71
Operating Costs (Fuel, VOM and FOM)	7.01	7.42	6.18	6.71	4.40	4.91
Total	7.01	7.42	8.67	9.20	10.10	10.62
Model variance	**5.59%**		**5.80%**		**4.89%**	

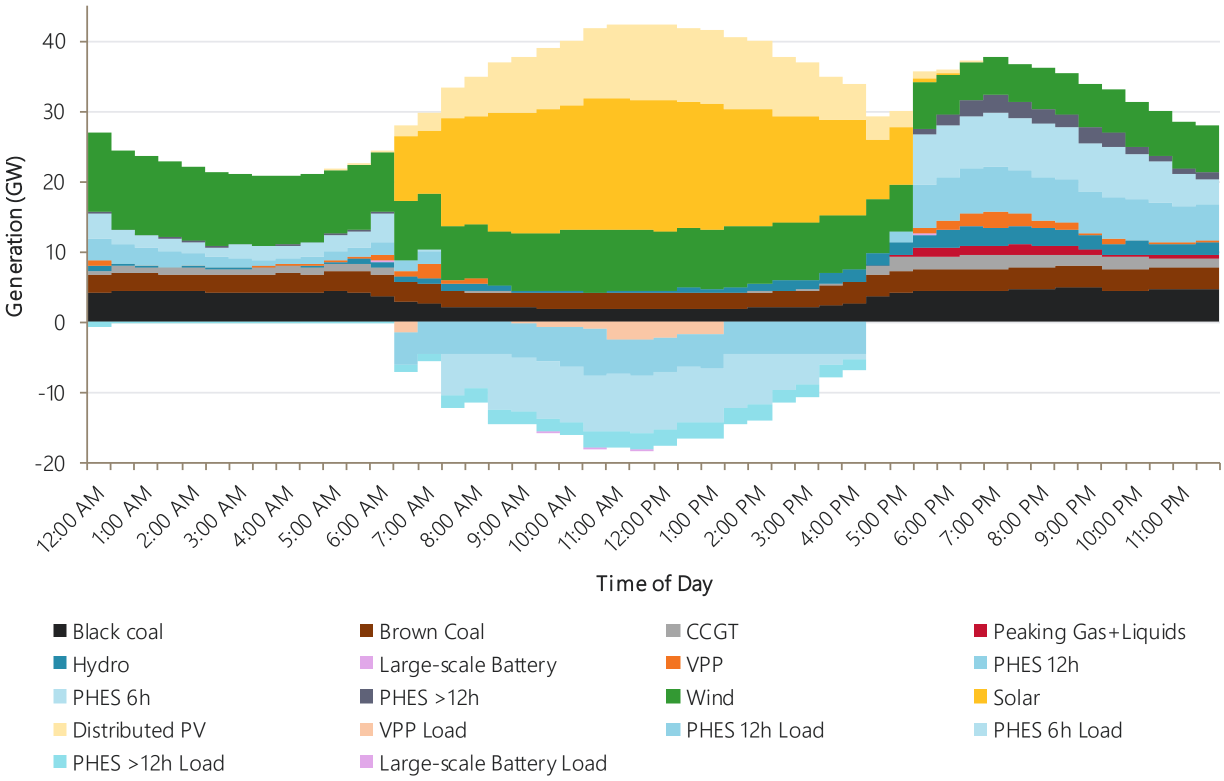
The ST modelling has assessed the reliability of the DLT under multiple iterations and reference years[15], using a methodology broadly consistent with the reliability forecasting approach applied in the Electricity Statement of Opportunities (ESOO). The analysis confirms that the proposed supply and transmission developments maintain the overall reliability of the power system, with expected unserved energy below the current reliability standard.

4.2 Role of intra-day storage operations

With significant development of solar generation both behind and in-front of the meter, the role for intra-day energy management to store surplus daytime energy for use during evening demand peaks will increase. This intra-day energy shifting role is forecast to be filled by existing hydro schemes, embedded battery storages, and pumped hydro storages of 6-12 hours. Other emerging energy storage technologies may also perform the role if economically viable. Existing hydro and thermal capacity, complemented by the Snowy 2.0 project and BoTN, avoids the medium-term need for deeper storage systems to shift energy seasonally across the year.

Figure 48 below demonstrates the strong need for intra-day energy shifting provided by embedded batteries and pumped hydro. As shown in the figure, pumped hydro takes advantage of low-cost surplus solar generation in the day to pump water back up to the head storage for use later in the day, when the sun has gone down and generation is more valuable. This minimises the need for other capacity – GPG or remaining coal capacity – to operate excessively to meet demand overnight.

Figure 48 Example day with high VRE operation in 2040 from the Central Scenario demonstrating the need for energy shifting

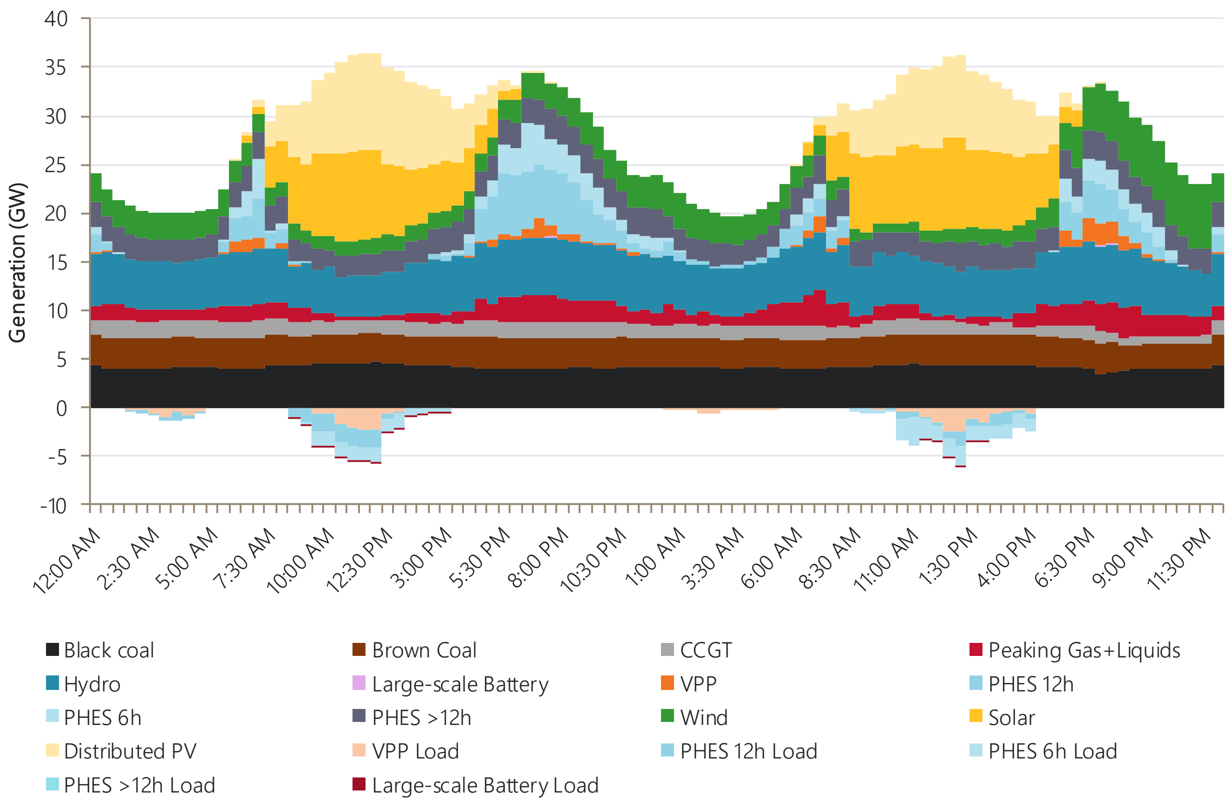


15 For the purpose of this Draft ISP, fewer Monte Carlo simulations have been run than would be relied upon for a reliability forecast.

During periods of high customer demand or low VRE, there may be less excess renewable generation for filling energy storages. On occasions such as these, the power system must rely on other forms of dispatchable generation such as hydro, gas or coal to meet the evening peak demand when stored energy might otherwise be used.

Figure 49 demonstrates the operational variability that may occur in the forecast horizon due to weather variance. On these days, while there is sufficient generation to fully meet demand, the system lacks the excess VRE that would enable full replenishment of the pumped hydro storages during the middle of the day.

Figure 49 Two consecutive days in March 2040 with minimal refilling of pumped storage, Central scenario



In the medium term while coal generation continues to be available, the exposure to weather variance is lessened, provided these traditionally less flexible power stations can ramp up and down as required. In the longer term, the need for transmission and storages to enable VRE diversity – technological and geographical – will grow to maximise the resilience to weather variance.

The need for storages able to shift energy over longer periods

The depth of PHES relates to the size of its energy storing potential, relative to its generating capacity. Shallow storages – from 1-4 hours (batteries) up to around 8 hours (pumped hydro or solar thermal) – are valued for their ability to smooth generation or shift demand intra-day. Most notably, solar generation coupled with shallow storage helps smooth out daily troughs or peaks in grid demand as already shown in Figure 48.

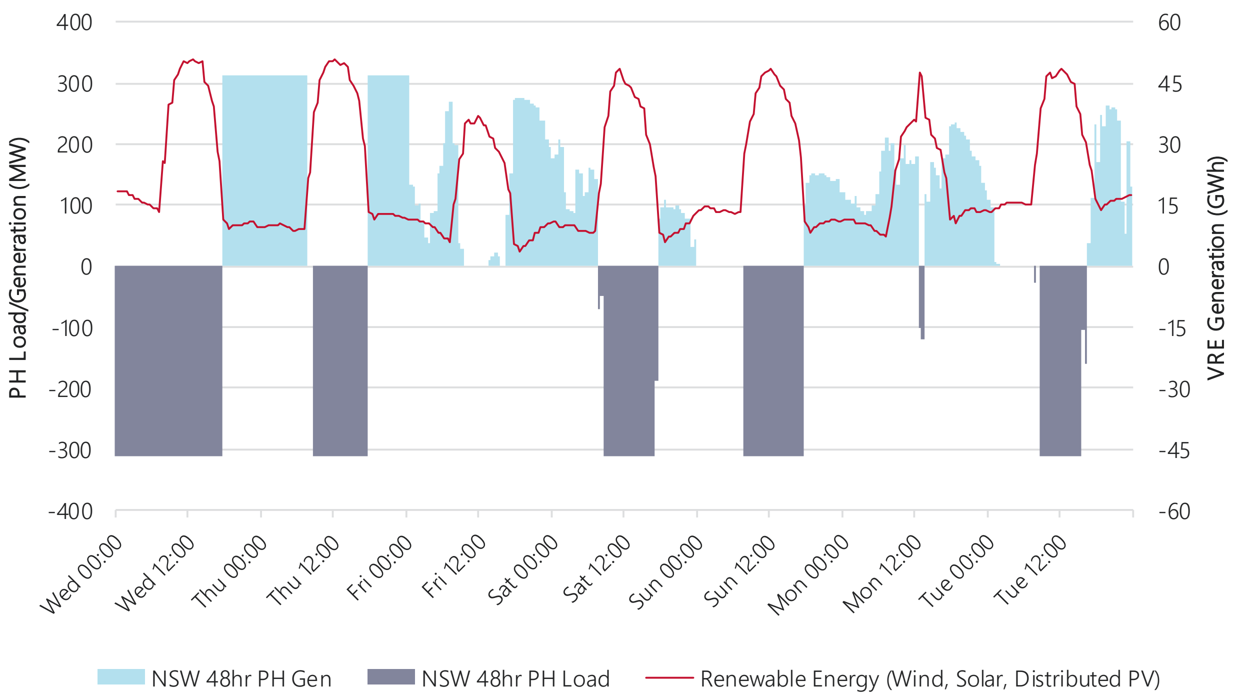
Deeper storages, with sufficient stored energy potential to allow continuous generation for 24, 48, or even 168 hours (1 week) provide the flexibility to offer both intra-day energy shifting, and longer-term shifting across seasons. Larger traditional hydro schemes provide greater storage potential, depending on the operational flexibility of the hydro-electric facilities given potential other reasons for water releases, such as for irrigation purposes.

While the Snowy 2.0 project may provide a week's worth of energy storage potential, the new energy storage projects selected under most scenarios in this Draft ISP are much shallower, with a maximum depth of 48 hours.

Figure 50 shows New South Wales' projected VRE generation for a week in the Step Change scenario in 2042, as well as the pumping and generation of the deepest 48 hour storage. The figure demonstrates the role this deeper storage plays in shifting energy between days. As shown in the figure, while the first two days present relatively high VRE, allowing efficient filling of the storages, the third and sixth days present limited opportunities for excess VRE to be used to fill storages. Instead, these deep storages are discharged to manage days and nights of lower VRE availability.

In practice, this will require accurate operational forecasting of near-term weather conditions and demand to allow efficient energy management decisions to fill and discharge from storages appropriately and avoid using stored energy before it is really needed.

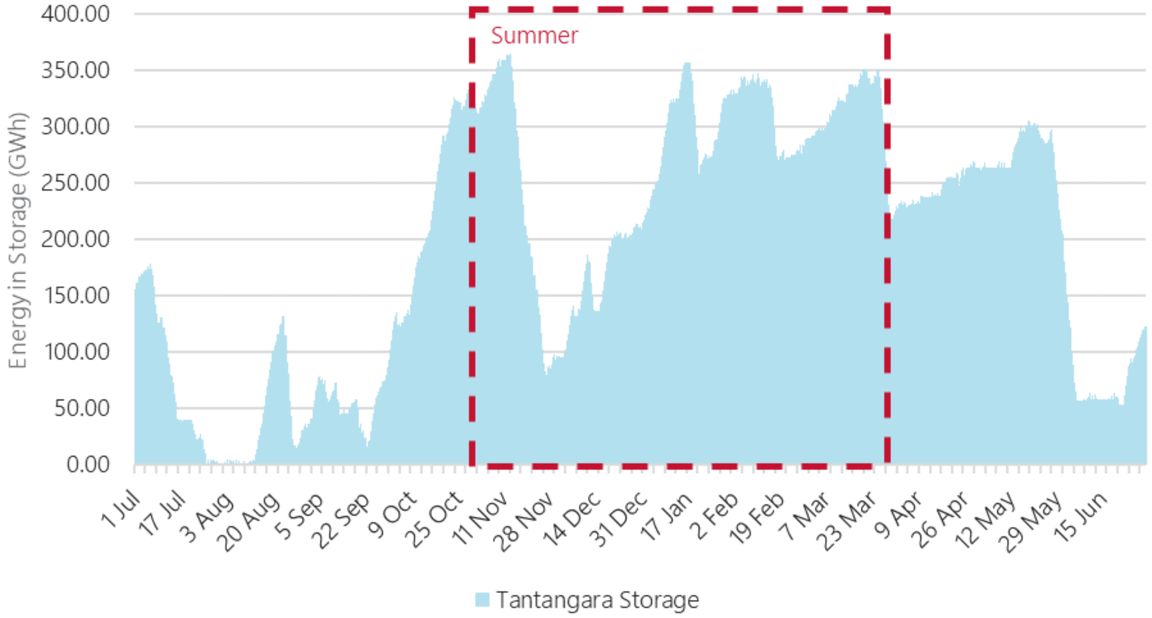
Figure 50 Deep storage management for a week in 2042, Step Change scenario



Snowy 2.0 is a deeper storage, and this additional depth may allow its operation to more closely resemble conventional hydro. Figure 51 below displays the projected energy stored in Snowy 2.0's Tantangara (upper) reservoir over the course of a forecast year. It demonstrates the seasonal management of this deep storage; maximising the stored energy during summer is important to deliver peak capacity at times of maximum demand.

The steep drops in this area chart represent periods of high stored energy release. This may be due to renewable energy availability being lower over a prolonged period, or due to outages of other generators. The upward slopes are typically more gradual, demonstrating that efficient stored energy replacement is likely to more gradually take advantage of charging during times of abundant renewable energy and low prices.

Figure 51 Hourly energy in storage in Tantangara in 2039-40, Central scenario

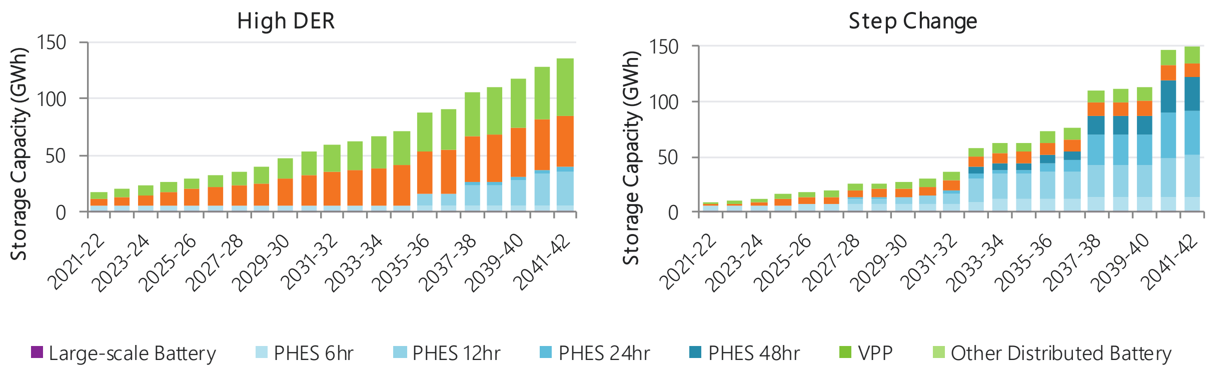


Role of distributed storage

Australia has the highest per capita uptake of rooftop solar PV in the world. AEMO forecasts that there will also be potential for rapid uptake of battery storage, electric vehicles and VPPs by Australian energy consumers. A VPP is a cloud-based, distributed power plant that aggregates the capacities of various distributed energy resources for the purpose of enhancing power generation and optimising the entire system. Aggregated and controllable distributed storages will provide greater system value than uncontrolled consumer battery systems, and will be a valuable complement to VRE. The VPPs play an important role in maintaining grid stability and managing peaks in demand by harnessing consumer-owned energy assets.

Though distributed storage may be built for a multitude of reasons, the way that it operates can cover some of the bulk energy storage role otherwise played by pumped hydro. AEMO's Step Change and High DER scenarios investigate this stronger role for VPPs. Figure 52 shows that in the High DER scenario, distributed batteries and VPPs almost completely displace new shallower pumped hydro from the storage mix, with battery storage meeting the need for intra-day shifting.

Figure 52 Storage available capacity (energy) to 2041-42, High DER and Step Change scenarios



4.3 An increasing need for flexibility

As increasing amounts of VRE are forecast to be built in the NEM, there is an increasing need for synchronous generation to operate with greater flexibility, responding to this renewable intermittency. This will affect the operation of coal-fired generation, GPG, hydro, and storage technologies. GPG, for example, is expected to produce less energy overall, but continue to provide a reliability and security role to complement VRE.

While energy storages may enable flexible and dispatchable management of VRE, charging behaviours will compound the need for flexibility, as battery charging and pumping loads will add to traditional consumer demands.

Potential challenges for coal-fired generation operation

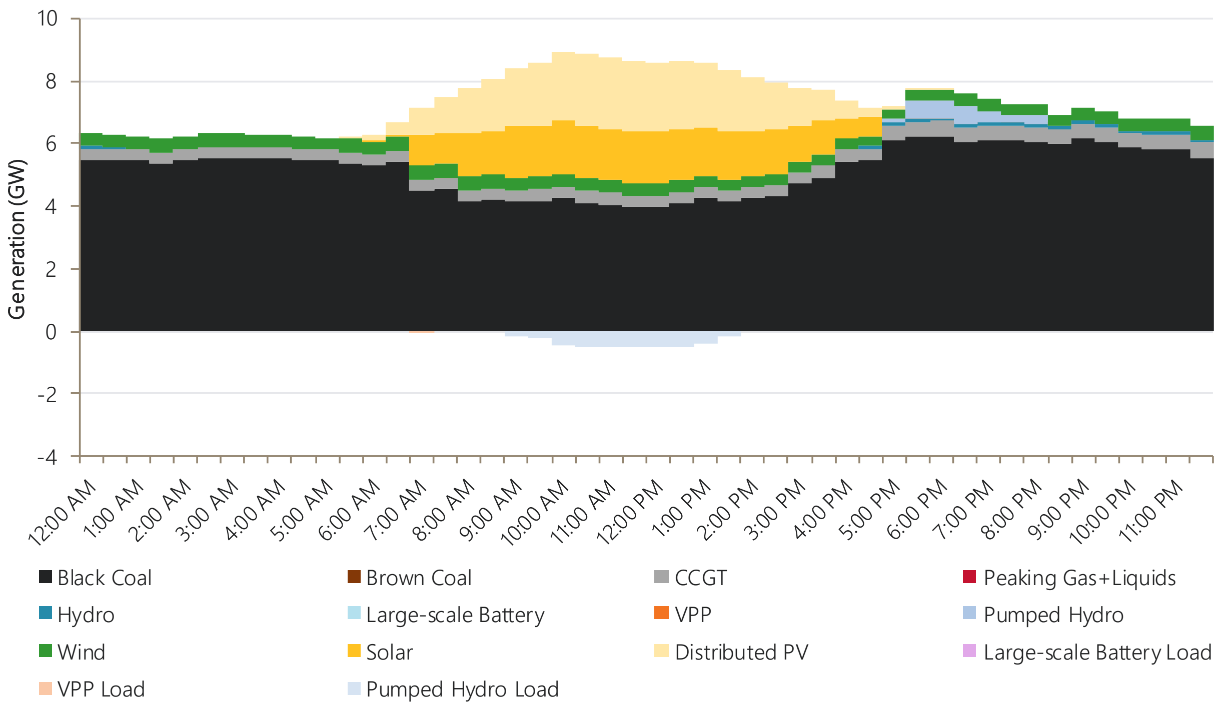
Coal-fired generation, the primary producer of energy in the NEM currently, has limited operational flexibility. Strong development of solar resources, including both rooftop and utility-scale solar PV, is forecast to lead to minimum loads in the middle of the day, which will challenge the operation of inflexible thermal generation.

Where practical, the incumbent generation fleet will need to adapt its technical operating envelope and operational approach to manage the demands of a power system increasingly exposed to weather fluctuations. This may include running in split mode operation; ramping down after the morning peak as solar generation increases, sitting at minimum stable levels, and ramping up to meet the evening peak. Daily ramping increases wear and tear on thermal generation, which may lead to increased maintenance requirements or accelerate the end of life for these plants.

Coal generators are already aware of these issues and are working on improving the flexible operation of coal generation in the future. However, this potential increased flexibility has not been included in the ST analysis of this Draft ISP discussed below.

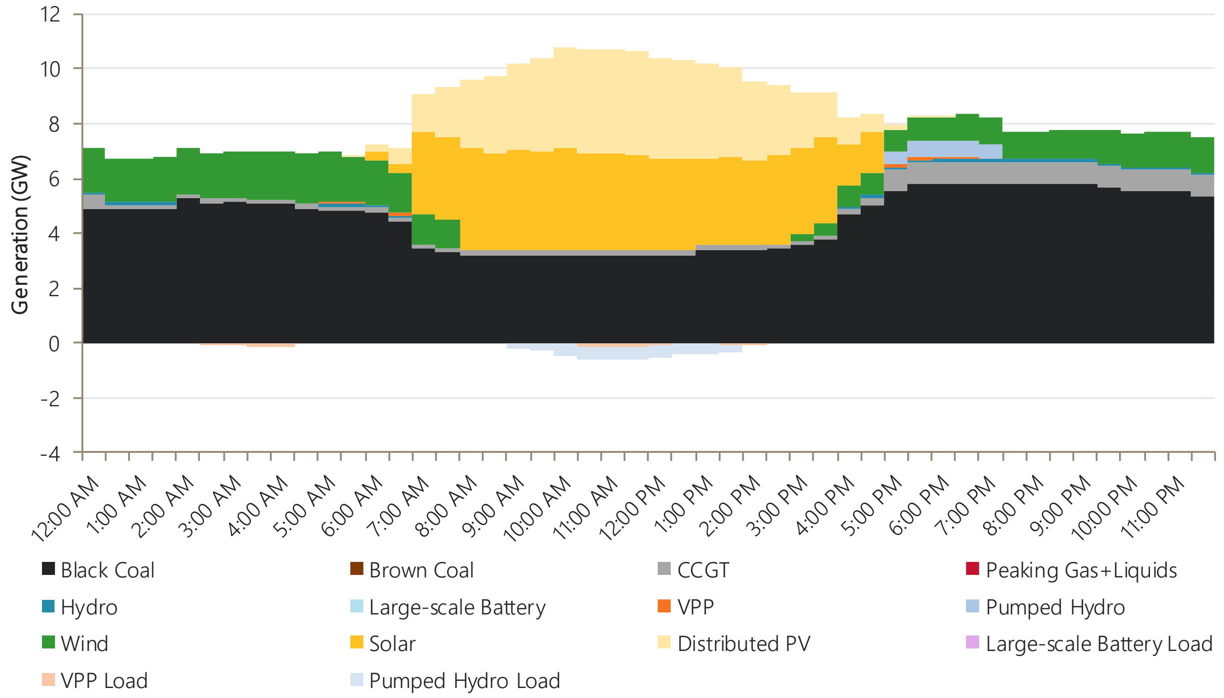
Figure 53 is an example of how the Queensland generation fleet is projected to respond to solar generation in 2020. During the middle of the day, coal generation is displaced by solar but ramps back up as solar generation decreases in the afternoon and evening. From 12:30 to 18:30 there is an increase in the coal and gas generation by about 3 GW, requiring a maximum ramp of 25 MW per minute.

Figure 53 Queensland generation in 2020, Central scenario



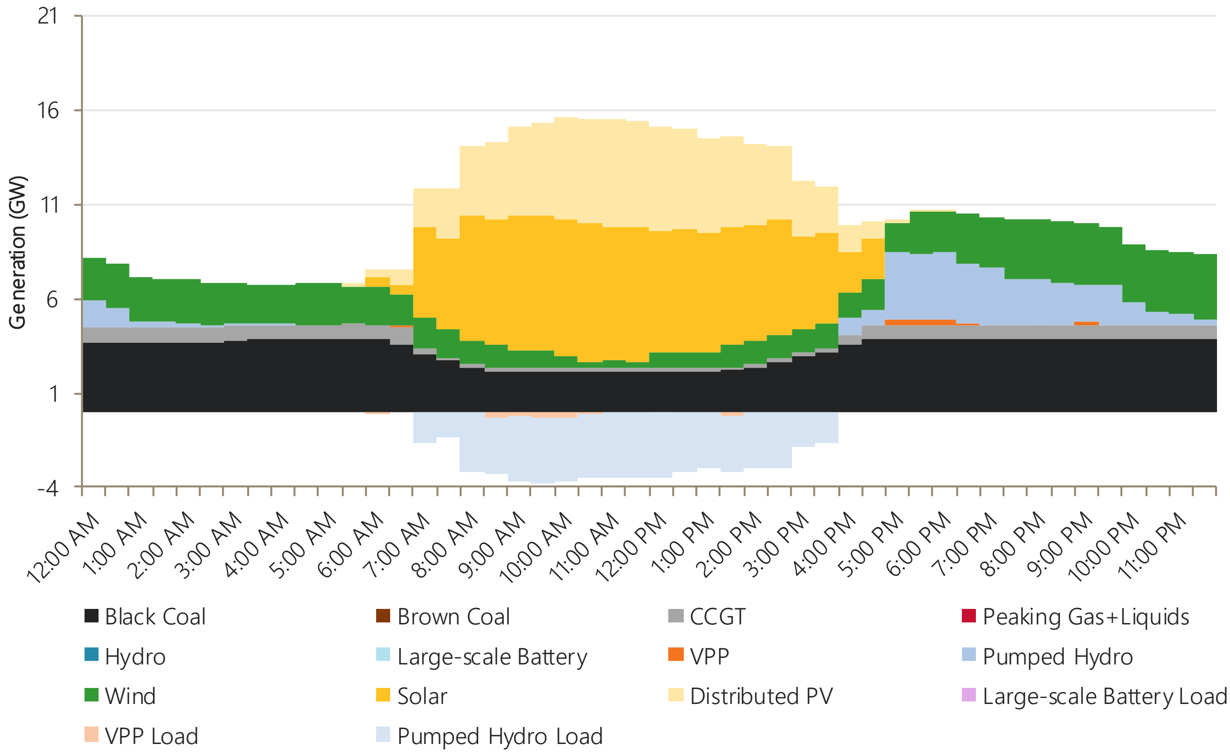
Below is a similar day in 2030 where this operational challenge increases. The increase in solar generation is increasing the 'duck curve' and resulting in an increase in generation levels of 4 GW over the same six-hour period. Without improvements in operational flexibility, it may be necessary to curtail VRE during the middle of the day to have sufficient and cost-effective ramping capacity available to meet the evening peak demand. For example, on this day in 2030, up to 2 GW of VRE is curtailed during the middle of the day to keep sufficient thermal capacity online and avoid a ramping need greater than would be technically feasible by the available fleet (in this period, at a max of 34 MW per minute).

Figure 54 Queensland generation in 2030, Central scenario



By 2040, solar penetration is projected to increase even further, resulting in a ramping need of over 6 GW across the afternoon and evening, however this is managed effectively with the increase in pumped hydro capacity. With operation of energy storages, the maximum ramp required from the thermal fleet is lower, at approximately 24 MW per minute. The pumped hydro assists in energy smoothing and also results in much less VRE having to be curtailed.

Figure 55 Queensland generation in 2040, Central scenario



The change in ramping requirements are forecast to evolve over time as outlined in the snapshots above. Figure 56 below shows the top and bottom 5% of ramping events from dispatchable generators.

Figure 56 Forecast top 5% and bottom 5% of ramp events in New South Wales from dispatchable generators by financial year to 2041-42

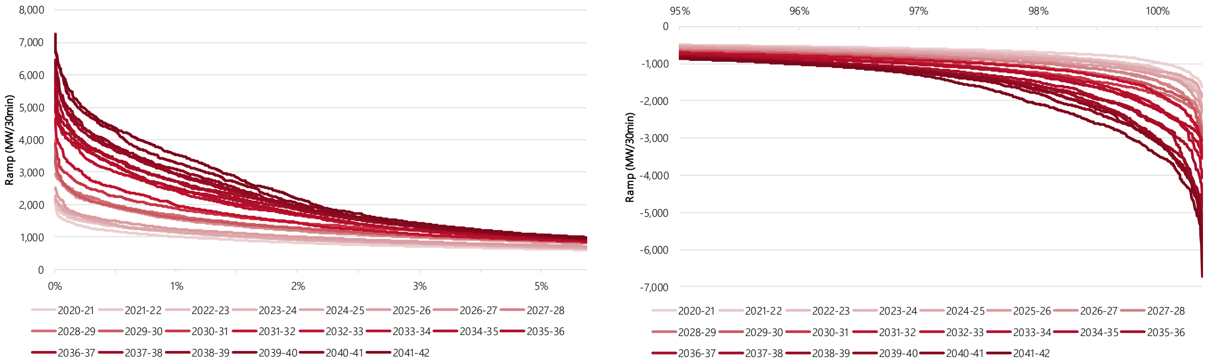


Figure 57 Forecast top 5% and bottom 5% of ramp events in Queensland from dispatchable generators by financial year to 2041-42

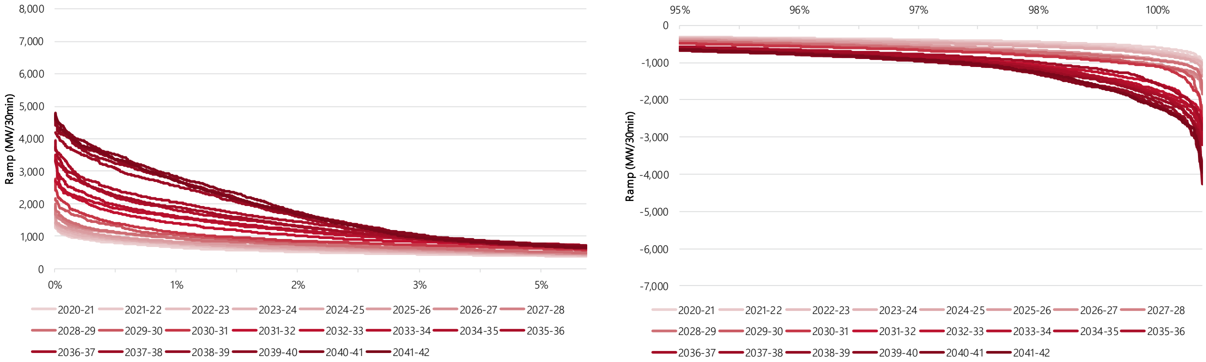


Figure 58 Forecast top 5% and bottom 5% of ramp events in Victoria from dispatchable generators by financial year to 2041-42

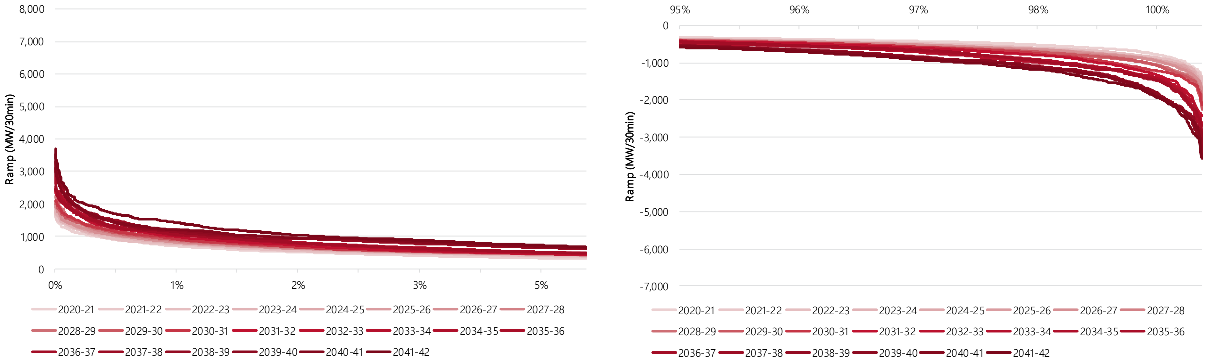
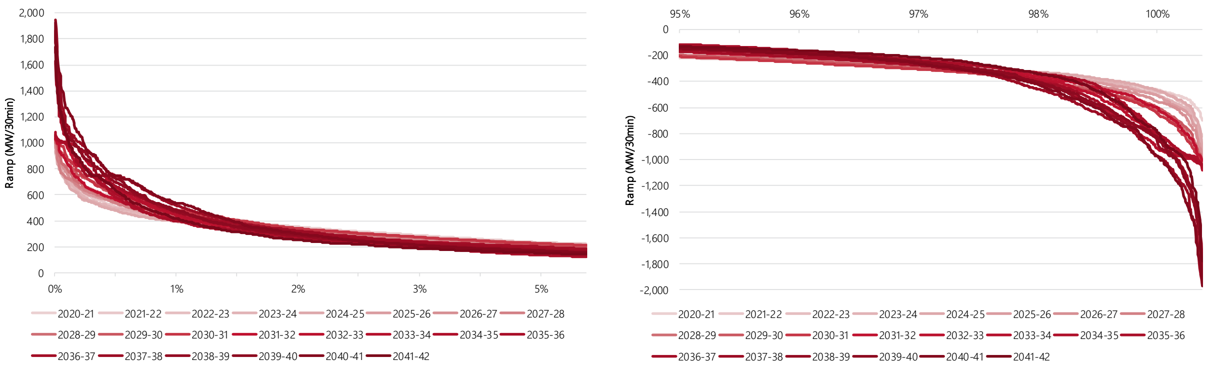


Figure 59 Forecast top 5% and bottom 5% of ramp events in South Australia from dispatchable generators by financial year to 2041-42

Figure 60 Forecast top 5% and bottom 5% of ramp events in Tasmania from dispatchable generators by financial year to 2041-42



The maximum ramp up and down forecast for the thermal generation fleet (that is, coal, CCGT, and peaking plants) for each region and each year are provided in Table 6 and Table 7 below. The effect that pumped hydro storages has in reducing the ramping requirements of thermal generation is clear as more storages are developed in the 2030s.

Table 6 Thermal fleet maximum ramp up event (MW/min)

	New South Wales	Queensland	South Australia	Tasmania	Victoria
2019-20	55	59	29	5	31
2020-21	63	54	35	5	34
2021-22	54	57	31	5	45
2022-23	60	57	30	5	37
2023-24	52	61	31	5	33
2024-25	58	61	35	5	34
2025-26	56	61	26	5	38
2026-27	57	74	30	4	41
2027-28	58	75	30	4	47
2028-29	59	79	31	5	41
2029-30	51	86	34	5	41
2030-31	55	87	41	5	47
2031-32	47	102	36	3	45
2032-33	46	121	38	4	54
2033-34	48	113	35	2	54
2034-35	49	107	36	0	54
2035-36	55	80	25	5	57
2036-37	55	88	22	5	62

	New South Wales	Queensland	South Australia	Tasmania	Victoria
2037-38	66	108	17	5	70
2038-39	69	78	16	5	55
2039-40	66	94	16	5	56

Table 7 Thermal fleet maximum ramp down event (MW/min)

	New South Wales	Queensland	South Australia	Tasmania	Victoria
2019-20	46	42	24	5	25
2020-21	48	49	34	5	31
2021-22	46	54	24	5	38
2022-23	50	54	28	5	30
2023-24	51	60	33	4	32
2024-25	46	64	32	5	36
2025-26	46	68	28	5	44
2026-27	50	89	35	4	38
2027-28	60	85	21	4	40
2028-29	67	91	36	5	44
2029-30	53	93	33	5	59
2030-31	102	95	32	5	53
2031-32	39	115	33	3	60
2032-33	39	131	39	2	57
2033-34	39	130	40	2	58
2034-35	102	135	40	0	55
2035-36	65	106	28	5	63
2036-37	67	94	25	5	59
2037-38	71	124	17	4	75
2038-39	71	117	16	5	84
2039-40	69	122	15	5	86

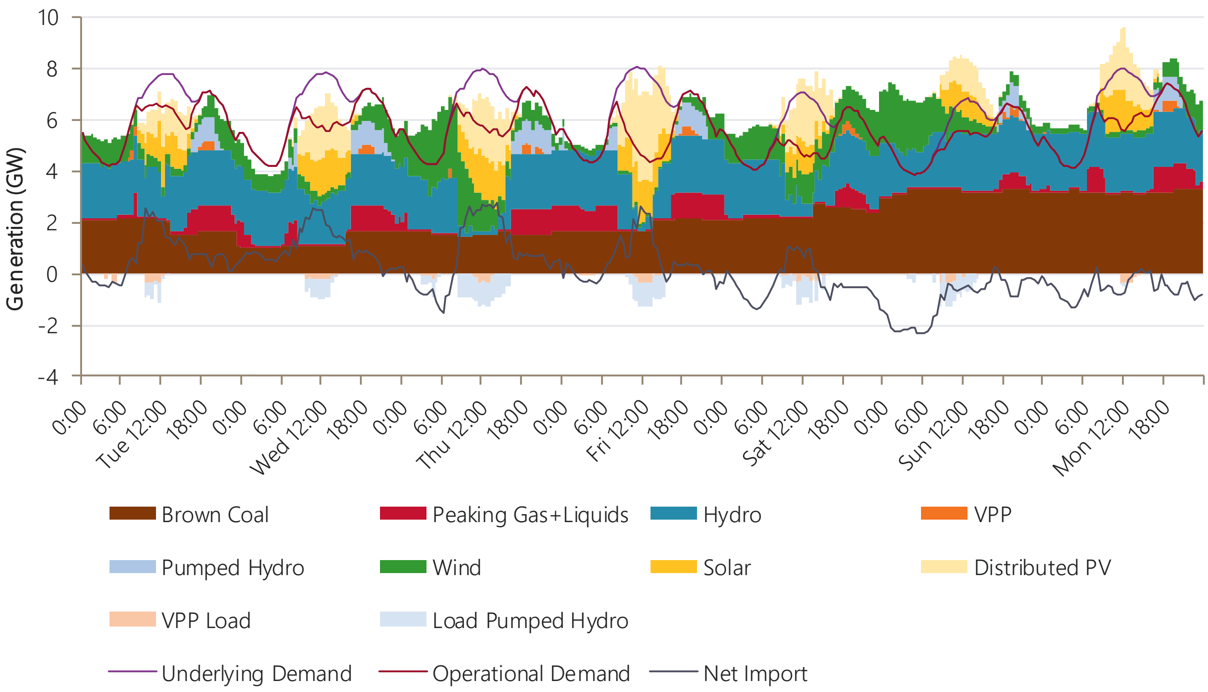
4.4 Greater reliance on the energy potential of the weather

The optimal development path identified in this Draft ISP projects a strong role for VRE and energy storage to replace coal-fired generation over time. Greater reliance on weather as an energy source will also mean the power system may become more exposed to the vagaries of weather. The system needs to be sufficiently resilient to extreme weather events including wind droughts (still wind conditions for a week or more), hydro droughts, dark storm clouds that limit solar generation output, storm events, bushfires, or extreme temperatures that increase demand while reducing the capacity of thermal plant.

The future generation mix must operate within these varying weather conditions across the year. Gas and hydro generation, currently providing peak or mid-merit capacity, will be called upon to provide energy when renewable energy is less available and shallow storages have been depleted.

Figure 61 below demonstrates what a week in Victoria may look like when there are low levels of wind generation available. During these days of low wind, Victoria's demand is met by a mix of coal generation, pumped hydro and battery storages supported heavily by peaking gas and liquids to meet the evening peak, but the bulk of Victoria's energy is met by hydro generation. At times, imports from neighbouring regions are required to meed Victorian demand, but later in the week there is sufficient generation capacity such that Victorian generation is able to be exported to other regions.

Figure 61 Low wind week in Victoria in June 2040, with high hydro availability in Victoria



The week in the figure above relies heavily on the availability of hydro generation. If this same forecast 2040 year instead had reduced rainfall conditions, the supply in Victoria during a low wind week may look more like Figure 62. With hydro generation unavailable during this week, Victoria is much more reliant on brown coal-fired generation to meet Victorian demand. Victoria is also reliant on imports on a daily basis, particularly from Tasmania (see Figure 63). These figures present the same generation mix, demonstrating that the ISP's preferred generation mix is projected to provide adequate resilience across a range of forecast weather patterns.

Figure 62 Low wind week in Victoria in April 2040, generation mix in Victoria

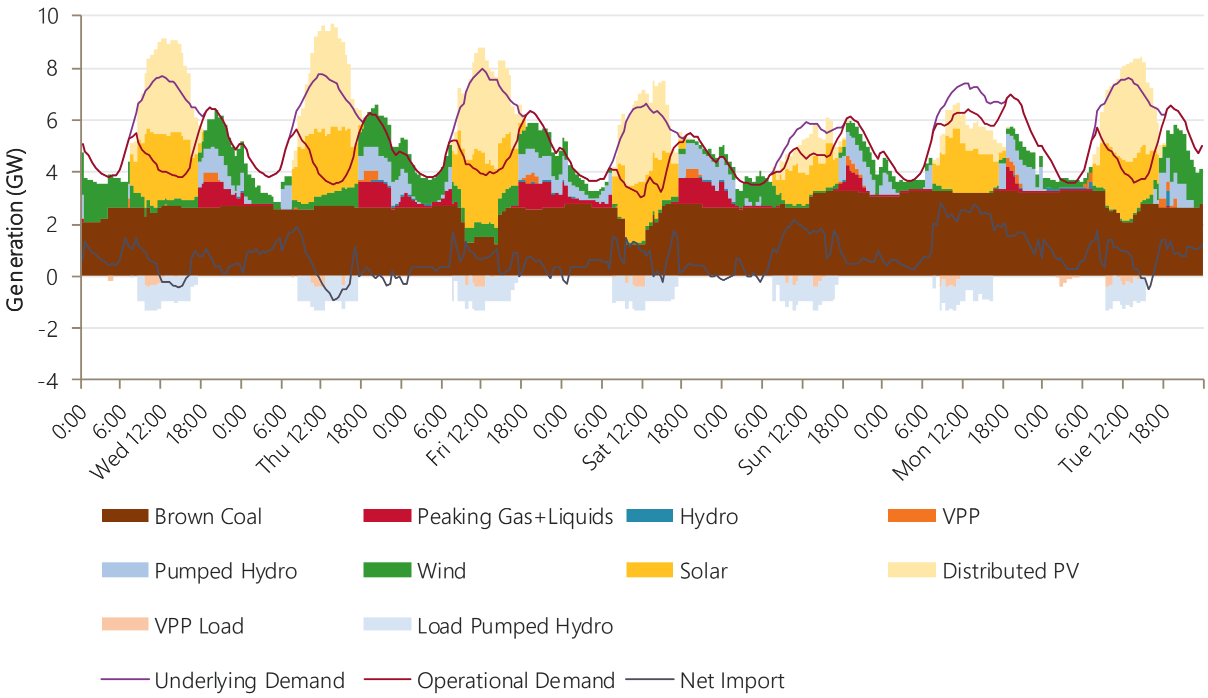
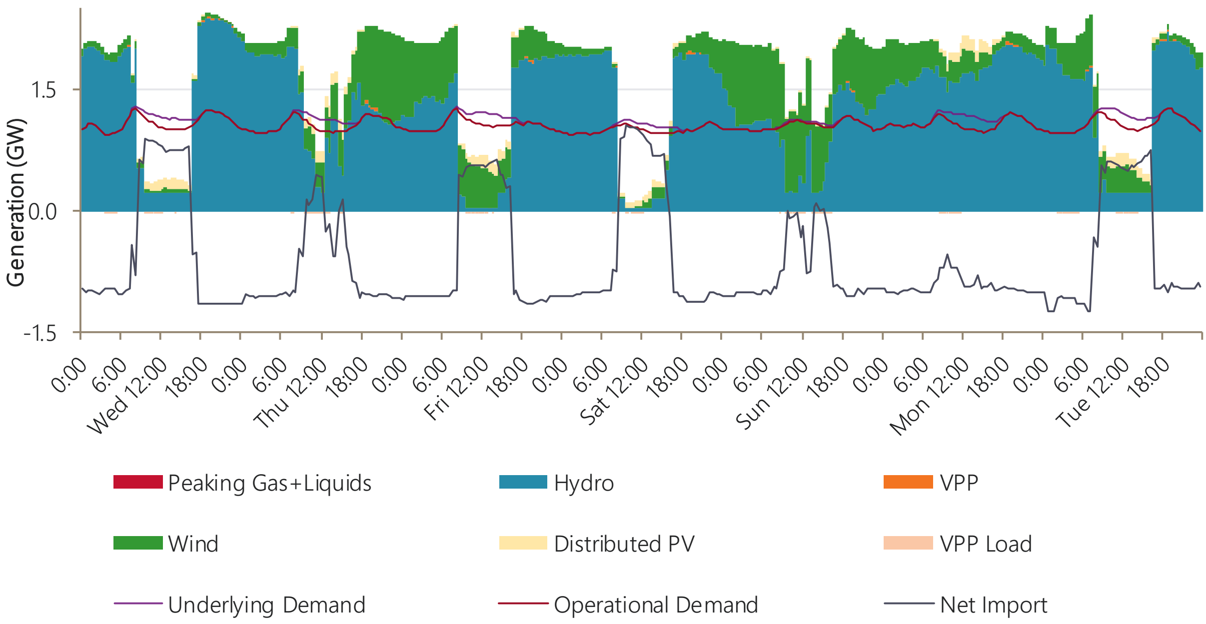


Figure 63 Same low wind week in Victoria in April 2040, generation mix in Tasmania



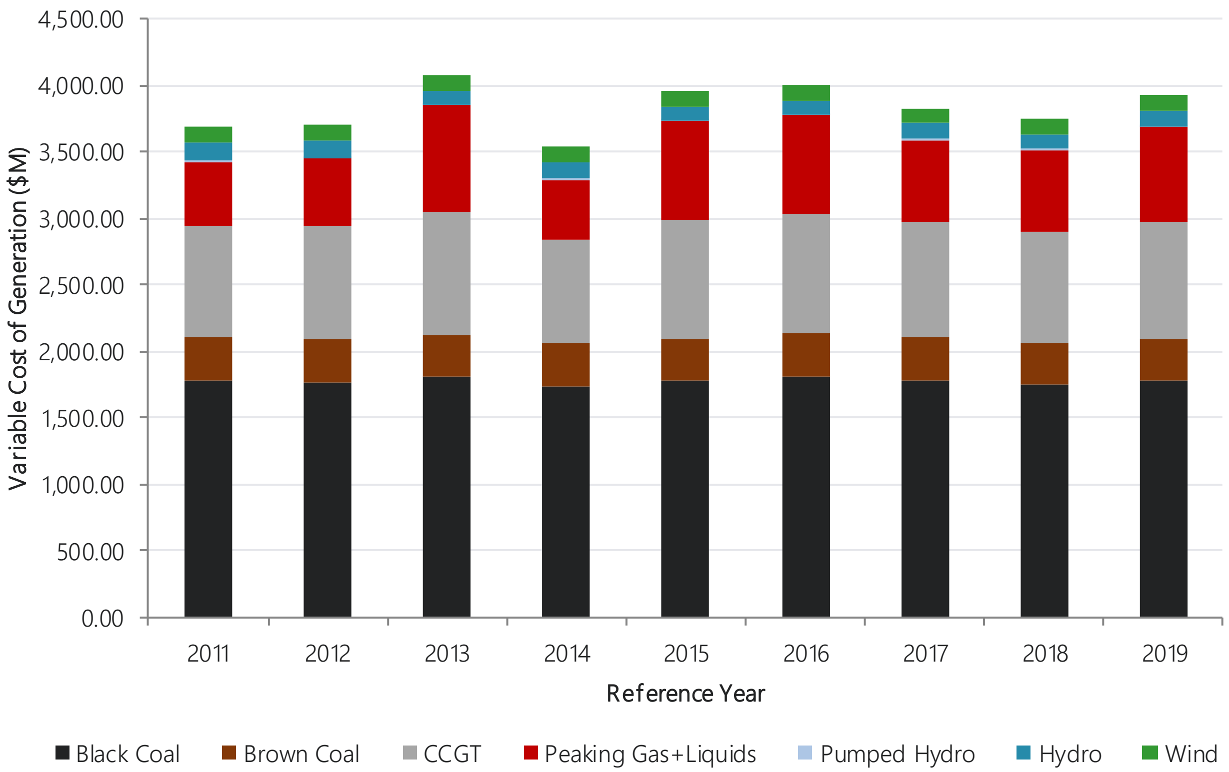
In this period of low wind output across the southern regions, the energy gap is met by a combination of thermal generation in those regions together with Tasmanian hydro, enabled by the larger interconnectors. Basslink and Marinus Link flow southward in the daytime – using mainland solar to conserve water in Tasmania – and northward in the evening and night. The remaining coal units in Victoria run day and night over most of the week. Snowy 2.0 runs down, generating more than it pumps. GPG and smaller storages (charged from solar and coal energy in the daytime) provide additional capacity in the evening peak.

Weather variation on the generation mix

As more VRE is installed in the NEM, the actual cost of generation becomes highly dependent on weather conditions. Tested under a range of historical weather patterns, the generation cost forecast in 2031-32 for the Central scenario can vary by up to $533 million, or nearly 15% between reference years. The majority of the difference is attributable to the operation of peaking plant, with gas being the key fuel that is utilised to fill the gap when VRE is unavailable or potential energy from storages is exhausted.

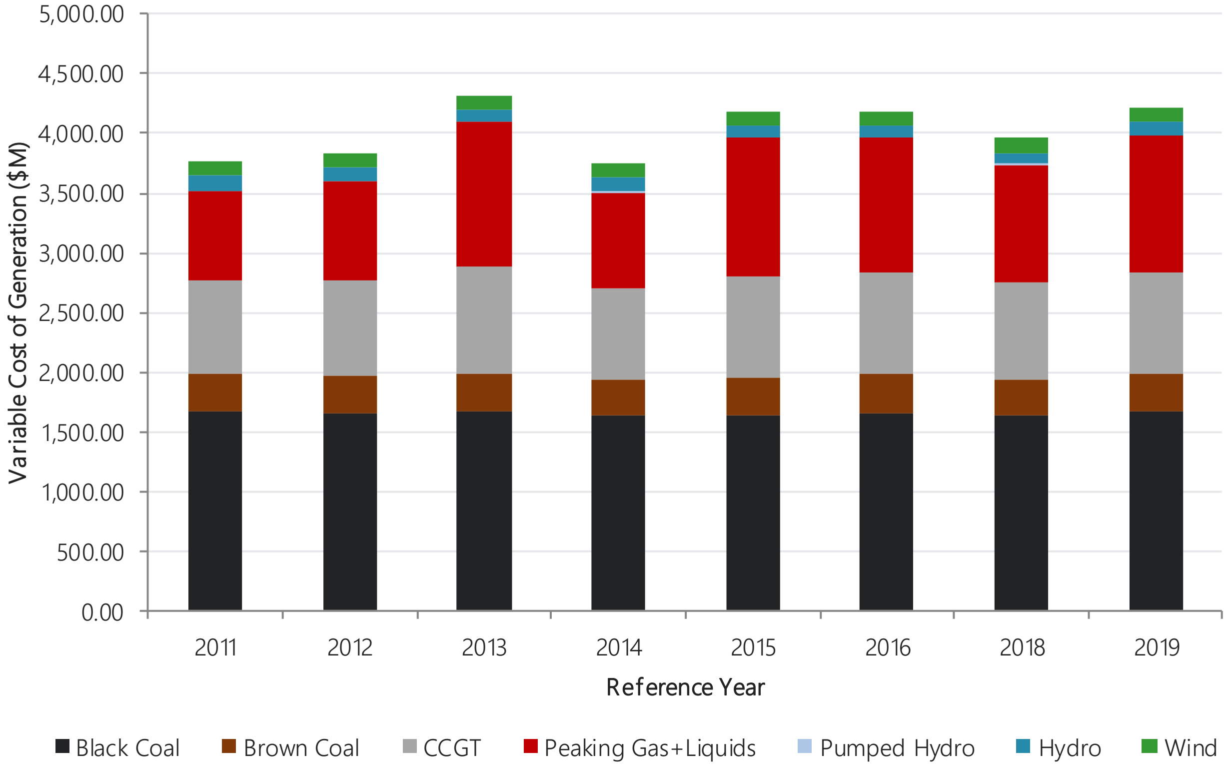
Figure 64 shows the variation of costs across different reference years with varying weather pattern assumptions. For example, in 2031-32 with the forecast renewable energy developments, the weather patterns within the 2013-14 reference year are expected to provide the highest contribution of renewable generation with 116.2 GWh of generation forecast. In contrast, the weather patterns within the 2015-16 reference year are expected to provide only 108.8 GWh of renewable energy, a difference of 7.4GWh (or approximately 6% lower available renewable energy).

Figure 64 Generation cost across reference years in 2031-32 for the Central scenario



While the generation costs across the NEM vary across weather patterns, Figure 65 shows that the weather-driven variability in generation cost is also impacted by the level of interconnection between regions. Should there be no further interconnection built beyond the no-regret grid projects discussed in Part C of the Draft ISP Report, the fuel costs are higher and more variable. The average rise in cost is $193 million, and the range spread between best- and worst-case reference years increases to $565 million. Without any new interconnection, weather-driven variances in generation costs would be even more pronounced. Additional interconnection therefore builds system resilience against the cost impacts of natural variations in weather that can be experienced from year to year.

Figure 65 Generation cost across reference years in 2031-32, Central scenario, without any interconnection beyond no-regret transmission projects



Revenue sufficiency and the impacts of weather variation

The ISP optimal development path is highly linked to the expected timing of coal-fired generation closures. The closures as identified in this Draft ISP are based on the timing identified by generators themselves (in the Central scenario), or earlier or later if the modelling indicates it is cost-effective to do so (in other scenarios). In reality, generation companies need to provide an adequate return to shareholders, and may close a plant earlier than presently estimated if it is not able to provide sufficient revenue to cover fixed and variable costs.

A basic method to assess the revenue sufficiency of generators involves calculating how long it takes for a generator to earn enough revenue to cover its fixed costs through the sale of its energy in the spot market, and ignoring potential other revenue sources and hedging opportunities. Net revenue earned is calculated as:

*net revenue = loss-adjusted generation * (pool price – SRMC)*

Due to the potentially sensitive nature of this analysis, AEMO is not able to report the outcomes for individual generators, but can confirm that revenue sufficiency using the above approach has been a consideration in the ISP results validation process.

Aurora Energy Research's independent economic analysis of AEMO's 2018 ISP and the economics of coal closures identified that some brown coal generators were at risk of early closure, particularly in a scenario where VRET is fully met by 2030[16].

4.5 Supplying maximum and minimum operational demand

The generation mix and interconnector support required to meet the maximum and minimum operational demand days varies across each region. The operation of these resources will increasingly depend on the

[16] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2019/20190526-AEMO-Phase-2-report-summary.pdf

prevailing weather conditions, and as outlined previously, efficient and focused use of energy storages, DSP and VPP are needed to ensure a reliable and secure grid.

Operational demand is the end customer demand net of rooftop PV and unaggregated batteries, that is, the demand that is expected to be met by large-scale or dispatchable generation technologies, including VPPs. Operational minimum demand generally occurs during weekends or public holidays, and has historically often occurred overnight. As installed rooftop PV capacity increases, minimum demand has been declining and is increasingly forecast to occur in the middle of the day, as is already occurring in South Australia.

The figures in this section demonstrate the forecast needs of the power system under the Central scenario, applying the weather profile from the actual 2013-14 reference year to the future years. Operational difficulties are likely to be as challenging in meeting maximum demands as they are to meet the system security and operability issues that arise due to minimum demands.

Increasing the accuracy of forecasting operational minimum demands and the conditions that surround them is an ongoing piece of work that AEMO is focused on.

Note that the dates and times mentioned in the analysis below refer to the synthetic reference years that AEMO has constructed to conduct this analysis. In no way are these actual forecasts of days and times when those minimum and maximum demand conditions will actually occur.

4.5.1 Queensland

Figure 66 Queensland – forecast maximum operational demand 07/01/2040, Central scenario

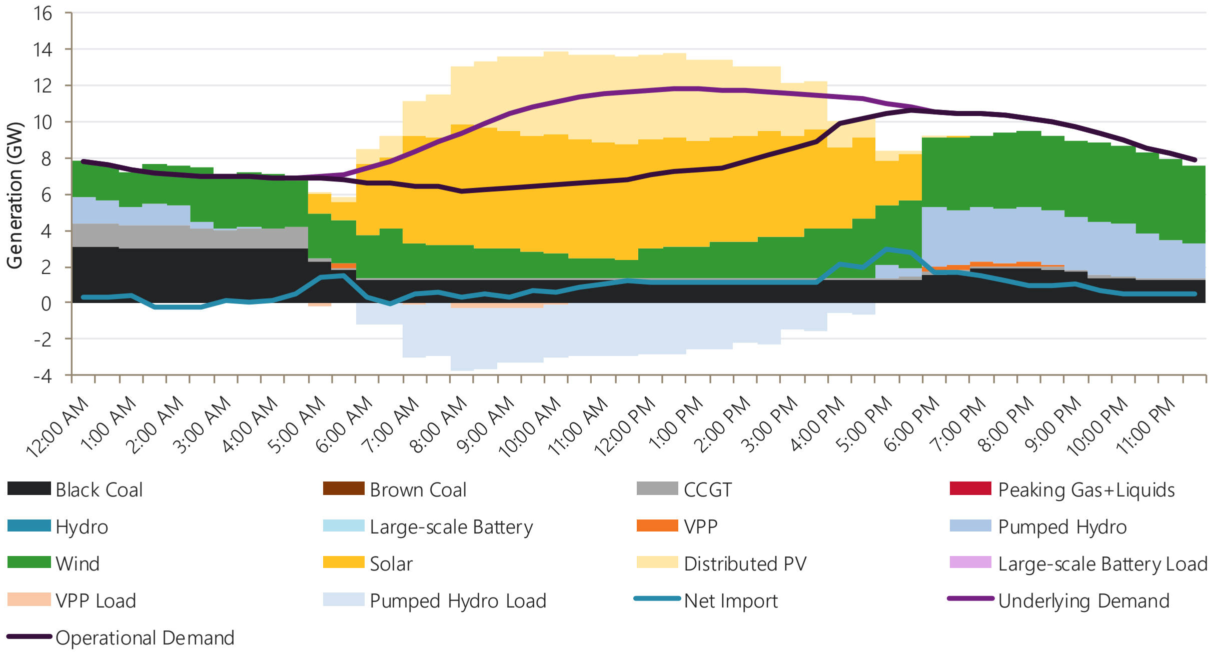
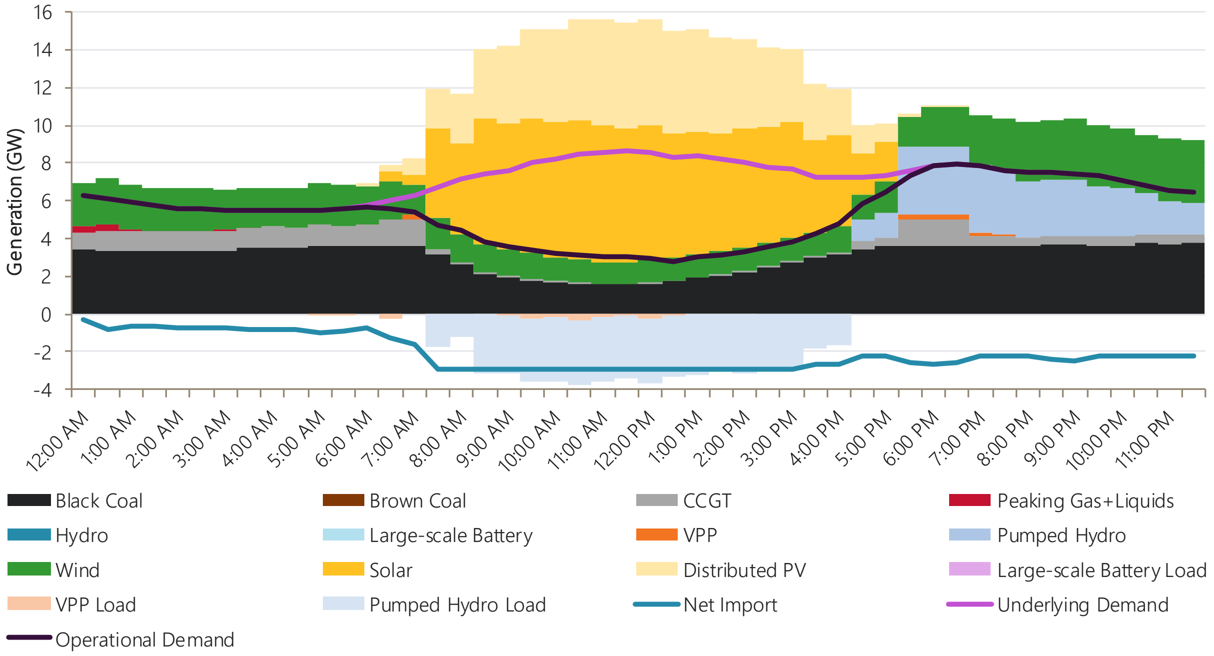


Figure 67 Queensland – forecast minimum operational demand 06/05/2040, Central scenario



For this synthetic reference year, maximum operational demand of 10,623 MW is forecast to occur in Queensland on 7 January 2040 at 1800 hours. The forecast minimum demand period occurs on 6 May 2040 at 1230 hours (midday) with operational demand only 2,790 MW. Observations include:

- For the minimum demand day, total generation at 1200 hrs is >10 GW but demand is less than 3 GW. All surplus energy is exported to New South Wales or used for charging battery and PHES.
- For the maximum demand day, coal-fired generation operates at minimum stable level throughout the day, ramps up for the evening peak, and then back to minimum at 2200 hrs. The value of stored energy is less than the marginal cost of coal-fired generation on this day, which is why pumped hydro runs into the night instead of coal-fired generation ramping up.
- Even in winter, large amounts of solar is still available during the minimum demand day. The major difference between these days is that during the minimum demand day, the generation far exceeds load, so exports to New South Wales occur.

4.5.2 New South Wales

Figure 68 New South Wales – forecast maximum operational demand 23/12/2039, Central scenario

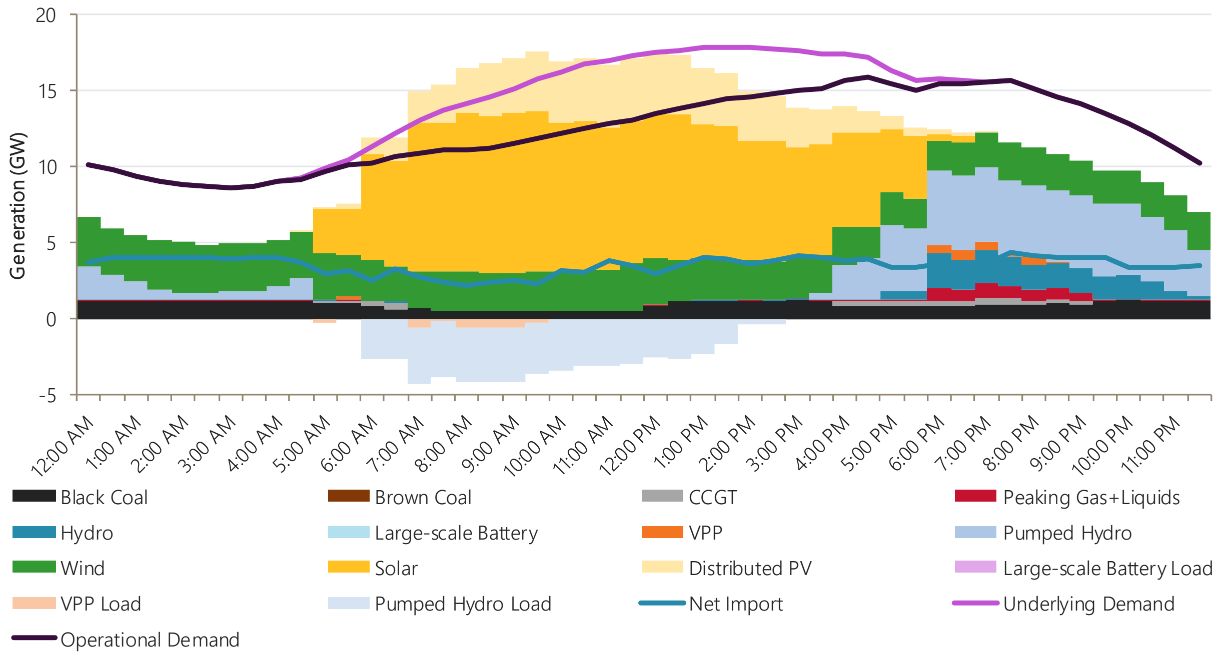
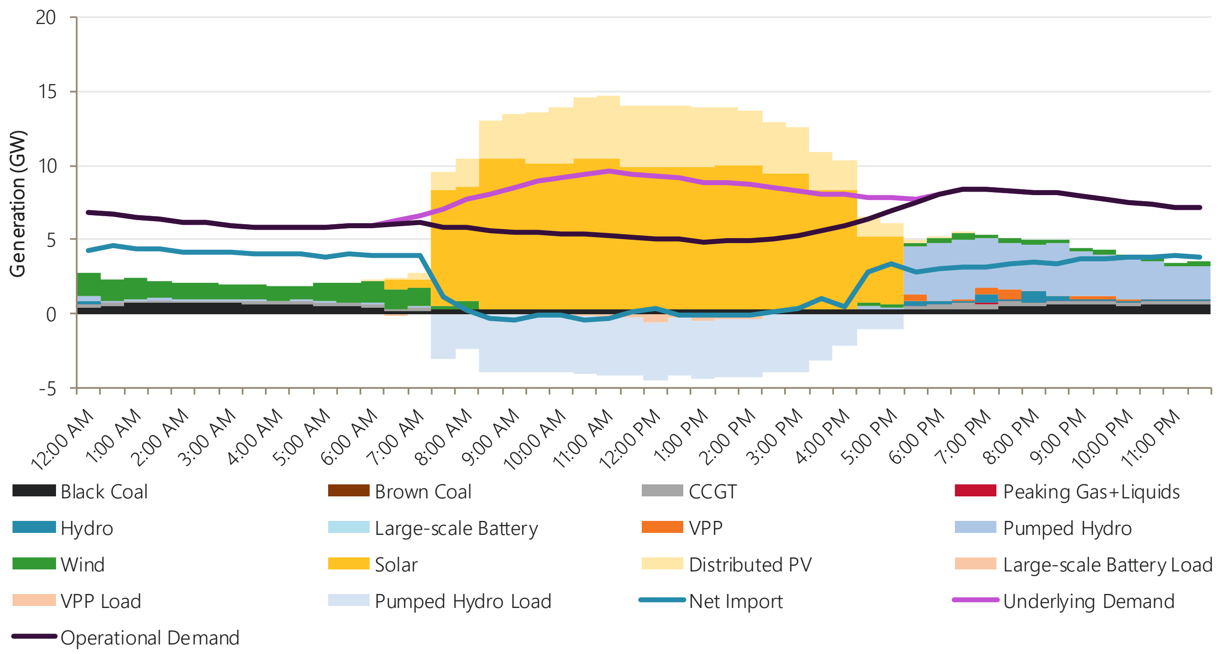


Figure 69 New South Wales – forecast minimum operational demand 01/04/2040, Central scenario



Maximum operational demand of 15,878 MW is forecast to occur on 23 December 2039 at 1700 hours. Minimum operational demand of 4,779 MW is forecast to occur on 1 April 2040 at 1300 hours. Observations include:

- The full suite of generation technologies is required to meet the evening ramp and peak demand. Imports from Victoria/Queensland are required throughout the day.

- Minimum synchronous generation is online throughout the minimum demand day. Slight surpluses in solar generation are exported during the middle of the day, but energy imports are required in the morning, evening and overnight.
- Very little coal-fired generation remains by 2040 given expected closure timings. For further discussion on the impacts of such conditions, see Appendix 7, Power System Security, which considers power system security, specifically inertia and system strength under low levels of synchronous generation to 2039-40.

4.5.3 Victoria

Figure 70 Victoria – forecast maximum operational demand 19/01/2040, Central scenario

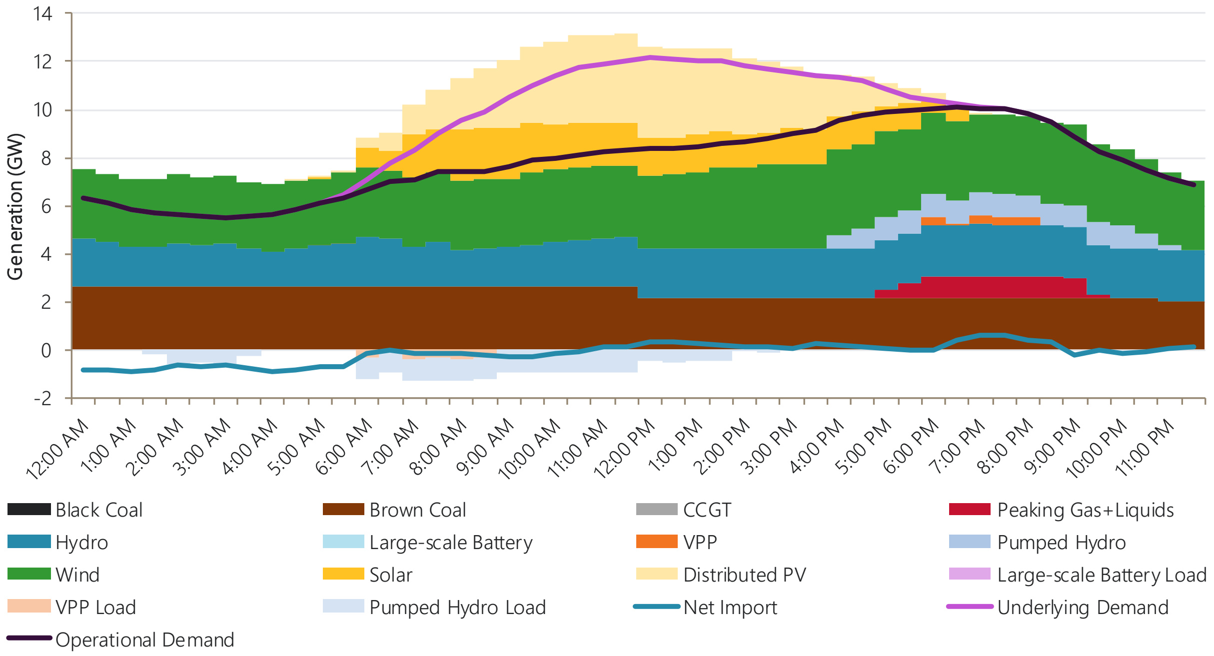
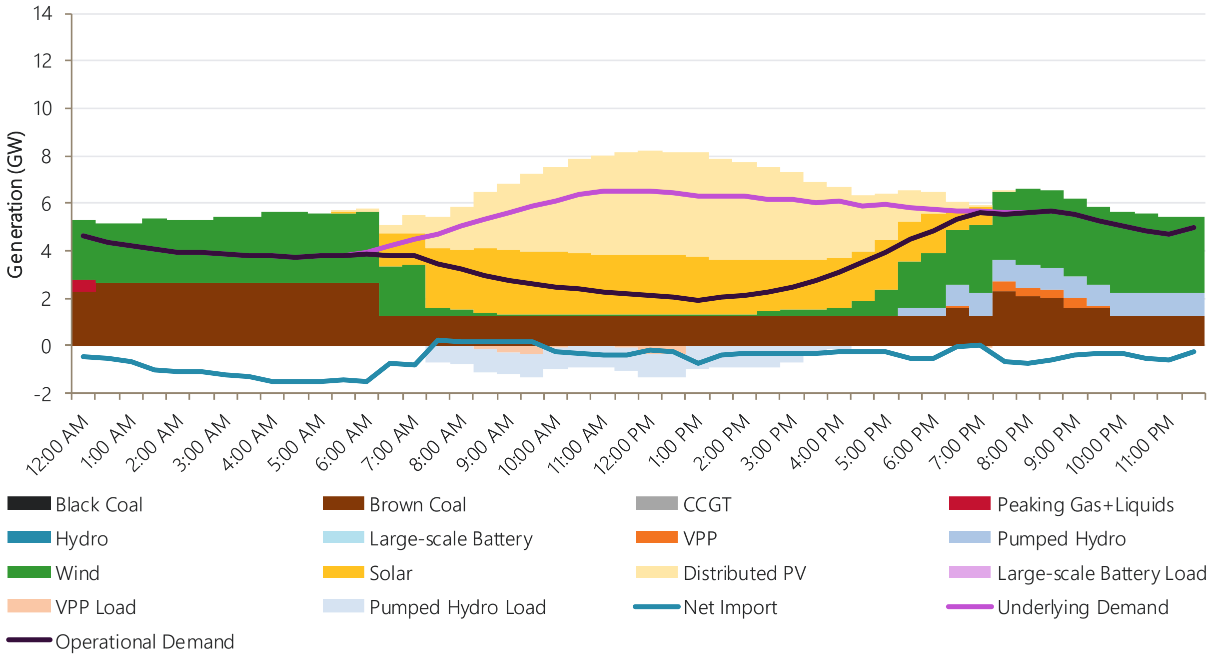


Figure 71 Victoria – forecast minimum operational demand 29/01/2040, Central scenario



Maximum operational demand of 10,114 MW is forecast to occur on 19 January 2040 at 1900 hours. Minimum operational demand of 1,946 MW is forecast to occur less than a month later on 29 January 2040 at 1330 hours. Observations include:

- Rooftop PV in Victoria has grown so much by 2040, that the minimum operational demand occurs in January, rather than in winter or shoulder periods as would previously be expected.
- Pumped hydro forms a smaller part of the supply mix within Victoria relative to other regions. Victoria instead relies on strong interconnectors with storages in Tasmania and the Snowy scheme to shift any excess of VRE that may occur.
- During the middle of the day on the minimum demand day, the existing coal fleet drops to minimum stable levels.

4.5.4 South Australia

Figure 72 South Australia – Forecast maximum operational demand 19/01/2040, Central scenario

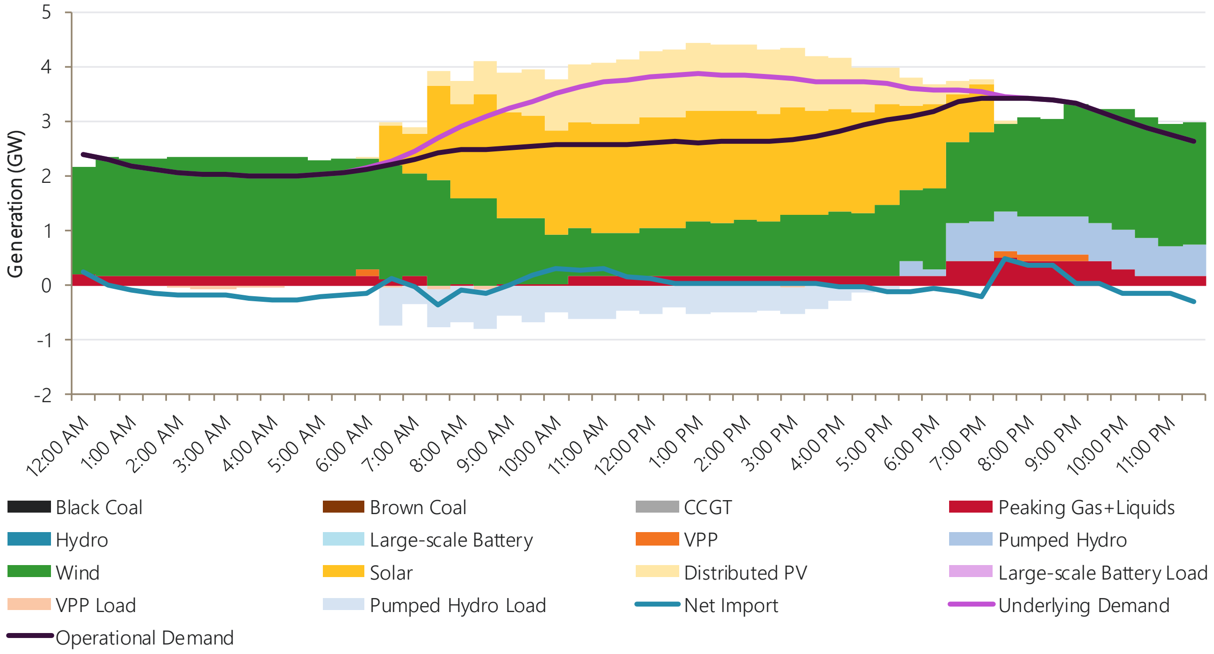
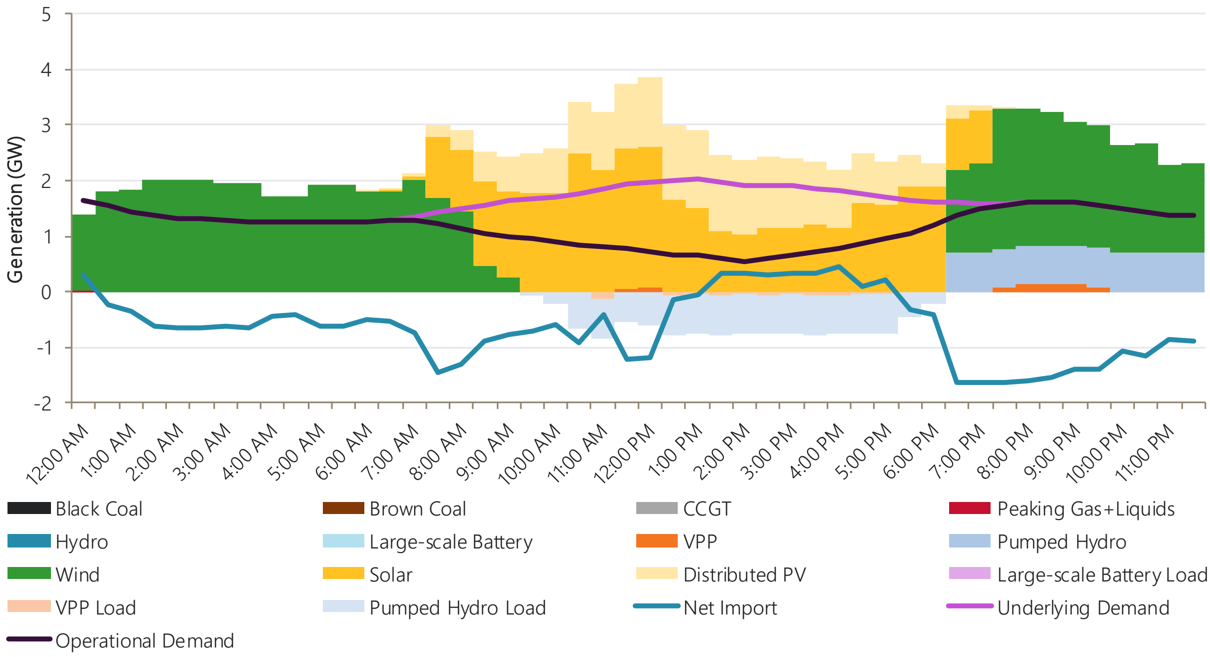


Figure 73 South Australia – Forecast minimum operational demand 19/02/2040, Central scenario



Maximum operational demand of 3,421 MW is forecast to occur on 19 Jan 2040 at 1900 hours. Minimum operational demand of 553 MW is forecast to occur on 19 February 2040 at 1400 hours. Observations include:

- GPG peaking plant operate at low levels through the afternoon of the maximum demand day to ensure there is sufficient energy in pumped hydro storage and batteries to meet the evening demand peak, at which point generation from peaking plant and storages ramp up to help meet this peak.
- Note the wind curtailment occurring in the middle of the day during the minimum demand day (evidence by lack of wind), as the low operational demand means that not all available renewable generation is required in South Australia, and surplus generation is also not needed in Victoria or New South Wales. No synchronous generation is online at this time.

4.5.5 Tasmania

Figure 74 Tasmania – Forecast maximum operational demand 24/08/2039, Central scenario

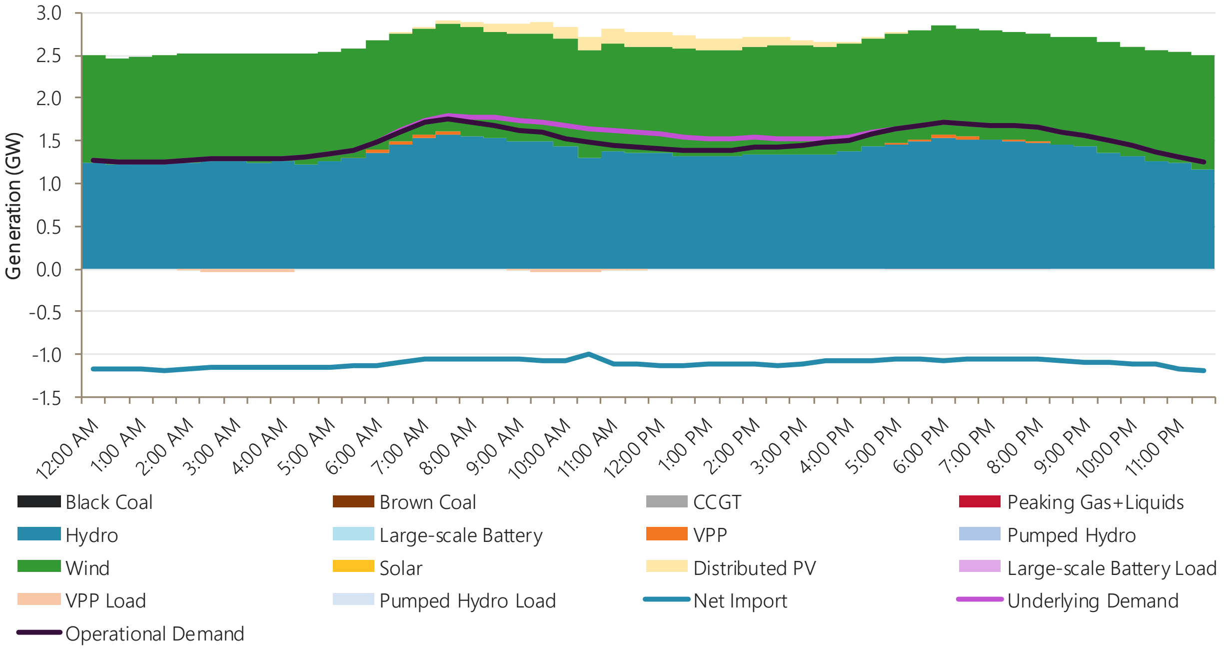
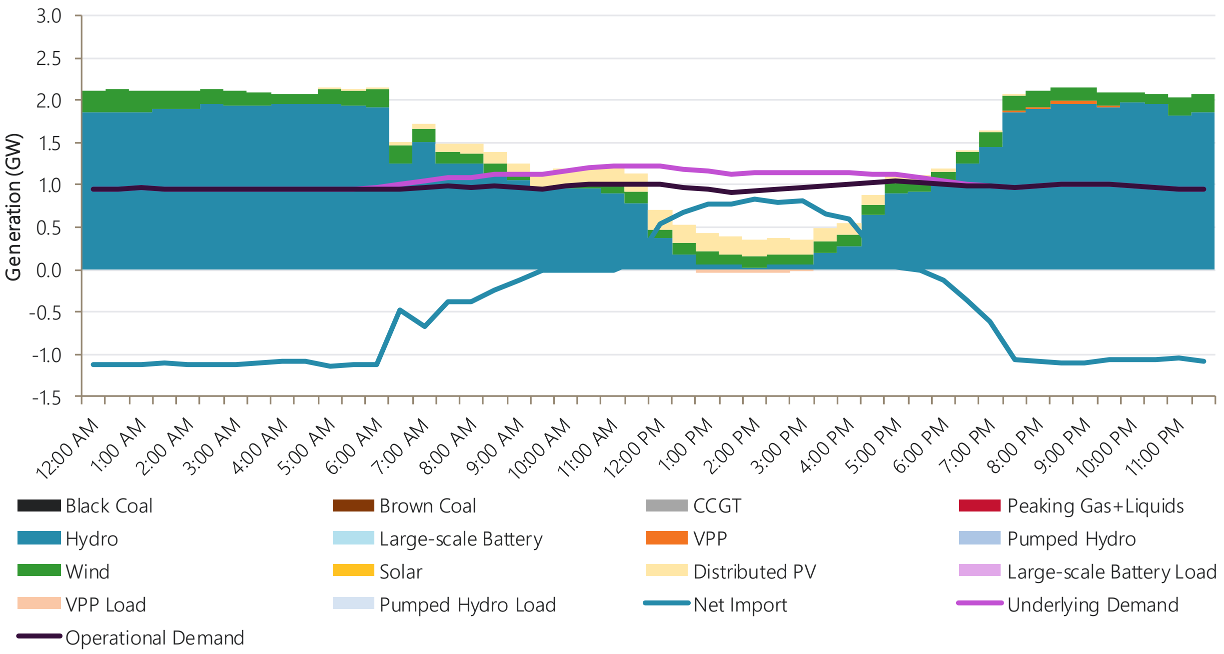


Figure 75 Tasmania – Forecast minimum operational demand 26/12/2039, Central scenario



Maximum operational demand of 1,758 MW is forecast to occur on 24 August 2039 at 0800 hours. Minimum operational demand of 918 MW is forecast to occur on 26 December 2035 at 1330 hours. Observations include:

- Typically, on a maximum demand day, Tasmania still has surplus generation to export energy to the mainland.

- On a minimum demand day, the region is able to take advantage of low demand and excess energy from the mainland, with little regional generation.

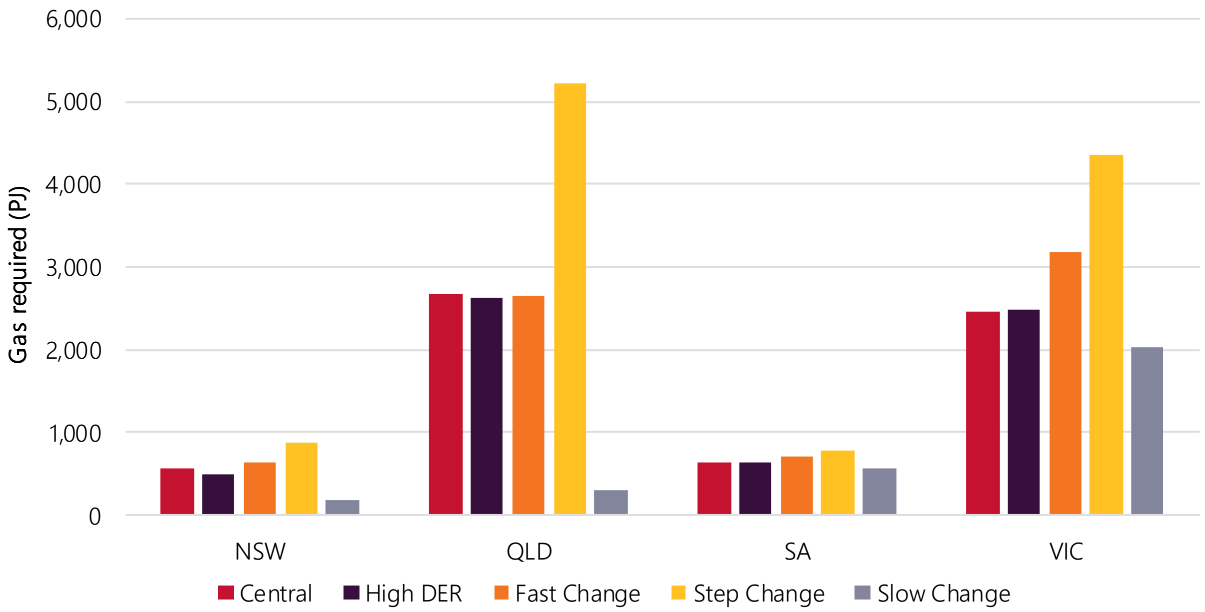
4.6 Gas development in Eastern and South Eastern Australia

Development of new sources of gas beyond currently existing or committed projects will be required to meet gas demand across eastern and south eastern Australia by residential, commercial, and industrial gas consumers, gas for LNG export, and gas supply for GPG.

As highlighted in the 2019 GSOO, existing southern gas reserves are in decline, and more development is required in the southern states as early as 2023 to ensure that all forecast demand is met. This development could relate to a new field development or an LNG import terminal, and associated pipelines to deliver the gas to market.

Figure 76 below shows the quantities of gas in PJ beyond currently existing and committed projects that are projected to be required to meet forecast gas demand out to 2040 under all five scenarios, and the projected location of these new gas sources, based on AEMO's integrated ISP Model outcomes (see Appendix 9).

Figure 76 New sources of gas projected to be required out to 2040 in each region under all scenarios



These forecasts highlight that at least 200 PJ of new gas and associated production will need to be developed each year between 2025 and 2037. From that point, major Queensland reserves are expected to decline, and will need to be replaced with currently contingent or prospective resources so forecast LNG exports will be met through the 2040s.

Figure 77 Annual quantities of gas from fields not currently existing or committed, to be produced to meet gas consumption forecasts to 2040

GPG gas consumption can vary significantly from year to year and is highly influenced by the generation mix in the NEM and the level of interconnection between regions. The gas consumption forecasts for the optimal development path have been tested under the Central scenario against two counterfactuals:

- No new interconnectors, beyond existing transmission capacity.
- No new interconnectors, beyond the no-regret grid projects identified in Part C of the Draft ISP.

Under the first counterfactual, the forecast additional GPG beyond the optimal development path would require a further 30 PJ per annum of extra gas from 2023-24, over and above the 200PJ increase in annual supply already identified under the optimal development path.

If the no-regret grid projects go ahead, then the forecast additional GPG beyond the optimal development path is minimal before 2035, and reaches a maximum impact of 21 PJ in 2039.

Figure 78 Forecast additional gas required for GPG beyond the Central scenario optimal development path if no interconnector development

Appendix 5. Cost benefit analysis

The Draft ISP reveals how targeted investment in new transmission:

- Provides net market benefits, minimises overall system cost and supports consumer value.
- Manages and facilitates the transition to an affordable power system with significant VRE and DER. This transition includes:
  - Connecting REZs where wind and solar resource quality is high.
  - Increasing the capability to share diverse resources between regions of the NEM, and replacing energy and system security services traditionally provided by thermal plant.
  - Providing security and resilience to manage new power system risks and the impacts of climate change.
  - Incorporating the benefits available from DER.

The projected portfolio of new resources involves substantial amounts of geographically dispersed renewable generation, placing a greater reliance on the role of the transmission network. Investment in the transmission network will be needed to efficiently connect and share these low fuel cost resources.

Making the right investments will provide flexibility, security, and economic efficiency because the power system is taking maximum advantage of existing resources, integrating VRE, and supporting efficient competitive alternatives for consumers.

This appendix provides additional detail about how AEMO modelled potential development paths under the range of five plausible future scenarios, to identify the optimal path that is projected to deliver net market benefits while also minimising potential regret, given the uncertainties facing decision-makers.

5.1 Method for identifying the optimal development path

All investors, policy-makers, and industry stakeholders must make decisions while being uncertain about policy, market, and technical outcomes. AEMO's approach in the 2020 ISP is to minimise the potential regrets associated with decisions that are made in the face of uncertainty.

To apply this method, AEMO has forecast the potential resource developments for each of the defined scenarios, and a subset of the sensitivities, across a range of decisions relating to the scale and timing of transmission infrastructure. The model seeks to minimise costs to consumers and maximise operational efficiency for the industry.

In reality, decision-making is dynamic to the best information available at the time a choice is made. Several decision gateways can exist across an investment that may provide opportunity to adjust to a better investment pathway when more information is available at a later time.

As outlined in the Draft ISP Report, AEMO has identified the optimal development path using the following steps:

1. Determine the optimal path under each scenario separately.

- AEMO has simulated many different pathways involving different timing and transmission combinations, to identify the optimal path for each scenario separately. Sample iterations of this approach are shown in the figure below, with each row representing a simulated interconnector combination.

Figure 79 Example of optimal pathway iterations

QNI Minor	VNI Minor	Energy Connect	Humelink	QNI 2E	QNI 3D	QNI 3E	VNI 6	VNI 7	MarinusLink 1st cable	MarinusLink 2nd cable
2022-23	2022-23	2023-24	2025-26	2028-29		2031-32		2031-32	2036-37	
2022-23	2022-23	2023-24	2025-26	2028-29		2031-32	2031-32		2036-37	
2022-23	2022-23	2023-24	2025-26	2028-29				2031-32	2036-37	
2022-23	2022-23	2023-24	2025-26		2028-29			2031-32	2036-37	
2022-23	2022-23	2023-24	2025-26	2026-27		2031-32		2031-32	2036-37	
2022-23	2022-23	2023-24	2025-26		2031-32			2026-27	2036-37	
2022-23	2022-23	2023-24	2025-26	2028-29		2031-32		2028-29	2036-37	
2022-23	2022-23	2023-24	2025-26	2026-27				2031-32	2036-37	
2022-23	2022-23	2023-24	2025-26	2028-29		2031-32		2026-27	2036-37	
2022-23	2022-23	2023-24	2025-26	2026-27		2031-32		2028-29	2036-37	
2022-23	2022-23	2023-24	2025-26		2028-29			2028-29	2036-37	
2022-23	2022-23	2023-24	2025-26		2026-27			2031-32	2036-37	
2022-23	2022-23	2023-24	2025-26		2028-29			2026-27	2036-37	
2022-23	2022-23	2023-24	2025-26	2028-29		2031-32		2031-32	2026-27	
2022-23	2022-23	2023-24	2025-26		2028-29			2031-32	2026-27	
2022-23	2022-23	2023-24	2025-26		2028-29			2036-37	2026-27	
2022-23	2022-23	2023-24	2025-26	2028-29		2031-32		2028-29	2026-27	
2022-23	2022-23	2023-24	2025-26	2026-27		2031-32		2028-29	2026-27	
2022-23	2022-23	2023-24	2025-26		2026-27			2031-32	2026-27	
2022-23	2022-23	2023-24	2025-26							
2022-23	2022-23	2023-24	2025-26		2026-27				2026-27	
2022-23	2022-23	2023-24	2025-26		2028-29			2026-27	2026-27	
2022-23	2022-23	2023-24	2025-26	2026-27		2031-32		2028-29	2026-27	2031-32

2. Apply five alternative candidate development paths to identify generation developments and system costs.
3. Identify generation developments and system costs for a counterfactual, for each scenario, which does not involve interconnection transmission developments.
4. Determine net market benefits by comparing system costs in 2) against the counterfactual, per scenario, in 3).
5. Determine scenario regret costs by comparing system costs under 2) against optimal system costs under 1) for each scenario.
6. Choose the least worst regret decision as the optimal development path that delivers a positive net market benefit in the Central Scenario.

5.2 The benefits of the optimal development path

Using the approach described above, the optimal development path outlined in the Draft ISP includes:

- Developing priority transmission projects:
  - QNI Minor in 2022-23.
  - VNI Minor in 2022-23.
  - Project EnergyConnect in 2023-24.
  - Western Victoria transmission augmentation in 2024-25.
  - HumeLink in 2025-26.
- Actioning work to develop:
  - QNI Medium transmission project by 2026-27 to 2028-29.
  - VNI West transmission project by 2026-27, to mitigate the risks of early coal-plant closures.
  - Marinus Link between 2026-27 and 2036-27.

Additionally, early works to enable the Marinus Link to be 'shovel ready' should be progressed to increase optionality if this interconnector needs to be accelerated in future.

These projects will increase access to REZs across the NEM.

The 2020 Draft ISP outlines signposts that may be observed over the coming years which may assist future decision-making about these continued investments.

This section outlines the annual benefits and costs of each scenario under the 'Accelerated VNI West and Shovel Ready Marinus Link' development path, in comparison to an outlook with no new interconnector developments.

No interconnector developments counterfactual

To identify the benefits of the transmission projects associated with the ISP's optimal development path, AEMO has forecast counterfactuals for each scenario that limit transmission investment:

- **No new transmission** – this case examines the generation development response and system costs without the development of inter-regional transmission corridors. *This was the counterfactual presented in the 2018 ISP*.
- **No incremental investments in transmission beyond no-regret projects** – this case examines the generation development response and system costs without transmission projects beyond the no-regret projects which were found to be beneficial in all scenarios, and hence are common to all candidate development paths, specifically:
  - QNI Minor.
  - VNI Minor.
  - HumeLink.
  - Project EnergyConnect.

5.2.1 Central scenario

Without transmission investment, a significant development of new generation resources is projected to be required to replace retiring aging assets across the NEM. The cost of this development is shown in the figures below, which present the net difference between the Accelerated VNI West and Shovel Ready Marinus Link pathway and the no new transmission counterfactual.

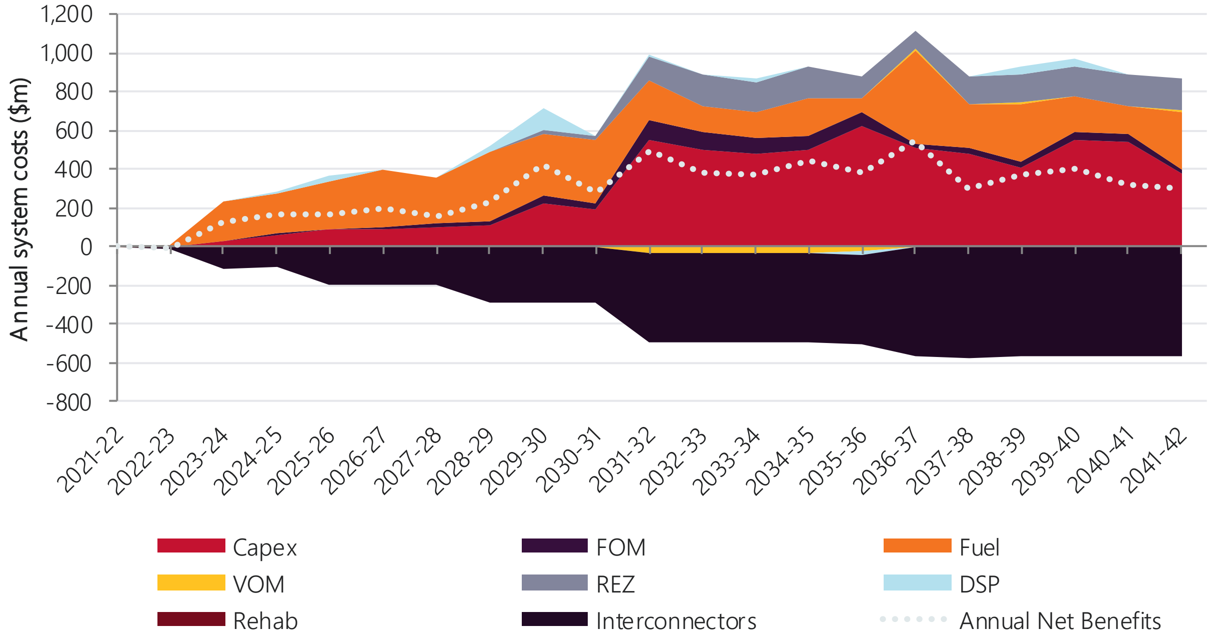
In these figures, positive numbers show that a higher proportion of that class of costs is forecast in the no transmission counterfactual, and negative numbers indicate that a greater proportion of that class of costs is forecast in the optimal development path. As an example, in Figure 80:

- The optimal development path projects much greater interconnector development costs, rising to approximately $565 million a year by 2040 (represented as a negative benefit in the figure).
- The counterfactual projects a material increase in capital expenditure, as a response to the limited ability to share resources across regions without further interconnection, reaching approximately $555 million a year in 2040 (represented as positive benefits, or cost savings, in the figure).

When the outcomes for each component are combined, the net annual benefits can be quantified, represented by the dotted line. By the end of the outlook period, the interconnectors are forecast to provide a net benefit of approximately $300-400 million a year.

Under the Central scenario, the net benefits from the introduction of further interconnection accrue materially from 2023-24, resulting in a net benefit of at least $120 million a year, primarily driven by fuel cost savings and capital deferral related to delaying firming thermal generation developments. This gradual trend in fuel cost savings and capital deferral continues through to 2032, at which time significant thermal retirements will accelerate across the NEM, requiring a stronger regional generation and storage development response (red area in figure) were greater energy sharing between regions not available.

Figure 80 Forecast optimal development path net annual benefits to 2041-42, Central scenario



Note: The annual system costs in the figure do not include the costs associated with the development of Marinus Link or VNI West as "shovel ready". In this scenario, the shovel ready costs associated with Marinus Link are presented in the accompanying table.

Figure 81 and Table 8 provide summaries of the total net benefits to 2041-42 of the optimal development path in comparison to the counterfactual, in net present value (NPV) terms. This shows that a $3.3 billion (in NPV terms) investment in the optimal development path interconnectors and early works for MarinusLink is forecast to provide $5.8 billion of market benefits in the form of cost savings. Much of this benefit is due to greater use of low fuel cost generation, lowering overall fuel costs ($2.2 billion), as well as reducing capital costs associated with generation developments ($2.6 billion). Net market benefits of $2.5 billion are delivered from this optimal development path.

Figure 81 Forecast NPV of total costs to 2041-42, comparing optimal development path to counterfactual, Central scenario

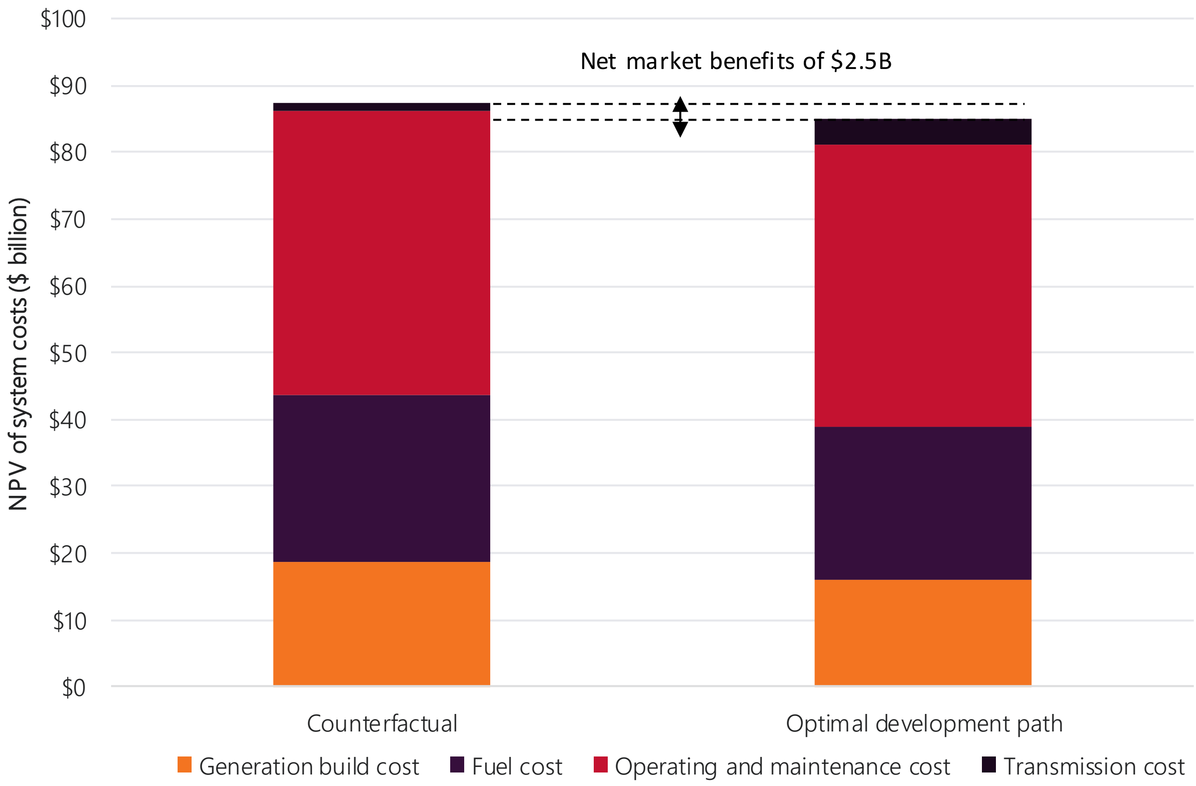


Table 8 Net market benefits of optimal development path by category, Central scenario

Benefit category	Net Benefit ($M)
Capex	$2,554
FOM	$317
Fuel	$2,248
VOM	-$87
DSP (may include USE below the current reliability standard)	$136
REZ	$598
Gross Market Benefits	$5,766
Interconnectors	-$3,220
Shovel Ready Costs / Bring Forward Costs	-$45
Total Net Benefits	$2,501

These benefits are accrued due to the differences in the generation technologies developed and operated between the optimal development path and the no transmission counterfactual outcomes for the Central scenario (see Figure 82). Without interconnection to share geographically diverse renewable resources, there is an increased need for GPG to provide firming capacity, and an increased need for additional local energy storages across the NEM.

Figure 82 Forecast capacity developments to 2041-42 for the optimal development path compared to no interconnectors, Central scenario

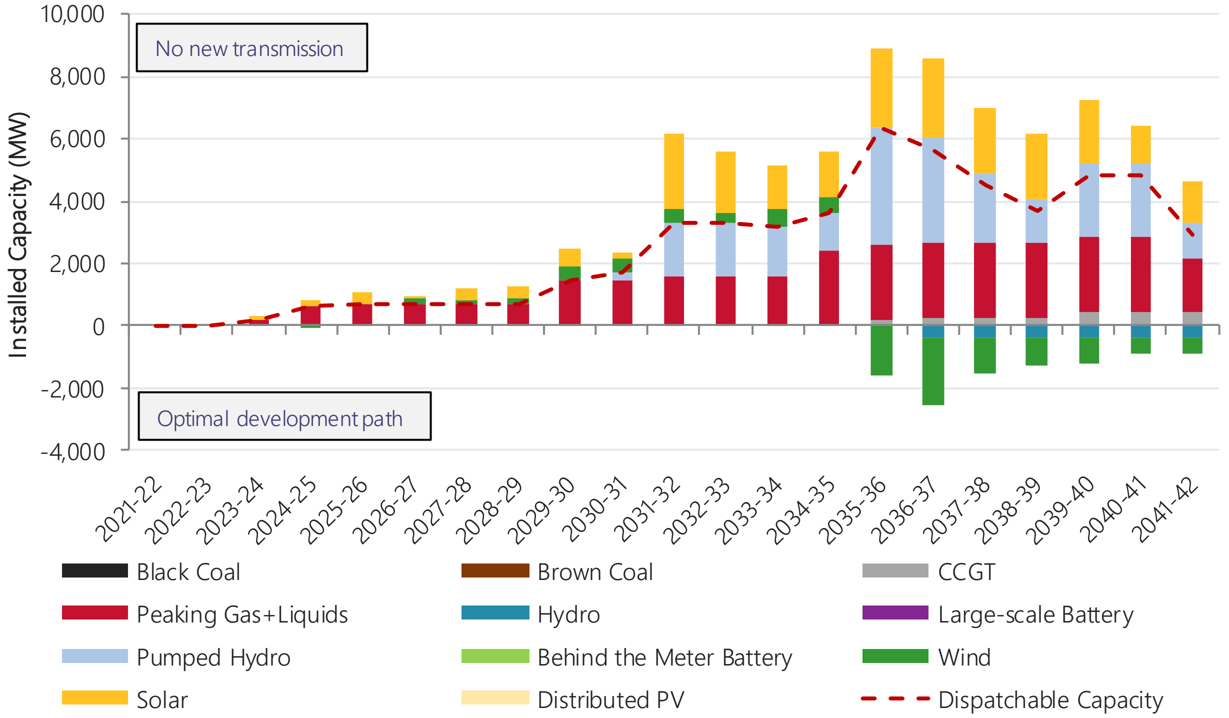
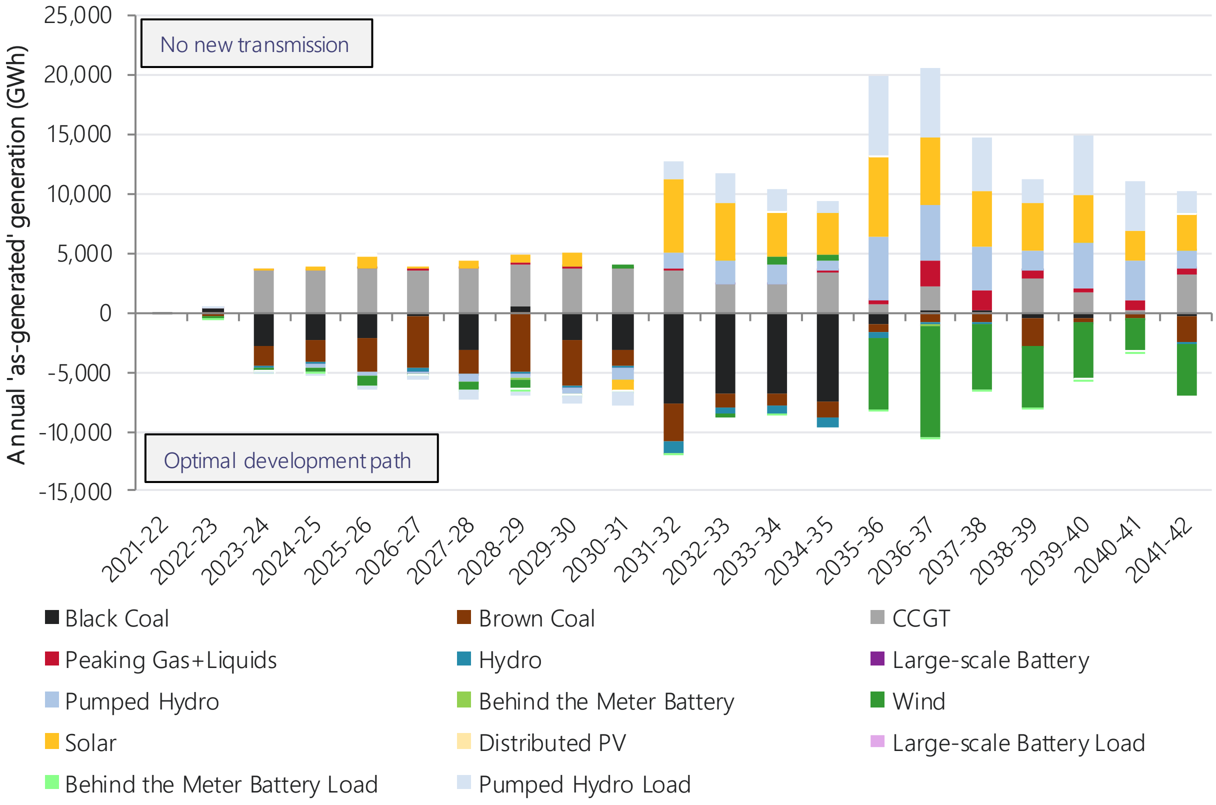


Figure 83 presents the generation production outcomes between the two pathways, and highlights – through the greater use of lower cost fuel sources – the benefits forecast to be associated with further interconnection. Positive values in this figure mean there is more generation of that technology type in the counterfactual whereas negative values meant there was less.

Initially, from 2023-24 to 2030-31, the fuel cost savings are attributed to the greater utilisation of low fuel cost coal generation under the optimal development path, in comparison to higher cost gas generation in the counterfactual. Once coal generation retires, greater utilisation of GPG is needed in the counterfactual, while the optimal development path would enable more efficient use of wind generation.

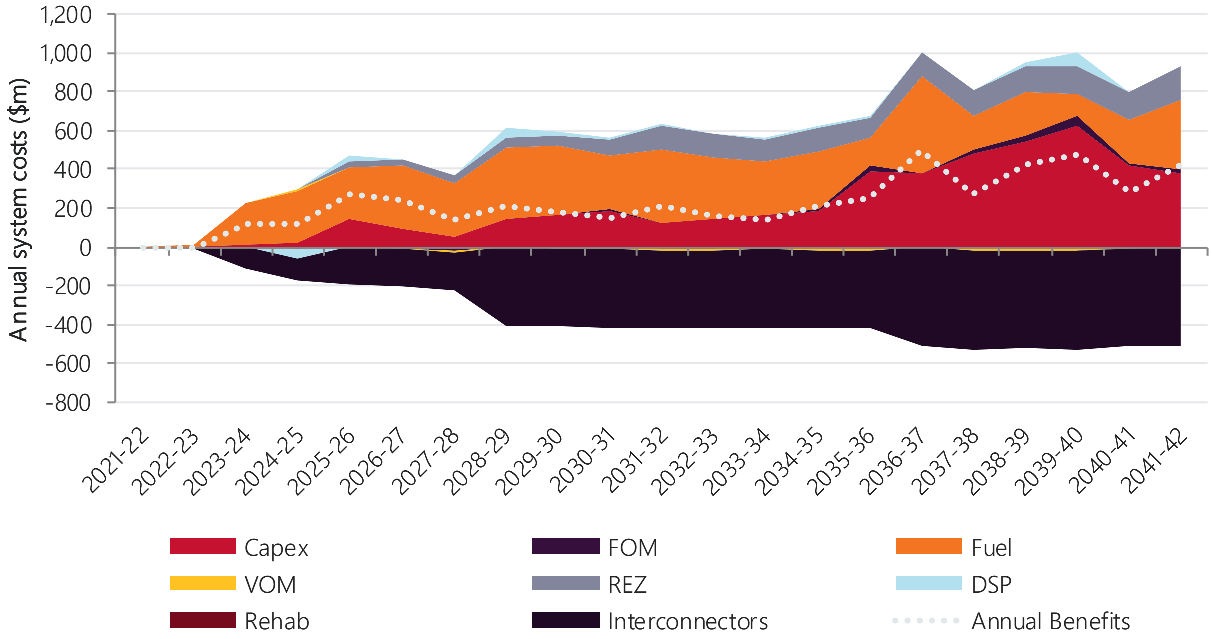
Figure 83 Forecast generation outcomes to 2041-42 for the optimal development path compared to no interconnectors, Central scenario



5.2.2 Fast Change

Similar to the Central Scenario, the benefits of the optimal development path in the Fast Change scenario are associated primarily with fuel and capital deferral savings. This scenario includes more VRE geographical diversity across NEM regions and therefore utilises the transmission system differently to the Central Scenario. Likewise, the relative net market benefits of the optimal development paths are lower in this scenario than the Central Scenario. The benefits are marginally lower than the Central Scenario, because the forecast greater regional VRE diversity and greater DER deployment reduces the relative reliance on transmission to share resources, thereby lowering the projected impact on capital expenditure in particular, relative to the Central Scenario.

Figure 84 Forecast optimal development path net annual benefits to 2041-42, Fast Change scenario



Note: The annual system costs in the figure do not include the costs associated with the development of Marinus Link or VNI West as "shovel ready". In this scenario, the shovel ready costs associated with Marinus Link are presented in the accompanying table.

Table 9 provides a summary of the total net market benefits of the optimal development path in comparison to the counterfactual for the Fast Change scenario. This shows that an interconnection investment of $3.0 billion in NPV terms to 2041-42 provides $2.0 billion of net market benefits through the more efficient use of fuel ($2.6 billion) and generation developments ($1.8 billion).

Table 9 Net benefits of optimal development path, Fast Change scenario

Benefit category	Net Benefit ($M)
Capex	$1,761
FOM	$18
Fuel	$2,558
VOM	-$62
DSP (may include USE below the current reliability standard)	$68
REZ	$664
Gross Market Benefits	$5,007
Interconnectors	-$2,980
Shovel Ready Costs / Bring Forward Costs	-$45
Total Net Benefits	$1,982

Figure 85 presents the generation development outlook differences between the optimal development path and counterfactual outcomes for the Fast Change scenario. As observed in the net benefit outcomes from

Figure 84, the difference is attributed to the deferred need for approximately 2,000 MW of GPG and 700 MW of energy storages by 2025-26. The development of this dispatchable capacity grows in the counterfactual to replace aging coal generation. The relative costs of these developments result in an increasing benefit for the transmission pathway. With the reduced ability to share firming resources across regions in the counterfactual outlook, a greater reliance on a combination of solar and storage is projected to be required to meet demand requirements.

Figure 85 Forecast capacity developments to 2041-42 for optimal development path compared to no interconnectors, Fast Change scenario

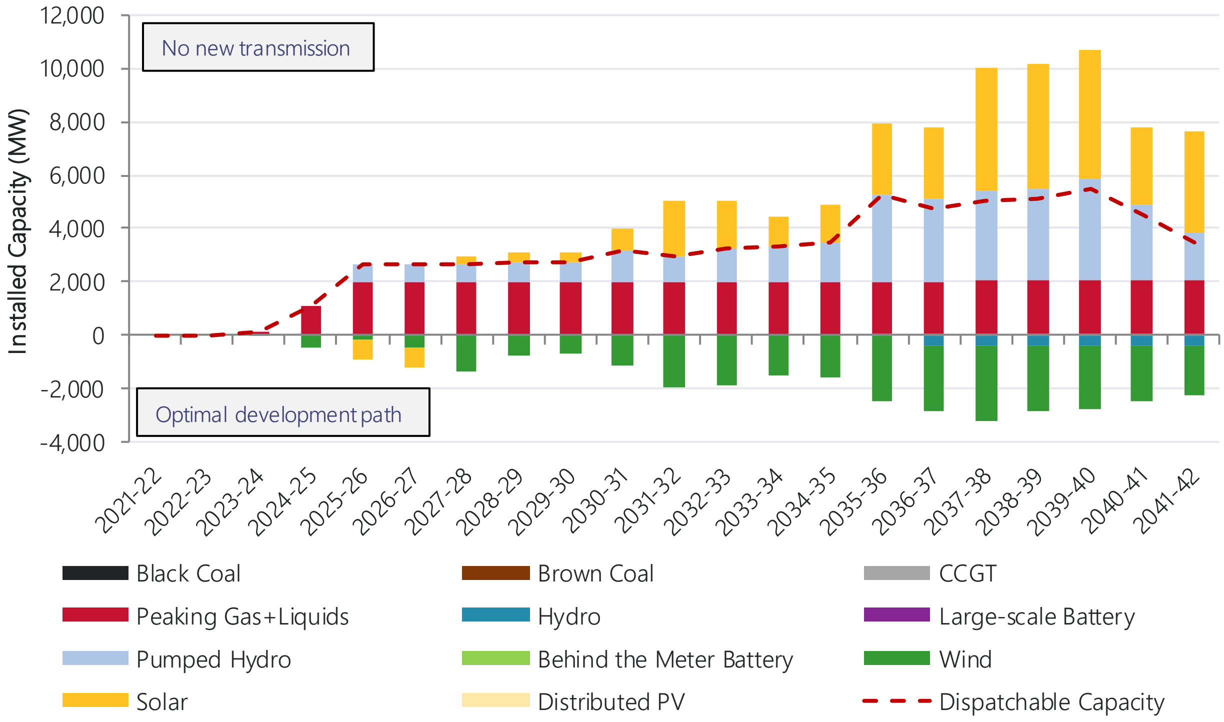
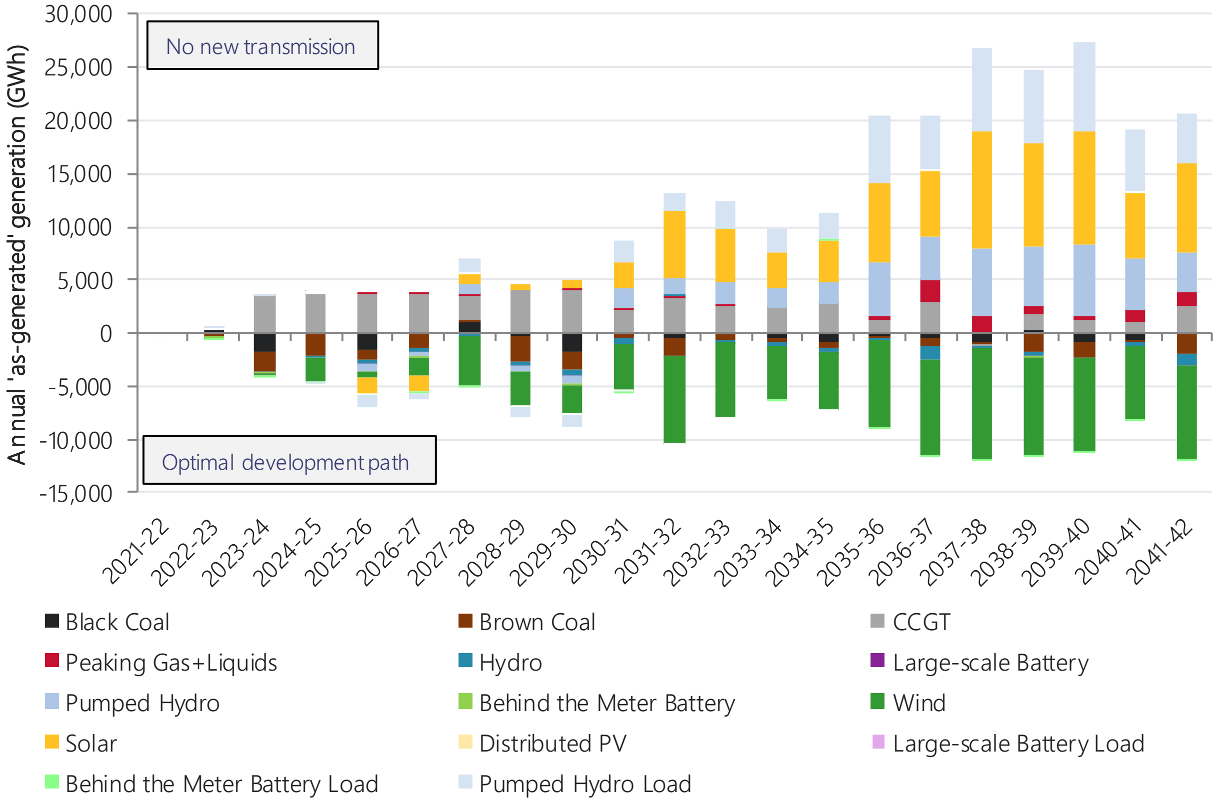


Figure 86 presents the generation production outcomes between the two interconnector pathways. In this scenario, the optimal development path enables greater diversity of VRE, with more wind generation and a lesser need for GPG to operate.

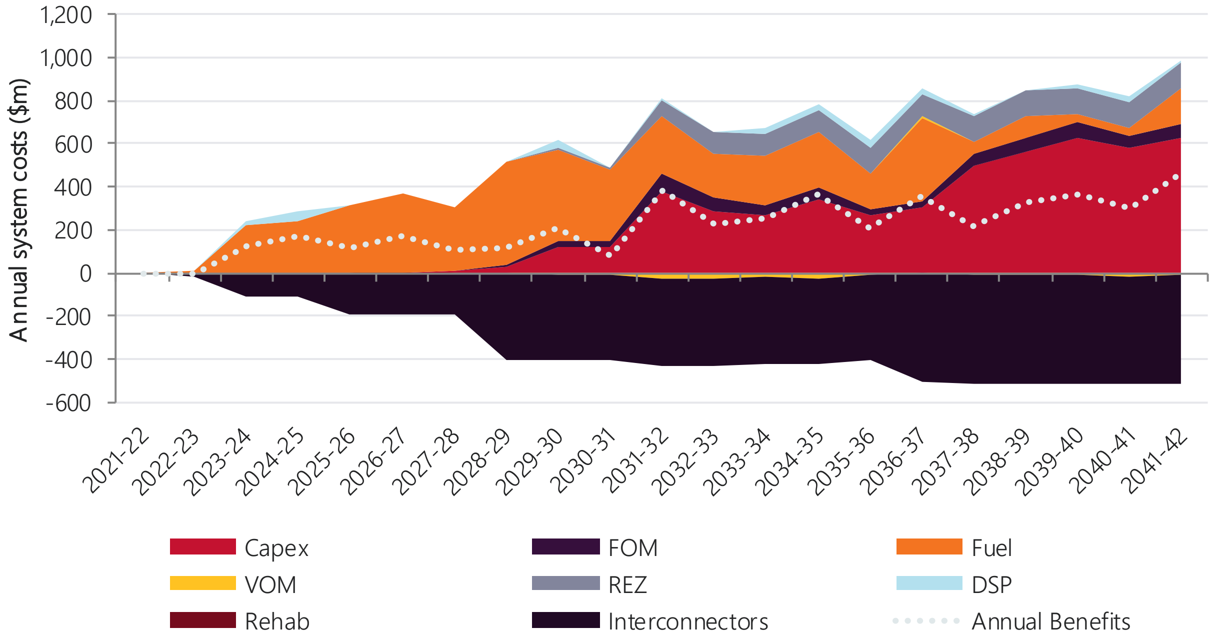
Figure 86 Forecast generation outcomes to 2041-42 for optimal development path compared to no interconnectors, Fast Change scenario



5.2.3 High DER

The High DER scenario with the optimal development path shows positive annual benefits due to projected savings in fuel costs, following by reduced investments in new generation capacity that would be required locally to replace aging assets. This is similar to the trend in the Central scenario. This scenario has much greater volumes of DER, and lower grid demand lowers the relative benefits of the pathway relative to some other scenarios. In this scenario, net benefits in NPV terms to 2041-42 amount to almost $1.9 billion, as shown in Figure 87 and Table 10.

Figure 87 Forecast optimal development path net annual benefits to 2041-42, High DER scenario



Note: The annual system costs in the figure do not include the costs associated with the development of Marinus Link or VNI West as "shovel ready". In this scenario, the shovel ready costs associated with Marinus Link are presented in the accompanying table.

The total net market benefits of the optimal development path in comparison to the counterfactual for the High DER scenario shows that an interconnection investment of $3.0 billion in NPV terms to 2041-42 provides $1.9 billion of net benefits through the more efficient use of fuel ($2.4 billion) and generation developments ($1.8 billion).

Table 10 Net benefits of optimal development path, High DER scenario

Benefit category	Net Benefit ($M)
Capex	$1,780
FOM	$251
Fuel	$2,362
VOM	-$67
DSP (may include USE below the current reliability standard)	$121
REZ	$441
Gross Market Benefits	$4,888
Interconnectors	-$2,980
Shovel Ready Costs / Bring Forward Costs	-$45
Total Net Benefits	$1,863

Figure 88 presents the differences in projected installed capacity in the High DER scenario with the optimal development path against the no interconnector development counterfactual. The forecast capacity response is more muted than other scenarios, given the much higher level of consumer developments, reducing some need for grid-scale solutions.

The projected impact on the generation mix is outlined in Figure 89. In the first years of the study period, the early delivery of the optimal development path is forecast to enable increased operation from the low-cost brown coal fleet.

Figure 88 Forecast capacity developments to 2041-42 for optimal development path compared to no interconnectors, High DER scenario

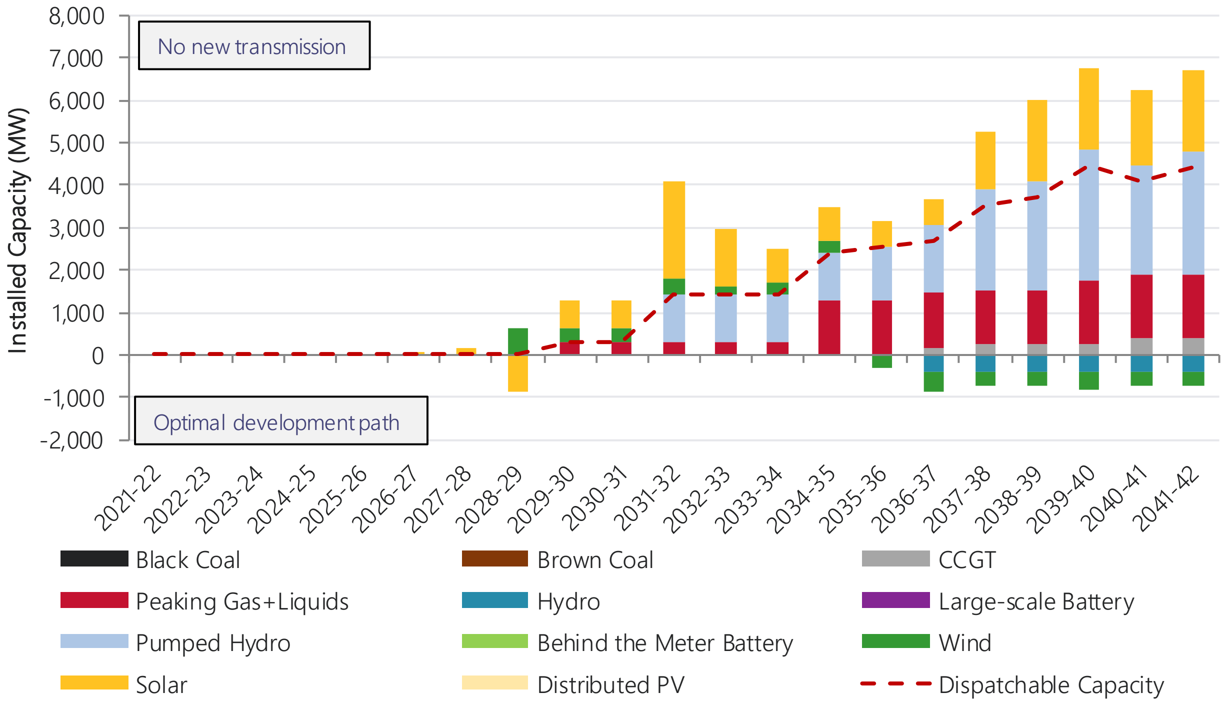
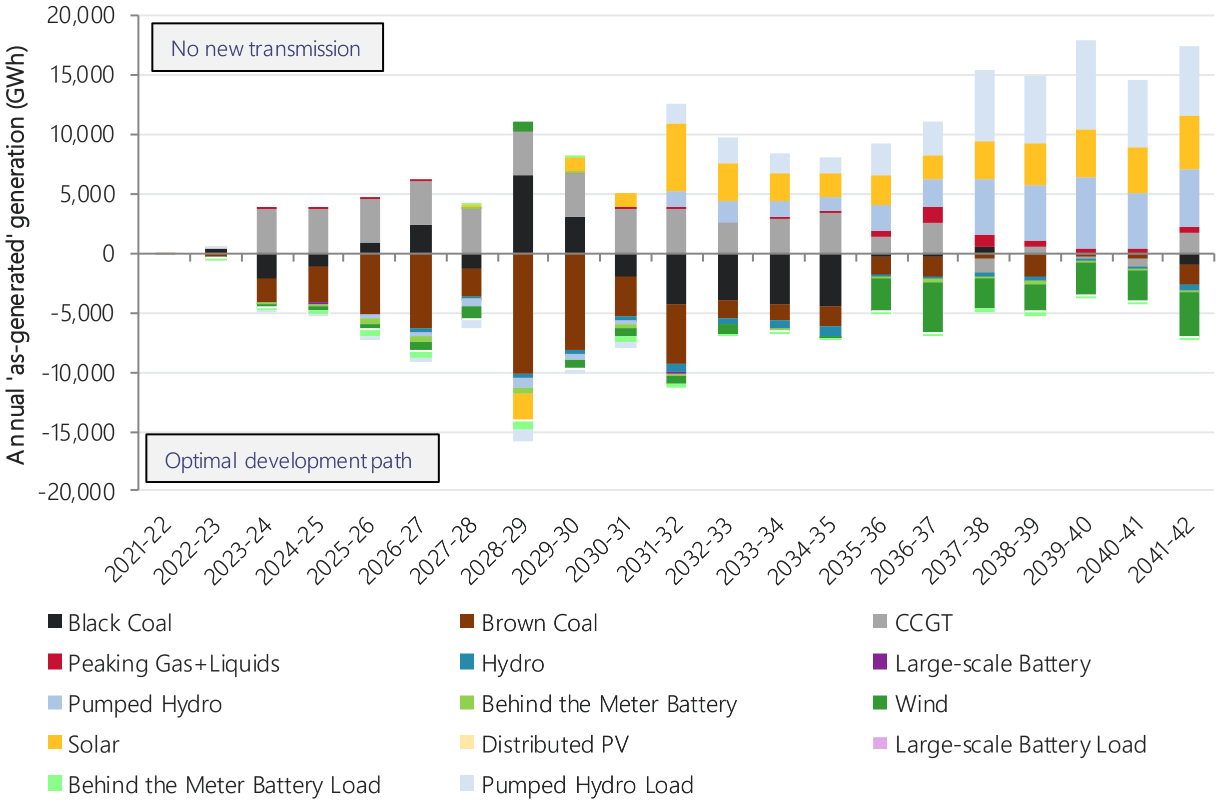


Figure 89 Forecast generation outcomes to 2041-42 for optimal development path compared to no interconnectors, High DER scenario



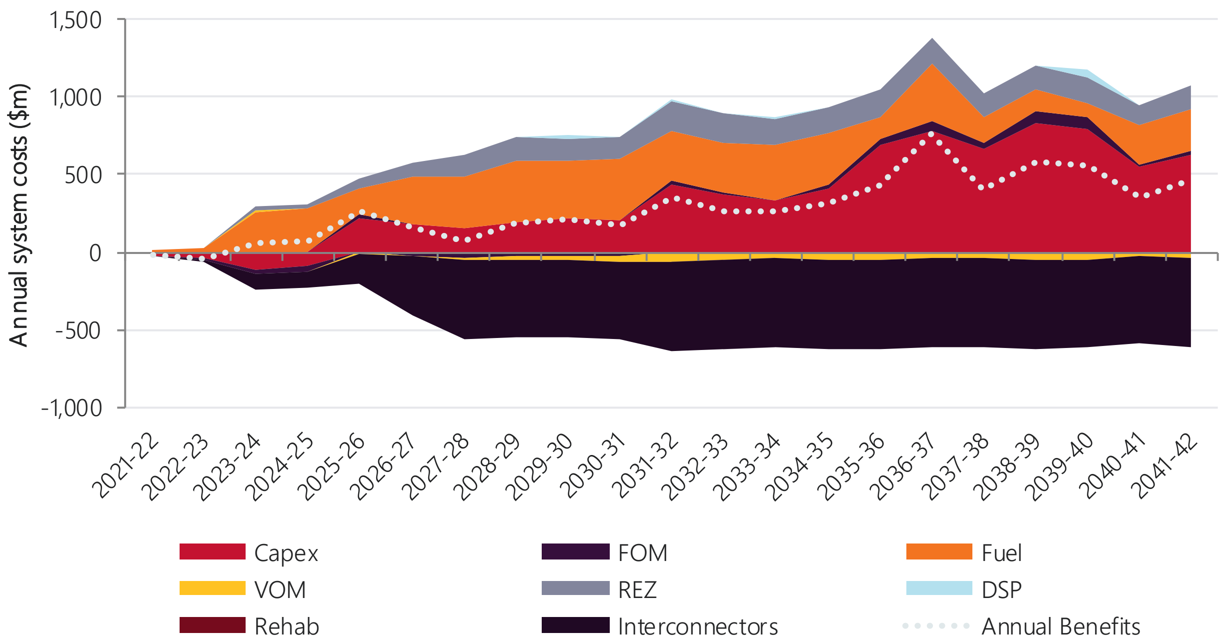
5.2.4 Step Change

The Step Change scenario under the optimal development path displays the highest benefits of increased transmission between southern regions of the NEM among all candidate pathways studied, with net benefits in NPV terms to 2041-42 reaching over $2.3 billion.

As shown in Figure 90, net benefits are forecast to grow steadily, chiefly driven by savings in the capital cost of generation investments ($2.7 billion) and fuel costs ($2.6 billion). Interconnector costs in the Step Change scenario are also the greatest among all the studied scenarios, eventually peaking at over $500 million per annum from 2031-32 with the completion of both stages of the Marinus Link project.

The Step Change scenario projects significant net benefits from pursuing an additional link between the mainland and Tasmania from 2026-27 (the only scenario to project benefits for both stages), and provides maximum resilience to potential closure risks associated with economic, technical or policy pressures with stronger connectivity between New South Wales, Victoria and Tasmania.

Figure 90 Forecast optimal development path net annual benefits to 2041-42, Step Change scenario



A breakdown of the net benefits in NPV terms is provided in Table 11[17]. While capital expenditure and fuel cost benefits are projected to be the main value streams, benefits are also forecast to be accrued from lower costs associated with expansion of REZs as well as savings in reliability costs.

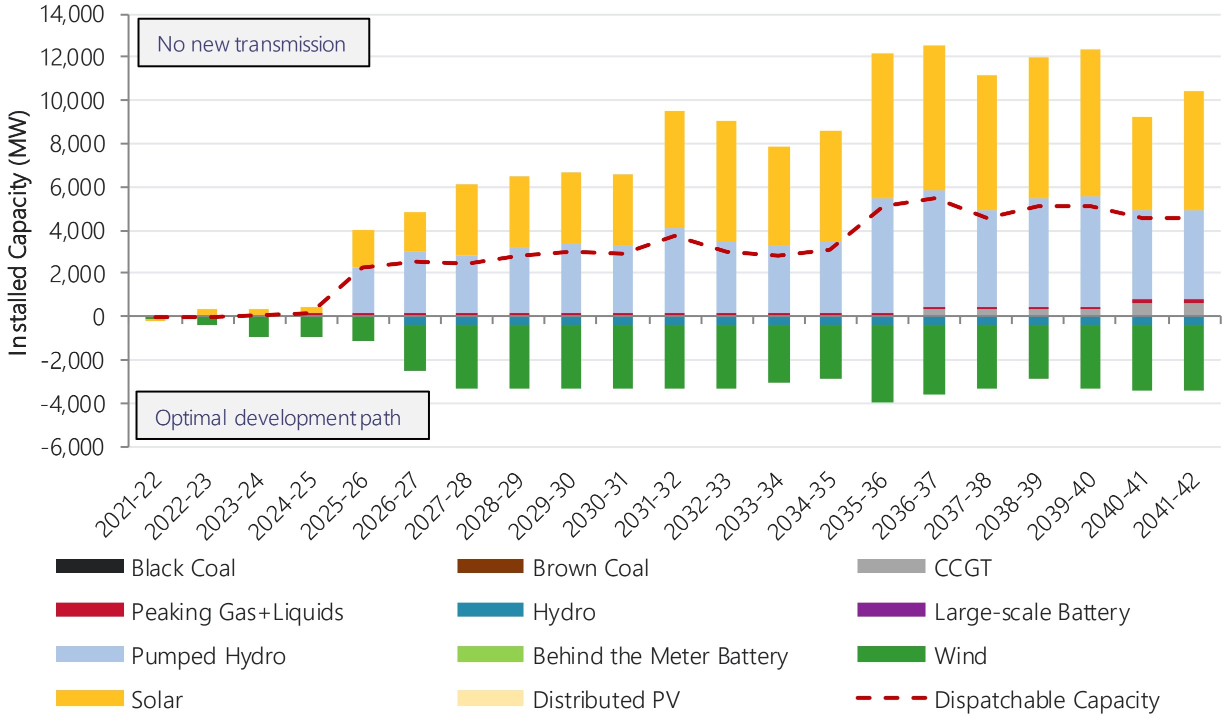
Table 11 Net benefits of optimal development path, Step Change scenario

Benefit category	Net Benefit ($M)
Capex	$2,739
FOM	$27
Fuel	$2,585
VOM	-$243
DSP (may include USE below the current reliability standard)	$46
REZ	$1,133
Gross Market Benefits	$6,287
Interconnectors	-$3,948
Shovel Ready Costs / Bring Forward Costs	$0
Total Net Benefits	$2,339

[17] Note: The annual system costs in the figure do not include the costs associated with the development of Marinus Link or VNI West as "Shovel Ready". In this scenario, no early works prior to construction are assumed as the accelerated development of both VNI West and Marinus Link in the next decade is forecast to be needed.

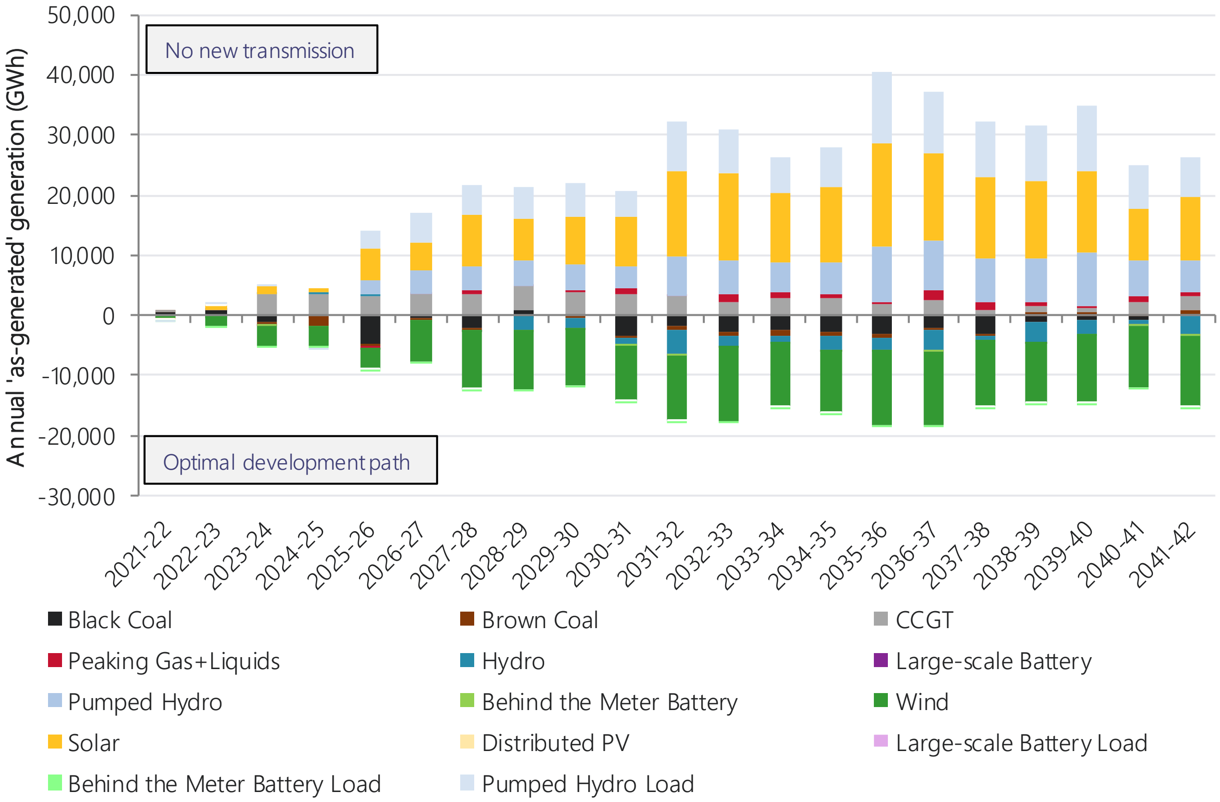
Figure 91 presents the differences in forecast capacity development under the Step Change scenario between the two different pathways. Under the optimal development path, complemented by Marinus Link, generation expansion is projected to rely on a higher share of wind resources and hydro availability. Conversely, lack of interconnector development is forecast to increase the need for new dispatchable generation, in the form of pumped hydro complemented by solar.

Figure 91 Forecast capacity developments to 2041-42 for optimal development path compared to no interconnectors, Step Change scenario



The differences in capacity are reflected in the generation mix. Figure 92 shows projected year-on-year differences in generation between the optimal development path and the no interconnectors counterfactual, in the Step Change scenario. With the optimal development path, reliance on GPG is forecast to decrease and be replaced by higher contributions from wind and hydro as well as coal generation and behind-the-meter batteries. Conversely, without interconnector developments, the mix is projected to increasingly feature a higher share of grid-scale storage complemented by solar.

Figure 92 Forecast generation outcomes to 2041-42 for optimal development path compared to no interconnectors, Step Change scenario

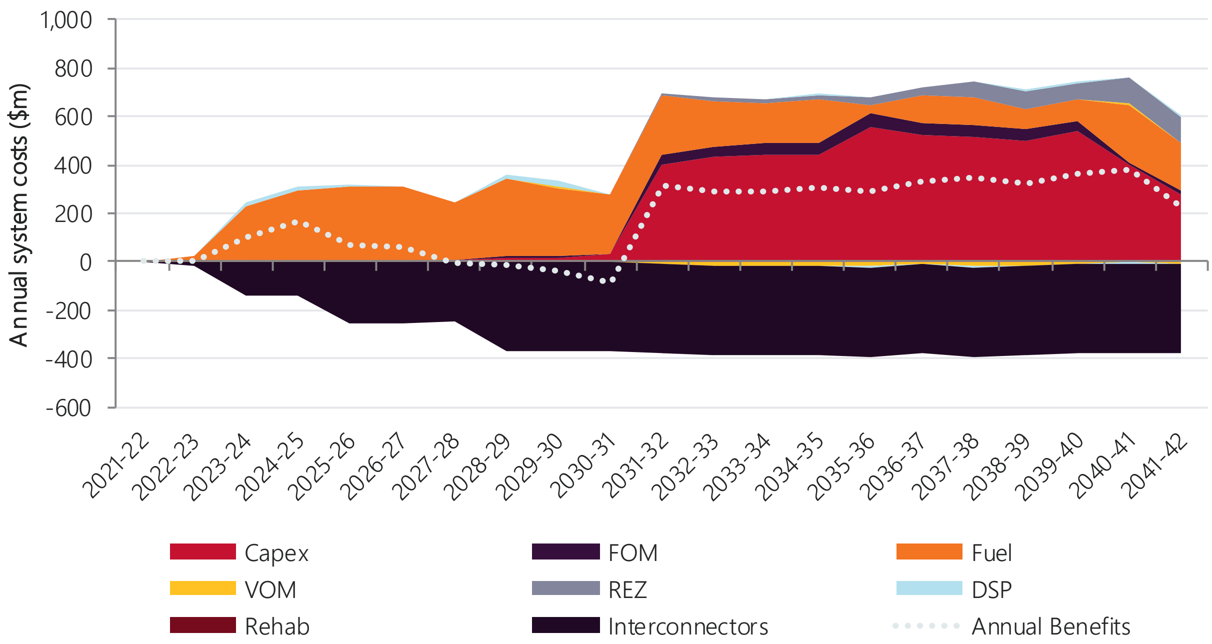


5.2.5 Slow Change

As outlined in Section 3.2.5, the Slow Change scenario presents a scenario with relatively low need for inter-regional energy sharing due to a reduced development outlook, while coal generation may have life extensions. In this scenario, the cost of transmission is projected to be greater than the benefits delivered, and the transmission pathway would seek to abandon the development should sufficient signposts provide effective guidance that this scenario's assumptions would occur.

As shown in Figure 93, benefits provided by transmission investment is relatively flat between 2023-24 to 2030-31, with the delayed closure of several coal fired generators beyond their estimated life. In the optimal development path for the Slow Change scenario almost all savings are associated with fuel costs, which average approximately $200 million a year from 2023-24. Savings step up from 2030-31, when the optimal development path avoids capital expenditure on firming GPG capacity, which would be required without the additional transmission to replace retiring generators, saving approximately $300 million -$500 million per annum, as Figure 93 shows.

Figure 93 Forecast optimal development path net annual benefits to 2041-42, Slow Change scenario



Note: The annual system costs in the figure do not include the costs associated with the development of Marinus Link and VNI West as "shovel ready". In the Slow Change scenario, less new interconnection is needed, and it is assumed that subsequent decisions not to continue through to construction are made. Early works incurred prior to construction are assumed sunk under this development path.

Table 12 provides a summary of the total net benefits of the optimal development path in comparison to the counterfactual for the Slow Change scenario. This shows that an investment of $2.2 billion in NPV terms to 2041-42 in interconnectors is projected to provide $0.94 billion of net benefits through the more efficient use of fuel ($1.7 billion) and generation developments ($1.4 billion).

Table 12 Net benefits of optimal development path, Slow Change scenario

Benefit category	Net Benefit ($M)
Capex	$1,354
FOM	$122
Fuel	$1,650
VOM	-$33
DSP (may include USE below the current reliability standard)	$49
REZ	$115
Gross Market Benefits	$3,257
Interconnectors	-$2,161
Shovel Ready Costs / Bring Forward Costs	-$155
Total Net Benefits	$941

Figure 94 presents the projected generation development outlook differences between the optimal development path and counterfactual outcomes for the Slow Change scenario. As outlined previously, without transmission investment additional local generation resources are projected to replace coal retirements, approximately 3,000 MW of peaking thermal and 1,200 MW of solar generation from 2031-32.

Figure 94 Forecast capacity developments to 2041-42 for optimal development path compared to no interconnectors, Slow Change scenario

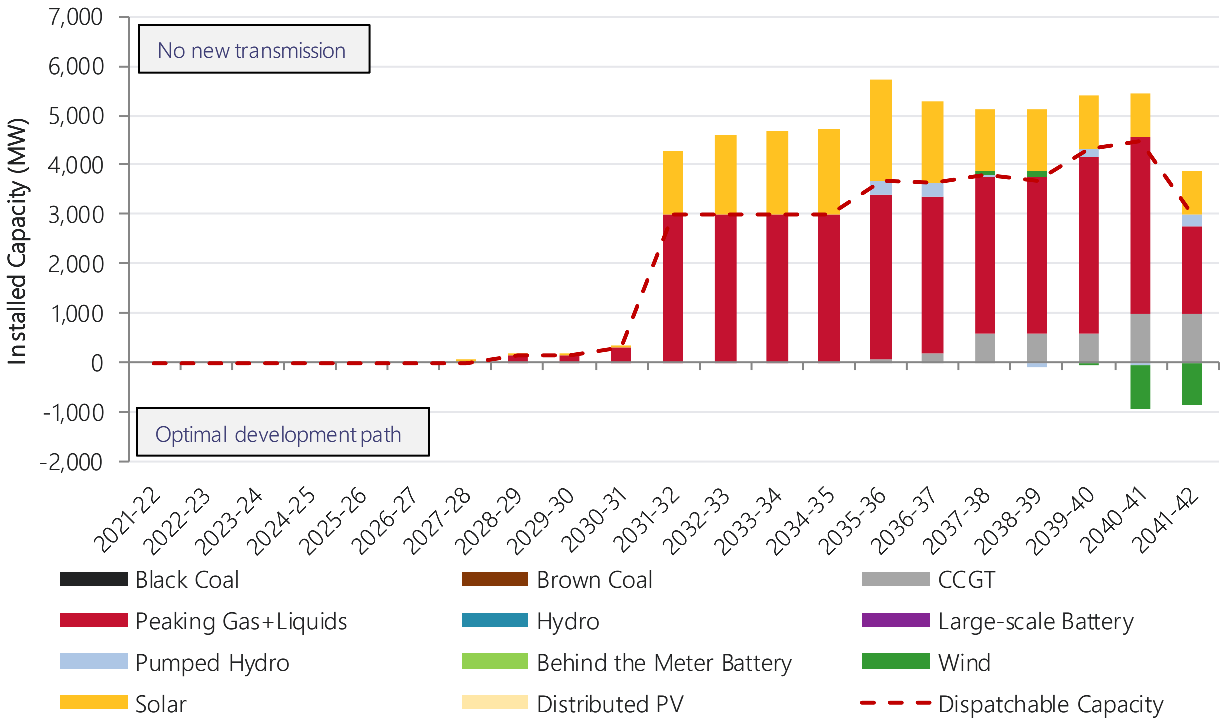
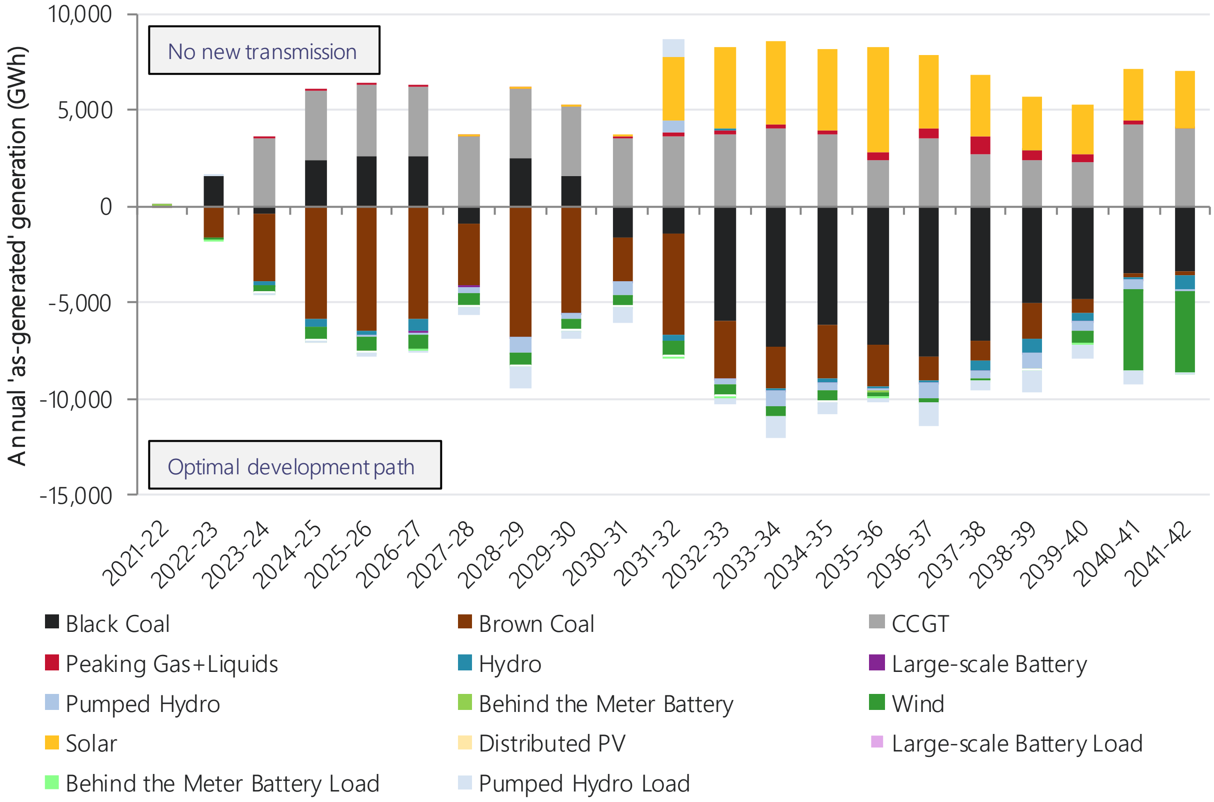


Figure 95 presents the generation production for the counterfactual without transmission relative to the optimal development path. The fuel cost savings outlined previously are shown in this figure, demonstrating a reduction in thermal generation from existing combined-cycle gas turbines (CCGTs) in place of lower fuel cost alternatives like brown coal.

After 2031, with the retirement of a number of coal units across the NEM, the generation production outlook for the two pathways diverges in a similar manner to the Central scenario. The counterfactual pathway pursues a suite of local alternatives to provide replacement energy through a combination of CCGTs, peaking thermal, and solar. With the introduction of the optimal development path, replacement energy is provided by additional wind generation complemented by greater utilisation of existing coal generators.

Figure 95 Forecast generation outcomes to 2041-42 for optimal development path compared to no interconnectors, Slow Change scenario



5.3 Testing the robustness of the development paths

AEMO has used scenario analysis to investigate core themes affecting the evolution of the future power system. Additional sensitivities that complement these scenarios have also been considered to assess the robustness of the candidate development paths to specific decisions that may be taken in the near future.

The 2020 Draft ISP examines the robustness of the candidate development paths to:

- Potential delayed delivery of the Snowy 2.0 project.
- Potential early closure of brown coal generation in Victoria.
- Potential repeal of the QRET.
- Potential early load closure in Victoria.
- Potential early development of Central West New South Wales REZ.

The robustness of each candidate plan was measured by assessing whether the impact of the event on total system costs diminished with the candidate development path in place, or conversely, whether stranded asset risk increased as a consequence of this decision. This reduction in cost impact can be calculated from the difference in regret cost between the candidate development path and the development path based on optimal investment timing if Central scenario was known to occur with certainty.

Sensitivity analysis has also been used to investigate whether the projected resource mix of the optimal development path under the Central scenario materially changes if key uncertain input assumptions change. Specifically:

- Potential reduction in grid-scale battery system costs.

- Potential for less pumped hydro to be available on the mainland.

5.3.1 Impact of a delay in Snowy 2.0

While Snowy 2.0 is a committed project, prudent planning must consider the impact to the power system if the project was not delivered on time with the current commissioning schedule.

AEMO has conducted a sensitivity with a four-year delay to the project to investigate the impact on the forecast costs, benefits, and resource mix of the NEM. The transmission required to unlock the project – the HumeLink transmission project – will be delivered independently to Snowy 2.0, and in this sensitivity is not delayed with the storage project.

Under all candidate development paths, AEMO's sensitivity analysis forecasts that the power system is relatively resilient to such a delay, with no material impact to the overall system costs. This assessment is on the premise that the transmission projects that form part of the candidate development path (and HumeLink in particular) are delivered on schedule, providing the necessary resilience in the event of Snowy 2.0 delay.

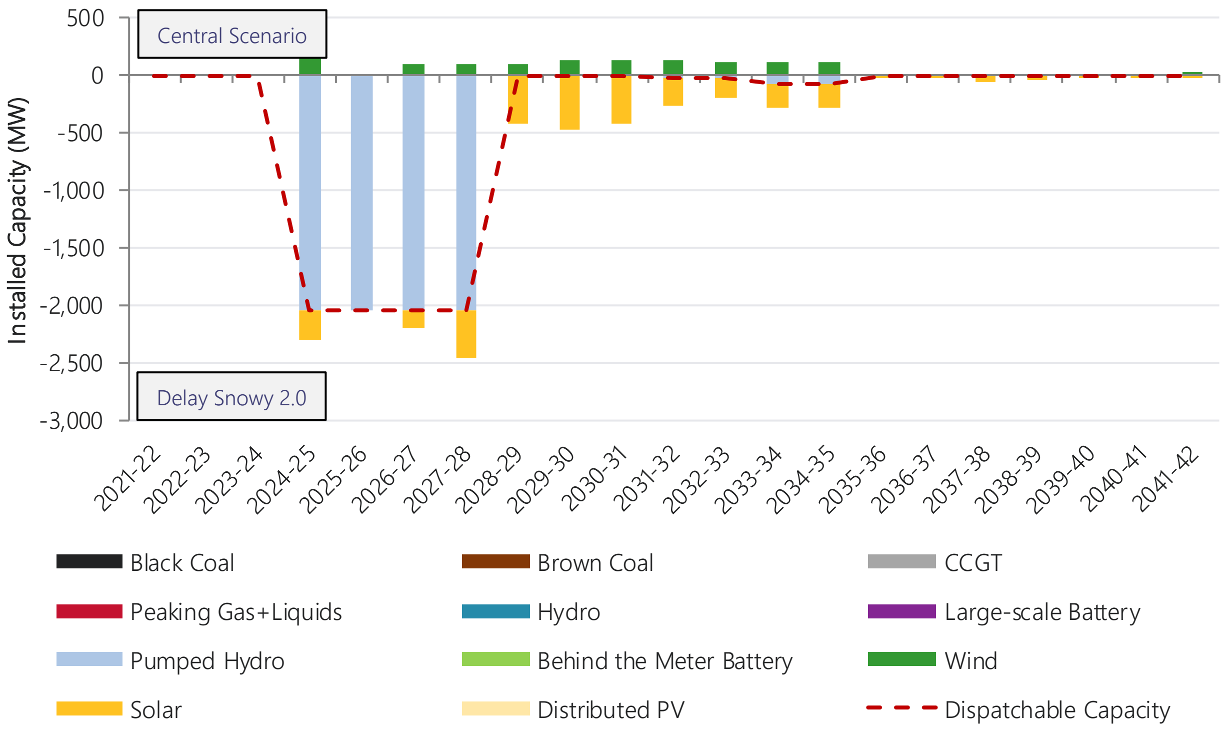
As shown in Table 13, the candidate development paths are only shown to be marginally more beneficial in the event of a delay in Snowy 2.0 commissioning under the Central scenario.

Table 13 Reduction in cost impact of a Snowy 2.0 delay under the candidate development paths ($ million)

Candidate Development Path	Central Scenario regret cost	Delayed Snowy sensitivity regret cost	Reduction in cost impact
No Acceleration	0	0	0
VNI West accelerated	-67	-66	0.3
Marinus Link accelerated	-288	-281	7.4
VNI West and Marinus Link accelerated	-380	-372	8.2
VNI West and Marinus Link 'shovel ready'	-112	-112	0.3

As Figure 96 shows, a Snowy 2.0 delay is not forecast to lead to emergency alternative firming capacity provided the priority grid projects identified in this Draft ISP are still progressed to enable more efficient sharing of resources across regions. With the delay of Snowy 2.0, the signal for solar development and generation would be reduced. With sufficient awareness of a delay, development would be best placed to shift towards earlier wind development than solar generation, given the reduced capacity to shift intra-day solar surplus energy without the storage project.

Figure 96 Forecast capacity differences to 2041-42 in sensitivity where Snowy 2.0 is delayed by 4 four years, in the Central scenario



For the 2020 Draft ISP, AEMO has not completed the reliability assessments associated with this sensitivity to a level consistent with the Electricity Statement of Opportunities (ESOO). Nor does the analysis consider whether the level of reliability would satisfy the New South Wales Energy Security Target, announced in November 2019 as part of the Government's New South Wales Electricity Strategy[18]. While the long-term development models do not build firming generation in the interim, suggesting there is enough dispatchable capacity with the additional interconnector support in New South Wales and the broader NEM, additional resources may be required after the retirement of Liddell if Snowy 2.0 was delayed. If relevant, further analysis and simulations may be needed to test reliability implications of a Snowy 2.0 delay prior to the publication of the 2020 Final ISP. Also note that the impact of a delay of more than four years may be much more severe as further power station exits are expected from 2029 onwards. At this point Snowy 2.0 additional dispatchable capacity would be essential for the NEM in the longer term.

5.3.2 Impact of an early brown coal generator closure in Victoria

Consistent with the findings in AEMO's July 2019 ISP Insights report into pumped hydro energy storage (PHES)[19], the preferred timing of new transmission augmentations is strongly linked to coal-fired generation closures. Under recent National Electricity Rules (NER) changes, participants are required to provide at least three years' notice of closure. However, some generation technologies and particularly transmission infrastructure can take much longer than that to plan and build, so the power system, and consumers, remain exposed to risks of unplanned early retirements or extended outages of coal-fired generation if the system was planned and developed to be 'just in time'.

Planning for a more strongly interconnected system ahead of closures of coal-fired generation can avoid or delay substantial investment in more expensive alternatives to support reliability and security of supply. Particularly if that transmission would be considered as part of the portfolio of solutions to replace

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

[19] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2019/ISP-Insights---Building-power-system-resilience-with-pumped-hydro-energy-storage.pdf.

retirements in the longer term. Developing these earlier than the closures would be a prudent planning approach to minimise the risks associated with earlier closures (or delivery delays) and enabling new generation to be built ahead of the retirement without the risk of being significantly constrained off.

ISP modelling considers the risk of unplanned early retirements or extended outages of coal-fired generation. For the purposes of this sensitivity analysis, AEMO has assumed the entire Yallourn brown coal power station in Victoria closes in 2027, several years earlier than the next planned retirement.

As shown in Table 14, the delivery of VNI West is observed to significantly reduce the cost impact of an early closure. Developing the VNI West transmission project 'just in case' is forecast to lower costs by $118 million in NPV terms. As shown, accelerating VNI West (with or without developing Marinus Link to 'shovel ready' status) would benefit consumers were this risk to eventuate.

Table 14 Reduction in cost impact of an early closure of Yallourn power station under the candidate development paths ($ million)

Candidate Development Path	Central scenario regret costs	Early Retirement sensitivity regret costs	Reduction in cost impact
No Acceleration	0	-118	118
VNI West accelerated	-67	0	67
Marinus Link accelerated	-288	-156	132
VNI West and Marinus Link accelerated	-380	-307	73
VNI West and Marinus Link 'shovel ready'	-112	-45	67

Under the Central scenario, and in the absence of a transmission solution that would strengthen the Victoria – New South Wales corridor, this closure is projected to require additional investments in dispatchable generation to support the region (Figure 97).

Figure 97 Forecast differences in installed capacity in Victoria to 2041-42 in sensitivity with early coal closure, Central scenario

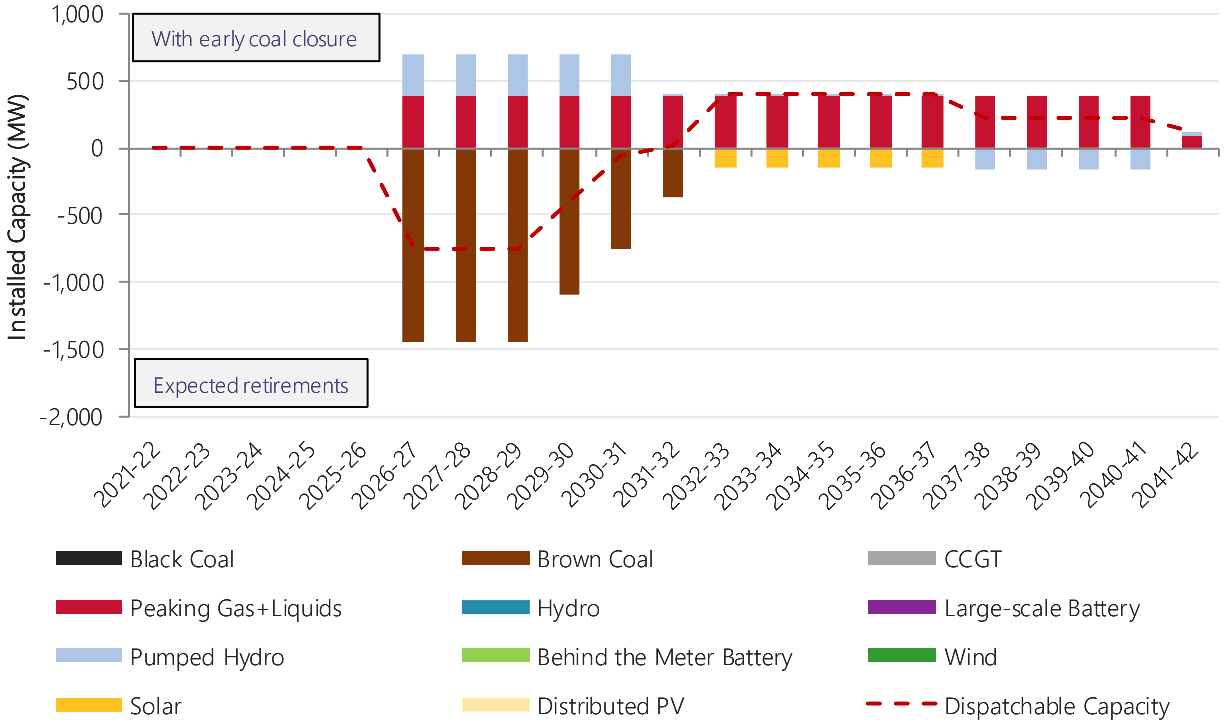
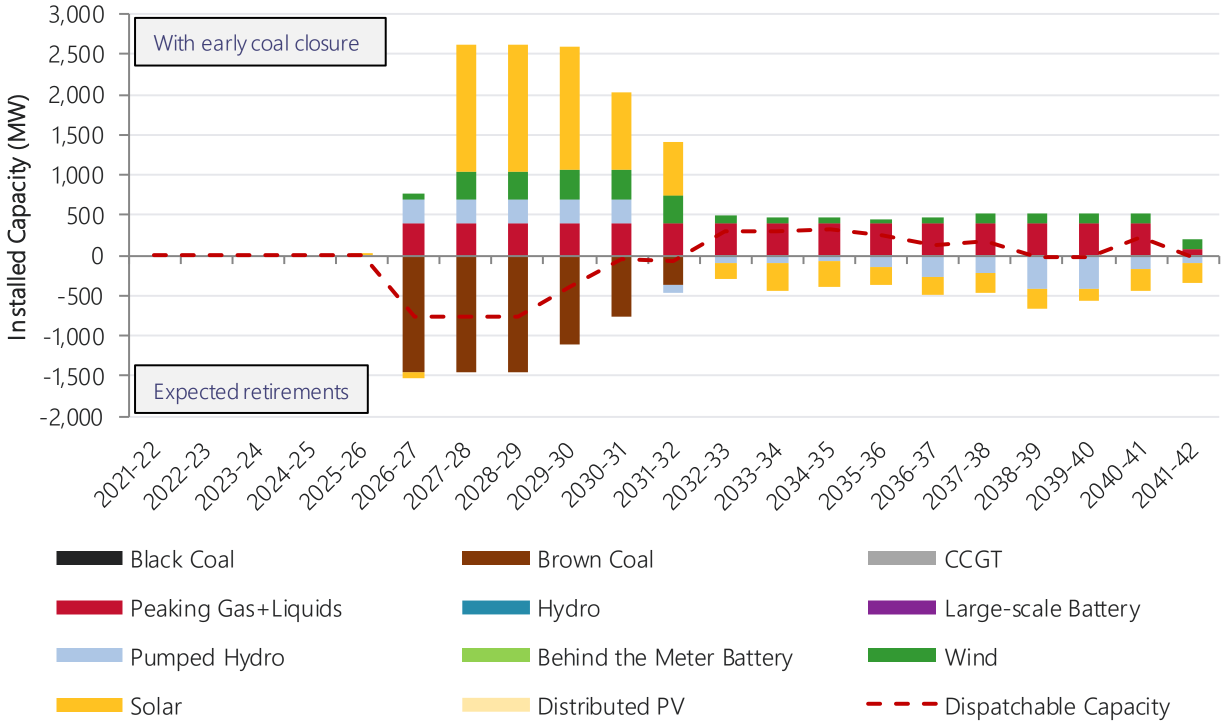


Figure 97 above demonstrates the generation response projected in Victoria encompasses a mix of additional gas-powered peaking assets and earlier storage solutions amounting to over 600 MW (which is less than the retired capacity). While some investments would be just brought forward by several years (until delivery of the transmission upgrade), part of the capital expenditure in long-lived assets such as thermal generators could be avoided with pre-emptive delivery of a transmission solution.

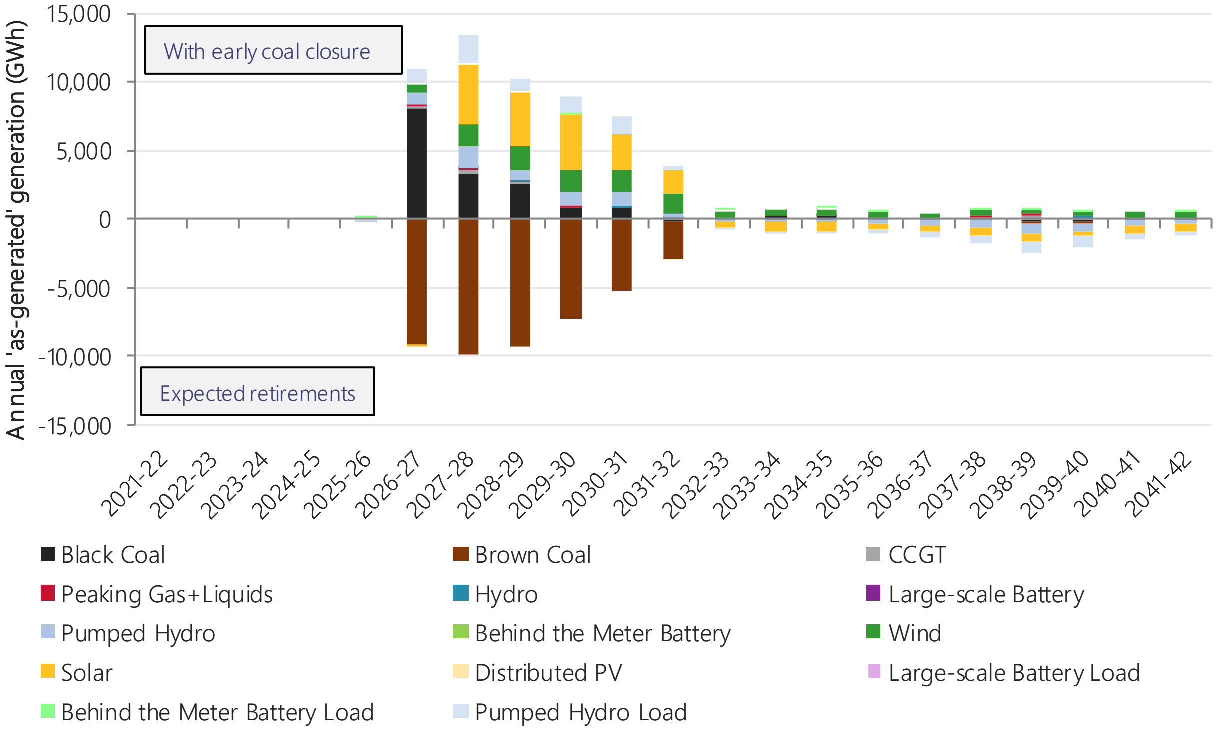
Sudden loss of brown coal capacity would also affect generation investments in other regions since Victoria is no longer able to export as much generation. Figure 98 shows that almost 2 GW of wind and solar projects are forecast to be developed earlier across the NEM to replace the lost energy production that would otherwise be provided by Yallourn.

Figure 98 Forecast differences in installed capacity in the NEM to 2041-42 in sensitivity with early coal closure, Central scenario



The differences in generation response to an early closure are projected to gradually reduce over time and mostly resolve with the delivery of VNI West, although there remains residual 'regret' associated with building GPG locally that would otherwise not have been needed. Greater utilisation of the remaining black coal fleet, as well as increased operation of VRE, is forecast to offset the lost energy production due to the closure, as seen in Figure 99.

Figure 99 Forecast differences in generation in the NEM to 2041-42 in sensitivity with early coal closure, Central scenario



Earlier development of VNI West would provide insurance against closure risks by delivering greater access to the Snowy 2.0 scheme and better reserve sharing with New South Wales.

In the Central scenario, the probability of a closure need only be as high as 36% in the Central scenario for increased transmission between Victoria and New South Wales to be a valuable insurance policy against the risks of early closure.

Figure 100 demonstrates how this percentage has been calculated, using a decision tree to calculate the option value of accelerating VNI West. The impacts of two decisions are considered: accelerate VNI West now or defer it to later years (2031-32). The NPVs of the regret costs for each development path and timing of closure demonstrate that:

- If it was known with certainty that Yallourn would close by 2031-32 the least regret decision regarding VNI West would be to avoid acceleration of the transmission investment.
- If Yallourn was to close in 2027 and this timing was certain, then accelerating VNI West would be a no-regret development path.

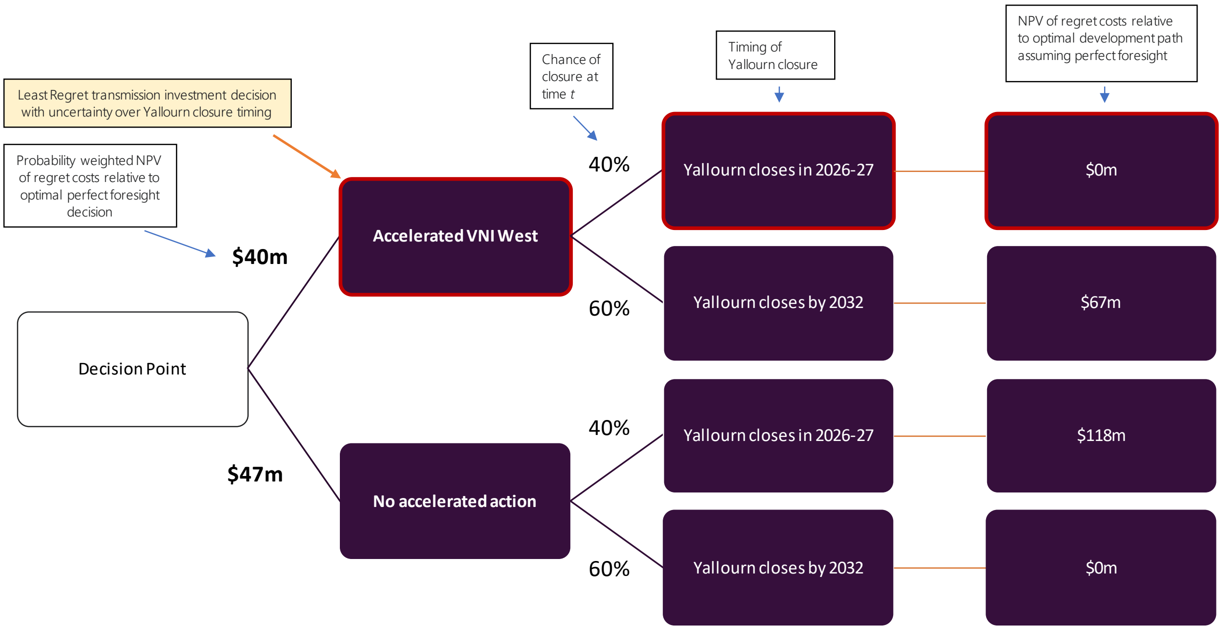
However, given the uncertainty around the timing of closure:

- If VNI West was accelerated and the early closure did not eventuate the regret cost associated with this decision would be $6.7 million.
- If VNI West was not accelerated and loss of Yallourn occurred in 2027 the regret costs would rise to $118 million.

Given the uncertainties around timing of generation closures in Victoria the analysis shows that, if likelihood of losing Yallourn in full by 2027 exceeds approximately 36%, expediting VNI West would be a least regret outcome.

For example, assuming a 40% probability to lose Yallourn in 2027 the decision to accelerate VNI West now is the least regretful ($40 million). A wait and see approach, on the other hand is projected to increase regret cost by $7 million ($47 million). In this example, with a 40% likelihood of a closure (above the estimated decision break-even mark of 36%), the decision to accelerate VNI West would lead to a lower investment regret relative to the optimal power system mix.

Figure 100 Estimated regret of accelerating VNI West if there was a 40% probability of Yallourn closing early



5.3.3 Impact of a repeal of the Queensland Renewable Energy Target

The QRET is a major driver of projected investment in renewable generation in Queensland up to 2030. This sensitivity identifies the impact of this policy being removed on the timing and location of renewable resource developments, particularly across Queensland and New South Wales.

Without the QRET providing an explicit catalyst for Queensland investment, this sensitivity projects:

- Queensland having lower VRE developments, with 2.0 GW less wind capacity and 2.9 GW less solar capacity developed in Queensland by 2030.
- Efficient investment of VRE in other regions, with additional solar capacity (almost 600 MW) in New South Wales and lesser amounts of additional wind and solar in Tasmania and South Australia respectively by 2030.
- Without other drivers for VRE, lower NEM-wide capacity than the Central scenario.

Without the QRET, New South Wales would be the preferred development location of renewable energy to replace retiring coal generation across both Queensland and New South Wales by 2040. This regional generation difference would impact the value of some transmission developments. While in both this sensitivity and the Central scenario there is excess energy for export from Queensland to New South Wales (and the regions beyond), there are unlikely to be sufficient developments to provide enough benefits for the second stage of the large QNI upgrade.

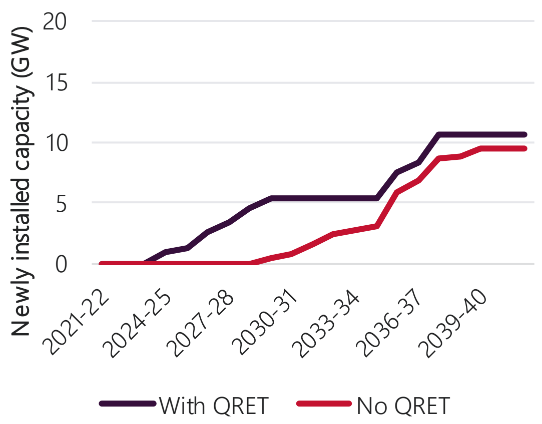
As shown in Table 15, the accelerated delivery of VNI West is forecast to deliver minor additional cost savings ($18 million) if QRET is repealed, by making more efficient use of existing resources.

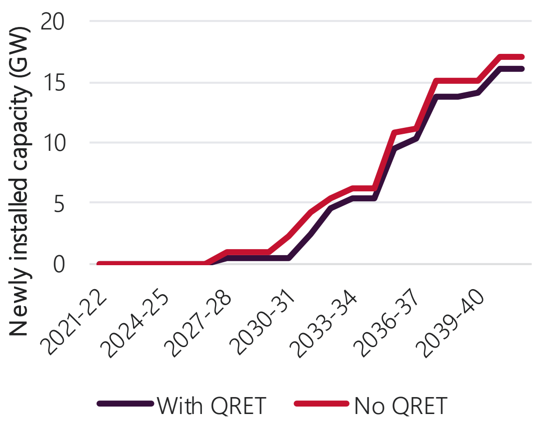
Table 15 Reduction in cost impact of a QRET policy repeal under the candidate development paths ($ million)

Candidate Development Path	Central Scenario regret cost	QRET repeal sensitivity regret cost	Reduction in cost impact
No Acceleration	0	0	0
VNI West accelerated	-67	-49	18
Marinus Link accelerated	-288	N/A	N/A
VNI West and Marinus Link accelerated	-380	N/A	N/A
VNI West and Marinus Link 'shovel ready'	-112	-94	18

Overall, as seen in Figure 101, there is forecast to be 1.9 GW less wind capacity and 2.3 GW less solar capacity developed across the NEM in 2030 if QRET is repealed. By 2035, the sensitivity re-aligns to the VRE magnitude of the Central scenario, confirming that the QRET is facilitating the development of VRE projects in Queensland several years earlier than would otherwise occur, in order to increase the Queensland renewable generation proportion.

Figure 101 Forecast regional VRE development to 2041-42 in Queensland (left) and New South Wales (right) in sensitivity with QRET repealed, Central scenario





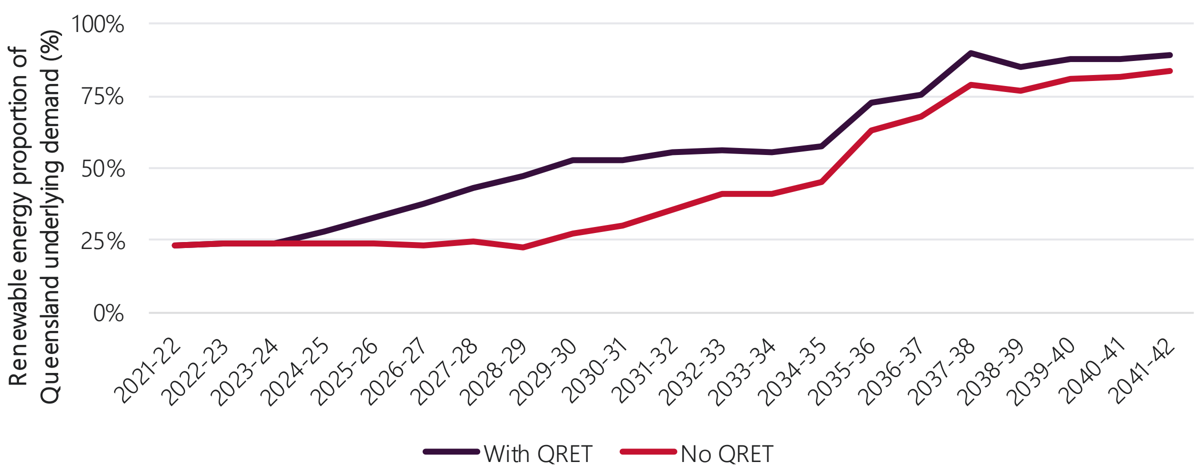
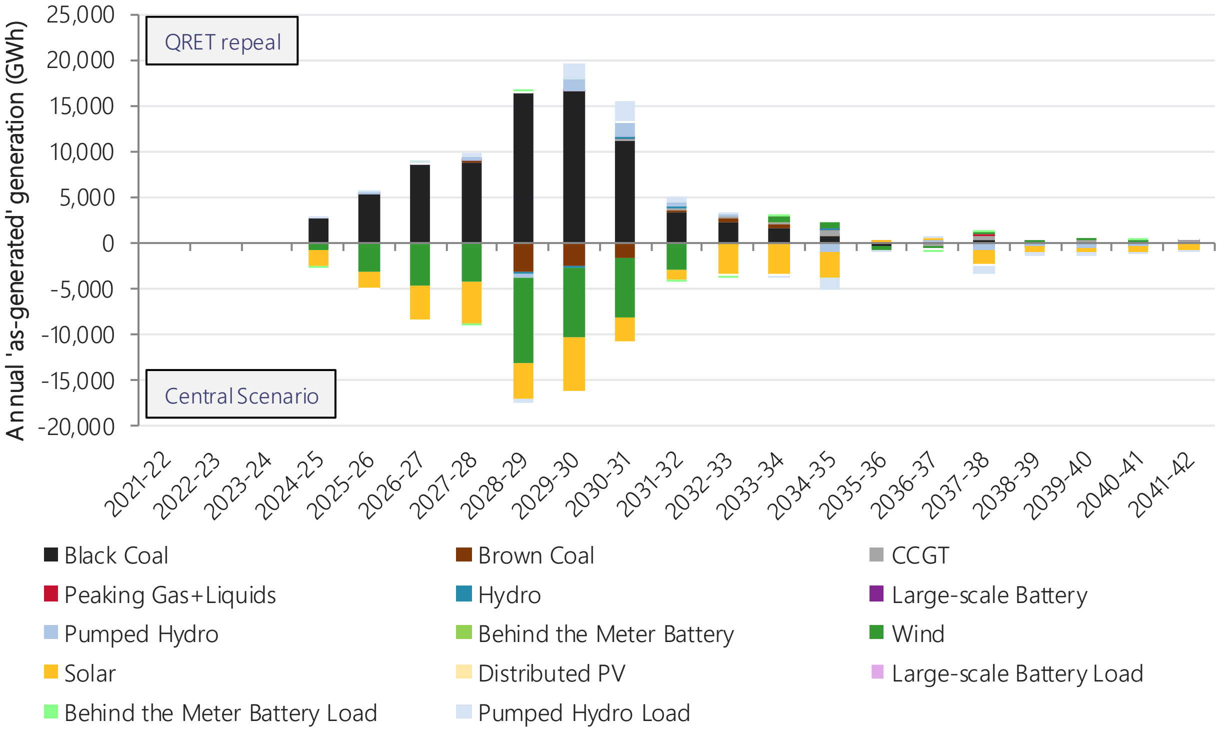


Figure 102 below demonstrates the differences in forecast generation between this sensitivity and the Central scenario, demonstrating that with less VRE developed in the 2020s, much greater operation of the incumbent black coal generation fleet is forecast.

Figure 102 Forecast differences in generation in the NEM to 2041-42 in sensitivity with QRET repealed, Central scenario



5.3.4 Impact of early load closure

This sensitivity considers the potential impact on Central scenario forecasts of the early closure of a major industrial load in Victoria in 2021-22, assumed to represent approximately 10% of Victorian demand.

Due to Victoria's unique supply portfolio, consisting of low marginal cost generation and multiple interconnector paths to adjacent regions, the impact of an industrial load closure is forecast to impact more than just the Victorian region. Figure 103 shows the projected material reduction in black coal production in New South Wales and Queensland in this sensitivity.

Victoria's VRET is linked to local generation, therefore the early load closure would not materially reduce the local VRE development need in absolute terms, unless total Victorian generation (including exports) reduced. This may occur if the load closure led to a coal generator closure, or significant constraint on export, although preliminary revenue sufficiency analysis undertaken as part of this Draft ISP does not indicate that this would be the likely consequence of such an event.

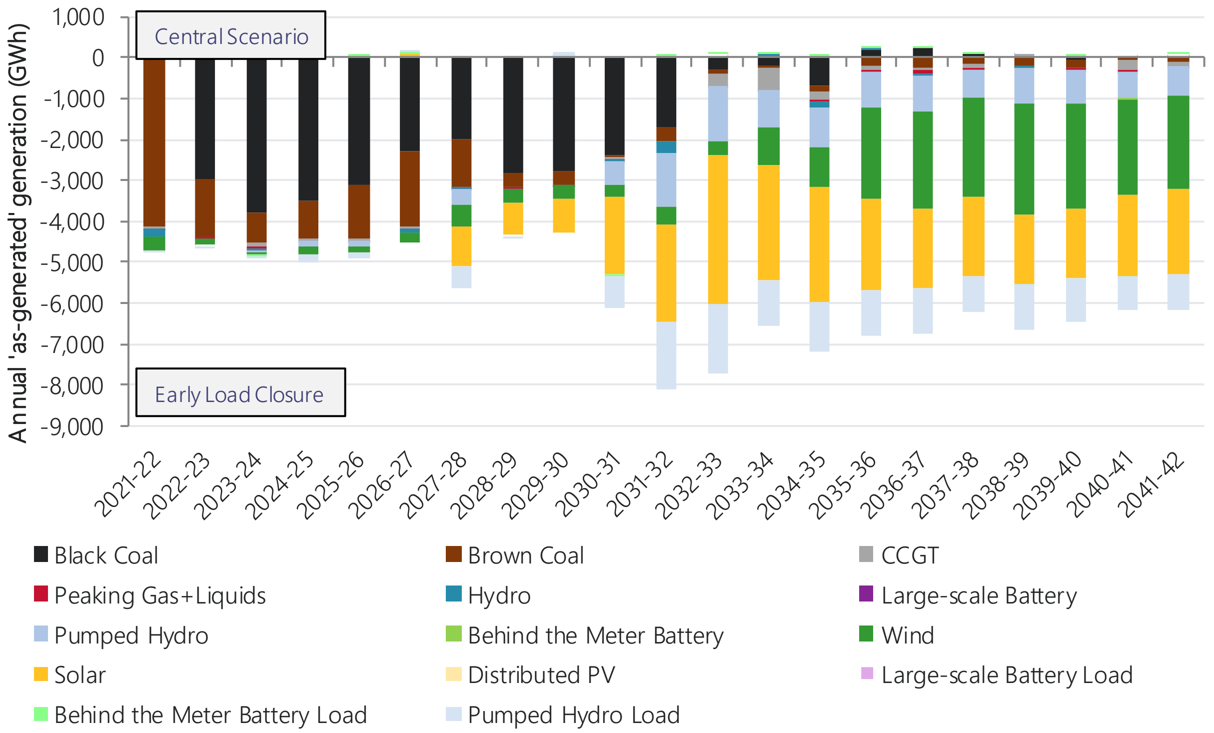
As such, in the short to medium term, the assumed load closure is projected to increase the availability of brown coal generation to export to neighbouring regions. In the long term (beyond 2030), less VRE is forecast to be developed, lowering the energy storage capacity needed in Victoria.

As shown in Table 16, accelerating VNI West is forecast to deliver some additional cost savings (approximately $34 million) in the event of an early load closure, largely due to reducing constraint on exports.

Table 16 **Reduction in cost impact of an early load closure under the candidate development paths ($ million)**

Candidate Development Path	Central scenario regret cost	Early load closure sensitivity regret cost	Reduction in cost impact ($ million)
No Acceleration	0	0	0
VNI West accelerated	-67	-32	34
Marinus Link accelerated	-288	N/A	N/A
VNI West and Marinus Link accelerated	-380	N/A	N/A
VNI West and Marinus Link 'shovel ready'	-112	-78	34

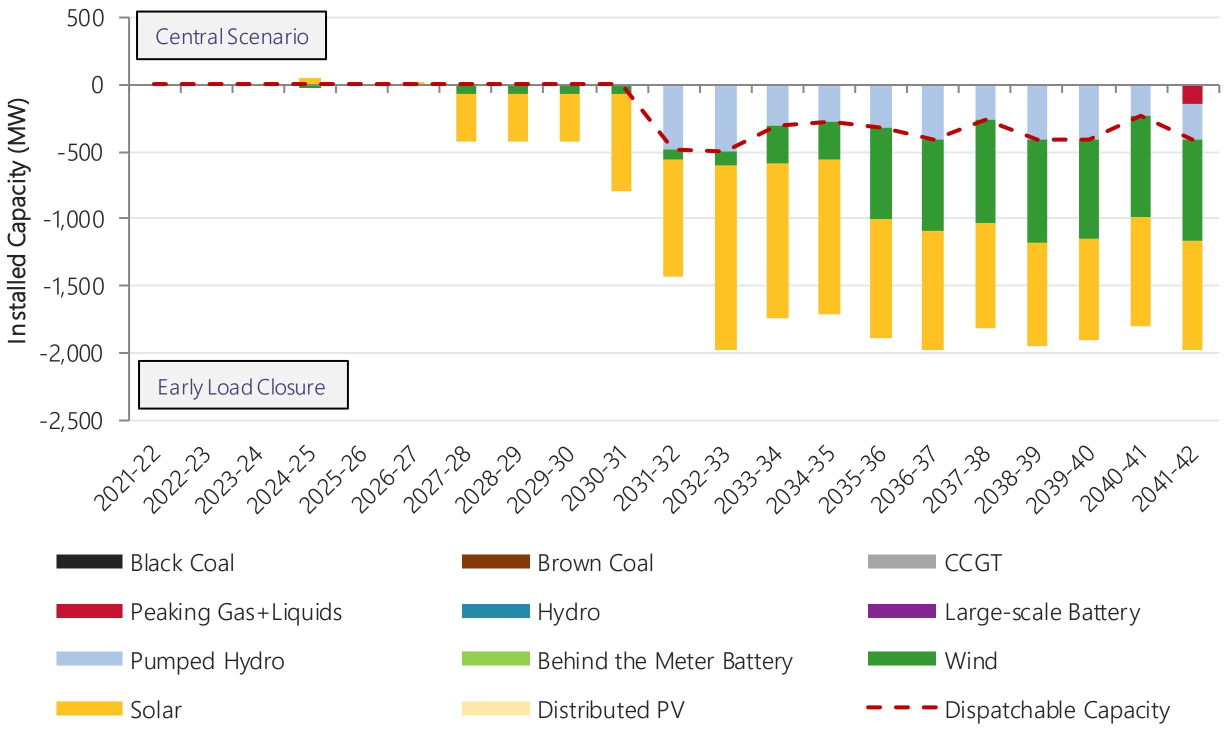
Figure 103 **Forecast difference in generation production to 2041-42 in sensitivity with early load closure, Central scenario**



The loss of a major industrial load would typically impact the generation portfolio that services the load. For the 2020 Draft ISP, AEMO has not conducted sufficiently detailed analysis to determine with confidence whether sufficient revenue streams are available to the incumbent energy provider to avoid a local generator closure. The coal fleet is assumed to continue to retire according to announced retirement dates.

As this existing coal fleet exits, less new generation is needed since the industrial load closure has reduced total consumption. Therefore, from 2031-32, a suite of VRE and large-scale storage developments is projected to be deferred, as shown in Figure 104.

Figure 104 Forecast difference in capacity to 2041-42 in sensitivity with early load closure, Central scenario



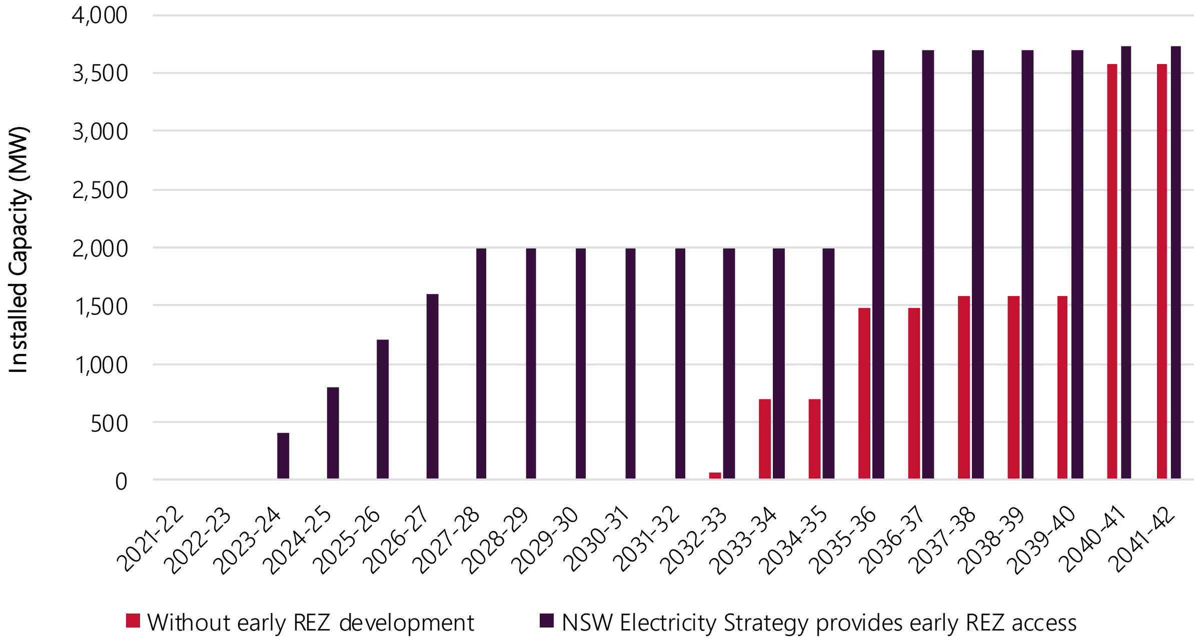
5.3.5 Impact of transmission access improvements to Central West New South Wales REZ

The recently announced New South Wales Electricity Strategy intends to facilitate investments in new generation capacity in key areas of New South Wales, particularly the Central West REZ.

AEMO has carried out a sensitivity under the Central scenario to assess how the Electricity Strategy could impact REZ development in New South Wales and determine the influence on the optimal development path. In this sensitivity AEMO has incorporated transmission development to increase access to this REZ by 3 GW, and assumed development of at least 2 GW of VRE in the REZ in response by 2027-28.

Figure 105 presents the differences in capacity installed in the Central West REZ with and without increased transmission access. Without increased access promoted through this Electricity Strategy, development in New South Wales is gradual. This sensitivity represents a significant acceleration of New South Wales VRE investment than forecast in the Central scenario.

Figure 105 Installed capacity in Central West New South Wales REZ with and without increased transmission access (MW)



As shown in Table 17, this sensitivity slightly reduces the benefits of accelerating VNI West (by $17 million). With increased local generation in New South Wales there is slightly less need for early transmission works, although the majority of the benefits still remain.

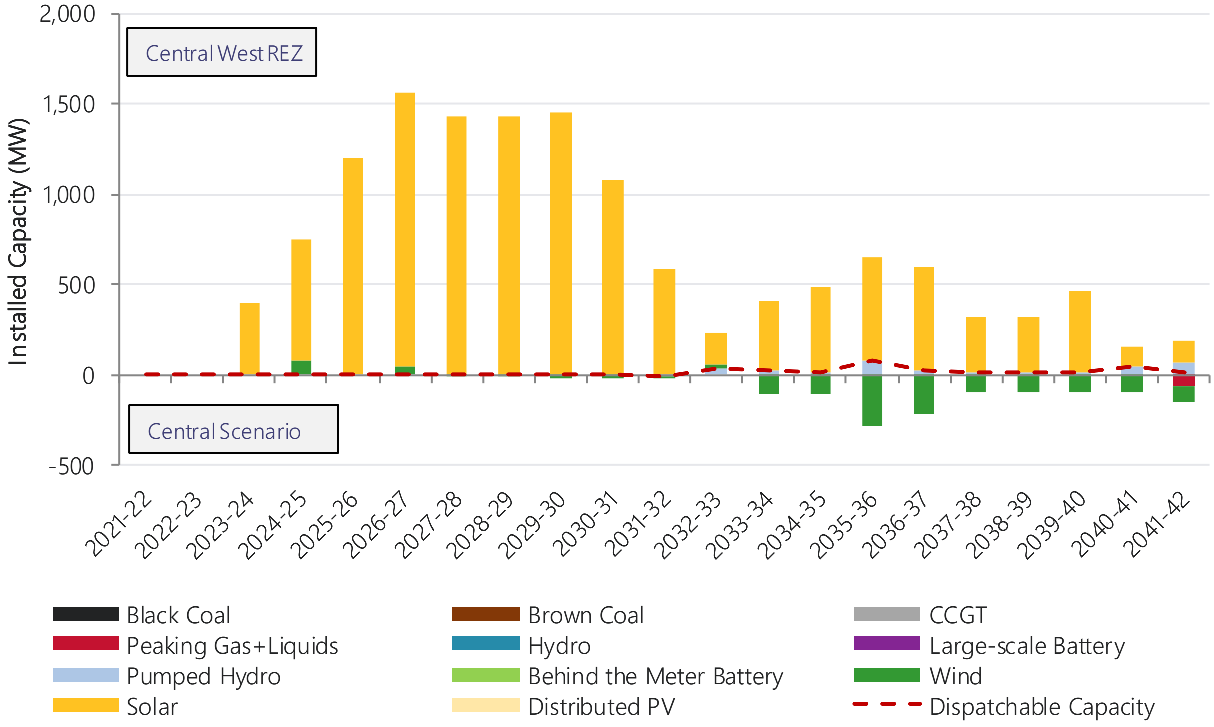
Table 17 Reduction in cost impact of facilitated development of Central West New South Wales REZ under the candidate development paths ($ million)

Candidate Development Pathway	Central Scenario	Central West NSW REZ repeal sensitivity	Reduction in cost impact
No Acceleration	0	0	0
VNI West accelerated	-67	-83	-17
Marinus Link accelerated	-288	N/A	N/A
VNI West and Marinus Link accelerated	-380	N/A	N/A
VNI West and Marinus Link 'shovel ready'	-112	-129	-17

In this sensitivity, the NPV of net market benefits of the development path with QNI Medium upgraded to QNI Large in 2031-32 are $7 million lower than under the development path without QNI Large. This sensitivity therefore reconfirms that the QNI Large staged investment provides less value in scenarios that increase the renewable generation in New South Wales, such as is forecast in the Fast Change, High DER, and Step Change scenarios (with higher NSW VRE and DER).

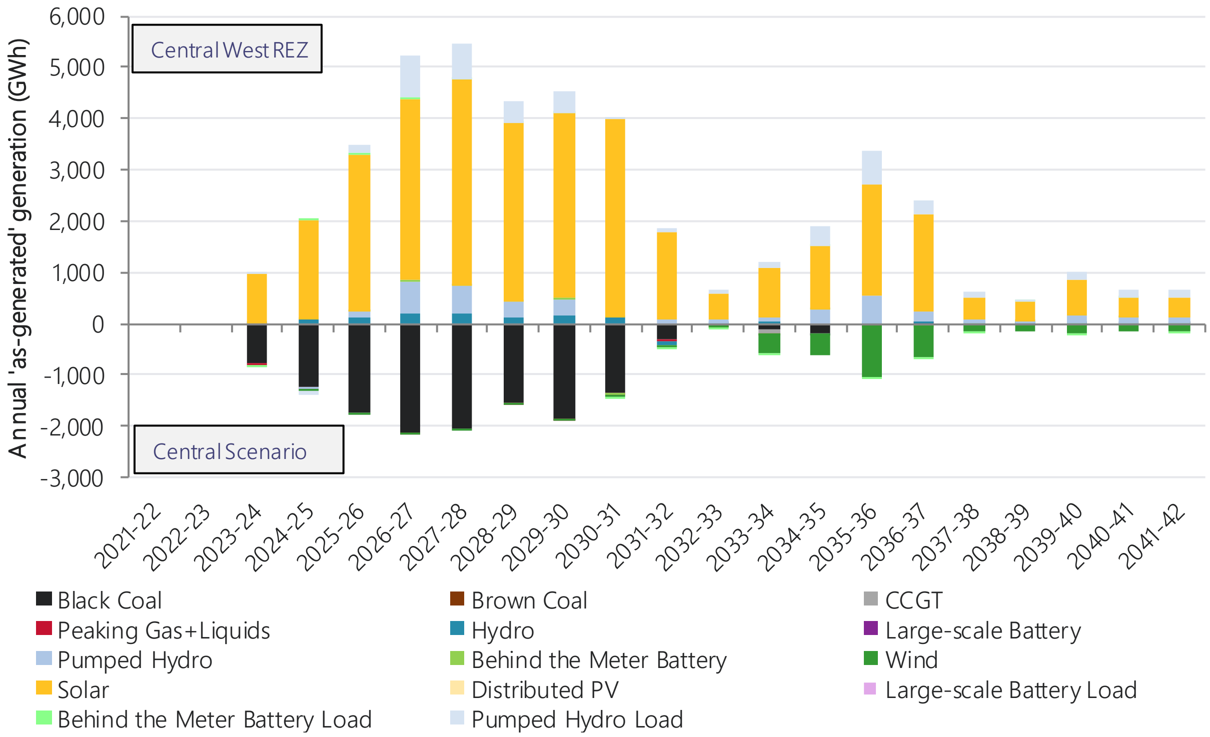
Overall, the establishment of the Central West REZ is forecast to lead to greater investments in VRE generation in New South Wales, particularly solar generation. By 2032, the sensitivity mostly re-aligns to the VRE magnitude of the Central scenario, indicating that the New South Wales Electricity Strategy will be facilitating the development of VRE projects in New South Wales up to a decade earlier than would otherwise occur, in order to increase the state's renewable generation proportion.

Figure 106 NEM-wide Impact of improved access and REZ development requirements in New South Wales



AEMO's modelling indicates that while the development of the Central West REZ will increase local solar production, there may also be some corresponding reduction in generation provided by coal generation in New South Wales. The net energy production of the New South Wales energy mix though is greater with this earlier VRE development, meaning there is slightly less reliance on imports to meet regional demand

Figure 107 Forecast difference in generation production to 2041-42 in sensitivity in New South Wales



5.3.6 Impact of reduced battery storage cost

Some stakeholders have indicated to AEMO that battery costs may be lower than have been assumed in AEMO's *Forecasting and Planning Scenarios, Inputs and Assumptions Report*[20], particularly if integrated with VRE on-site, sharing connection assets of other balance of plant. To address this concern, AEMO has conducted a sensitivity with a 30% reduction in capital cost for both 2-hour and 4-hour battery storage options.

Grid-scale battery storage is not forecast as a strong development option to either provide peak capacity or energy shifting within AEMO's ISP modelling, based on current cost and availability assumptions around PHES. The reduction of battery storages by 30% does not provide additional development incentive, with no impact on the resource mix or cost of the overall development plan.

The role of shallow storage energy management is projected to be provided by embedded distributed storages, particularly provided by VPPs. While there may be other security service revenue streams that current batteries are able to take advantage of, this would need to be a significant portion of the batteries revenue stream to be sufficient to drive battery development at scale under current cost assumptions.

5.3.7 Impact of reduced availability of pumped hydro on the mainland

The forecast development of VRE and storage solutions relies on the availability of a portfolio of storage solutions with variable depths in order to properly complement and enable the flexible operation of renewable energy. Some stakeholders have indicated to AEMO that mainland storages may be more limited in both availability and depth than what has been assumed in *AEMO's Forecasting and Planning Scenarios, Inputs and Assumptions Report*. To address this concern, and identify the impact on resource developments, AEMO has conducted a sensitivity with limited pumped hydro sites on the mainland NEM.

For this sensitivity AEMO forecast the development opportunities with adjusted assumptions listed in Table 18. Tasmanian resources are not reduced in this sensitivity, given the prevalence of existing hydro facilities.

Table 18 Reduction in storage availability in the modelled sensitivity

Candidate Development Pathway	Central scenario	Reduced PHES availability sensitivity	Available capacity in sensitivity
Queensland	4,900 MW 6-48hr storages available	1,200 MW 6hr storages only	24%
New South Wales	7,000 MW 6-48hr storages available	3,345 MW 6hr storages only	48%
Victoria	3,600 MW 6-48hr storages available	1,151 MW 6hr storages only	32%
South Australia	2,034 MW 6-48hr storages available	478 MW 6hr storages only	24%
Tasmania	3,137 MW 6-48hr storages available	3,137 MW 6-48hr storages available	100%

The sensitivity identified that reducing the availability of mainland PHES facilities may lead to increased reliance on VRE technological diversity, with greater projected development of wind generation facilities to reduce energy management requirements during daytime solar production periods. In this sensitivity,

[20] Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies

storages were developed up to available limits in some regions, and complemented by GPG as required. As seen in the figures below, the relative build of storages is similar in both the Central scenario and the sensitivity, until available storages are exhausted after coal retirements in the late 2030s.

Figure 108 Forecast storage development in the Central scenario with limited storage availability (MW)

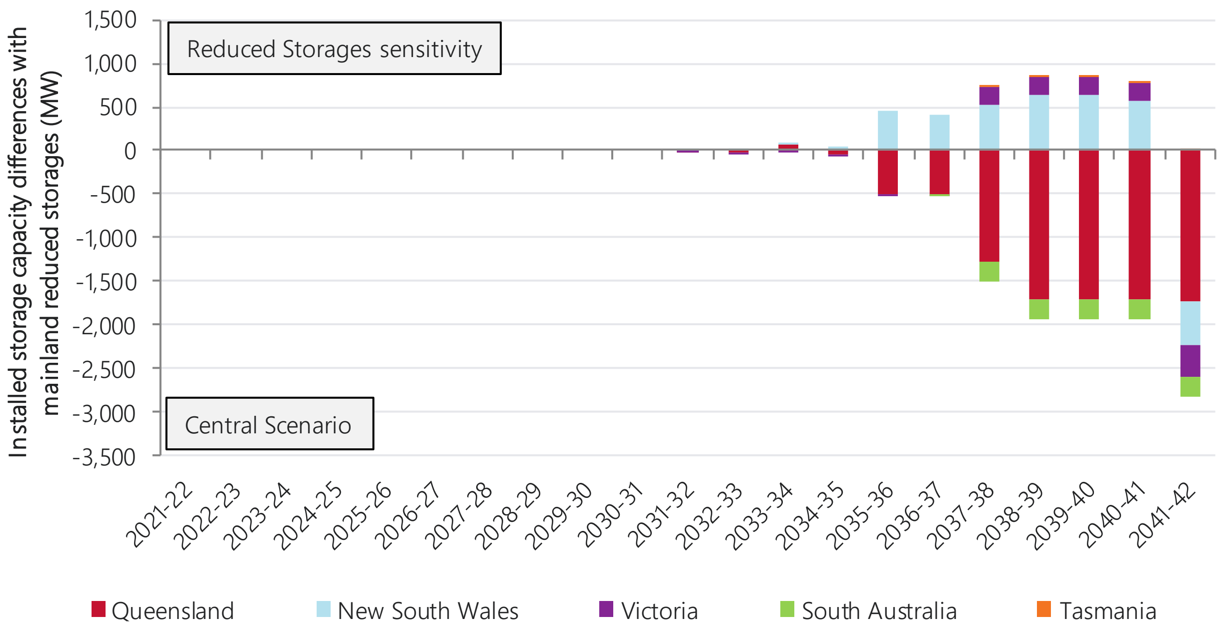


Figure 109 Forecast VRE and GPG development in the Central scenario with limited storage availability (MW)

AEMO conducted this sensitivity with and without the early development of the Marinus Link interconnector to identify whether limited availability of mainland storages may increase the benefits provided by that interconnector. Given that the resource mix was not materially altered by this sensitivity prior to 2036, the value of bringing forward the Marinus Link interconnector remained largely unchanged. On this basis, AEMO has concluded that limiting availability of mainland PHES does not materially alter the optimal development path actionable ISP projects or timing, although the magnitude of benefits delivered may be higher.

5.4 Demonstrating the utilisation of the optimal development path

With greater diversity of generation technologies, varying dispatch and consumption profiles, the role of key inter-regional flows paths will be critical to the efficient and secure operation of the NEM.

This section describes the forecast increasing role for energy sharing between adjacent regions, considering the existing and identified interconnector augmentations considered in the optimal development path. These simulation outcomes are based on the detailed long term (DLT) expansion model, which is able to quantify the relative merits of both generation and transmission augmentations to total system costs. The DLT is based on a five region model using nominal interconnector limits, and does not consider detailed intra-regional transmission constraint equations. Consequently, the total energy transfers presented below are a guide only for macro-regional interactions and changes, and not a substitute for detailed power systems analysis. More detailed analysis of transmission utilisation will be conducted prior to the 2020 Final ISP.

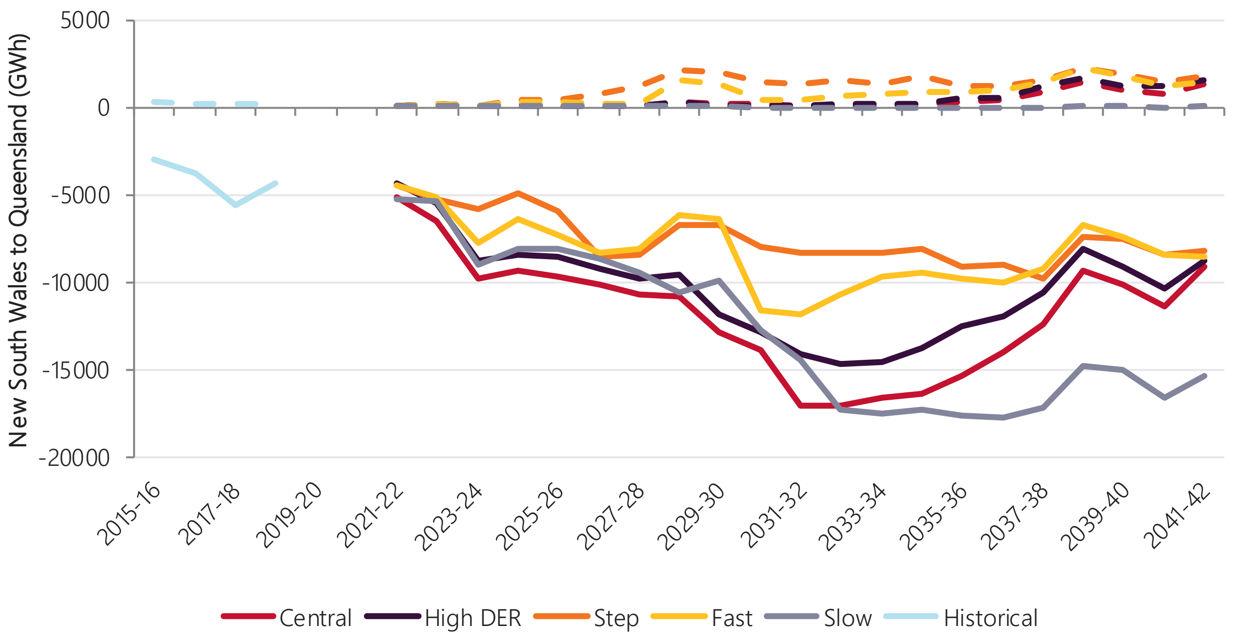
The solid lines below the x-axis represent flows either to the South or to the East depending on the orientation of the adjacent regions. In Figure 110 these solid lines represent southerly energy flows from Queensland to New South Wales. Conversely the dotted lines represent either northerly or westerly flows; for the figure below this represents flows to the north from New South Wales to Queensland.

Historically Queensland has been a significant net exporter of excess coal fired generation to New South Wales. These historical trends continue and accelerate under the five scenarios considered, driven by state based policies, strong DER development and a relatively young thermal coal fleet. These factors act to increase inter-regional transfers into NSW enabled by the QNI augmentations highlighted in the optimal development path.

These historical trends continue and accelerate under the five scenarios considered, driven by state based policies, strong DER development and a relatively young thermal coal fleet. These factors act to increase inter-regional transfers into NSW enabled by the QNI augmentations highlighted in the optimal development path.

The Slow Change scenario in particular makes great use of the QNI Medium augmentation to export surplus generation from relatively new coal fired generators in Queensland to New South Wales to help cover the exit of its aging fleet. The Step Change scenario makes more use of bi-directional flows to maximise geographic diversity once significant volumes of VRE are installed in all regions across the NEM.

Figure 110 Inter-regional transfers New South Wales to Queensland



Much like Queensland, the Victorian region has played a role historically in supporting New South Wales through material energy transfers. These transfers have also been heavily influenced by the operation of the Snowy generation scheme which is located directly along key transmission assets on this flowpath. As a result of the location of these hydro assets, the production outlook for the scheme due to inflows heavily influences the year on year variability of the net energy transfers between the two regions. This year on year variability is presented in Figure 111.

Under the optimal development path initial exports from Victoria to New South Wales increase compared to those historically observed due to a combination of; network augmentations (VNI minor), state based policies in Victoria and retirements in New South Wales. These factors act to increase exports from Victoria into New South Wales before the deployment of VNI West.

With the introduction of VNI West, the variability and sharing of energy resources between Victoria and New South Wales significantly increases. Through the use of greater interconnection the regions are more able to share variable generation production to exploit geographical diversity between generation resources across the NEM.

The Step Change scenario draws on southerly flow most often out of all scenarios, due to the earlier closure of brown coal generators forecast in this scenario.

Figure 111 Inter-regional transfers Victoria to New South Wales

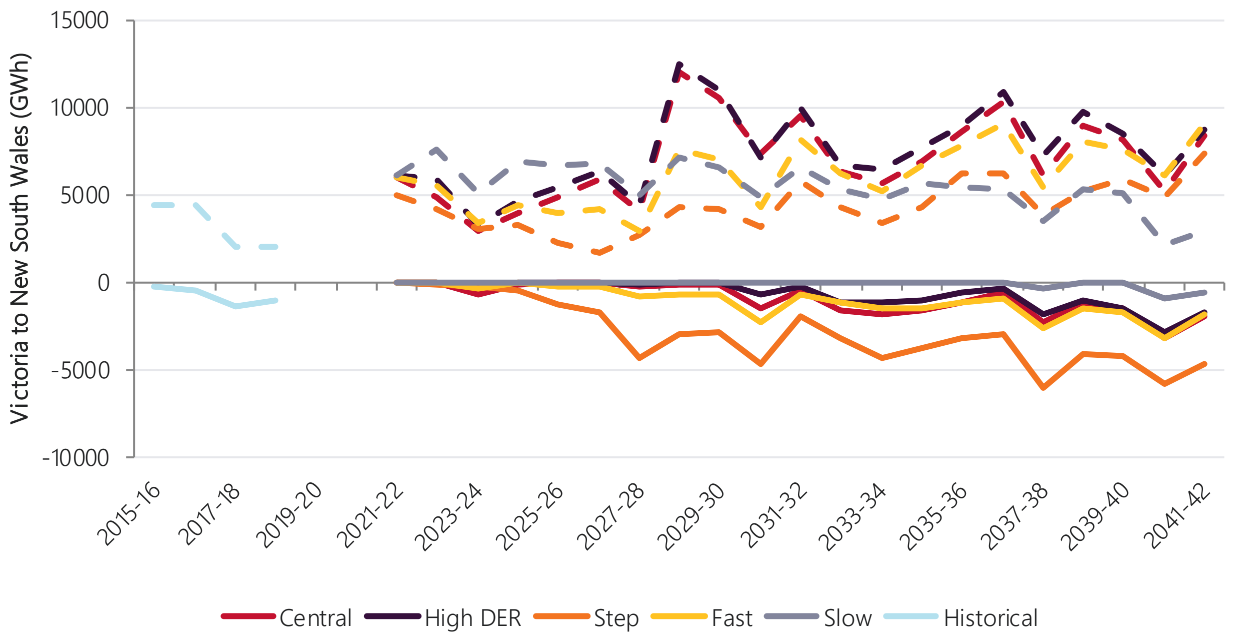
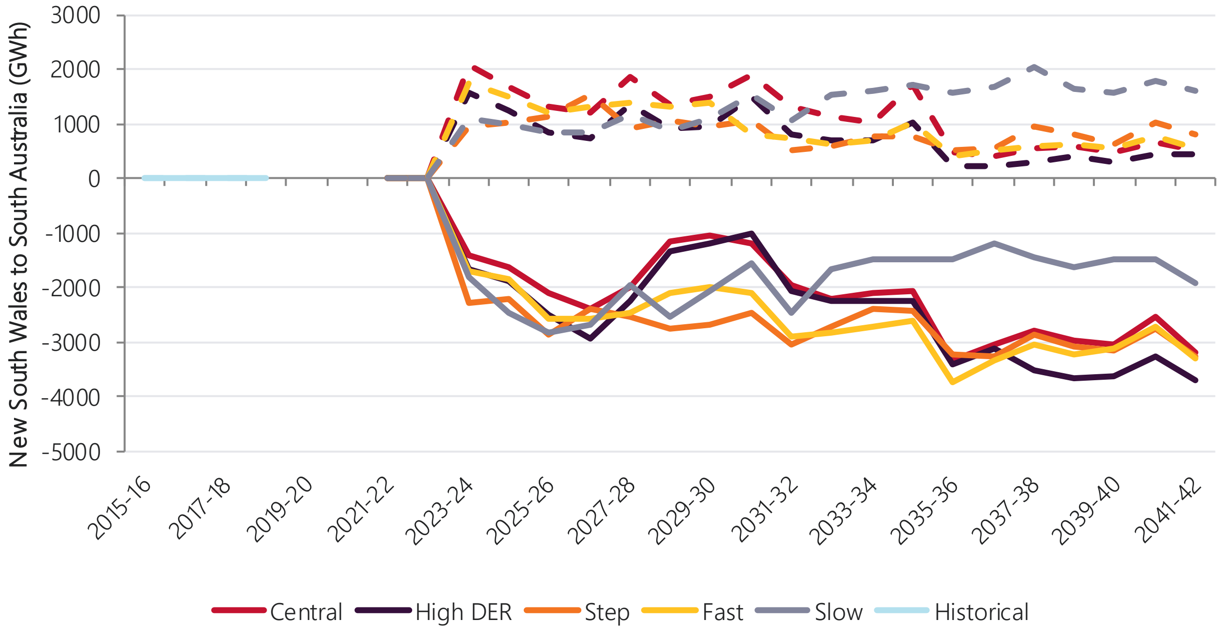


Figure 112 presents the energy transfers between New South Wales and South Australia with the introduction of the Project EnergyConnect interconnector. Positive values (dotted line) represent flows from New South Wales into South Australia, conversely the negative solid lines represent energy transfers from South Australia into New South Wales.

With the introduction of Project EnergyConnect in 2023-24, energy transfers between the adjacent regions are forecast to be broadly evenly split across westerly and easterly flows. There is a combination of factors that leads to this relationship, with South Australia having a high proportion of VRE in comparison to adjacent regions, leading to exports in to New South Wales via Project EnergyConnect during high renewable production periods. In a complementary manner, during periods of lower VRE production, South Australia is able to access lower cost black coal-fired generation from New South Wales reducing the need to call upon local gas and peaking generation to meet local demand.

Figure 112 Inter-regional transfers New South Wales to South Australia (Project EnergyConnect)

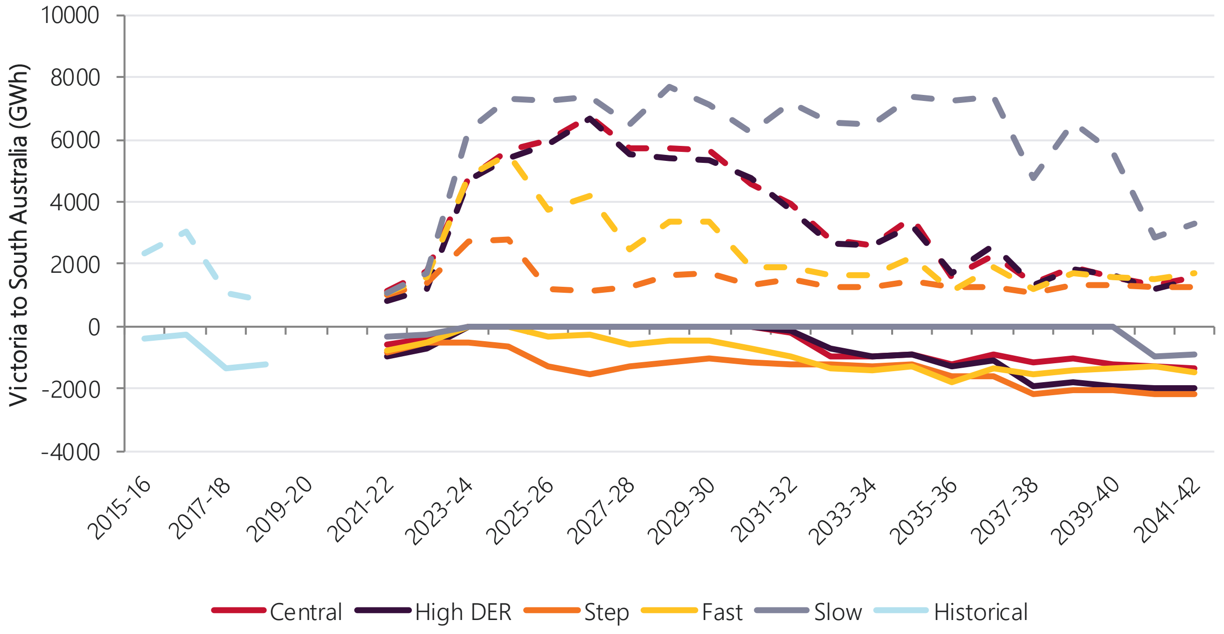


Historically the energy transfers between South Australia and Victoria have predominately been influenced by access to low cost thermal generation, notably brown coal generation. With a number of phased retirements in both regions experienced in the past few years, the energy transfers between these regions have been changing. Most recently, net energy transfers between the regions has neutralised through a combination of generation developments and operational requirements. This trend is forecast to briefly continue in the near term before the introduction of a number of grid developments including but not limited to Project EnergyConnect and the system strength remediation project. With the introduction of this interconnector the ability to share resources between South Australia, Victoria and New South Wales is enhanced to provide a more efficient generation production outcome. This increased transfer outlook is presented in Figure 113 coinciding with the introduction of Project EnergyConnect and reduced expectation for higher utilisation of existing thermal generators in South Australia.

The inter-regional transfers are forecast to be dominated by flow in the westerly direction, particularly in the Slow Change scenario, where low consumption increases the value of transmission to share existing resources more efficiently across the NEM. Towards the end of the planning horizon, in all other scenarios, there is more balanced flow in both directions due to greater penetration of VRE across the two regions corresponding to a reduction in dispatchable thermal generation.

The inter-regional transfers are forecast to be dominated by flow in the westerly direction, particularly in the Slow Change scenario, where low consumption increases the value of transmission to share existing resources more efficiently across the NEM. Towards the end of the planning horizon, in all other scenarios, there is more balanced flow in both directions.

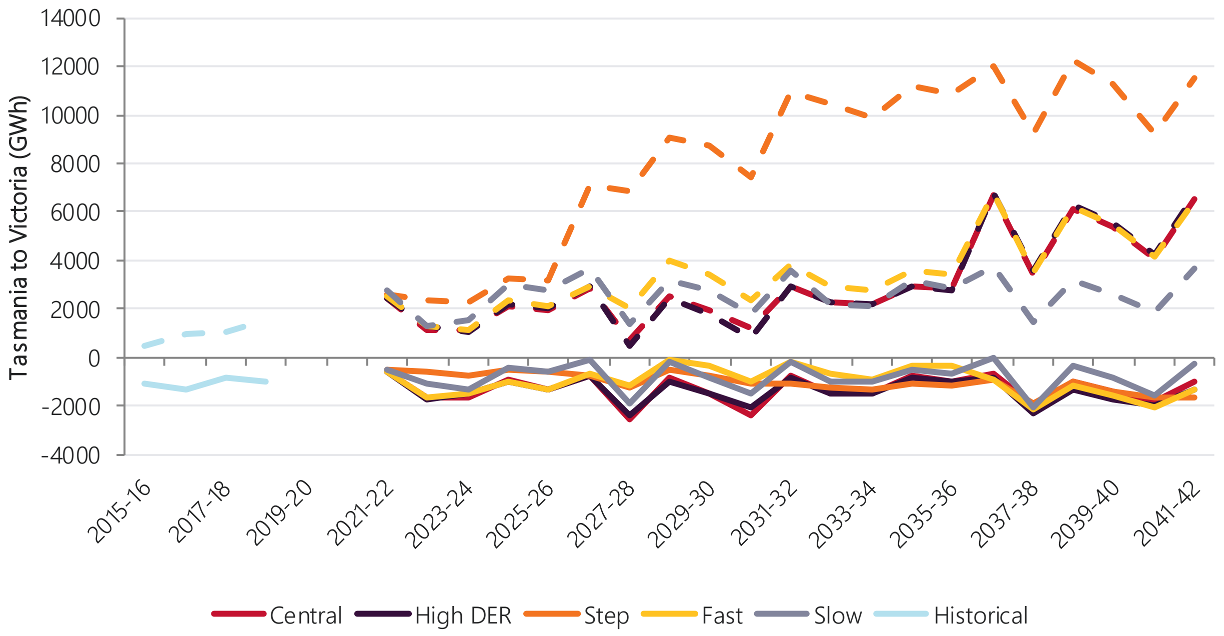
Figure 113 Inter-regional transfers Victoria to South Australia



Historically the prevailing energy transfers from Tasmania into Victoria have been significantly influenced by the year on year inflows to the hydro schemes throughout Tasmania. This trend is expected to continue, and this variability is visible in Figure 114.

The expectation for variation in long term trends across the 20 year outlook period for transfers between Tasmania and the mainland will predominately be influenced by hydro scheme and large-scale wind developments.

Figure 114 Inter-regional transfers Tasmania to Victoria



5.5 Drivers of regret for candidate development paths

As outlined in the Draft ISP, AEMO investigated five alternative candidate development paths before selecting the optimal development path. These candidate paths were selected based on different decisions around timing of future transmission developments that need to be made now:

1. **No accelerated action** – take no further action on VNI West and Marinus Link in the next 24 months.
2. **Accelerated VNI West** – progress VNI West immediately (targeting operation by 2028-29, or by 2026-27 under some scenarios/sensitivities), and take no action on Marinus Link.
3. **Accelerated Marinus Link** – progress Marinus Link immediately (targeting operation by 2026-27), and take no action on VNI West.
4. **Accelerated VNI West and Marinus Link** – the combination of candidates 2 and 3, i.e. progress both VNI West and Marinus Link immediately.
5. **Accelerated VNI West and shovel-ready Marinus Link** – progress VNI West immediately (targeting operation by 2028-29, or by 2026-27 under some scenarios/sensitivities), and progress Marinus Link only to the "shovel-ready" development stage, to shorten lead times to delivery when needed.

The following section compares generation and energy storage development opportunities under these candidate development paths against the development opportunities if transmission was optimally timed for a particular scenario assuming perfect foresight ("optimally timed development").

These differences form the basis for the regret costs calculated in the Part D of the Draft ISP, and are summarised in Table 19 below for completeness. The regret cost represents the reduction in future benefits (i.e. increase in total system costs) resulting from making a sub-optimal decision. Candidate development paths with relatively low regret costs are more readily able to adapt over time to accommodate future uncertainties and therefore carry less risk of over or under investment.

For each scenario and candidate development path, the regret costs are calculated as:

Regret cost = Cost (candidate development path) less Cost (optimally timed development)

where

- The cost of the candidate development path assumes all investment decisions associated with that path are made now, but future developments are then re-optimised to adapt to the scenario drivers as appropriate
- The cost of the optimally timed development reflects the optimal path for the specific scenario that maximises net market benefits assuming perfect foresight.

Table 19 Regret costs

Scenario / Sensitivity	No accelerated action	Accelerated VNI West	Accelerated Marinus Link	Accelerated VNI West and Marinus Link	Accelerated VNI West and shovel-ready Marinus Link
Central	0	-67	-288	-380	-108
High DER	0	-83	-279	-470	-124
Step Change	-240	-139	0	0	0
Slow Change	0	-25	-130	-155	-155
Fast Change	0	-80	-25	-170	-121
Worst Regret	**-240**	**-139**	**-288**	**-470**	**-155**

Scenario / Sensitivity	No accelerated action	Accelerated VNI West	Accelerated Marinus Link	Accelerated VNI West and Marinus Link	Accelerated VNI West and shovel-ready Marinus Link
Early retirement	-118	0	-156	-307	-41
No QRET	0	-49	N/A	N/A	-94
Snowy 2.0 delay	0	-66	-281	-372	-107
Central West NSW REZ	0	-83	N/A	N/A	-129
Early load closure	0	-32	N/A	N/A	-78

5.5.1 No acceleration

The "no acceleration" development path is broadly consistent with the 'optimally timed developments' of the Central, High DER, Slow Change, and Fast Change scenarios (assuming perfect foresight). However, pursuing this approach can result in material regrets typically associated with an accelerated rate of retirements for existing coal generators. In the Step Change scenario, 'no acceleration' actually means that action is delayed and interconnector developments will not be able to be developed in accordance with the optimal timing that maximises net market benefits.

Figure 115 below shows the overall lower costs projected for the "optimally timed development" (assuming perfect foresight) compared to the "no acceleration" development path in the Step Change scenario. In this scenario, negative values show costs that are lower in the "optimally timed development". Even though the interconnector costs are higher, the key contributor to overall lower costs for the "optimally timed development" is generation capital deferral benefit (lower capex). The regret cost of $240 million under this scenario and candidate development path therefore reflects the additional cost (ultimately borne by consumers) associated with building new generation than would otherwise be needed if Marinus Link was in operation.

Figure 115 Forecast drivers of regret costs to 2041-42 for "no acceleration" when compared to "optimally timed development", Step Change scenario

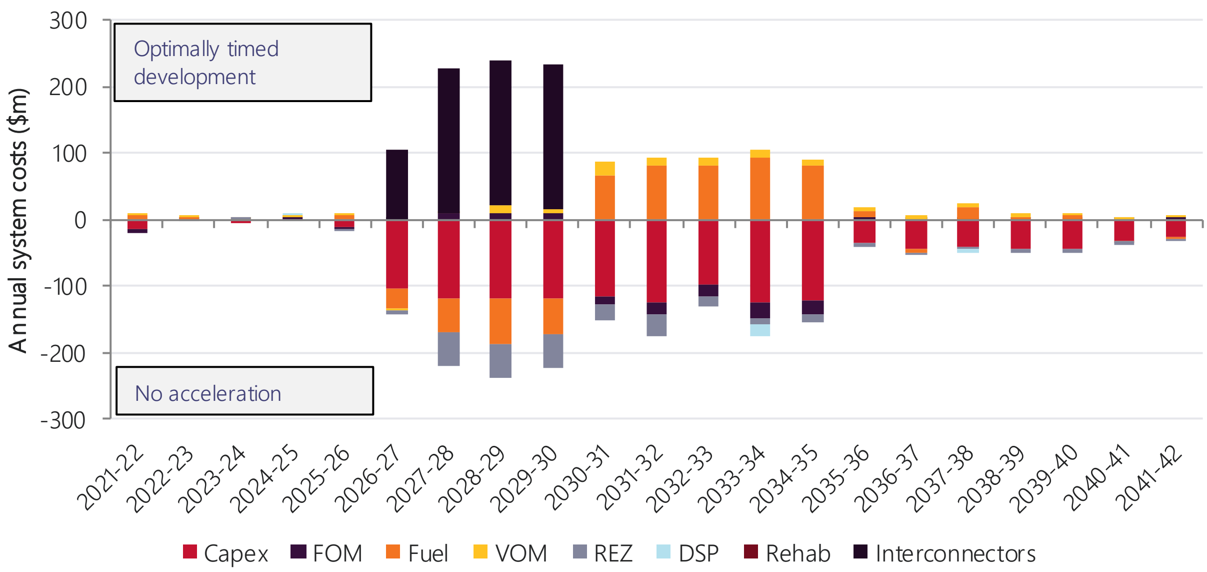


Figure 116 shows that the projected capex cost difference is due to less solar and pumped hydro developments (negative values indicate less capacity in the candidate development path than in the "optimally timed development"). The "optimally timed development" deploys Marinus Link earlier, utilising the efficient operation of Tasmanian hydro assets and wind generation, reducing the need for additional development to offset earlier coal retirements.

Figure 117 shows generation output difference in black coal and CCGT that drive the projected fuel cost differences between the "optimally timed development" and "no acceleration".

Figure 116 Forecast installed capacity differences to 2041-42 for "optimally timed development" compared to "no acceleration", Step Change scenario

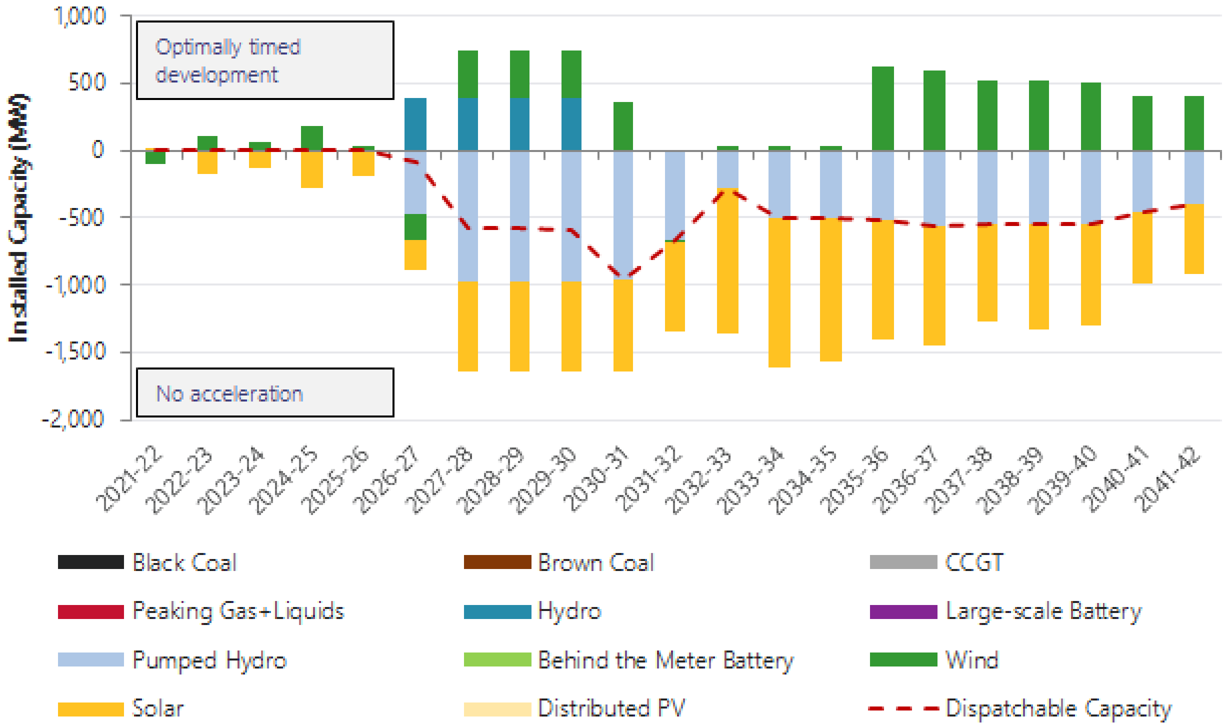
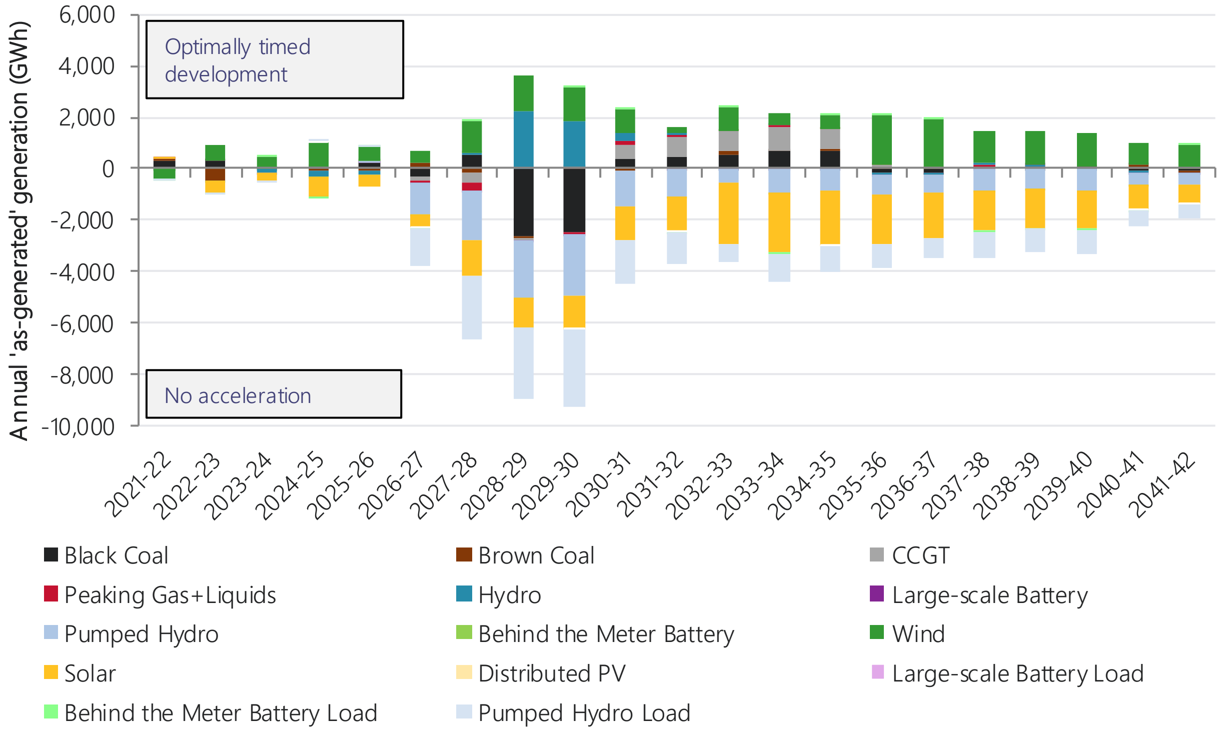


Figure 117 Forecast generation output differences to 2041-42 for "optimally timed development" compared to "no acceleration", Step Change scenario



5.5.2 VNI West accelerated

In the Central, High DER and Fast Change scenarios, the VNI West accelerated candidate development path delivers similar fuel cost savings and capital deferral benefits as the optimally timed development, albeit three years earlier, given that it incorporates the accelerated development of the VNI West interconnector (see Figure 118).

These benefits are almost as large as the cost of the accelerated developments, leading to relatively low regret costs of between $67 million and $83 million across the Central, High DER and Fast Change scenarios. The Step Change scenario has lower benefits than the 'optimally timed development' as the candidate development path results in a four year delay in delivering the Marinus Link interconnector in this scenario. In the Slow Change scenario, early works of approximately $25 million are assumed to be spent, but not needed, as further development of this link is abandoned.

Figure 118 Forecast drivers of regret costs for "VNI West accelerated development" when compared to "optimally timed development", Central scenario

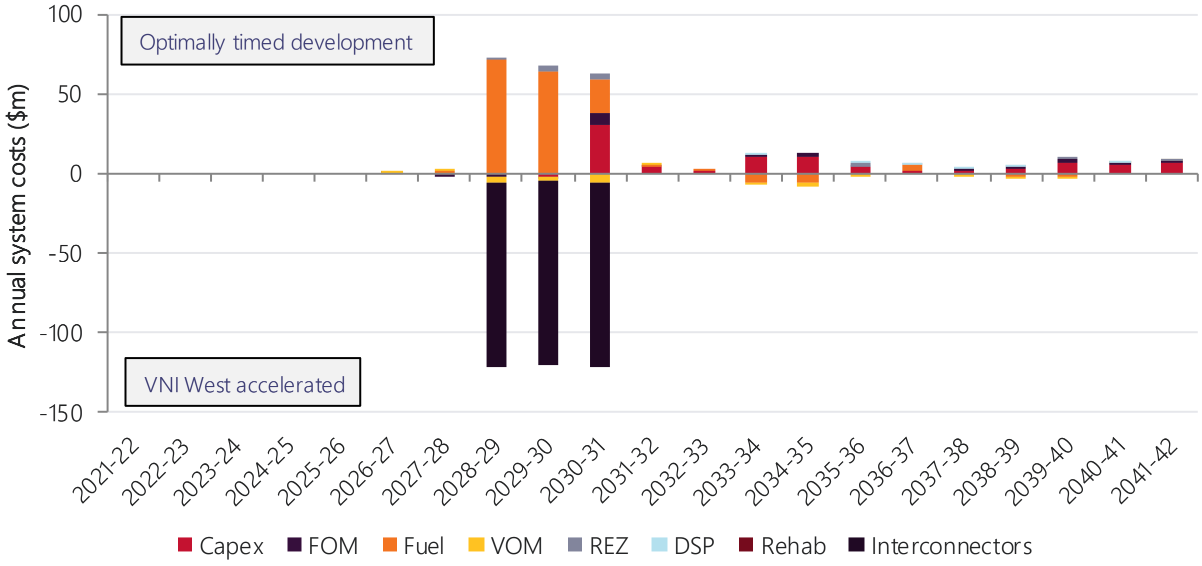


Figure 119 presents the forecast capacity differences between the Central scenario's 'optimally timed development' and 'VNI West accelerated' development paths. As shown, the primary difference is the VRE build in 2030-31, with the 'optimally timed development' path requiring additional new solar capacity as Yallourn progressively retires in absence of VNI West (which is not retired to the next year).

With earlier transmission development in the optimal development path, if early brown coal retirement does not occur, more Victorian brown coal generation can be shared efficiently with neighbouring regions, offsetting the relatively higher cost generation in New South Wales and Queensland (as shown in Figure 120). Differences are relatively small after 2031-32 given that the two development paths converge, in terms of interconnector developments.

Figure 119 Forecast installed capacity differences to 2041-42 for "optimally timed development" compared to "VNI West accelerated", Central scenario

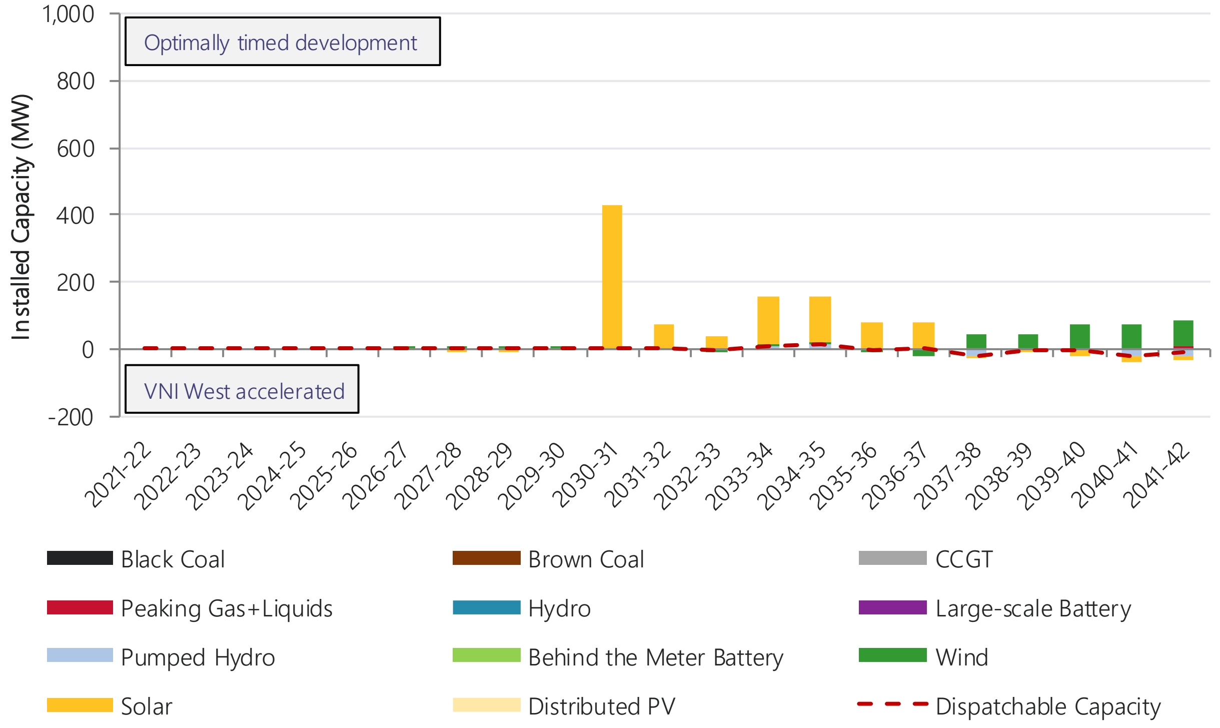
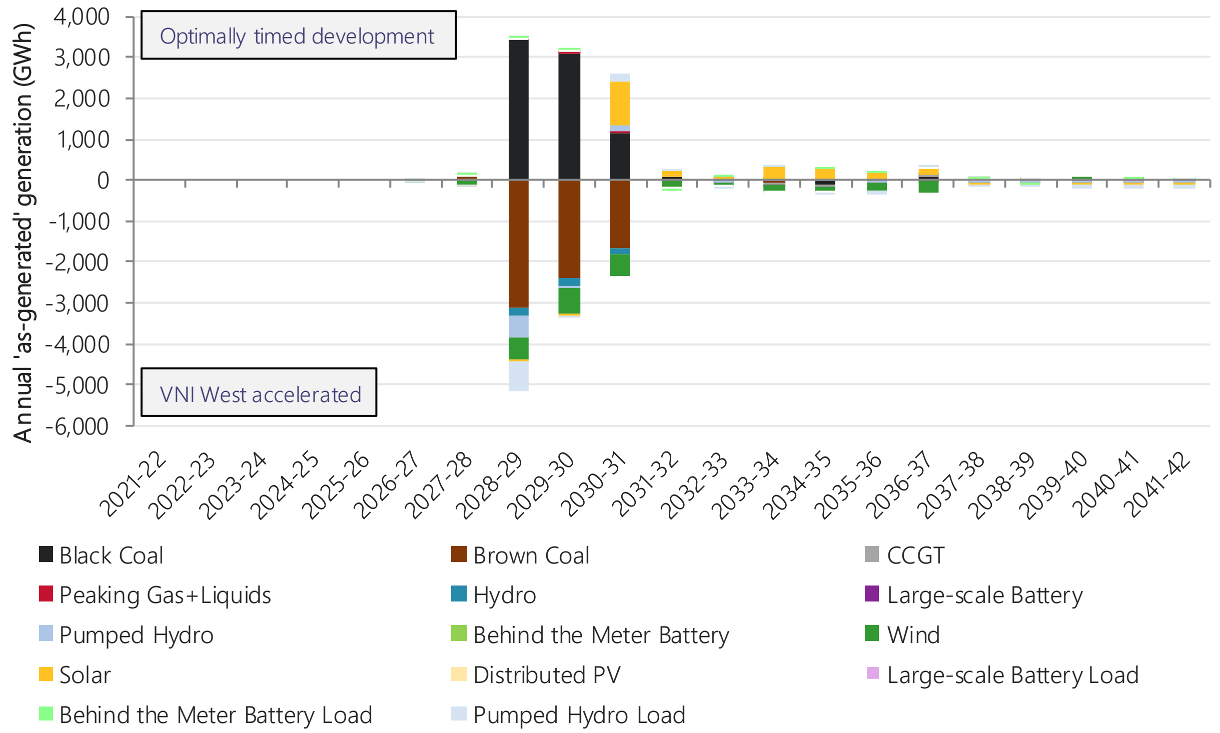


Figure 120 Forecast generation differences to 2041-42 for "optimally timed development" compared to "VNI West accelerated", Central scenario



5.5.3 Marinus Link accelerated

The Marinus Link accelerated candidate development path is projected to deliver benefits in both the Central and High DER scenarios, through a minor reduction in fuel and new entrant development costs, shown in Figure 121.

These minor benefits do not outweigh the cost of accelerating the Marinus Link interconnector, producing a total regret cost of $279 million to $288 million in these two scenarios.

In the Step Change scenario there is no-regret cost as Marinus Link is built at the optimal time for this scenario. Similarly, in Fast Change scenario, where less VRE is built in Victoria to 2030, the benefits of accelerated Marinus Link development are greater and so therefore the regret costs are much smaller ($25 million).

Figure 121 Forecast drivers of regret costs for "Marinus Link accelerated development" when compared to "optimally timed development", Central scenario

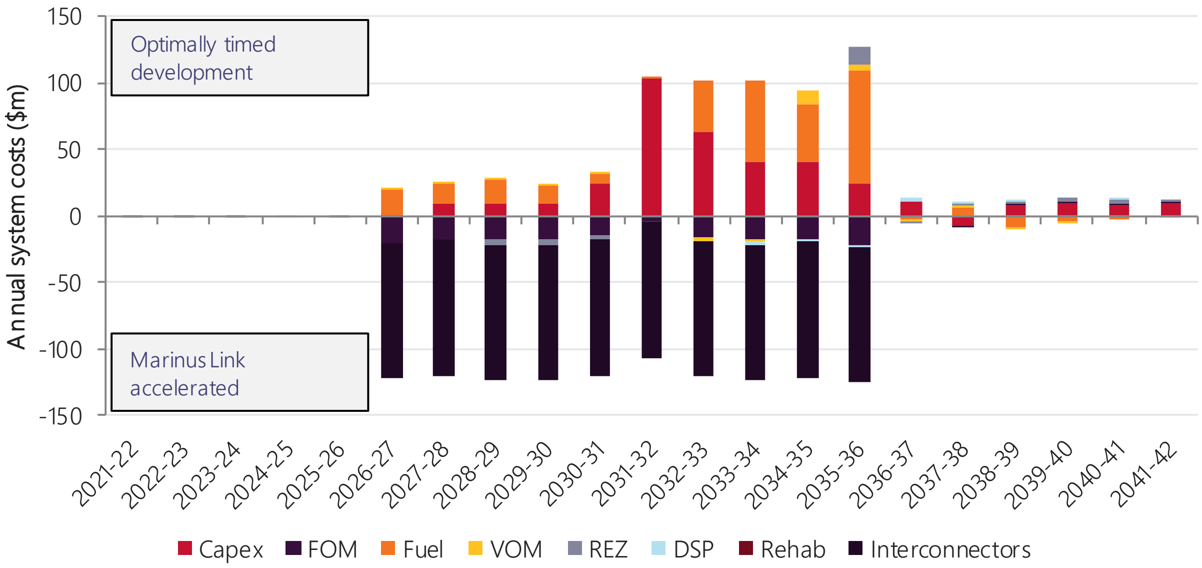
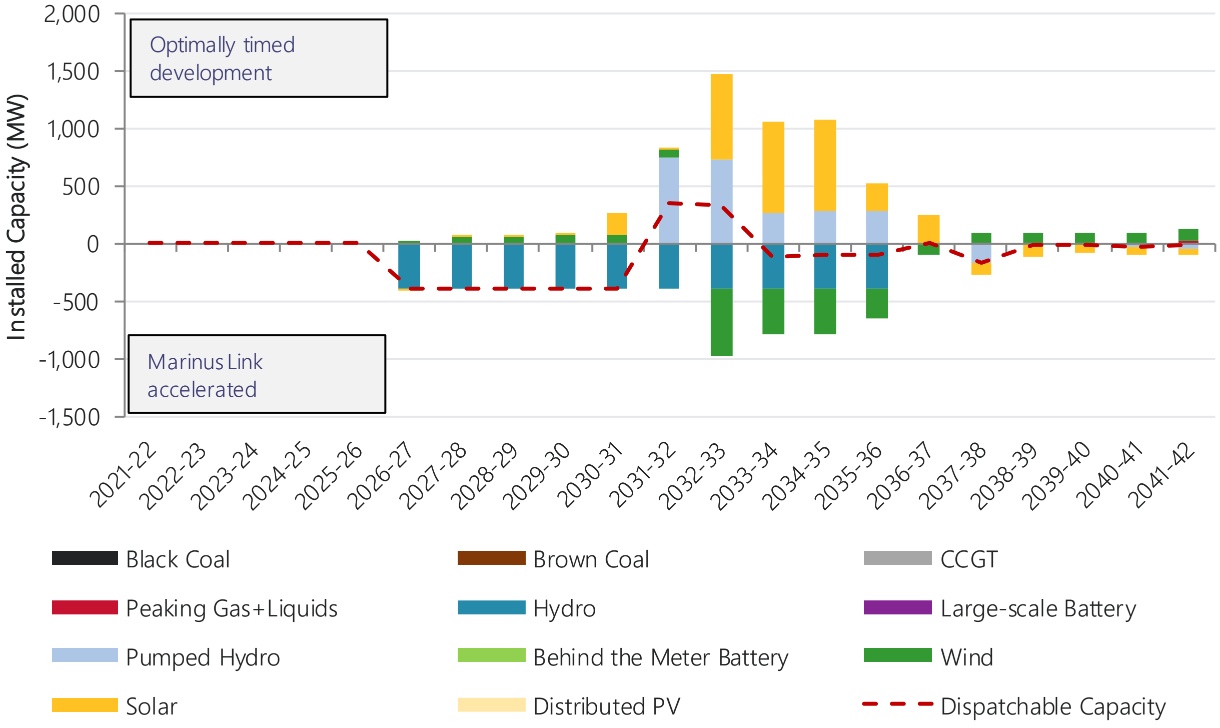


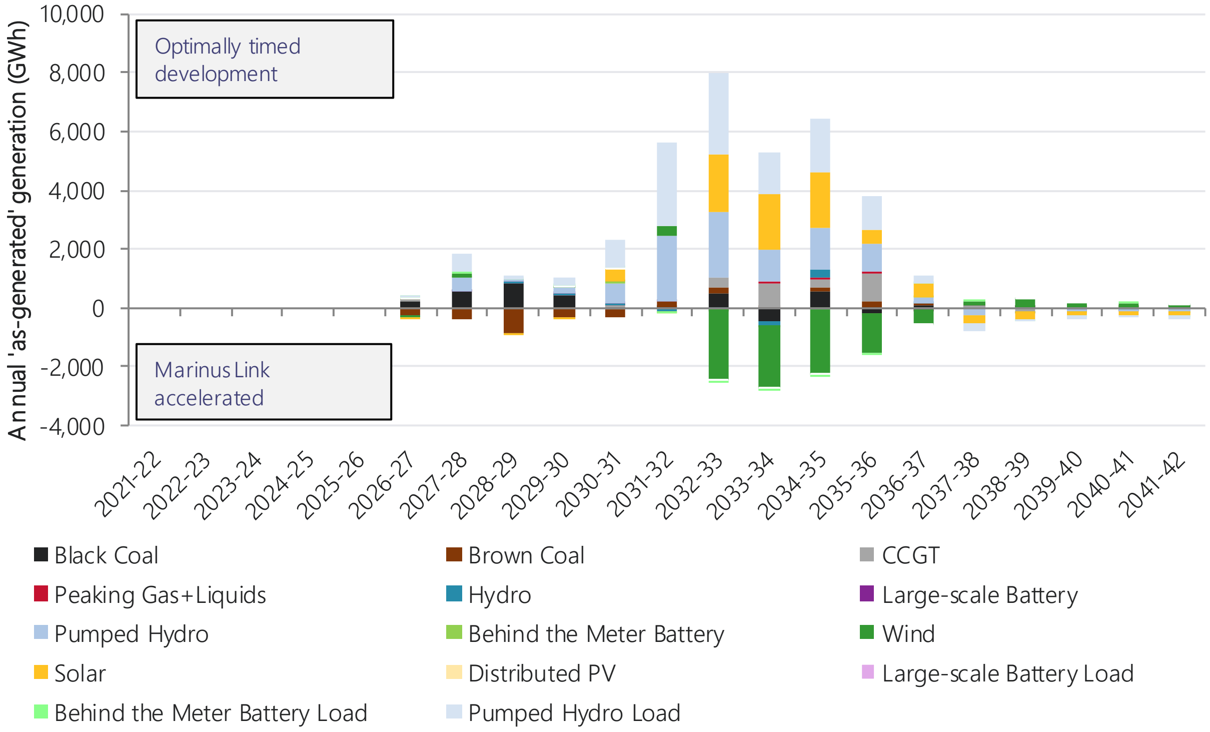
Figure 124 presents the forecast capacity differences between the Central scenario's "optimally timed development" and "accelerated Marinus Link" development paths. As thermal generators begin to retire from 2031-32, the generation development outlooks diverge, with the "optimally timed development" selecting a pumped hydro and solar response, and the "accelerated Marinus Link path" using existing hydro and new entrant wind to replace the retirements. From 2036-37, the interconnector development paths converge, resulting in very similar total system costs, generation capacity, and generation production outcomes.

Figure 122 Forecast installed capacity differences to 2041-42 for "optimally timed development" compared to "accelerated Marinus Link", Central scenario



As shown in Figure 121 and Figure 122, there is minimal operational difference between the two development paths from 2026-27 to 2030-31, and this is reflected in the similar generation production outcomes in Figure 125. Of note is the period after 2033, where there is a transition away from wind generation in the candidate development path with Marinus Link accelerated, to a system that favours the utilisation of complementary solar generation with pumped hydro. As the interconnector development paths converge in 2036-37, the generation production outcomes also align between the two development paths.

Figure 123 Forecast generation differences to 2041-42 for "optimally timed development" compared to "accelerated Marinus Link", Central scenario



5.5.4 VNI West and Marinus Link accelerated

Accelerated development of both VNI West (brought forward to 2028-29) and Marinus Link (to 2026-27) is projected to come at a regret cost of $380 million in the Central scenario, primarily driven by the higher cost associated with expediting both augmentations.

AEMO modelling indicates that the increase in transmission expenditure under this candidate development path would not be adequately offset by savings in fuel and generation investment costs. As outlined in Figure 124, if both VNI West and Marinus Link were accelerated, projected savings in the first few years are primarily driven by minor reductions in fuel cost. From 2030-31 until the two pathways converge again in 2036-37, the presence of both interconnectors is projected to defer new generation investments, due to better energy and reserves sharing within the mainland and between mainland and Tasmania. Yet, while the savings in fuel costs, generation capex and intra-regional transmission costs (REZ costs) are projected to exceed $311 million, the increase in costs associated with bringing forward development timing of the transmission infrastructure is estimated to reach $691 million.

Delivery of Marinus Link in 2026-27 could assist with unlocking latent hydro capacity available in Tasmania early, as well as bringing forward investments in wind generation. Increased ability to share reserves would also delay the need for additional dispatchable capacity on the mainland as existing assets begin to retire in the early 2030s. From 2036-37 until the end of the study period, the projected impact on installed capacity is marginal, with slightly less wind and solar installations under the VNI West and Marinus Link accelerated pathway (see Figure 125).

Differences in projected capacity installed are reflected in the generation mix, particularly from 2030. As Figure 126 shows, the generation portfolio is forecast to feature a higher contribution from wind and lower reliance on storage, solar and gas generation.

Figure 124 Forecast drivers of regret costs of the VNI West and Marinus Link accelerated development path when compared to the "optimally timed development", Central scenario

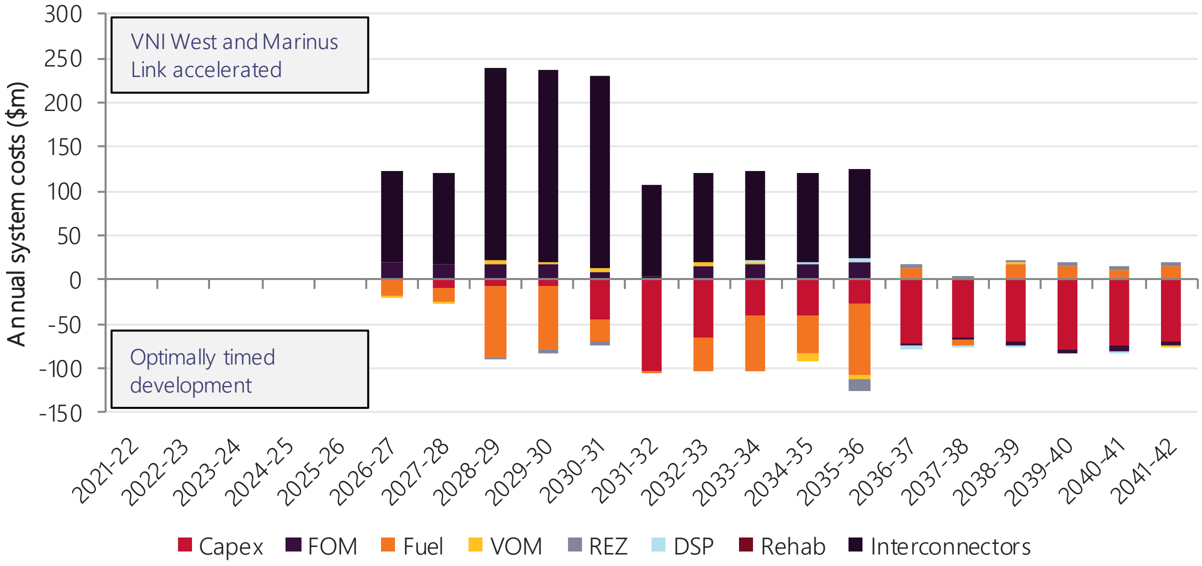


Figure 125 Forecast installed capacity differences to 2041-42 for "optimally timed development" compared to "VNI West and Marinus Link accelerated", Central scenario

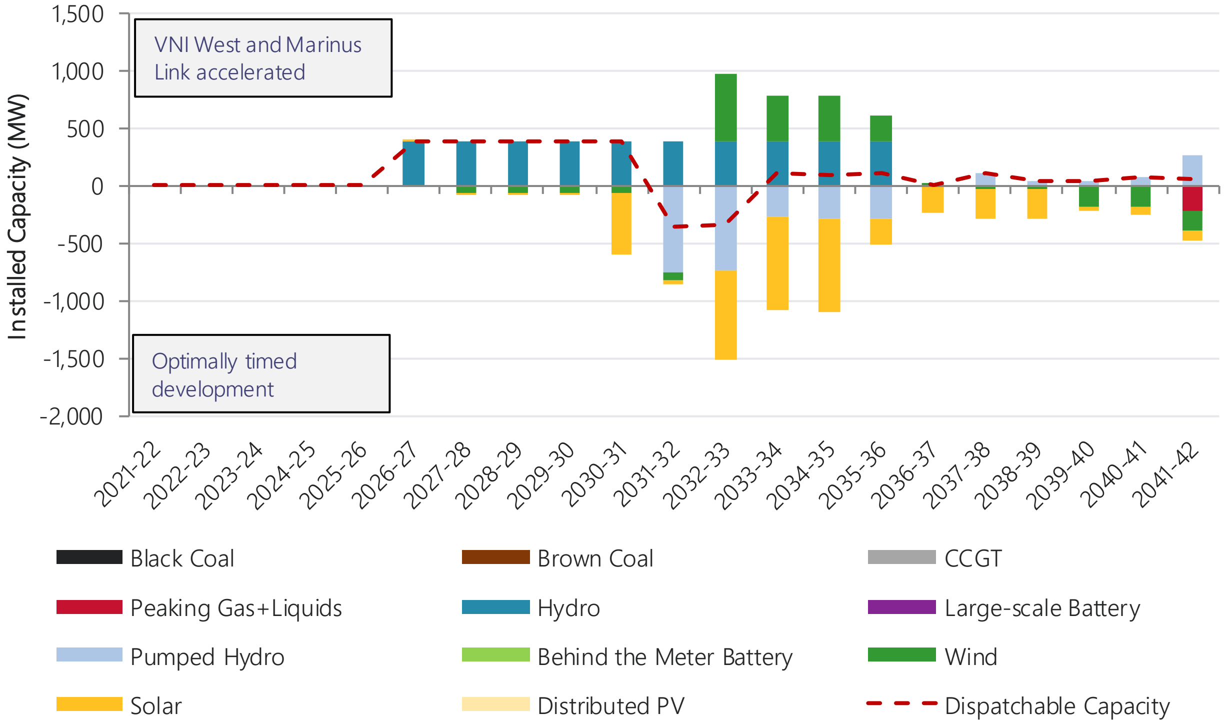
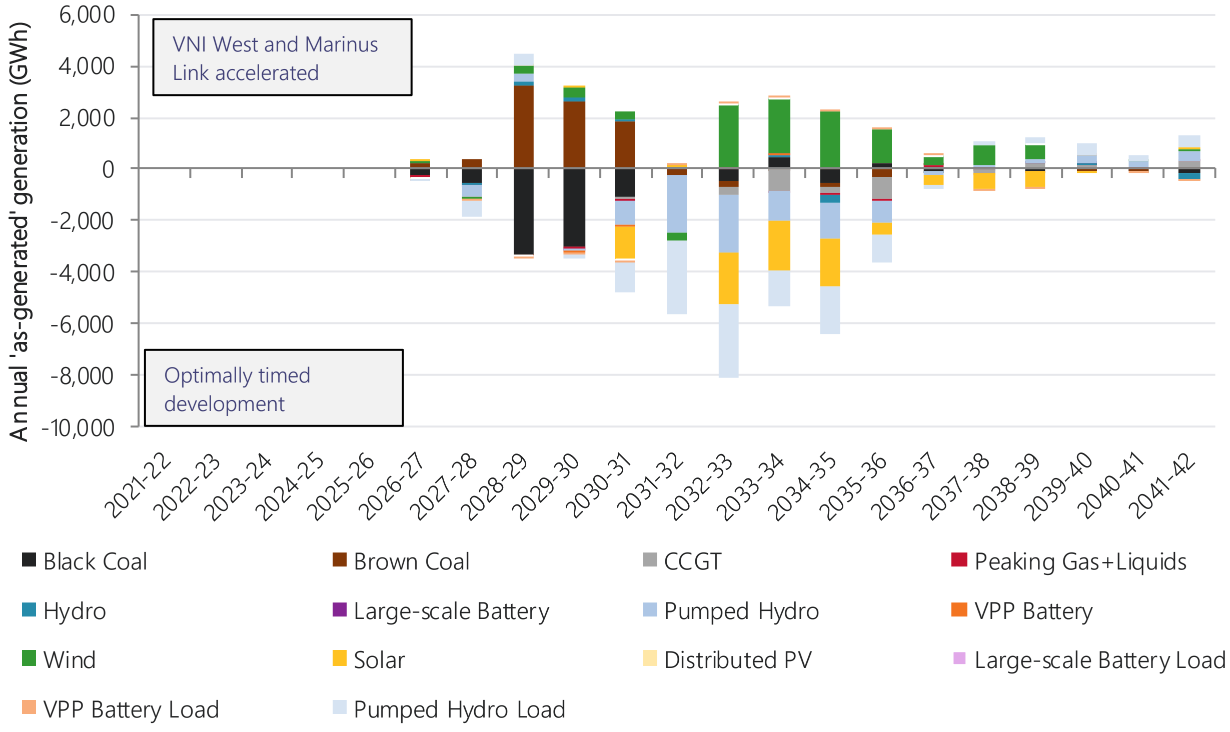


Figure 126 Forecast generation differences to 2041-42 for "optimally timed development" compared to "VNI West and Marinus Link accelerated", Central scenario



5.5.5 VNI West accelerated and Marinus Link shovel ready

The gross market benefits delivered from the candidate development path are identical to those delivered by the VNI West accelerated candidate development path under the Central, High DER and Fast Change scenarios. In these scenarios, Marinus Link is still constructed in accordance with its 2036-37 optimal timing, however by bringing forward the early works, approximately $41 million additional cost is incurred due to the time value of money.

This cost represents option value, as it allows Marinus Link to be built earlier if needed, and is also estimated to save costs of approximately $20 million by keeping current momentum going and avoiding need to rework the feasibility and business case assessments at a later date.

In the Step Change scenario, with accelerated closures of coal-fired generators to meet strong carbon reduction ambitions, this candidate development path represents no regret, as Marinus Link is optimally timed to be available when needed.

Appendix 6. Network investments

This section outlines the individual transmission network elements in projects that were assessed for inclusion in candidate development plans and the eventual ISP optimal development plan.

The 2019 Input & Assumptions workbook[21] details the complete set of credible options considered when preparing and evaluating the development plans. The options include non-network solutions, such as generation and storage.

AEMO welcomes submissions from interested parties on potential non-network solutions that may meet the identified need for these projects.

In this appendix, all dates are indicative, and on a financial year basis. For example, 2023-24 represents the financial year ending June 2024.

6.1 The transmission roadmap

Table 20 and Figure 127 outline major components of ISP optimal development plan along with other developments and projects, and the approval status of each project. Click on a project name in the table to link to the relevant section of this Appendix.

Table 20 Summary of the transmission projects (not all actionable ISP projects)

Group	Project	Indicative Timing †	Approval Status	Actionable ISP Project
Group 1 (Priority grid projects)	SA system strength remediation	2020-21 to 2021-22	Committed	Committed
	Western Victoria transmission augmentation	2025-26	Committed	Committed
	QNI Minor	2021-22	RIT-T in progress	Actionable (Continue RIT-T)
	VNI Minor	2022-23	RIT-T in progress	Actionable (Continue RIT-T)
	Project EnergyConnect	2023-24	RIT-T in progress	RIT-T in progress
	HumeLink	2024-25	RIT-T in progress	Actionable (Continue RIT-T)
	VNI West (formerly "KerangLink")	2026-27 to 2028-29	RIT-T in progress	Actionable (Continue RIT-T)

[21] AEMO. *2019 Input and Assumptions Workbook*, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan.

Group	Project	Indicative Timing †	Approval Status	Actionable ISP Project
	Progress Marinus Link to “shovel-ready”	2023-24	RIT-T in progress	No – Progress to ‘shovel ready’
Group 2 (Near term grid projects)	QNI Medium	2026-27 to 2028-29	Not started	Actionable (Initiate RIT-T)
Group 3 (Future grid options)	Marinus Link	2026-27 to 2036-37	RIT-T in progress	No – Progress to ‘shovel ready’ as Group 1; finalise assessments for decision by 2023-24
	QNI Large	2030s to 2040s	Not started	No – further assess needs, timing and implementation options
	Far North Queensland REZ	2025-26 to 2036-37	Not started	No – further assess needs, timing and implementation options
	Gladstone Grid Reinforcement	2025-26 to 2035-36	Not started	No– further assess needs, timing and implementation options
	Central to Southern Queensland	2024-25 to 2036-37	Not started	No – investigate short term options to relieve near term congestion earlier
	New England REZ	Mid-2030s	Not started	No– further assess needs, timing and implementation options
	North West NSW REZ	Mid-2030s	Not started	No– further assess needs, timing and implementation options
	Central West NSW REZ ‡	2025 to 2036-37	Not started‡	No– undertake further assessment of the recently announced policy and re-assess needs, timing and implementation options
	Sydney load centre reinforcement	2026-32	Not started	No– further assess needs, timing and implementation options before 2022 ISP
	South East South Australia REZ	2028-29 to 2038-39	Not started	No– further assess needs, timing and implementation options
	Mid North South Australia REZ	2028-29 to 2036-37	Not started	No– further assess needs, timing and implementation options

† The earliest time by when the project has been found to needed in the optimal development plan, allowing for practical delivery times. Regulatory approval is generally required years before construction can be completed.
‡ The timing of developments and projects to implement Central West New South Wales REZ may change due to the recent announcement of the New South Wales Electricity Strategy.

6.1.1 Group 1 committed priority grid projects

The Draft 2020 ISP identifies the following Group 1 priority projects that are already committed:

- South Australia system strength remediation.
- Western Victoria Transmission Network Project.

South Australia System Strength Remediation

The 2018 ISP recommended synchronous condensers as an urgent need for system strength remediation. ElectraNet has since gained regulatory approval to install two synchronous condensers at Davenport and two at Robertstown[22].

The project is expected to be completed in early 2020-21.

Identified need

AEMO declared a system strength gap in December 2016. In 2017, the Fault Level rule change[23] required TNSPs to maintain a minimum level of system strength, as defined by AEMO. In 2018 AEMO also declared an inertia gap in South Australia, recommending high-inertia synchronous condensers in South Australia that would address both the inertia shortfall and the declared system strength gap.

Augmentation description

This project is committed and includes installation of:

- Two high inertia synchronous condensers at Davenport 275 kilovolt (kV) substation.
- Two high inertia synchronous condensers at Robertstown 275 kV substation.

Each of the four synchronous condensers provide 575 megavolt amperes (MVA) nominal fault current and 1,100 MWs of inertia. Figure 128 highlights the location of the four synchronous condensers.

[22] ElectraNet. Strengthening Sough Australia's power system, at https://www.electranet.com.au/what-we-do/projects/power-system-strength/.

[23] AEMC: Managing Power System Fault Levels, at https://www.aemc.gov.au/rule-changes/managing-power-system-fault-levels

Figure 127 Summary of the ISP optimal development plan

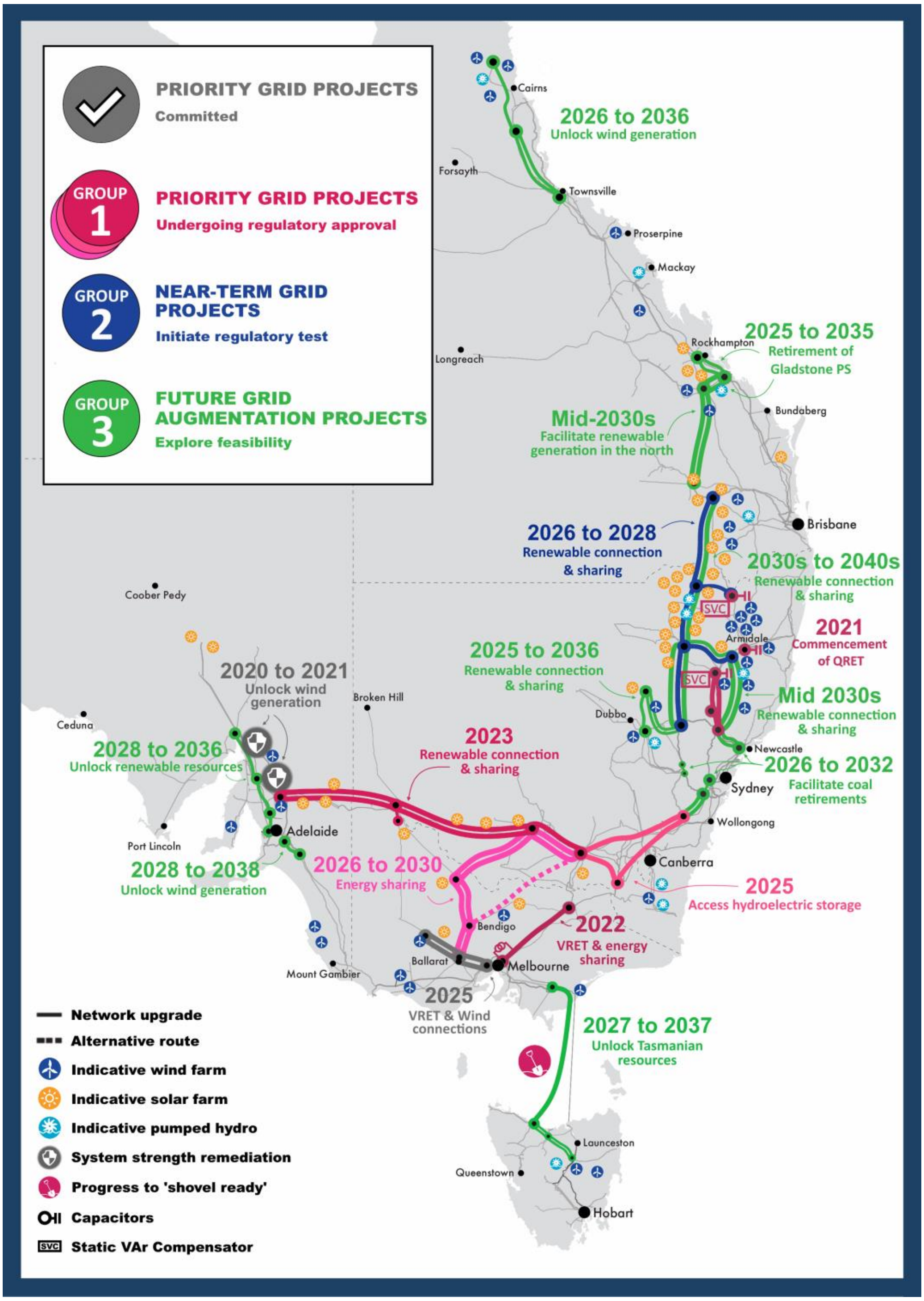
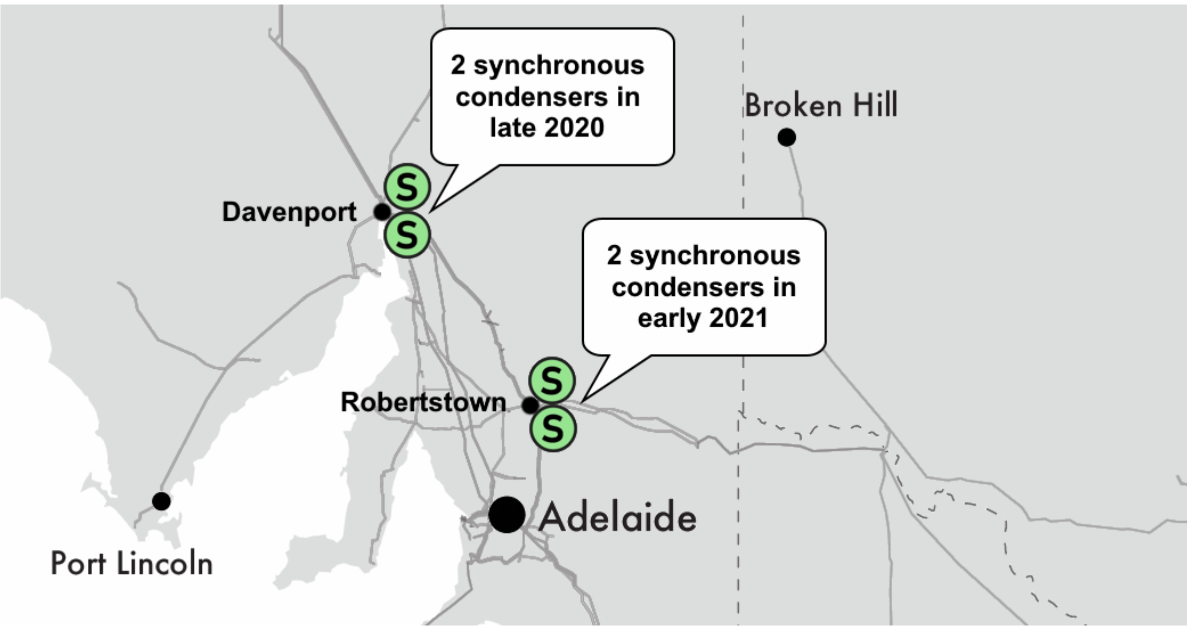


Figure 128 Synchronous condenser locations and commissioning dates



Western Victoria transmission augmentation

Western Victoria transmission augmentation is a combination of 500 kV and 220 kV transmission augmentations to alleviate constraints identified on the 220 kV network between Moorabool and Horsham. These constraints are due to the development of large-scale renewable generation within the area.

Identified need

The identified need for the Western Victoria augmentation is to increase the thermal capacity of the Western Victoria power system, reducing constraints on the network that would restrict generation within this REZ. It will deliver net market benefits and support the energy market transition by reducing the capital cost and dispatch cost of generation in the long term[24].

Augmentation description

The Western Victorian augmentation works are separated into two phases – a short-term and a medium term- upgrade (see Figure 129).

The short-term 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.

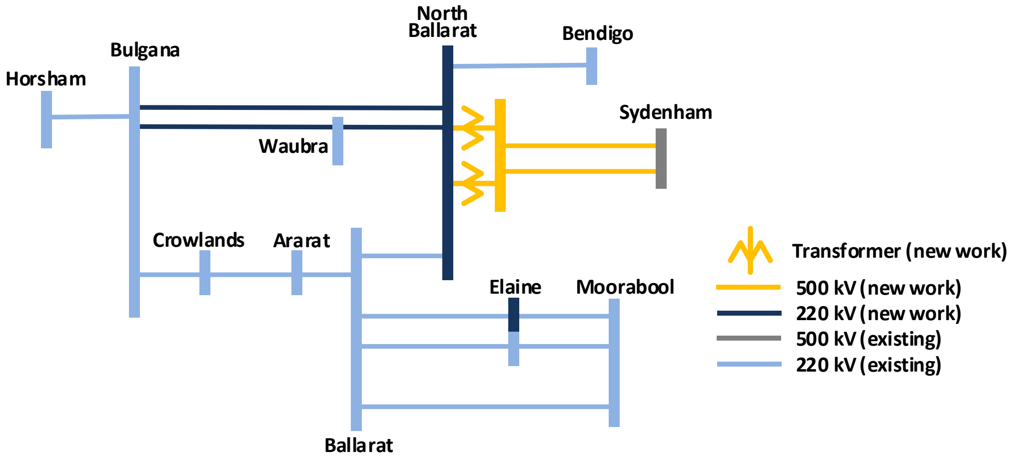
The medium-term augmentation includes:

- A new terminal station at North Ballarat.

[24] AEMO, 2019 Victoria Annual Planning Report found at, https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/VAPR/2019/Victorian-Annual-Planning-Report-2019.pdf

- A new 500 kV double circuit transmission line from Sydenham to North Ballarat.
- A new 220 kV double circuit transmission line form North Ballarat to Bulgana (via Waubra).
- 2 x 500/220 kV transformers at North Ballarat.
- Cut-in the existing Ballarat–Bendigo 220 kV line at North Ballarat.
- Moving the Waubra Terminal Station connection from the existing Ballarat–Ararat 220 kV line to one of the North Ballarat–Bulgana 220 kV lines.
- Cut-in the existing Moorabool–Ballarat No. 2 220 kV line at Elaine Terminal Station.

Figure 129 Single line diagram of Western Victoria transmission augmentation



Timing and staging

Western Victoria transmission augmentation is a committed project. The short-term augmentation is expected to be complete by 2021, and the medium-term augmentation, which is currently on track, is to be commissioned in 2025.

Augmentation cost

The short-term Western Victoria transmission augmentation cost estimate is approximately $5.5 million with an accuracy of ±30%.

The medium-term Western Victoria transmission augmentation cost estimate is $473 million with an accuracy of ±30%.

These augmentation costs are aligned with the Western Victoria Project Assessment Conclusion Report (PACR)[25].

Associated REZ benefits

Currently the generation interest within the Western Victoria REZ (V3) exceeds the capacity of the transmission network. With the growth of inverter-based generation in this area, generator outputs are being constrained due to thermal and stability limitations. Network security issues also arise due to diminishing system strength within the area. The level of VRE is expected to increase beyond present levels when Victoria's VRET is met.

The Western Victoria transmission augmentation project seeks to reduce the emerging constraints on the network, unlock renewable energy resources, reduce congestion, and improve the productivity of existing

[25] AEMO, Western Victorian Renewable Integration, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2019/PACR/Western-Victoria-RIT-T-PACR.pdf.

assets. System strength and marginal loss factors will be improved within Western Victoria following this upgrade.

6.1.2 Group 1 new priority grid projects

The Draft 2020 ISP identifies the following Group 1 priority projects that are not currently committed:

- Queensland to New South Wales Interconnector (QNI) Minor and Victoria to New South Wales Interconnector (VNI) Minor upgrades to existing interconnections between New South Wales with Queensland and Victoria respectively. Both projects are currently undergoing regulatory approval processes. Completion of QNI Minor is expected in 2020-21, and VNI Minor in 2022-23;
- Project EnergyConnect, a new interconnector between South Australia and New South Wales, which is close to completing its regulatory approval process and should be delivered in 2023-24.
- HumeLink, an augmentation to reinforce the New South Wales Southern Shared Network and increase transfer capacity between Snowy Hydro and the state's demand centres. This project has commenced its regulatory approval process earlier this year and should be delivered in 2024-25;
- VNI West, a new interconnector between Victoria and New South Wales, which is commencing its regulatory approval process concurrently with the publication of this Draft ISP and is highly desirable by 2026-27 but no later than 2028-29, meaning that the project needs to commence immediately. This is likely to be the fastest way this project can be delivered with underwriting to cover early works combined with expedited planning and approval processes.
- Recommended project (but not yet 'actionable' under draft ISP rules) – progressing with the design and approvals process for Marinus Link (a second, and potentially third, HVDC cable connecting Victoria to Tasmania, with associated AC transmission), to make the project 'shovel-ready' while deferring the final decision on the project to 2023-24 when delivery signposts are clearer. This low-cost, low-regret investment would allow more time for further assessment before the 2022 ISP, and still permit delivery of Marinus Link by as early as 2027-28 if a decision to proceed was made by 2023-24. AEMO's detailed modelling has shown that early completion of Marinus Link would be beneficial if the NEM began to progress towards the Step Change scenario, or if VNI West were delayed or dispatchable generation alternatives in Victoria were more expensive than currently assumed

Project EnergyConnect

Project EnergyConnect is a new interconnector between New South Wales and South Australia with approximately 916 km from Robertstown in South Australia to Wagga Wagga in New South Wales, via the most north section of the Victorian Transmission network. It traverses between east and west, linking the REZ of Riverland (S2) and Murray River (V2), South West New South Wales (N6) and Wagga Wagga (N7), providing the option for additional capability for these REZs.

A RIT-T is in progress[26]. This upgrade is currently on track to be commissioned in 2023-24.

Identified need

The identified need for Project EnergyConnect is to deliver net market benefits and support energy market transition through:

- Lowering dispatch costs, initially in South Australia, through increasing access to supply options across regions.
- Facilitating the transition to a lower carbon emissions future and the adoption of new technologies, through improving access to high quality renewable resources across regions.
- Enhancing security of electricity supply in South Australia.

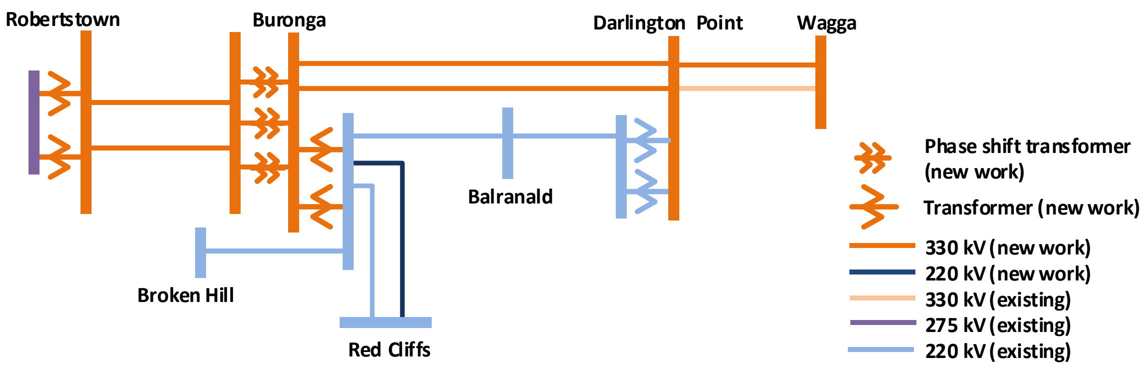
[26] ElectraNet, Project EnergyConnect, https://www.electranet.com.au/projects/south-australian-energy-transformation/.

Augmentation description

Project EnergyConnect involves:

- A new Robertstown–Buronga–Darlington Point 330 kV double circuit line.
- An additional 330 kV single circuit from Darlington Point to Wagga.
- A new double circuit 220 kV line (conductor strung on one side and operated as a single circuit) from Buronga to Red Cliffs.
- 275/330 kV transformers at Robertstown.
- 3 x 330 kV phase shift transformers at Buronga.
- 2 x 330/220 kV transformers at Buronga.
- Turn Robertstown–Para 275 kV line into Tungkillo.
- 2 x 100/-100 MVAr synchronous condensers at Buronga 330 kV.
- 2 x 100/-100 MVAr synchronous condensers at Darlington Point 330 kV.
- Shunt capacitor banks at Robertstown, Buronga, and Darlington Point substations.
- Shunt line reactors at Robertstown, Buronga, and Darlington Point on Robertstown–Buronga–Darlington 330 kV lines.
- A special protection scheme to detect and manage loss of either interconnection of Victoria – South Australia or New South Wales – South Australia.

Figure 130 Single line diagram of Project EnergyConnect



Timing and staging

Project EnergyConnect is a committed project and it is timed optimally in 2023-24 across all scenarios.

The additional single circuit from Buronga to Red Cliffs is proposed with double circuit towers. The second circuit is planned to be added with increased renewable generation in Murray REZ (V2).

There is an associated staging option for the Riverland (S2) REZ, which is discussed in Section 8.3.25.

Augmentation cost

The capital cost estimate is $1,530 million (2018-19 dollars). This augmentation cost is aligned with the South Australia Energy Transformation RIT-T Project Assessment Conclusion Report (PACR).

This augmentation cost includes all new transmission and land and easements associated with the Project EnergyConnect project. Reactive and synchronous plant to address voltage control and system strength and special protection scheme make up approximately 19% of the total cost.

Network capability improvement

Project EnergyConnect would allow a maximum nominal transfer capacity of 800 MW in both directions between New South Wales and South Australia. In addition, this project would increase the existing Victoria – South Australia interconnector (Heywood) transfer capacity by 100 MW in both directions.

With the implementation of special protection scheme to prevent potential loss of one AC interconnector with South Australia for a non-credible loss of other AC interconnector with South Australia, the overall transfer capacity of both AC interconnectors with South Australia (New South Wales – South Australia and Victoria – South Australia) is limited to 1,300 MW import into South Australia and 1,450 MW export from South Australia.

Associated REZ benefits

The proposed Project EnergyConnect route traverses through the Riverland, Murray River, and South-west New South Wales REZs. This provides additional transfer capability from these zones to the wider grid of approximately 800 MW, 600 MW, and 380 MW respectively.

Furthermore, Project EnergyConnect improves the system strength in these zones (see Section 7.2.2).

QNI Minor

A minor upgrade to the New South Wales to Queensland interconnector was recommended as urgently needed in the 2018 ISP. Since that time, Powerlink and TransGrid have commenced a RIT-T[27] to confirm the optimal solution and gain regulatory approval. The draft outcome from this RIT-T, which was published on 30 September 2019, confirms the solution recommended in the 2018 ISP.

This upgrade is progressing through the RIT-T and is currently on track to undergo commissioning in 2021 or early 2022.

Identified need

The identified need for the minor New South Wales to Queensland upgrade, as determined by Powerlink and TransGrid, is *to increase overall net market benefits in the NEM through relieving existing and forecast congestion on the transmission network between New South Wales and Queensland*"[28].

Network limitations

The transfer capability across the New South Wales to Queensland interconnector is limited by transmission line thermal capacity, voltage stability, transient stability, and oscillatory stability. The capability across QNI at any particular time is dependent on a number of factors, including demand levels, generation dispatch, status and availability of transmission equipment, and operating conditions of the network.

For intact system operation, the transfer from Queensland to New South Wales is mainly limited by the following constraints:

- Stability limits for faults on either Sapphire to Armidale or Armidale to Dumaresq line.
- Thermal capacity of the 330 kV lines within northern New South Wales.
- Oscillatory stability upper limit of 1,200 MW.

For intact system operation, the transfer from New South Wales to Queensland is mainly limited by the following constraints:

- Stability limits on loss of the largest Queensland unit.

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[27] Powerlink and TransGrid, *Expanding New South Wales – Queensland Transmission Transfer Capacity*, at https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity/Documents/Expanding%20NSW-QLD%20Transmission%20Transfer%20Capacity%20PADR%20-%20Full%20Report.pdf.

[28] Powerlink and TransGrid, *Expanding New South Wales – Queensland Transmission Transfer Capacity*, at https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity/Documents/Expanding%20NSW-QLD%20Transmission%20Transfer%20Capacity%20PADR%20-%20Full%20Report.pdf.

- Transient stability associated with transmission line faults in the Hunter Valley.
- Voltage collapse for trip of the Liddell to Muswellbrook 330 kV line.
- Thermal capacity of the 330 kV and 132 kV transmission lines within northern New South Wales.
- Oscillatory stability upper limit of 700 MW.

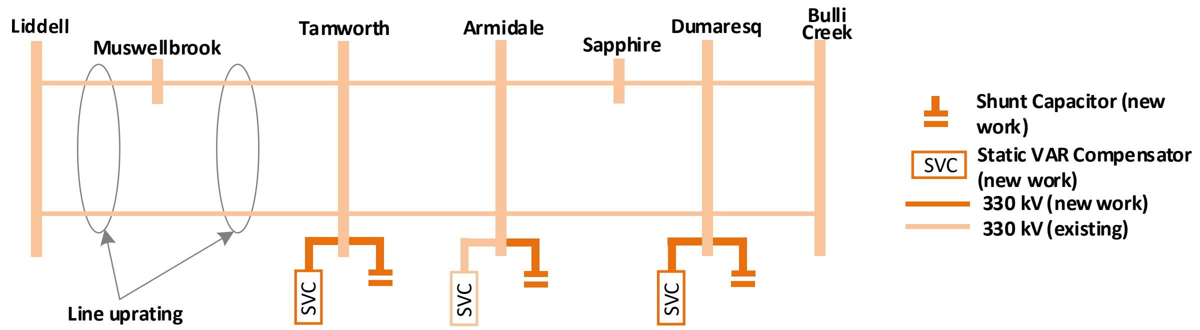
Preferred augmentation option

The preferred QNI Minor upgrade known as "QNI Option 1A" is a minor upgrade of the existing interconnector with uprating to increase thermal capacity of the existing transmission lines and installation of additional new capacitor banks and Static Var Compensators (SVCs). This upgrade is currently progressing through the RIT-T and is expected to undergo commissioning in 2021-22.

The recommended upgrade (QNI Option 1A) involves (see Figure 131):

- 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 a total of 700 megavolt amperes reactive (MVAr) 330 kV switched shunt capacitor banks at Armidale, Dumaresq, and Tamworth substations.
- Installation of dynamic reactive plant at Tamworth and Dumaresq.

Figure 131 Single line diagram of QNI Minor



Alternative augmentation options

A number of alternative options were included in Powerlink and TransGrid's Project Assessment Draft Report (PADR) [29] on expanding New South Wales to Queensland transmission transfer capacity". These are outlined below:

- Option 1B – Uprate Liddell–Tamworth and Liddell–Muswellbrook–Tamworth 330 kV lines.
- Option 1C – Install new dynamic reactive support at Tamworth and Dumaresq and shunt capacitor banks at Armidale, Dumaresq, and Tamworth.
- Option 1D – Cut-in Armidale–Dumaresq 330 kV line 83 at Sapphire substation and establish a mid-point switching station between Dumaresq and Bulli Creek.
- A 'virtual' transmission line comprised of grid-connected battery systems. This option targets both northerly and southerly QNI stability and thermal limits by installing a battery energy storage system

[29] Powerlink and TransGrid, *Expanding New South Wales – Queensland Transmission Transfer Capacity*, at https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity/Documents/Expanding%20NSW-QLD%20Transmission%20Transfer%20Capacity%20PADR%20-%20Full%20Report.pdf.

(BESS), controlled by a System Integrity Protection Scheme (SIPS) at two ends of the QNI corridor. The operation of each BESS would mimic a 'virtual transmission line' following a transmission line contingency. Following two BESS options were considered:

– Option 5A – Small scale BESS (2 x 40 MW / 20 MWh) located at Liddell in New South Wales and Halys in Queensland.
– Option 5B – Large scale BESS (2 x 200 MW / 100 MWh) located at Liddell in New South Wales and Calvale in Queensland.

Powerlink and TransGrid identified that QNI Option 1A delivers the greatest expected net benefits of all above alternative options considered and is the 'preferred option' in their PADR[30].

Timing and staging

QNI Option 1A was a group 1 project in the 2018 ISP and is on track to be delivered in 2021-22. AEMO's 2020 Draft ISP modelling indicates that this project will provide value as soon as it can be completed.

Augmentation cost

The capital cost estimate is from $122 million to $228 million (2019 dollars).

Network capability improvement

The QNI transfer capability is influenced by generation connection along the transmission corridor. With the existing Sapphire Wind Farm, QNI Option 1A will increase nominal transfer capacity by approximately 150 MW from New South Wales to Queensland and by approximately 165 to 215 MW from Queensland to New South Wales.

VNI Minor

A minor upgrade to the Victoria to New South Wales interconnector was recommended as urgently needed in the 2018 ISP. Since that time, AEMO and TransGrid have commenced a RIT-T[31] to confirm the optimal solution and gain regulatory approval. The draft outcome from this RIT-T, which was published on 30 August 2019, is largely consistent with the solution recommended in the 2018 ISP.

This upgrade is progressing through the RIT-T and is currently on track to be commissioned in 2022-23.

Identified need

The identified need for Minor Victoria to New South Wales upgrade, as determined by AEMO and TransGrid, is "*to realise net market benefits by increasing the power transfer capability from Victoria to New South Wales*"[32].

Network limitations

The transfer capability across the Victoria to New South Wales interconnector is limited by transmission line thermal capacity, voltage stability, and transient stability. The capability across this interconnector at any particular time is dependent on a number of factors, including demand levels, generation dispatch, status and availability of transmission equipment, and operating conditions of the network.

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[30] Powerlink and TransGrid, *Expanding New South Wales – Queensland Transmission Transfer Capacity*, at https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity/Documents/Expanding%20NSW-QLD%20Transmission%20Transfer%20Capacity%20PADR%20-%20Full%20Report.pdf.

[31] AEMO and TransGrid. *Victoria to New South Wales Interconnector Upgrade Regulatory Investment Test for Transmission*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2019/VNI-RIT-T/Victoria-to-New-South-Wales-Interconnector-Upgrade-RIT-T-PADR.pdf.

[32] AEMO and TransGrid. *Victoria to New South Wales Interconnector Upgrade Regulatory Investment Test for Transmission*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2019/VNI-RIT-T/Victoria-to-New-South-Wales-Interconnector-Upgrade-RIT-T-PADR.pdf

For intact system operation, the transfer from Victoria to New South Wales is mainly limited by the following constraints:

- Thermal capacity of:
  - South Morang 500/330 kV transformers.
  - South Morang–Dederang 330 kV lines.
  - Upper Tumut–Canberra 330 kV line.
  - Dederang–Mount Beauty 220 kV lines.
  - Murray–Lower Tumut 330 kV line.
  - Murray–Upper Tumut 330 kV line.
- Voltage stability for potential loss of Alcoa Portland potlines.
- Transient stability for a potential fault on a Hazelwood–South Morang 500 kV line.

For intact system operation, the transfer from New South Wales to Victoria is mainly limited by the following constraints:

- Thermal capacity of:
  - Murray–Dederang 330 kV lines.
  - South Morang–Dederang 330 kV lines.
  - Dederang–Mount Beauty 220 kV lines.
  - Mount Beauty–Eildon 220 kV lines.
  - Eildon–Thomastown 220 kV line.
  - Bendigo–Shepparton 220 kV line.
- Voltage collapse for a potential outage of largest generating unit in Victoria or Basslink.

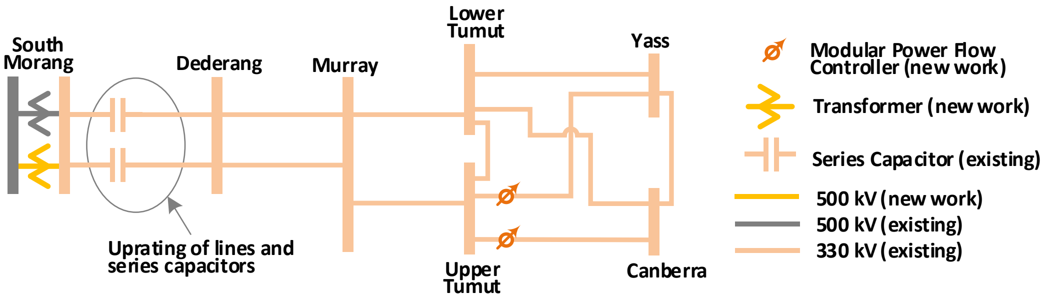
Preferred augmentation option

VNI Option 1 is a minor upgrade of the existing Victoria – New South Wales interconnector with the installation of an additional 500/330 kV transformer, uprating to increase thermal capacity of the existing transmission, and installation of power flow controllers to manage the overload of transmission lines.

The recommended upgrade (VNI Option 1) involves (see Figure 132):

- Installation of a new 1,000 MVA 500/330 kV transformer at South Morang Terminal Station.
- Uprating of the South Morang – Dederang 330 kV lines from the existing design operating temperature of 75°C to 82°C and uprating of associated series capacitors to match increased line rating.
- Installation of modular power flow controllers on both the Upper Tumut – Canberra and Upper Tumut – Yass 330 kV lines to increase transfer capability between Lower Tumut/Upper Tumut and Canberra/Yass. An alternative option is uprating of Upper Tumut to Canberra 330 kV line from the existing operating temperature of 85°C to 100°C.

Figure 132 Single line diagram of VNI Minor



Alternative augmentation options

A number of alternative options were included in AEMO and TransGrid's Project Assessment Draft Report (PADR)[33] on the Victoria to New South Wales interconnector upgrade. These were:

- Replacing the existing South Morang F2 transformer with a transformer with higher capacity as an alternative to an additional South Morang 500/330 kV transformer.
- Additional 330 kV circuit(s) in parallel with the existing 330 kV South Morang – Dederang lines. Replacing the existing 330 kV South Morang – Dederang lines with higher capacity conductors as an alternative to uprating existing 330 kV lines between South Morang and Dederang.
- Additional 500 kV single circuit line between Snowy and Bannaby as an alternative to uprating existing 330 kV lines between Snowy and Sydney.
- A non-network option of battery energy storage system (BESS), which improves the stability limit.

AEMO and TransGrid's PADR found VNI Option 1 delivers the greatest expected net benefits of all above alternative options considered and is the 'preferred option'.

Timing and staging

The Minor Victoria to New South Wales upgrade is currently on track to be commissioned in 2022-23. AEMO's 2020 Draft ISP modelling indicates that this project will provide value as soon as it can be completed.

Augmentation cost

The capital cost estimate is $56 million to $105 million (2019 dollars).

Network capability improvement

The VNI Option 1 would increase nominal transfer capacity by approximately 170 MW from Victoria to New South Wales.

HumeLink

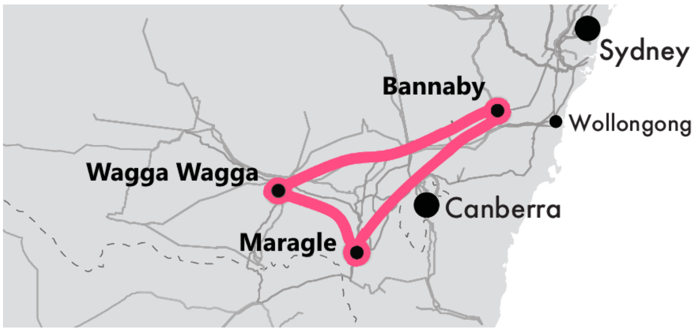
HumeLink is a proposed transmission network augmentation that reinforces the New South Wales southern shared network to increase transfer capacity to the state's demand centre. The proposed transmission upgrades span a distance of approximately 630 km. TransGrid is currently undertaking a RIT-T to identify the preferred option to augment this corridor.

The ISP modelled a triangle configuration with a 500 kV transmission line from Maragle to Bannaby to Wagga Wagga and back to Maragle (outlined in the figure below). This route provides access to Wagga Wagga (N7)

[33] AEMO and TransGrid. *Victoria to New South Wales Interconnector Upgrade Regulatory Investment Test for Transmission*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Victorian_Transmission/2019/VNI-RIT-T/Victoria-to-New-South-Wales-Interconnector-Upgrade-RIT-T-PADR.pdf.

and Southern New South Wales Tablelands (N4) REZs and provides a 500 kV access point at Wagga Wagga for future network expansion between New South Wales and Victoria.

Figure 133 HumeLink transmission upgrade



The 2,000 MW expansion of the Snowy Mountains Hydroelectric Scheme (Snowy 2.0) will connect to the shared network at Maragle. 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. At present, access to existing and new capacity around the Snowy Mountains is limited by constraints on the 330 kV and 132 kV transmission network between the Snowy Mountains and Sydney.

Identified need

The identified need for HumeLink is to deliver a net market benefit by:

- Increasing the transfer capacity and stability limits between the Snowy Mountains and major load centres of Sydney, Newcastle, and Wollongong, enabling greater access to lower cost generation to meet demand in these load centres.
- Reducing the need for new GPG in New South Wales to meet demand following coal generation retirement.
- Facilitating the development of renewable generation resource areas in Wagga Wagga and southern New South Wales Tablelands REZs and increasing their transfer capability.

Network limitations

The transfer capability from Snowy to Sydney is limited by transmission line thermal capacity, voltage stability, and transient stability. The capability of this corridor at any particular time is dependent on a number of factors, including demand levels, generation dispatch, status and availability of transmission equipment, and operating conditions of the network.

For intact system operation, the transfer from Snowy to Sydney is mainly limited by the following constraints:

- Thermal capacity of:
  - Lower Tumut–Yass 330 kV line.
  - Lower Tumut–Canberra 330 kV line.
  - Canberra–Yass 330 kV line.
  - Yass–Marulan 330 kV line.
  - Kangaroo Valley–Dapto 330 kV line.
  - Bannaby–Gullen Range.
  - Bannaby–Sydney West.
- Voltage stability limit between Upper Tumut/Lower Tumut and Bannaby.

Preferred augmentation option

With the proposed amount of 2,040 MW generation of Snowy 2.0 and planned retirement of Liddell Power Station, a large transmission network augmentation is required to transport Snowy 2.0 generation to Sydney, Wollongong, and Newcastle load centres. TransGrid is currently undertaking a RIT-T[34] process to identify a preferred network augmentation and/or non-network option to address the identified need.

Network options include:

- Lines running directly from Maragle to Bannaby.
- Lines running from Maragle to Bannaby via Wagga Wagga.
- A triangle linking Maragle, Wagga Wagga and Bannaby.
- A variant to Option 3, which further extends the new line to Sydney.

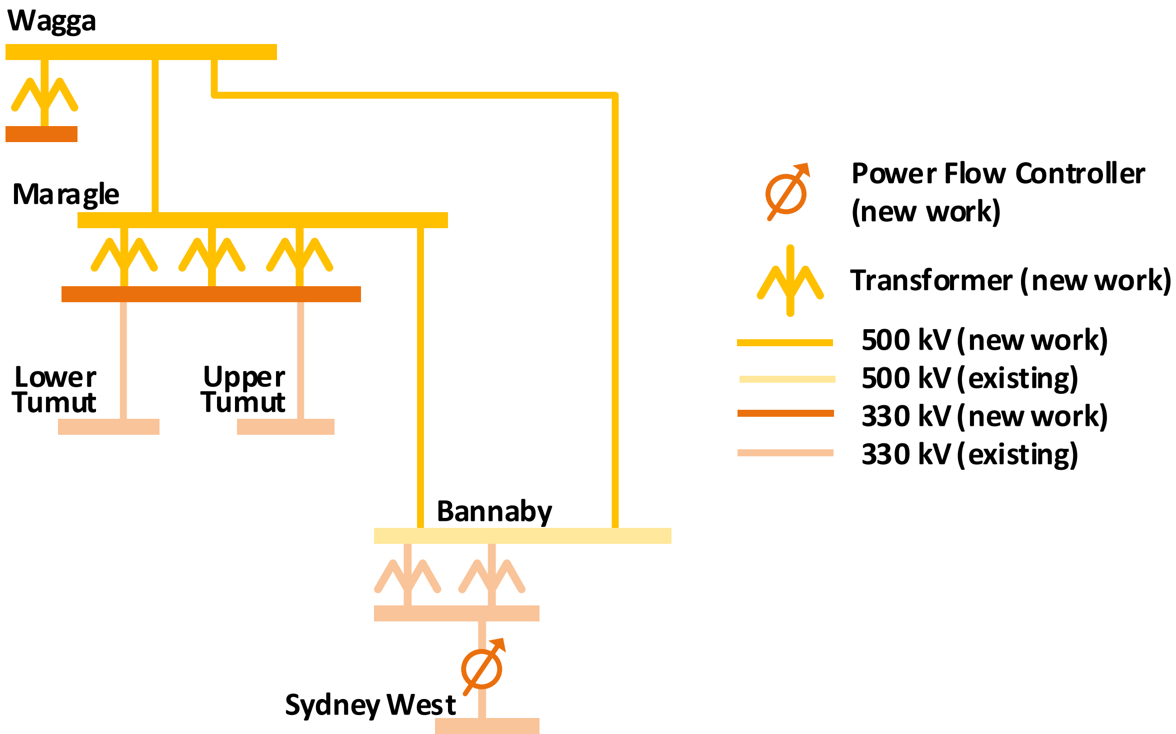
These options are being considered at operating voltage of 330 kV and 500 kV and, initially operating at 330 kV with an ability to convert to 500 kV.

For the 2020 ISP, a triangle linking Maragle, Wagga Wagga and Bannaby (Option 3) at 500 kV voltage level has been modelled with Snowy 2.0 generation, and tested additional new generation and storage outlook and all other interconnector options across the NEM. This selected option involves (Figure 105):

- A new 500 kV single circuit from Maragle to Bannaby.
- A new 500 kV single circuit from Maragle to Wagga Wagga.
- A new 500 kV single circuit from Wagga Wagga to Bannaby.
- Cut-in Lower Tumut – Upper Tumut 330 kV line at Maragle.
- Three 500/330 kV 1500 MVA transformers at Maragle.
- One 500/330 kV 1500 MVA transformer at Wagga Wagga.
- Power flow controller on Bannaby – Sydney West 330 kV line.

[34] TransGrid PSCR. https://www.transgrid.com.au/what-we-do/projects/regulatory-investment-tests/Documents/TransGrid%20PSCR_Reinforcing%20NSW%20Southern%20Shared%20Network.pdf

Figure 134 Single line diagram of HumeLink option



Timing and staging

TransGrid is currently undertaking a RIT-T for HumeLink with an expected service date in 2024-25.

AEMO studies have shown that an additional 500/330 kV transformer at Wagga is required for Snowy 2.0 pumping load to access renewable generation from South Australia via Energy Connect, North West Victoria, and South West New South Wales. It is recommended that the HumeLink RIT-T investigate the need for a second transformer at Wagga.

Augmentation cost

The indicative capital cost is $945 million to $1,755 million (2019 dollars).

Network capability improvement

Since HumeLink does not remove the network constraints south of Upper Tumut and Lower Tumut, the Victoria – New South Wales transfer capacity remains same as VNI Option 1. With 870 MW import from Victoria to New South Wales, notional transfer capability from Upper Tumut/Lower Tumut to Bannaby increases by 2,230 MW.

VNI West – Major upgrade between Victoria and New South Wales

Overview

VNI options 5A, 6, and 7 are large transmission network augmentations which connects Victoria and New South Wales. VNI Option 5A is additional new transmission lines between South Morang and Murray via Dederang. The routes of VNI Options 6 and 7 passes through western part of Victoria. VNI Option 6 connects North Ballarat and Wagga Wagga via Shepparton and the route passes through Central North Victoria and Wagga Wagga REZs. VNI Option 7 connects North Ballarat and Darlington Point via Kerang and the route passes through eastern section of Murray REZ and South West New South Wales REZs. In addition, the VNI Option 6 path is closer to possible Victorian pumped storage at Ovens Murray than the VNI Option 7 path.

Identified need

The identified need is for additional transfer capacity between New South Wales and Victoria, to realise net market benefits by:

- Efficiently maintaining supply reliability in Victoria following the closure of further coal-fired generation and the decline in ageing generator reliability – including mitigation of the risk that this plant closes earlier than expected.
- Facilitating efficient development and dispatch of generation in areas with high quality renewable resources in Victoria and southern New South Wales through improved network capacity and access to demand centres.
- Enabling more efficient sharing of resources between NEM regions.

Network limitations

The transfer capability across the Victoria to New South Wales interconnector is limited by transmission line thermal capacity, voltage stability, and transient stability. The capability across this interconnector at any particular time is dependent on a number of factors, including demand levels, generation dispatch, status and availability of transmission equipment, and operating conditions of the network.

For intact system operation, the transfer from Victoria to New South Wales is mainly limited by the following constraints:

- Thermal capacity of:
  - South Morang 500/330 kV transformers.
  - South Morang–Dederang 330 kV lines.
  - Upper Tumut–Canberra 330 kV line.
  - Dederang–Mount Beauty 220 kV lines.
  - Murray–Lower Tumut 330 kV line.
  - Murray–Upper Tumut 330 kV line.
- Voltage stability for potential loss of Alcoa Portland potlines.
- Transient stability for a potential fault on a Hazelwood–South Morang 500 kV line.

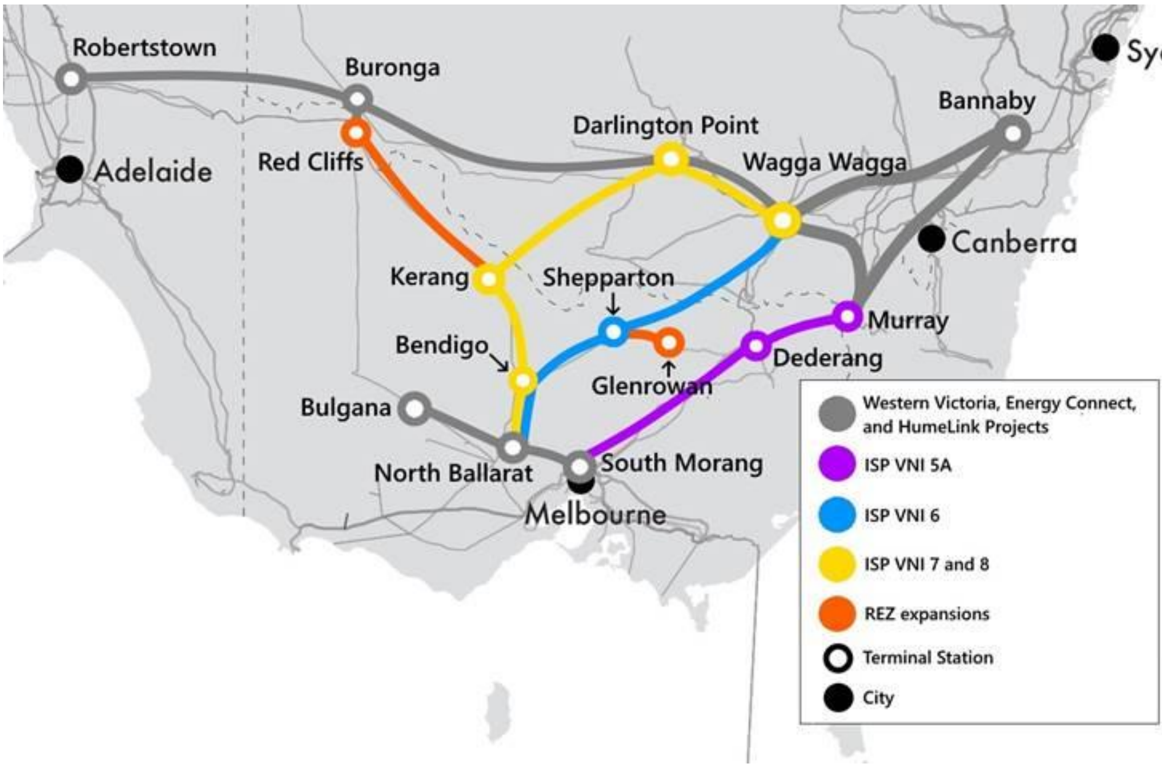
For intact system operation, the transfer from New South Wales to Victoria is mainly limited by the following constraints:

- Thermal capacity of:
  - Murray–Dederang 330 kV lines.
  - South Morang–Dederang 330 kV lines.
  - Dederang-Mount Beauty 220 kV lines.
  - Mount Beauty–Eildon 220 kV lines.
  - Eildon-Thomastown 220 kV line.
  - Bendigo-Shepparton 220 kV line.
- Voltage collapse for a potential outage of the largest generating unit in Victoria, or of Basslink.

Augmentation options

Figure 135 shows the three transmission corridors that were assessed. These options connect via Kerang (yellow), Shepparton (blue), or Dederang (purple). Further information on these options is included in the sections that follow.

Figure 135 VNI West transmission options



VNI Option 5A (via Dederang)

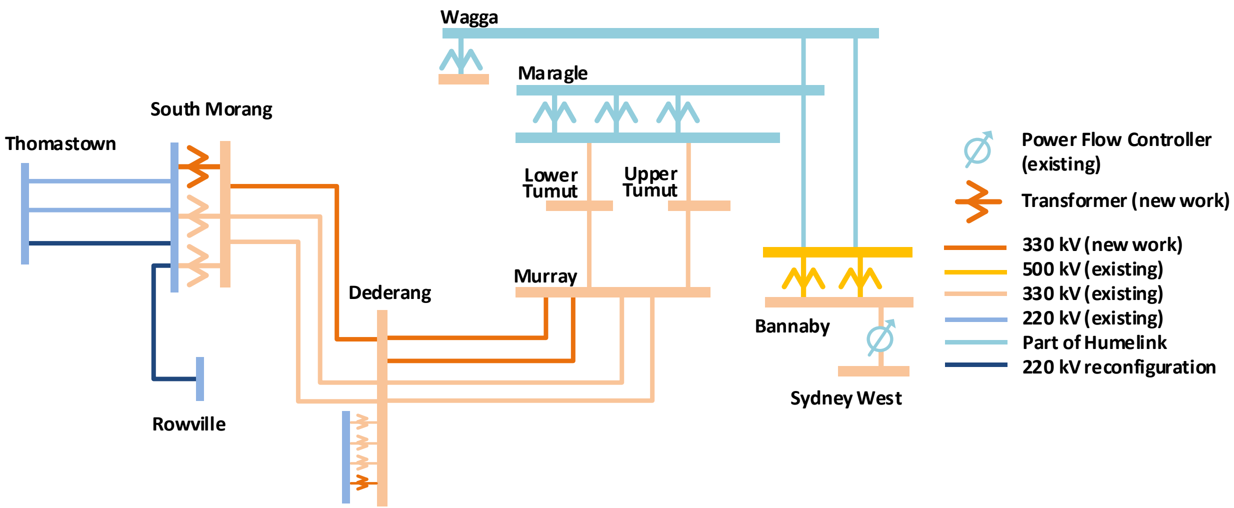
Augmentation description

A possible route for an additional new transmission line to address the identified need, except access to high quality wind and solar resources, is from South Morang to Murray via Dederang (VNI Option 5A), with approximately 350 km route length. This is the shortest route to access Snowy generation to Melbourne load centre. VNI Option 1 and HumeLink are assumed to be in place.

VNI Option 5A involves following augmentation (see Figure 136):

- Two 330 kV lines from Murray to Dederang.
- One 330 kV line from Dederang to South Morang with series capacitors.
- Uprating the Murray–Lower Tumut 330 kV line.
- Uprating the Murray–Upper Tumut 330 kV line.
- One additional 330/220 kV transformer at Dederang (fourth transformer).
- One additional 330/220 kV transformer at South Morang (third transformer).
- Cut-in Rowville–Thomastown 220 kV line at South Morang to form third South Morang–Thomastown 220 kV line.
- Additional reactive plants at Wodonga, Jindera, and Wagga.

Figure 136 Single line diagram of VNI Option 5A



Augmentation cost

The estimated capital cost is $570 million to $1,060 million (2019 dollars).

Network capability improvement

With VNI Option 1 in place, VNI Option 5A and HumeLink provide an additional notional transfer capacity of 380 MW from Victoria to New South Wales and 1,000 MW from New South Wales to Victoria. Transfer capability from Snowy to Sydney is limited by the amount of generation in southern New South Wales along with import from Victoria and South Australia to New South Wales. At times of high demand in New South Wales, transfer capability from Snowy to Sydney is limited to a notional value of 5,100 MW.

VNI West via Shepparton (VNI Option 6)

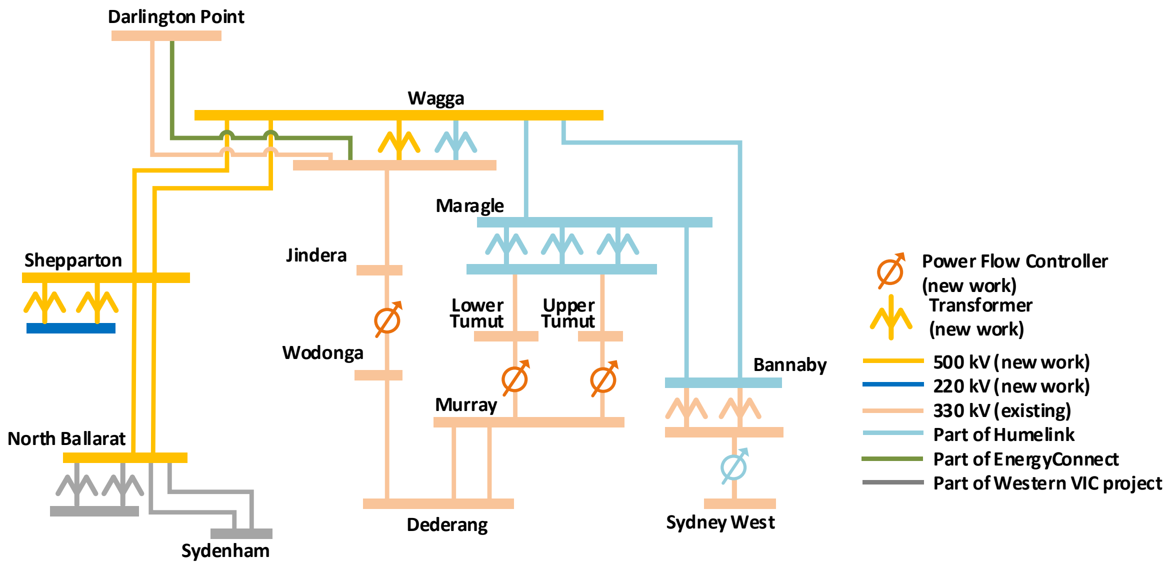
Augmentation description

A possible route for an additional new transmission line to address the identified need is from North Ballarat to Wagga Wagga via Shepparton (VNI Option 6), with approximately 440 km route length. HumeLink provides connection between Wagga Wagga and Bannaby. VNI Option 1 is assumed to be in place.

VNI Option 6 involves following augmentation (see Figure 137):

- Two 500 kV lines from North Ballarat to Shepparton.
- Two 500 kV lines from Shepparton to Wagga Wagga.
- Two 500/220 kV 1000 MVA transformers at Shepparton.
- One additional 500/330 kV 1500 MVA transformer at Wagga Wagga.
- Power flow controllers to prevent overloading on 330 kV lines between Upper/Lower Tumut and South Morang. Possible locations are on the Murray–Lower Tumut, Murray–Upper Tumut and Wodonga–Jindera 330 kV lines.
- Additional reactive plant at North Ballarat, Shepparton, and Wagga Wagga.

Figure 137 Single line diagram of VNI Option 6



Augmentation cost

The estimated capital cost is $940 million to $1,730 million (2019 dollars).

Network capability improvement

With VNI Option 1 in place, VNI Option 6 and HumeLink provide an additional notional transfer capacity of 1,930 MW from Victoria to New South Wales and 1,800 MW from New South Wales to Victoria. Transfer capability from Snowy to Sydney is limited by the amount of generation in southern New South Wales along with import from Victoria and South Australia to New South Wales. At times of high demand in New South Wales, transfer capability from Snowy to Sydney is limited to a notional value of 5,100 MW.

VNI West via Kerang (VNI Options 7 and 8)

Augmentation description

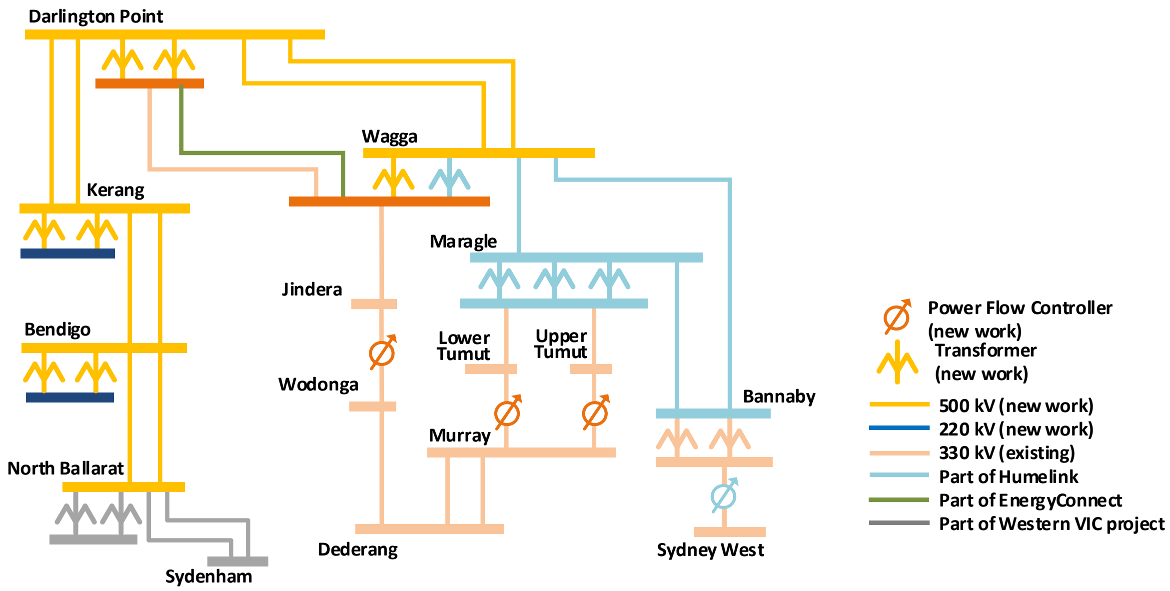
A possible route for an additional new transmission line to address the identified need is from North Ballarat to Bendigo to Kerang to Darlington Point to Wagga Wagga, with approximately 605 km route length. VNI Option 7 is designed with 500 kV transmission voltage. Also, an alternative option with a designed voltage at 330 kV North Ballarat to Kerang to Darlington Point to Wagga has been tested. HumeLink provides 500 kV connection between Wagga Wagga and Bannaby in both VNI Option 7 and 8. VNI Option 1 is assumed to be in place.

VNI Option 7 involves following augmentation (see Figure 138):

- Two 500 kV lines from North Ballarat to Bendigo.
- Two 500 kV lines from Bendigo to Kerang.
- Two 500 kV lines from Kerang to Darlington Point.
- Two 500 kV lines from Darlington Point to Wagga Wagga.
- Two 500/220 kV 1000 MVA transformers at each of Bendigo and Kerang Terminal Stations.
- Two 500/330 kV 1500 MVA transformers at Darlington Point.
- One additional 500/330 kV 1500 MVA transformer at Wagga Wagga.

- Power flow controllers to prevent overloading on 330 kV lines between Upper/Lower Tumut and South Morang. Possible locations are on the Murray–Lower Tumut, Murray–Upper Tumut and Wodonga–Jindera 330 kV lines.
- Additional reactive plant at Bendigo, Kerang, Darlington Point and Wagga Wagga.

Figure 138 Single line diagram of VNI Option 7



Augmentation cost

The estimated capital cost for VNI Option 7 is $1,300 million to $2,410 million, and for VNI Option 8 is $1,010 million to $1,880 million (2019 dollars).

Network capability improvement

With VNI Option 1 in place, VNI Option 7 and HumeLink provide an additional notional transfer capacity of 1,930 MW from Victoria to New South Wales and 1,800 MW from New South Wales to Victoria.

With VNI Option 1 in place, VNI Option 8 and HumeLink provide an additional notional transfer capacity of 1,130 MW from Victoria to New South Wales and 800 MW from New South Wales to Victoria.

Similar to VNI Option 6, transfer capability from Snowy to Sydney is limited by the amount of generation in southern New South Wales along with import from Victoria and South Australia to New South Wales. At times of high demand in New South Wales, transfer capability from Snowy to Sydney is limited to a notional value of 5,100 MW in both VNI Options 7 and 8.

Alternative options considered

The following alternative options have been considered to increase the transfer capability between New South Wales and Victoria.

VNI option 3

VNI Option 3 is an incremental network augmentation, which includes a series capacitor on the Wodonga–Dederang 330 kV line, a large size of power flow controller on the Jindera–Wodonga 330 kV line, an additional 330/220 kV transformer at Dederang, and additional reactive plants, with a cost estimate of $100 million to $180 million. This option increases the notional transfer capacity by 300 MW from New South Wales to Victoria and provides no additional increase from Victoria to New South Wales.

VNI Option 4

VNI Option 4 includes VNI Option 1 and a new 330 kV transmission line from Dederang to Yass via Jindera and Wagga Wagga, with a cost estimate of $485 million to $905 million. This option increases the notional transfer capacity by 430 MW from Victoria to New South Wales and by 300 MW from New South Wales to Victoria.

VNI option 9

VNI Option 9 is VNI Option 7 (or alternatively VNI Option 6) plus an extension from Bannaby to Sydney to remove network constraints between Bannaby/Marulan/Kangaroo Valley and Sydney West/Sydney South. The cost estimate to extend the transmission network from Bannaby to Sydney is $340 million to $640 million. This option increases the transfer capability from Victoria to New South Wales by 200 MW and from Snowy to Sydney by 500 MW compared to transfer capability in VNI Option 7 (or VNI Option 6).

With the retirement of coal generation in New South Wales, there is a need to increase transfer capability from Bannaby to Sydney. The 500 kV extension from Bannaby to Sydney is identified as an intra-regional network augmentation.

VNI Option 10

VNI Option 10 is VNI Option 9 plus third 500 kV line from Wagga/Maragle to Bannaby. The third line can be second circuit in a double circuit tower configuration with an incremental cost estimate of $70 million to $110 million. This option increases Snowy to Sydney transfer capability approximately by 1,500 MW.

VNI option 11

VNI Option 11 is a HVDC transmission option. It involves two 1,000 MW HVDC-VSC bi-pole transmission line from Sydenham to Wagga/Maragle and two 1,000 MW HVDC-VSC bi-pole transmission line from Wagga/Maragle to South Creek. This HVDC option and the existing parallel AC transmission network increases the Victoria to New South Wales transfer capability by 2,130 MW and New South Wales to Victoria transfer capability by 2,000 MW. Further transfer from Victoria/South Australia to New South Wales and total amount of generation at Upper/Lower Tumut and Snowy 2.0 is limited by transmission capability from Snowy to Sydney to an amount of 5,100-5,500 MW. Connection of renewables generation to HVDC is more complex than to HVAC systems with a higher cost.

Possible connection at Donnybrook

Donnybrook is located between South Morang and Sydenham 500 kV line route. It is a possible alternative connection point for VNI Option 5A, instead of South Morang, and for VNI option 6 and 7, instead of North Ballarat. In the case of VNI Option 5A, a 550/330 kV transformer is also required at Donnybrook. This is a potential variation to VNI Options 5A, 6, and 7. AEMO and TransGrid will assess the feasibility of this variation through the RIT-T process.

Progress Marinus Link to 'Shovel-Ready'

AEMO recommends (although it is not actionable under the Draft ISP rules) to progress the design and approvals process for Marinus Link (a second, and potentially third, HVDC cable connecting Victoria to Tasmania), to make it "shovel-ready", while deferring the final decision on the project to 2023-24 when delivery signposts are clearer. These early works are strongly recommended as a low-cost, low-regret approach, that will provide more time for assessment before the 2022 ISP, but still permit delivery of Marinus Link by as early as 2027-28 if a decision to proceed was made by 2023-24.

See Section 5.5.3 for more information on the market benefits of Marinus Link, and Section 6.1.4 for further details on the Marinus Link design.

6.1.3 Group 2 near-term grid projects

AEMO's 2020 Draft ISP identifies the following Group 2 investment:

- A medium upgrade to QNI to increase transfer capability between Queensland and New South Wales (QNI 2E), configured to provide route diversity to the existing QNI interconnector and provide access to REZs, particularly in New South Wales.

Medium QNI Upgrade – actionable ISP project

AEMO's ISP modelling determined that a Medium QNI Upgrade is beneficial in all scenarios before the closure of the next New South Wales and/or Queensland black coal generators following Liddell Power Station.

The QNI Medium is part of the optimal solution helping to minimize total system costs in all scenarios and is therefore also a no-regret development. Only the timing of the project varies, which is linked to retirement of black coal in New South Wales and Queensland. This project will be required by no later than 2028-29. In the Fast Change and Step Change scenarios, earlier coal retirements, and corresponding build of VRE, could increase the urgency for development of this interconnector to as soon as possible (assumed no earlier than 2026-27) to more efficiently utilize resources between Queensland and New South Wales.

Based on ISP modelling, AEMO recommends that:

- A Medium QNI Upgrade is required.
- Powerlink and TransGrid should commence a RIT-T with a PADR publication 18 months following the release of the Final 2020 ISP, i.e. 10 December 2021.

This inter-regional augmentation between Queensland and New South Wales (listed as QNI 2E in the input and assumptions work book) is configured as a single-circuit 500 kV transmission line using double-circuit transmission towers – providing optionality to string a second circuit and expand the flow capacity in future.

Identified need

The identified need is for additional transfer capacity between Queensland and New South Wales, to realise net market benefits by:

- Efficiently maintaining supply reliability in New South Wales following the closure of further coal-fired generation and the decline in ageing generator reliability.
- Facilitating efficient development and dispatch of generation in areas with high quality renewable resources in northern New South Wales through improved network capacity and access to demand centres.
- Enabling more efficient sharing of resources between NEM regions.

Network limitations

The transfer capability across the New South Wales to Queensland interconnector is limited by transmission line thermal capacity, voltage stability, transient stability, and oscillatory stability. The capability across QNI at any particular time is dependent on a number of factors, including demand levels, generation dispatch, status and availability of transmission equipment, and operating conditions of the network.

For intact system operation and with QNI minor upgrade (QNI Option 1A), the transfer from Queensland to New South Wales is mainly limited by the following constraints:

- Stability limits for faults on either Sapphire to Armidale, Dumaresq–Sapphire, or Armidale to Dumaresq line.
- Thermal capacity of the 330 kV lines within northern New South Wales.
- Oscillatory stability upper limit of 1,350-1,450 MW.

For intact system operation, the transfer from New South Wales to Queensland is mainly limited by the following constraints:

- Stability limits on loss of the largest Queensland unit.

- Transient stability associated with transmission line faults in the Hunter Valley.
- Voltage collapse for trip of the Liddell to Muswellbrook 330 kV line.
- Thermal capacity of the 330 kV and 132 kV transmission lines within northern New South Wales.

Preferred augmentation option

The medium QNI upgrade, which can later be expanded, includes a single 500 kV circuit between New South Wales and Queensland via the western part of the existing QNI. The proposed route goes through the North West New South Wales and Darling Downs REZs. A second 500 kV circuit provides long-term benefits under some scenarios (see Section 6.1.4 for further information about the possible staging of a higher capacity upgrade).

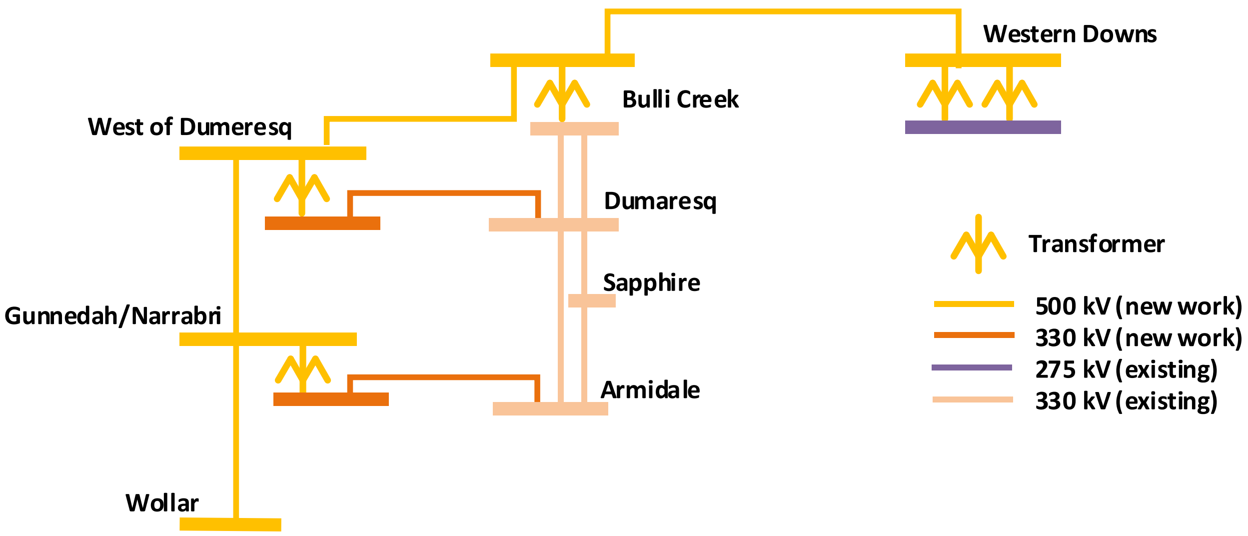
QNI 2E includes (see Figure 139):

- Single circuit 500 kV from Wollar to Gunnedah/Narrabri site to West of Dumaresq to Bulli Creek to Western Downs.
- New 330 kV single circuit line from Gunnedah/Narrabri site to Uralla or Armidale.
- New 330 kV single circuit line from West Dumaresq to Dumaresq.
- Establishing new 500/330 kV substations at Gunnedah/Narrabri site and new site West of Dumaresq (West Dumaresq).
- One 550/330kV 1500 MVA transformer at Gunnedah/Narrabri site.
- One 500/330 kV 1500 MVA transformer at west of Dumaresq.
- One 500/330 kV 1500 MVA transformer at Bulli Creek.
- Two 500/275 kV 1000 MVA transformer at Western Downs.
- Installing static and dynamic compensation at Wollar, Gunnedah/Narrabri, West Dumaresq, Bulli Creek, and/or Western Downs.

Work and investment can be undertaken to make any potential second circuit of the 500 kV (QNI 3E) more ready. These works could include:

- Easement and land acquisition.
- Substation works and bus extension, including provision of additional spare bays.

Figure 139 Single line diagram of QNI Option 2E



Augmentation cost

The estimated capital cost for QNI Option 2E is $1,040 million to $1,925 million (2019 dollars).

Network capability improvement

QNI Option 2E provides an additional notional transfer capacity of 885 MW from New South Wales to Queensland and 760 MW from Queensland to New South Wales, in addition to the transfer capacity increase from the Minor QNI Upgrade (Option 1A).

Timing and staging

The delivery of a staged major QNI interconnector upgrade is an optimal development in all scenarios, between 2026-27 and 2028-29, and provides support to export excess renewable generation in Queensland and/or increase efficient access to renewable generation at REZs in both Queensland and New South Wales. It also helps share resources more efficiently between regions as aging black coal-fired generators retire.

Due to its optimal nature and timing of need, AEMO has considered it prudent to classify this interconnector as a "Group 2" project.

Alternative options considered

The following alternative options to increase transfer capability between New South Wales and Queensland have been considered. It is assumed QNI minor upgrade (QNI Option 1A) is in place.

QNI Option 2

QNI Option 2 is a single circuit 330 kV line from Liddell to Tamworth to Armidale to Dumaresq to Bulli Creek to Braemar with a cost estimate of $600 million to $1,110 million. It passes through adjacent to the existing QNI route. This option increases the notional transfer capacity by 765 MW from New South Wales to Queensland and by 660 MW from Queensland to New South Wales.

QNI Option 3A

QNI Option 3A is a double circuit 330 kV line from Armidale to Dumaresq to Bulli Creek and uprating existing 330 kV transmission lines between Tamworth and Armidale with a cost estimate of $390 million to $730 million. It passes through adjacent to the existing QNI route. This option increases the notional transfer capacity by 100-335 MW from Queensland to New South Wales. This option is a first stage of QNI Option 3B.

QNI Option 3B

QNI Option 3B is a double circuit 330 kV line from Liddell to Braemar via Uralla, Sapphire, Dumaresq, and Bulli Creek with a cost estimate of $1,050 million to $1,960 million. It passes through adjacent to the existing QNI route. This option increases the notional transfer capacity by 1,200 MW from New South Wales to Queensland and 1,115 MW from Queensland to New South Wales.

QNI Option 3C

QNI Option 3C is two 500 kV circuits from Wollar/Bayswater to Uralla and two 330 kV circuits from Uralla to Braemar via Sapphire, Dumaresq and Bulli Creek with a cost estimate of $1,430 million to $2,650 million. This option increases the notional transfer capacity by 1,470 MW from New South Wales to Queensland and 1,265 MW from Queensland to New South Wales. This option also provides access to renewable generation in New England (N2) and Darling Downs (Q8) REZs.

QNI Option 3D

QNI Option 3D is two 500 kV circuits from Wollar to Western Downs via Gunnedah, west of Dumaresq, Bulli Creek with a capital cost estimate of $1,650 million to $3,070 million. This option increases the notional transfer capacity by 1,770 MW from New South Wales to Queensland and 1,520 MW from Queensland to New

South Wales. This option also provides access to renewable generation in New England (N2) and Darling Downs (Q8) REZs.

QNI Option 3E

As an expansion to QNI Option 2E, QNI Option 3E involves the installation of a second 500 kV circuit from Wollar to Gunnedah/Narrabri site to West of Dumaresq to Bulli Creek to Western Downs. This option is a Group 3 project – refer to section 6.1.4 for further details.

QNI Option 4A

QNI Option 4A is back-to-back HVDC converters at Bulli Creek to increase transfer in both directions between New South Wales and Queensland, with a cost estimate of $580 million to $1,070 million. This option with a system integrity protection scheme (SIPS) increases notional transfer capacity by 850 MW from New South Wales to Queensland and 470 MW from Queensland to New South Wales.

QNI Option 4B

QNI Option 4B is an HVDC option between Lismore in New South Wales and Mudgeeraba in Queensland. This involves dismantling the existing Directlink and extending the existing HVDC connection between Mudgeeraba 275 kV and Lismore 330 kV substations, with a cost estimate of $420 million to $780 million. This option increases the notional transfer capacity by 420 MW from New South Wales to Queensland.

QNI Option 4C

QNI Option 4C is two 1,000 MW HVDC bi-pole transmission lines between Bayswater and Western Downs, with a cost estimate of $1,470 million to $2,730 million. This option with a SIPS increases the notional transfer capacity by 2,245 MW from New South Wales to Queensland and 1,680 MW from Queensland to New South Wales. Connection of renewables generation to HVDC is more complex than to HVAC systems, with a higher cost.

QNI Option 5

QNI Option 5 is a non-network option. This involves installation of a 600 MW battery energy storage system (BESS) capable of discharging the total stored energy within 15 minutes at Halys and Liddell, with an estimated capital cost of $700 million to $1,300 million. This option with a System Integrity Protection Scheme (SIPS) increases the notional transfer capacity by 790 MW from New South Wales to Queensland and 325 MW from Queensland to New South Wales.

6.1.4 Group 3 future grid projects

Group 3 transmission investments are projects that would enable efficient development of variable renewable energy and storage systems required in the longer term in some scenarios, but in others are not considered necessary investments.

The primary driver for these investments relates to asset replacement, to further increase the sharing capacity between regions to firm the system further with increased retirements, particularly in the 2030s. The timing of the augmentations is uncertain, and actions to deliver these projects are not expected to be required until at least after the 2022 ISP.

AEMO's 2020 Draft ISP identifies the following Group 3 investments:

- **Marinus Link** – completion of works on a second, and potentially third, HVDC cable connecting Victoria to Tasmania. While AEMO projects that Marinus Link will eventually be required under all scenarios except Slow Change, it is difficult to lock down the optimal delivery timing for the first Marinus Link cable in this Draft ISP, as it ranges from 2026-27 to 2036-37 across the Draft ISP scenarios. That said, earlier development would be vital for dispatchable capacity to Victoria in a number of circumstances: if the Step Change scenario unfolds; if Yallourn Power Station retires earlier than anticipated; if storage options on the Australian mainland are delayed or not as readily available or more costly than assumed in this Draft ISP; or if VNI West were unexpectedly delayed.

- **Large QNI upgrade** – following the development of a Medium QNI upgrade (see Group 2), a larger QNI upgrade could be needed in the 2030s to increase the capacity of the network to host renewable energy and share both storage and firming services between the regions. This larger upgrade will depend on future renewable development in Queensland and New South Wales, and respective state policies for renewable generation. The recent announcement by the New South Wales government decreases the need for a larger interconnection with Queensland, even assuming QRET continues. In the High DER scenario, greater development of rooftop PV in New South Wales reduces the diversity of resources between the two regions and thereby also reduces the value of a larger interconnection. However, the New South Wales side of this upgrade will be needed to support the projected need for development of large amounts of VRE in North West and New England REZ in the 2030s to replace exiting coal-fired power stations in New South Wales. If not delivered as part of a larger QNI upgrade, the augmentations would still be needed on the New South Wales side (and completing the final stage of linking to Queensland would then be relatively smaller investment). As a result, this project should be considered in stages, with the New South Wales augmentations proceeding first in coordination with REZ development in the north of New South Wales, and considering the need for later completion of the connection across to Queensland if and when needed.
- **Queensland grid reinforcements**:
  - **Central to Southern Queensland upgrade** – with the development of high quality wind and solar energy resources in central and northern Queensland, a new double-circuit 275 kV transmission line from Calvale to Wandoan South is projected to reduce network congestion and provide value to consumers.
  - **Gladstone Grid reinforcement** – following the closure of Gladstone Power Station (currently expected in 2035), network upgrades are required to supply loads in the Gladstone area. The Gladstone Grid reinforcement is also forecast to be required with significant VRE generation connecting north of Bouldercombe.
- **New South Wales grid reinforcements**:
  - **Reinforcing Sydney, Newcastle, and Wollongong supply** – the Sydney, Newcastle, and Wollongong area will need to be supplied via different network paths once a number of key plant retire, currently anticipated at the end of the next decade (Eraring in 2032, and Vales Point in 2029). The commissioning of Project EnergyConnect, HumeLink, and VNI West will increase supply from the south, meaning that Bannaby to Sydney West requires reinforcement with additional 330 kV and 500 kV lines and additional 500/330 kV transformation. To the north, QNI Medium and new VRE and pumped hydro mean that the 500 kV network is expected to need to be strengthened in New South Wales. This is projected to require a number of additional 330 kV lines between Mount Piper and Wallerawang and between Bayswater and Liddell, and additional 500 kV lines between Bayswater to Eraring. Non-network options, including optimally located storage, could form a significant part of this reinforcement.
- **Supporting REZ expansions**:
  - In New South Wales, the New England, North West New South Wales and Central West REZs are projected to require additional 500 kV and 330 kV lines to accommodate the projected increase in VRE generation within these zones.
  - In Queensland, due to the great capacity factors in Far North Queensland, strengthening of the 275 kV network from Strathmore–Ross–Chalumbin–Walkamin is projected to be required, together with the development of additional substations and lines, to connect generation interest in remote areas. The design of the network will be influenced by the location of generation interest.

- In South Australia, to accommodate the project wind developments, South East South Australia REZ and the Mid North REZ are forecast to require augmentation. Mid North may also be required due to the retirement of gas generation, and the need for generation supplying the Adelaide region to come from alternative areas.

Marinus Link – a new cable between Tasmania and Victoria

Marinus Link is a second, and potentially third, HVDC cable interconnection between Tasmania and Victoria. It is proposed with a transfer capability of 750 MW (one cable) or 1,500 MW (two cables).

ISP modelling has determined that Marinus Link, connecting the 'Battery of the Nation' (BoTN) project with Victoria, would be beneficial in all scenarios except Slow Change. BoTN would deliver necessary large-scale and deep storage, and Marinus Link would facilitate that as well as unlock attractive wind resources in Tasmania. If the Step Change scenario occurs, one cable would be needed as soon as possible for the BoTN to store mainland VRE during the day and then release it back during peak demand periods.

AEMO recommends that the design and approvals process for Marinus Link be progressed, to make it 'shovel-ready', while deferring the final decision on the project to 2023-24 when delivery signposts are clearer. These early works are strongly recommended as a low-cost, low-regret approach, that will provide more time for assessment before the 2022 ISP, but still permit delivery of Marinus Link by as early as 2027-28 if a decision to proceed was made by 2023-24. See Section 5.5.3 for more information on this recommendation.

Identified need

The identified need for an additional Tasmania – Victoria interconnector is to deliver net market benefits and support energy market transition through:

- Allowing more efficient generation sharing between Tasmania and Victoria.
- Reduced generation dispatch costs.
- Reduced voluntary load curtailment and involuntary load shedding by improving reliability:
  - In Tasmania for an extended outage of Basslink or an extended low rainfall period.
  - In the mainland following retirement of coal generators.
- Facilitating access to increased dispatchable generation and storage.

Network limitations

The transfer capability across the Tasmania and Victoria interconnector is limited by the transmission capacity of the HVDC cable (Basslink) between Tasmania and Victoria.

In addition, with a second interconnector in the Burnie area, the thermal capacity of the following transmission lines becomes the limitation:

- Burnie–Sheffield 220 kV line.
- Sheffield–Palmerston 220 kV line.

Augmentation description

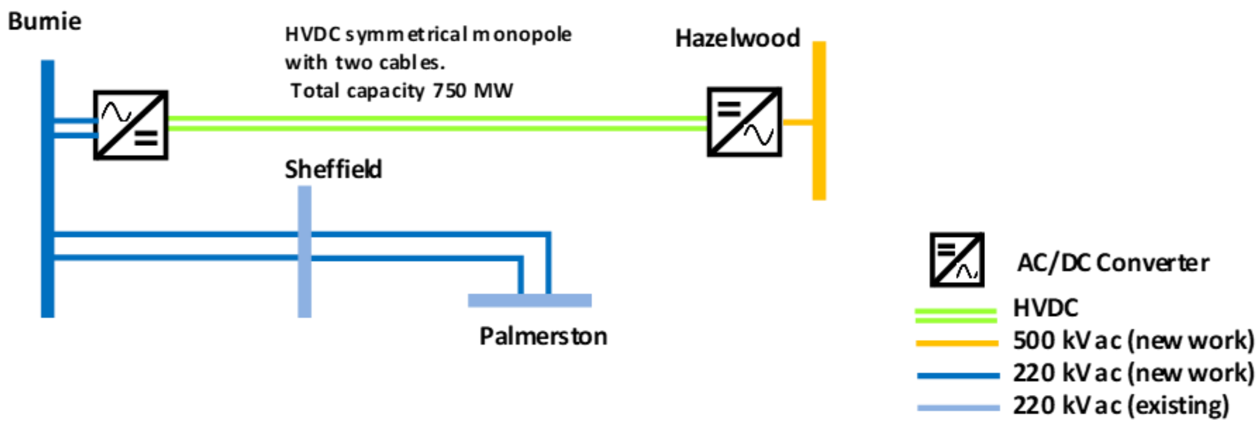
Marinus Link with one 750 MW interconnector involves (Figure 140):

- A 750 MW HVDC interconnector using voltage source converter technology and monopole configuration. Converter stations located in the Burnie area in Tasmania and the Hazelwood area in Victoria.
- AC network augmentations in Tasmania comprise:
  - A new 220 kV switching station in the Burnie area adjacent to the converter station.
  - A new double-circuit 220 kV transmission line from Burnie to Sheffield and decommissioning of the existing 220 kV single-circuit transmission line in this corridor.

– A new double-circuit 220 kV transmission line from Palmerston to Sheffield.

- AC network augmentations in Victoria comprise:
  – A 500 kV connection asset for connection of the converter station in the Hazelwood area to the Hazelwood 500 kV terminal station.

Figure 140 Single line diagram of Marinus Link 1 x 750 MW



Marinus Link with two 750 MW cables involves:

- Two 750 MW HVDC cables using voltage source converter technology and monopole configuration. Converter stations located in the Burnie area in Tasmania and the Hazelwood area in Victoria.
- AC network augmentations in Tasmania comprise:
  – Same as AC network expansion in Tasmania and Victoria for one 750 MW HVDC interconnector.
  – A new double-circuit 220 kV transmission line from Burnie to Staverton via Hampshire.
  – A new 220 kV switching station at Staverton.

It is assumed Project EnergyConnect will be commissioned prior to Marinus Link one 750 MW. Project EnergyConnect provides additional static and dynamic reactive plant at Darlington Point, and these reactive plants will assist to maintain voltage stability limits following a loss of 750 MW of Marinus Link.

Augmentation cost

Estimated capital cost of HVDC and AC network expansion:

- Marinus Link with one 750 MW cable – $1,150 million to $2,130 million (2019 dollars).
- Marinus Link with two 750 MW cable – $1,935 million to $3,590 million (2019 dollars).

Network capability improvement

The Marinus Link one 750 MW cable option provides an additional notional transfer capacity of 750 MW from Tasmania to Victoria (forward direction) and 500 MW from Victoria to Tasmania (reverse direction). In the reverse direction, transfer capability is limited to a largest contingency of 500 MW as per existing operational procedures of the frequency control special protection scheme (FCSPS).

The Marinus Link two 750 MW cable option provides an additional notional transfer capacity of 1,500 MW from Tasmania to Victoria (forward direction) and 1,250 MW from Victoria to Tasmania (reverse direction).

Alternative options

Alternative options with reduced transfer capacity of Marinus Link were considered. These include:

- One 600 MW HVDC monocable from Burnie area to Hazelwood area with a capital cost estimate of $1,085 million to $2,015 million.
- Two 600 MW HVDC monocables from Burnie area to Hazelwood area with a capital cost estimate of $1,820 million to $3,385 million.

Early works for Marinus Link

The potential development of the Marinus Link interconnector is an optimal development in most scenarios (except Slow Change) by the mid-2030s or sooner.

The interconnector would support the transition to replacement of retiring firm capacity in Victoria and the broader NEM, through increased access to existing and re-purposed improvements to expand the capacity of the Tasmanian hydro assets.

AEMO recommends proceeding with the initial design and approvals process for Marinus Link, to make it 'shovel-ready' while deferring the final decision on the project to 2023-24 when delivery signposts are clearer. This is assessed as a low-cost, low-regret investment would allow more time for further assessment before the 2022 ISP, and still permit delivery of Marinus Link by as early as 2027-28 if a decision to proceed was made by 2023-24.

While these early works do not fit in the framework of "actionable ISP project" or the framework currently proposed by the Draft ISP rules, they are nevertheless highly recommended by AEMO as a prudent approach to maintain the option for accelerating the development of Marinus Link should conditions requiring its earlier development eventuate, while providing the time to more fully assess the project.

QNI Large

Following the development of a Medium QNI upgrade (see Group 2), a larger QNI upgrade could be needed in the 2030s to increase the capacity of the network to host renewable energy and share both storage and firming services between the regions. The project strings a second 500 kV line to the actionable QNI 2E project (QNI Medium). This large upgrade is listed as QNI 3E in the input and assumptions work book.

This larger upgrade will depend on future renewable development in Queensland and New South Wales, and respective state policies for renewable generation. The recent announcement by the New South Wales government decreases the need for a larger interconnection with Queensland, even assuming the QRET continues. In the High DER scenario, greater development of rooftop PV in New South Wales reduces the diversity of resources between the two regions and thereby also reduces the value of a larger interconnection.

However, the New South Wales side of this upgrade will be needed to support the projected need for development of large amounts of VRE in North West and New England REZ in the 2030s to replace exiting coal-fired power stations in New South Wales. If not delivered as part of a larger QNI upgrade, the augmentations would still be needed on the New South Wales side (and completing the final stage of linking to Queensland would then be a relatively small investment).It is recommended to stage the project, delivering the New South Wales side first in coordination and alignment with needs and timing to develop REZ in northern New South Wales (for coal retirements), and then re-evaluating the need/timing for the full interconnection with Queensland at a later point. Designing the solution to allow flexibility may result in higher costs initially but the overall lowest cost over the life of the assets with highest benefits in the future NEM.

Identified need

The identified need for the QNI Large augmentation is:

- Improve access to high quality renewable resources in the North West New South Wales REZ.
- Increase the ability to share surplus energy between Queensland and New South Wales.

Network limitations

Network limitations are similar to the network limitations referred to in QNI medium upgrade (QNI 2E) with increased transfer capability.

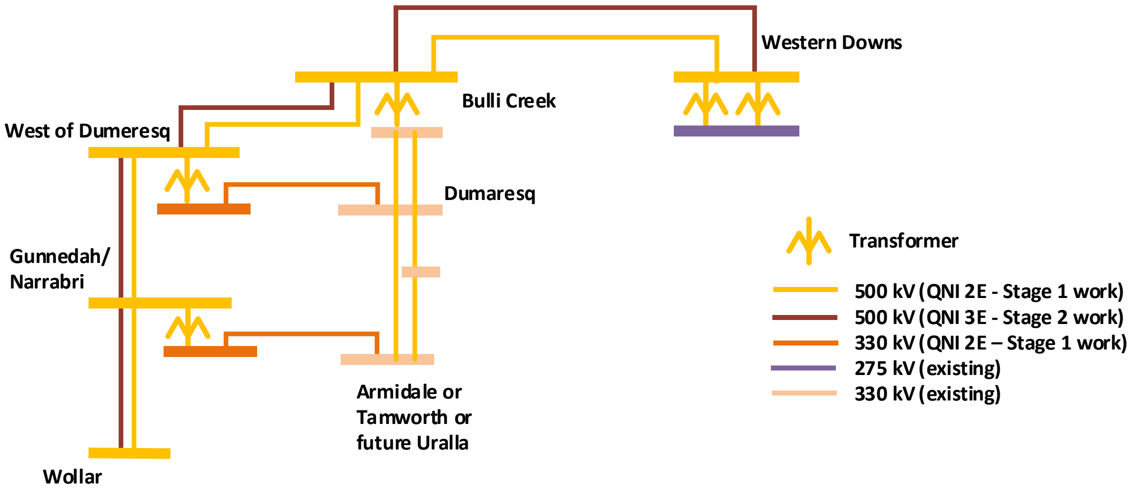
Preferred augmentation option – QNI 3E

The large QNI upgrade includes a second 500 kV circuit between New South Wales and Queensland via the western part of the existing QNI. The proposed route is same as the route of QNI medium upgrade (QNI 2E) and goes through North West New South Wales (N1) and Darling Downs (Q8) REZs. A second 500 kV circuit provides long-term benefits under some scenarios.

QNI 3E includes (Figure 141):

- A second 500 kV circuit from Wollar to Gunnedah/Narrabri site to West of Dumaresq to Bulli Creek to Western Downs.

Figure 141 Single line diagram of QNI 3E



Augmentation cost

The estimated capital cost for QNI Option 3E is $675 million to $1,250 million (2019 dollars). This assumes QNI Option 1A and QNI Option 2E are already commissioned.

Network capability improvement

QNI Option 3E provides an additional notional transfer capacity of 885 MW from New South Wales to Queensland and 760 MW from Queensland to New South Wales, above the transfer capacity with QNI Option 1A and QNI Option 3E.

Alternative options considered

Alternative options are similar to the alternative options listed for QNI medium upgrade.

Sydney / Newcastle / Wollongong load centre reinforcement

Transmission network augmentation or non-network services are projected to be needed between Bannaby and Liddell to supply the Sydney/Newcastle/Wollongong load areas following retirement of coal generation in New South Wales.

The identified need for transmission network augmentation and/or non-network services is to deliver net market benefits through reduced voluntary load curtailment and involuntary load shedding by improving reliability of supply to the Sydney/Newcastle/Wollongong load areas.

Network limitations

Thermal capacity of the following transmission lines:

- Avon–Marulan 330 kV line.
- Dapto–Marulan 330 kV line.
- Mount Piper–Wallerawang 330 kV line.
- Bannaby–Sydney West 330 kV line.
- Bayswater–Liddell 330 kV line.
- Liddell–Newcastle 330 kV line.

Studies are underway to identify further network limitations.

Augmentation description

With retirements of coal generation in New South Wales, the following network augmentations have been identified (see Figure 142).

Stage 1

Network augmentation with retirement of Liddell and Vales Point coal generation and increased Snowy generation and increased import from Victoria, South Australia, and Queensland:

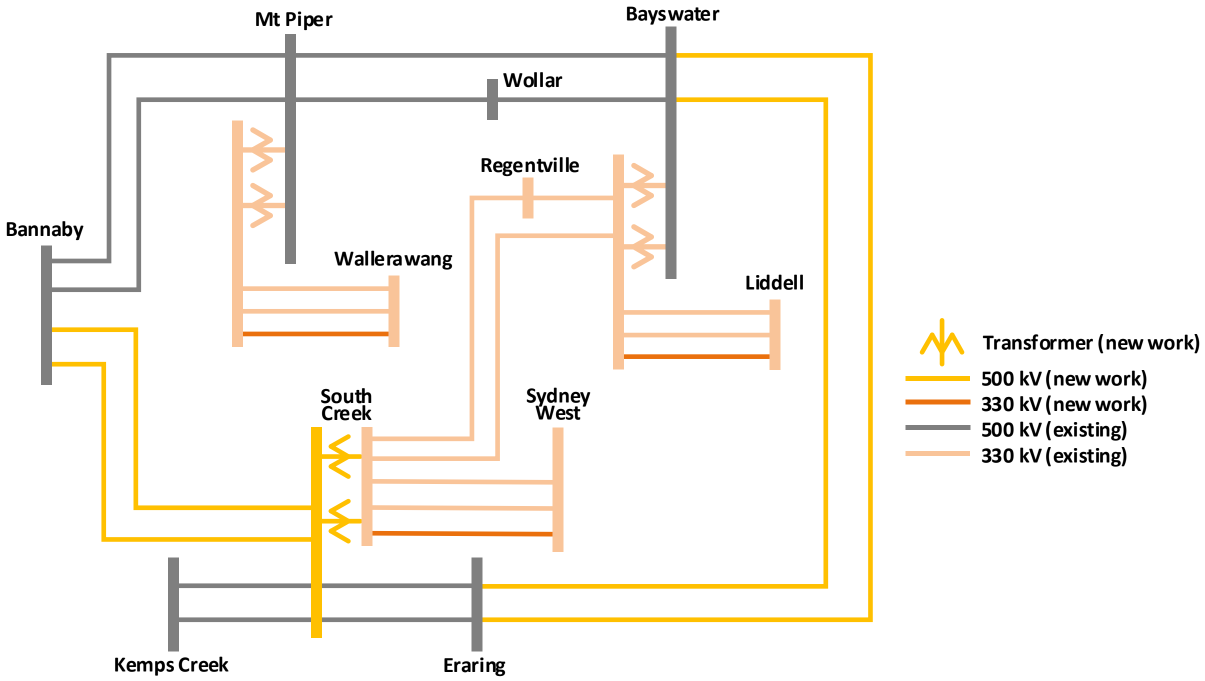
- Uprating of overload lines identified above.
- Two 500 kV lines from Bannaby to South Creek (closer to Sydney West).
- A new 500/330 kV substation at South Creek.
- Tap both Eraring–Kemps Creek 500 kV lines at South Creek.
- Two 500/330 kV 1,500 MVA transformers at South Creek.
- One 500/330 kV 1,500 MVA transformer at Bannaby.
- A new 330 kV transmission line from South Creek to Sydney West (8 km).
- Tap Sydney West–Bayswater 330 kV line at South Creek.
- Tap Sydney West–Regentville 330 kV line at South Creek.
- Third Mt Piper–Wallerawang 330 kV line.
- Third Bayswater–Liddell 330 kV line.

Stage 2

Network augmentation with additional retirement of Eraring coal generation and increased generation from North West New South Wales and New England REZs and increased import from Victoria, South Australia, and Queensland:

- Two 500 kV lines from Bayswater to Eraring.

Figure 142 Single line diagram of network development in Sydney area



Timing and staging

Timing and staging are subject to the timing of the coal retirements, possibility of network reconfiguration, load rebalancing, and non-network solutions. Timings are likely to be between 2026-27 and 2032-33.

Possible non-network solutions

Due to network constraints, unserved energy could occur during high demand periods and subject the distribution of customer loads between the substations. Non-network solutions, such as demand management and battery storage within the Sydney/Newcastle/Wollongong areas, would defer the timing of network augmentation to meet the supply reliability.

Cost estimates

Capital cost estimates of network expansion of Stage 1 is $375 million to $700 million, and of Stage 2 is $290 million to $540 million.

New England and North West New South Wales REZ expansions

These REZ augmentations are grouped together, because there are significant interactions between these two REZs, as well as with the large upgrade to QNI.

The identified need is to facilitate the connection of large amounts of high-quality renewable generation and ensure an even division of power across the network between Queensland, the New England and North West New South Wales REZs, and the Sydney load centre. This need is realised when generation in the New England and North West New South Wales REZs exceeds 400 MW above the existing and committed generation, or alternatively, when the additional hosting capacity of the North West New South Wales REZ provided by QNI 2E or 3E is exceeded.

Augmentation description

The North West New South Wales REZ transmission augmentation integrates with the proposed QNI Option 3E. Across all scenarios, except for Slow Change, large transmission augmentation is projected to be required to connect the solar generation in North West New South Wales and the wind generation in New England to the Sydney load centre.

A significant portion of the transmission augmentation for the North West New South Wales REZ can be met with QNI 3E. Additional to the augmentation provided by QNI 3E, the following is required to facilitate the increase of approximately 8,000 MW of generation in the New England and North West New South Wales REZs:

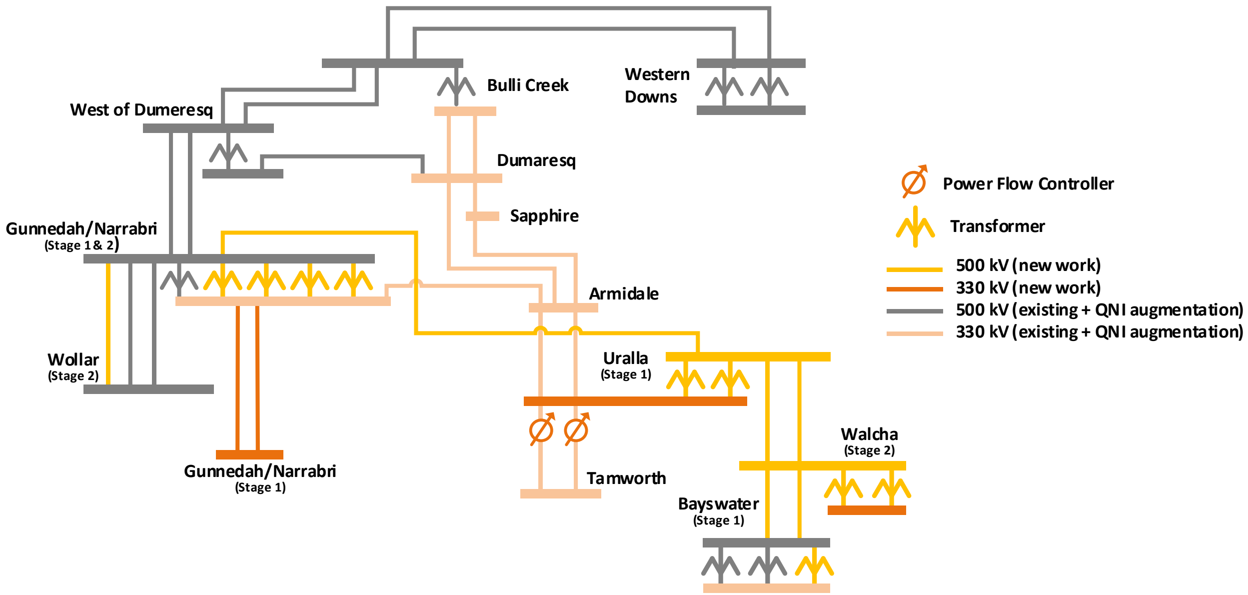
Stage 1 (additional Infrastructure required to QNI 3):

- Two 500/330 kV 1500 MVA transformers at Gunnedah/Narrabri.
- A new double circuit Gunnedah-Narrabri 330 kV line (dependant on connection interest in the area).
- Uprate Armidale–Tamworth 330 kV lines 85 and 86.
- Establish a new Uralla 500/330 kV substation.
- Turn both Armidale–Tamworth 330 kV lines 85 and 86 into Uralla.
- A new double circuit Uralla–Bayswater 500 kV line, string one side (route passing nearby Walcha).
- Power flow controllers on the Uralla–Tamworth 330 kV line.
- A new single circuit Uralla–Gunnedah/Narrabri 500 kV line.
- Two 500/330 kV 1500 MVA Uralla transformers.
- One 500/330 kV 1500 MVA Bayswater transformer.
- Additional reactive support.

Stage 2:

- Third single circuit Gunnedah/Narrabri–Bayswater/Wollar 500 kV line.
- String vacant circuit on Bayswater–Uralla 500 kV line.
- Two 500/330 kV transformers at Gunnedah/Narrabri.
- A new Walcha 500/330 kV Substation (dependant on connection interest in the area).
- Cut Uralla–Bayswater 500 kV line into Walcha.
- Two 500/330 kV 1500 MVA Walcha transformers.
- Additional 330 kV network may be required to connect potential renewable interest within these zones, 330 kV lines from Uralla, Walcha, Gunnedah/Narrabri. Under different scenarios, the REZ augmentation would be reduced according to the projected generation.

Figure 143 Single line diagram of the proposed network development in the New England and North West New South Wales REZs



Timing and staging

Driven by coal retirements, and potential synergies with the construction of the QNI upgrade, timing is optimally timed for mid-2030s in the Central scenario and the High DER scenario. It is also possible to bring this forward or make it shovel ready during QNI 2E/3E construction. New England and North West New South Wales REZ development should be taken into consideration during the design and construction of QNI2E/3E.

Table 21 Timing for New England and North West New South Wales augmentations

Scenario	Central	Step Change	High DER	Fast	Slow
Timing	2036	2025	2036	2034	N/A

Possible non-network alternatives

Network constraints are likely to occur during high VRE and during low demand. Strategically placed and operated non-network solutions, such as battery storage and/or pumped hydro, can defer the timing and/or reduce the scale of network augmentation. New England has good pumped hydro resources and, if strategically developed, can increase the hosting capacity within this REZ.

Augmentation cost

Stage 1 cost estimate = $820 to $1,520 million.

Stage 2 cost estimate = $290 to $535 million.

Central West New South Wales REZ expansion

The Central West New South Wales REZ is highlighted in the New South Wales Government's Electricity Strategy for development as the first pilot REZ in New South Wales. The New South Wales Government has stated in the strategy that it will support the transmission upgrades for a pilot 3,000 MW REZ in the Central

West REZ by 2028[35]. The development of 3,000 MW of new generation in the Central West REZ in this timeframe may require accelerated development of with associated transmission infrastructure.

Since this plan was announced just prior to completion of this Draft ISP, it has not been fully considered in this ISP. Subject to further policy detail becoming available, AEMO intends to assess the impact of this policy in the Final 2020 ISP.

The identified need is to facilitate the connection of large amounts of renewables generation remote from the existing network. This need is realised when generation in the Central West REZ exceeds approximately 700 MW above existing and committed generation.

Augmentation description

The following augmentation is required to increase the hosting capacity within the Central West REZ by approximately 2,000 MW:

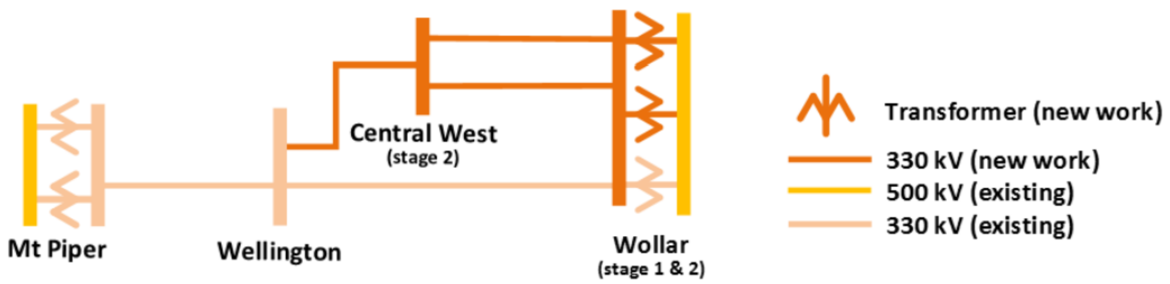
Stage 1 (improve hosting capacity by 700 MW):

- Establish a 330 kV switchgear at Wollar.
- One 500/330 kV 1,143 MVA Wollar transformer.

Stage 2 (improve hosting capacity by 1,000 MW):

- Establish a Central West Hub 330 kV substation to the north-west of Wollar.
- A new double circuit Central West – Wollar 330 kV line (160 km).
- A new single circuit Central West Hub – Wellington 330 kV line (120 km).
- One 500/330 kV 1,143 MVA Wollar transformer.

Figure 144 Single line diagram of the proposed network development in the Central West REZ



Timing and staging

Driven by the coal retirements in New South Wales, this is optimally timed in the central scenario in 2036. The impacts of the New South Wales Government's Electricity Strategy will be factored into further analysis on the optimal timing and scale of this upgrade in the 2020 Final ISP.

[35] New South Wales Government. The New South Wales Electricity Strategy, at https://energy.nsw.gov.au/sites/default/files/2019-11/NSW%20Electricity%20Strategy%20-%20Final%20detailed%20strategy_0.pdf.

Table 22 Timing of Central West New South Wales augmentation

Scenario	Central	Step Change	High DER	Fast	Slow
Stage 1 Timing	2035-36	>2024-25 †	2035-36	2032-33	N/A
Stage 2 Timing	2040-41	2037-38	N/A	2041	N/A

† Early development of renewable energy in the Central West NSW REZ would require staged upgrades within Central West starting in 2025. The NSW Government Electricity Strategy could bring forward transmission augmentation development within this zone.

Possible non-network alternatives

Network constraints are likely to occur during high VRE and during low demand. Strategically placed and operated non-network solutions such as battery storage and/or pumped hydro can defer the timing and/or reduce the scale of network augmentation. Central West has access to good pumped hydro resources which, if strategically developed, can increase the hosting capacity within this REZ.

Augmentation cost

Stage 1 – $24 million to $44 million.

Stage 2 – $299 million to $555 million.

Far North Queensland REZ expansion

This expansion is to enable the connection and transfer of energy from high wind capacity factor locations in Far North Queensland to the wider network. This need is realised when generation in the Far North Queensland REZ exceeds approximately 700 MW above the current existing and committed generation.

Augmentation details

The augmentation for Far North Queensland is divided into the transmission corridor upgrade as well as augmentations to connect renewable generation interest.

Transmission 275 kV corridor upgrade

- Stage 1 (Gain of approximately 600 MW)
  - Rebuild the double circuit Ross–Chalumbin 275 kV line at a higher capacity. Based on Powerlink's TAPR the Ross–Chalumbin 275 kV double circuit line displays extensive corrosion and major refit may be required at the end of technical service life around 2025-26 at an estimate cost of $85 million to $165 million[36]. This may place the replacement needs around 2035-36.
- Stage 2 (Gain of approximately 500-800 MW)
  - A new 275 kV single circuit Ross–Chalumbin 275 kV line.
  - Uprate the lower rated Ross–Strathmore 275 kV line.

Augmentations required to connect possible variable renewable energy interest

The route and substation selection will be refined considering connection interest. Possible options or combinations include:

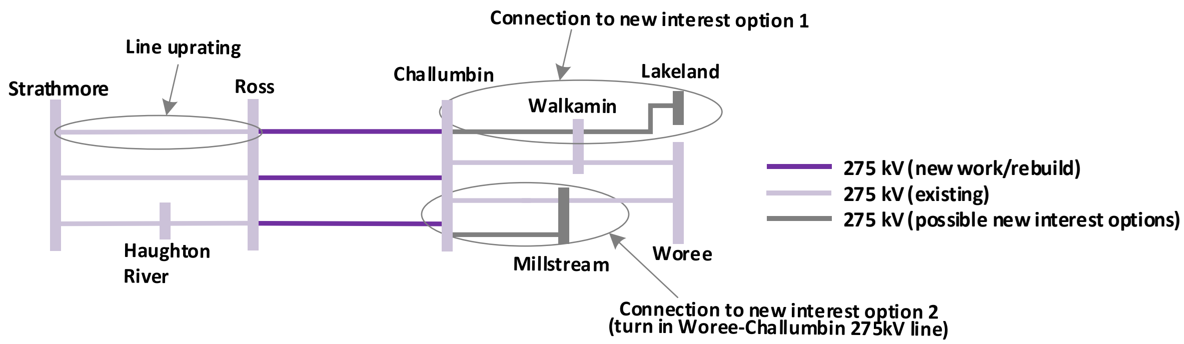
- A new substation to the North of the zone around the Lakeland area.
- A new single/double circuit Walkamin–Lakeland 275 kV line.
- A new single/double circuit Walkamin–Chalumbin 275 kV line.

and/or

[36] Powerlink's 2019 Transmission Annual Planning report page 74, at https://www.powerlink.com.au/sites/default/files/2019-09/Transmission%20Annual%20Planning%20Report%202019%20-%20Full%20report.pdf.

- A new 275 kV substation North of Millstream.
- Turn in Woree–Chalumbin 275 kV line at Millstream.
- A new single/double circuit Chalumbin–Millstream 275 kV line.

Figure 145 Single line diagram of the proposed network development in the Far North Queensland REZ



Timing and staging

The timing for this augmentation would be when the connection of wind in the Far North Queensland REZ exceeds 700 MW above what is currently committed and commissioned, which in the modelling typically coincides with coal retirement. For the Central scenario, both Part 1 and Part 2 are required by 2036-37. For the Step Change scenario, the timing is brought forward approximately 10 years, to around 2025-26.

Early works

Based on AEMO's wind resource estimates, Far North Queensland could have the highest wind resource quality in the NEM. Due to the scale of transmission infrastructure required to connect generation in Far North Queensland to the load centres, the augmentation costs are significant. Before committing to significant transmission build, installation of wind monitoring across the area should be investigated to confirm the wind resource quality within the Far North Queensland REZ candidate.

Augmentation cost

The costs estimated for the development of Far North Queensland REZ are as follows:

- Ross–Chalumbin 275 kV double circuit line rebuild (approximately $250 million to $300 million).
- Uprating of the lower rated Ross–Strathmore 275 kV line (approximately $10 million to $15 million).
- Development towards Lakeland assuming a single circuit Chalumbin–Walkamin–Lakeland 275 kV line (approximately $230 million to $430 million).
- Development towards Millstream assuming a single circuit Chalumbin–Millstream 275 kV line (approximately $45 million to $85 million).

Gladstone Grid Section Reinforcement

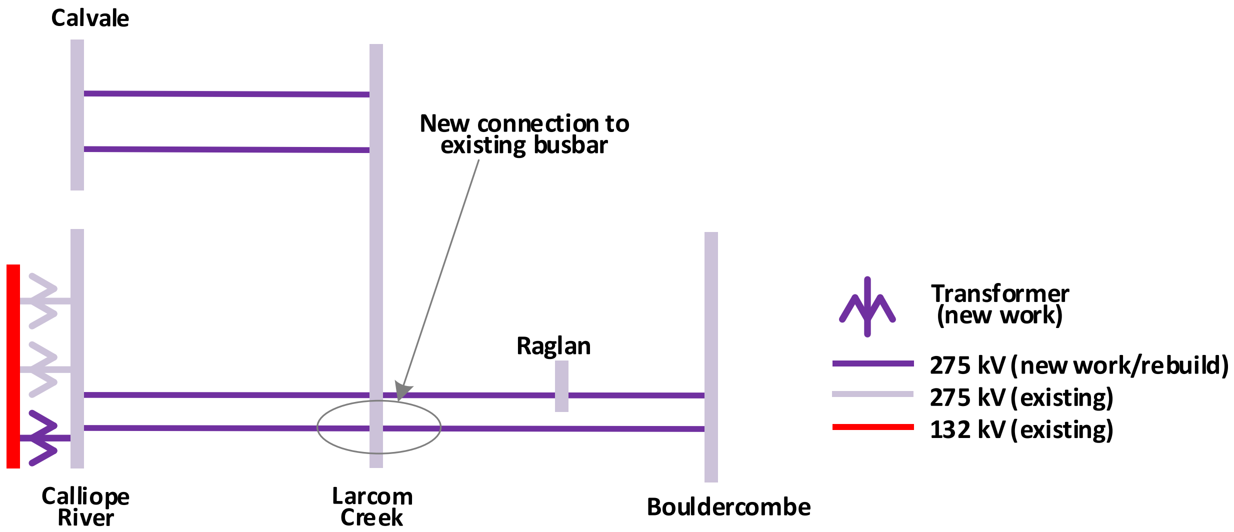
Following the closure of Gladstone Power Station, network upgrades will be required to supply major loads in the Gladstone area. Furthermore, with the significant increase in generation projected for the Far North, Isaac, and Fitzroy REZs, the thermal capacity of the network between Bouldercombe, Raglan, Larcom Creek, and Calliope River will be reached.

Augmentation description

The augmentation to address the thermal constraints includes:

- Rebuild the Bouldercombe–Raglan–Larcom Creek–Calliope River and the Bouldercombe–Calliope River 275 kV line as a high capacity double circuit line, for a gain of approximately 700-800 MW of additional hosting capacity.
- Turn Bouldercombe–Calliope River 275 kV line into Larcom Creek.
- A new double circuit Calvale–Larcom Creek 275 kV line.
- Third Calliope River 275/132 kV transformer.

Figure 146 Single line diagram of the proposed network development in the Gladstone Grid Section area



Timing and staging

Upgrading the Central to Southern Queensland (CQ–SQ) cut-set will further highlight the need for the upgrade on this network, as addressing this limitation will shift the limitations further north under high VRE output. The timing of this upgrade together with the upgrade on the CQ–SQ limit is being investigated further, however, currently it is expected when additional generation in the north of this limit exceeds approximately 2,000 to 2,500 MW.

Possible non-network alternatives

Network constraints are likely to occur during high VRE and during low demand. Strategically placed and operated non-network solutions such as battery storage and/or pumped hydro can defer the timing and/or reduce the scale of network augmentation. Isaac, Fitzroy, North Queensland, and Far North Queensland have access to areas with potential for good pumped hydro resources which, if strategically developed, can increase the hosting capacity within these REZs.

Augmentation cost

The estimated cost (full cost of the augmentation) is $160 million to $300 million.

Central Queensland to Southern Queensland

The CQ–SQ cut-set is defined as the power flow on the Calvale – Halys 275 kV lines, the Calliope River – Gin Gin 275 kV lines, and the Wurdong – Gin Gin 275 kV line. Transfer is limited to prevent voltage and transient stability. To increase the transfer across the CQ–SQ cut-set, these stability limits will need to be addressed.

This can be achieved by augmenting the network between Calvale and Wandoan South. This need is realised when generation in north of CQ–SQ exceeds 2,500 MW above existing and committed generation. This 2,500

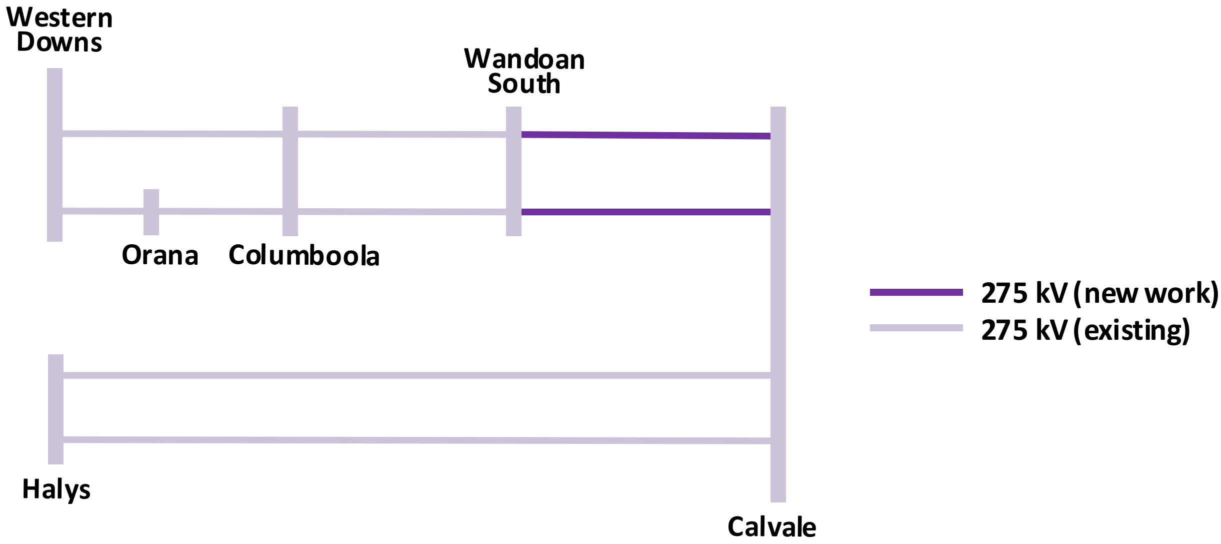
MW includes the generation connections in Far North Queensland, Northern Queensland Clean Energy Hub, Northern Queensland, Isaac, Barcaldine, and Fitzroy REZs.

Augmentation description

To increase the capacity of the CQ–SQ cut-set, the following augmentations would provide at least 900 MW increased capacity:

- A new double circuit Calvale–Wandoan South 275 kV line and associated reactive plant.
- To offset further development of CQ–SQ, placement of pumped hydro north of this cut-set could reduce increase the hosting capacity north of this cut-set.

Figure 147 Single line diagram of the proposed network development of the CQ–SQ cut-set



Timing and staging

With the development of high-quality wind and solar energy resources in central and northern Queensland, a new double-circuit 275 kV transmission line from Calvale to Wandoan South will reduce network congestion and provide value to consumers. These major investments are projected to be required in the 2030s. CQ–SQ stability constraints are projected to bind prior to 2024-25 and increase in 2026-27 when generation in northern Queensland increases above 2,000 MW. However, the binding of CQ–SQ is not projected to result in any unserved energy in Queensland. Further, the number of binding hours due to these stability limitations on CQ–SQ is projected to decrease following the retirement of Callide B and Gladstone, allowing more variable generation to be accommodated north of this cut-set.

Therefore, the timing of this upgrade is still being investigated, with an indicative timing of 2035-36 in the Central scenario for the development of a new double circuit Calvale – Wandoan South 275 kV line. Further investigations are underway to determine if a smaller augmentation on the CQ–SQ cut-set is required before 2030. Alternatives to address current congestion concerns could consider unregulated investment options, and could also explore options for non-network solutions.

Possible non-network alternatives

Network constraints are likely to occur during high VRE and during low demand. Strategically placed and operated non-network solutions such as battery storage and/or pumped hydro can defer the timing and/or reduce the scale of network augmentation. Isaac, Fitzroy, North Queensland, and Far North Queensland have access to areas with potential for good pumped hydro resources which, if strategically developed, can increase the hosting capacity within these REZs.

Augmentation cost

The estimated cost is $226 million to $420 million.

South East South Australia REZ

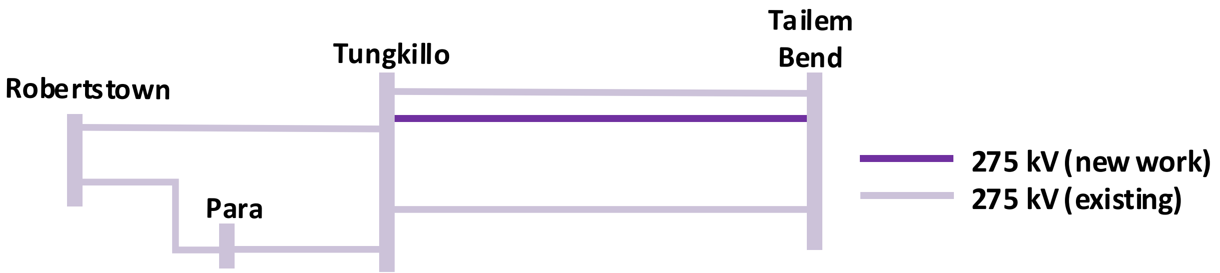
The identified need is to facilitate the connection of wind generation on the South Australia side of the Heywood interconnector. The present network is approaching capacity, and augmentation would be required with any connection of generation within this REZ.

Augmentation description

To increase the hosting capacity of the South East South Australia REZ beyond 55 MW, the following augmentation is proposed:

- String the vacant circuit on the Tungkillo – Tailem Bend 275 kV line.
- Install necessary dynamic reactive support.
- If wind generation location is in the southerly side of the REZ, alternative network augmentation may be required. This augmentation would be more costly.

Figure 148 Single line diagram of the proposed network development in the South East South Australia REZ



Timing and staging

The timing for this augmentation is optimally by 2038 in the Central scenario.

Table 23 Timing of South East South Australia augmentation

Scenario	Central	Step Change	High DER	Fast	Slow
Timing	2038	2036	2038	2032	2041

Possible non-network solutions

Since network constraints are likely to occur during in the South East South Australia REZ during high wind output worsened by low demand, non-network solutions such as large-scale storage (battery storage and/or pumped hydro) can defer the timing of network augmentation. The South East South Australia REZ has limited pumped hydro resources, so possible non-network solutions include large-scale batteries to assist in the deferral of network augmentations.

Augmentation cost

Costing stage 1: $20 million to $80 million (depending largely on the requirements for reactive plant).

Mid North Region

Due the nature of the South Australian network, generation north of Davenport contributes to congestion in the Mid North REZ. Consequently, addressing the Mid North congestion with the generation connecting in the Mid North REZ, and the REZs to the North and West (Mid North, Northern South Australia, Leigh Creek, Roxby Downs, and Eastern and Western Eyre Peninsula).

The identified need is to:

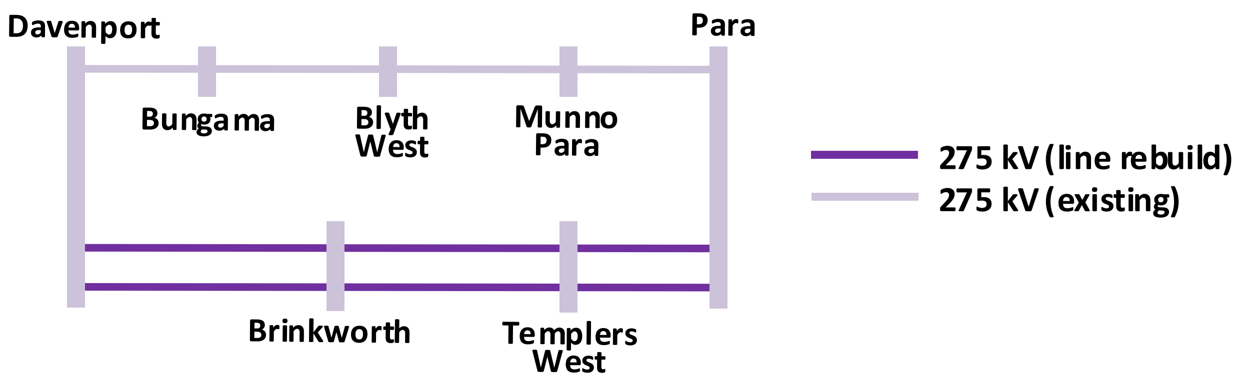
- To increase the transfer capability of the Mid North, Northern South Australia, Leigh Creek and Roxby Downs REZs to South Australia load centre as well to Heywood and Energy Connect interconnectors.
- To connect this additional generation to increase reliability following the retirement of gas generation in South Australia.

Augmentation description

To alleviate constraints between Davenport and Adelaide and between Davenport and Robertstown, increasing the hosting capacity by approximately 1,000 MW, the following augmentation is required:

- Rebuild the single circuit Davenport–Brinkworth–Templers West–Para 275 kV line at a high capacity double circuit line, and/or
- Reconfiguration of 132 kV network in the Mid-North REZ to ensure balance flows between the 275 kV and the 132 kV.

Figure 149 Single line diagram of the proposed network development in the Mid North



Timing and staging

This augmentation is optimally timed in 2036 in the Central scenario and 2035 in the Step Change scenario, and is triggered when the total generation in Mid North, Northern South Australia, Leigh Creek, and Roxby Downs exceeds 1,000 MW. The timing of this augmentation is heavily influenced by the retirement of gas generation and the configuration of the network in the Adelaide area.

Table 24 Timing of Mid North augmentation

Scenario	Central	Step Change	High DER	Fast	Slow
Timing	2035-36	2034-35	2034-36	2030-31	-

Augmentation cost

The estimated cost is $265 million to $475 million.

6.2 Alternative interconnector corridors

6.2.1 South Australia – Queensland Interconnector

The South Australia – Queensland interconnector option involves two 700 MW HVDC transmission lines (1,450 km) from Davenport in South Australia to Western Downs in Queensland, with an intermediate converter station at Broken Hill for renewable generation connection, with a cost estimate of $1,385 million to $2,575 million. This option provides a transfer capability of 700 MW between South Australia and Queensland.

This option was assessed and rejected in the analysis, as it did not deliver net market benefits comparable to the range of other options and the recommended option of Project EnergyConnect. Accordingly, it does not form part of the optimal development path.

Appendix 7. Power system security

Power system security relies on many services that have historically been provided by thermal synchronous generation. New technologies and approaches to these services will be required as the power system continues to transform and becomes dominated by inverter-based resources.

AEMO has performed engineering studies of the power system to identify future power system security requirements. The areas considered are voltage control, transient stability, system strength, frequency management, power system inertia, and dispatchability.

The services can be procured from the market, or provided by network services, or from new plant connecting to the grid by meeting technical standards. The ISP recommends some network investments for power system security.

7.1 Renewable Integration Study

AEMO has initiated a Renewable Integration Study (RIS)[37] as the first stage of a multi-year plan to support a secure and reliable NEM with a high share of renewables. The study focuses on quantifying the technical renewable penetration limits of the power system for a projected generation mix and network configuration in 2025.

The insights from the Renewable Integration Study complement existing ISP processes and form a basis for future work. This includes ultimate physical limits to renewable penetration, potential technology options to allow system operation up to these limits, and recommended regulatory and operational improvements.

7.1.1 RIS background

The ISP articulates a whole-of-system development path for the NEM, to design and execute the transition in a way that maximises benefits at lowest cost and risk to consumers.

In addition to the ISP, AEMO conducts further analysis where there is merit in a deeper level of inquiry, including analysis of those technologies that are at the forefront of the transformation. AEMO has published several relevant reports into the changing generation mix[38].

As a supplement to developing the 2020 ISP, AEMO commenced the RIS to take a deeper review into the specific system implications and challenges associated with the integration of large amounts of variable inverter-based renewable generation and decentralised energy on the power system.

[37] See https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Future-Energy-Systems/Renewable-Integration-Study.

[38] See RIS International Review Appendix A.3 for a summary of relevant past AEMO publications into the changing generation mix. At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Future-Energy-Systems/2019/AEMO-RIS-International-Review-Oct-19.pdf.

AEMO's Power System Requirements reference paper presented an overview of the specific requirements of the power system[39]. The RIS builds on that paper, to explore the specific opportunities and risks for maintaining the physical requirements of the power system while integrating variable inverter-based renewable resources at increasing levels of penetration.

The RIS is being undertaken in a series of steps:

- A review of leading international experience in wind and solar photovoltaic (PV) integration (published October 2019)[40].
- Detailed analysis of phenomena specifically related to wind and solar PV technologies.
- Presenting a view of what operating the NEM could look like over the next decade.
- Engaging with local and international organisations and independent experts to review and collaborate on AEMO's preliminary findings.
- A final report in March 2020 on the technical challenges associated with renewable integration and a roadmap to manage these.

The study uses a projected generation mix and network configuration as expected in 2024-25 as a focus for its detailed analysis. This time horizon was selected because it provides a future generation mix with a high capacity of installed renewable generation and given the ISP's Group 1 project list reduces the uncertainty in what capital transmission projects might be built in what locations. Concurrently, this outlook period keeps the horizon close enough to 201920 that it could still be reasonable to assume technology capabilities that are similar to those commercially available at present.

7.1.2 How the RIS interacts with the ISP

The RIS is a complementary publication to the ISP. The RIS has used the generation expansion model developed for the Neutral scenario of the ISP Insights paper on pumped hydro energy storage[41]. This is representative of a plausible 2024-25 generation mix (noting that in 204-225 the different ISP scenarios assessed showed little difference, with divergence in generation expansion only coming in later years of the ISP simulations).

The insights from the RIS will inform the 2020 Final ISP and future ISPs as well as providing foundational engineering advice to government and administrative policy-makers to support their consideration of future changes needed in electricity regulations and market designs.

Some of the emerging insights of relevance to the ISP are outlined in the following sections. The full results of the RIS will be published for consultation in 2020, prior to finalisation of the 2020 ISP.

7.1.3 Emerging insights of relevance to the ISP

Based on AEMO's investigations and analysis to date as part of the RIS, the following insights are beginning to emerge, which may influence the analysis carried out for the 2020 ISP.

- **Power ramping and variability management**.
  - Historical analysis of 2015 to 2019 showed the main contributor to ramps in net demand[42] over timeframes of 30, 60, and 90 minutes was the change in underlying demand.

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[39] AEMO, Power System Requirements, March 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

[40] AEMO, RIS International Review, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Future-Energy-Systems/2019/AEMO-RIS-International-Review-Oct-19.pdf.

[41] AEMO, Building power system resilience with pumped hydro energy storage, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2019/ISP-Insights---Building-power-system-resilience-with-pumped-hydro-energy-storage.pdf.

[42] This refers to MW changes that need to be covered by scheduled generation.

- By 2024-25, changes in wind and solar generation will become the main contributor to ramps in net demand.
- Studies are still ongoing to assess the likelihood that there would be sufficient online ramping capability in the scheduled generation fleet to meet these renewable-driven ramps in 2024-25.
- Analysis has confirmed that, while there is an increased coincidence in VRE ramping due to wind gusts and cloud cover if generators of the same fuel type are located very close to each other, the coincidence of these ramps drops significantly if generators are spaced more than 15 km apart. This trade-off should be considered as part of REZ planning.

- **Integration of DER**.
  - With higher levels of DER, there is the potential for the DER to impact bulk system security and require dedicated management strategies. Local distribution limits on DER are not expected to prevent this, and investments in the distribution system to support increasing DER may serve to amplify risks unless the distribution investments are designed appropriately with an eye to impacts on bulk system security from the higher levels of DER they would support.
  - Nevertheless, there is likely to be an operational limit, at least in the near term, to the amount of uncontrollable generation online that the power systems (transmission and distribution) can securely accommodate under different system conditions.
  - Similarly, there is likely to be an operational limit to the amount of small-scale behind the meter generation online that the system can securely accommodate under different system conditions (even if the generation is controllable).
  - A series of recommendations to better support DER integration are provided in section C1.2 of the main report.
- **Frequency control**.
  - Studies indicate that there is likely to be a need for regional inertia and frequency control reserves to ensure security during periods of high wind and solar output. This may necessitate that additional constraints be considered when developing the optimal development path in the ISP.
- **System strength**.
  - The need for a minimum number of online synchronous units in each region, where possible, to maintain minimum fault levels is expected to remain for the foreseeable future.
- **Staged approach**.
  - A staged, progressive, transition to lower levels of inertia and committed synchronous units, testing operational security thoroughly at each stage before proceeding to the next, will be essential to manage the increasing risks as lower levels are approached[43].
  - The Final ISP may need to consider to how any such staged transition might introduce short-term constraints, and the potential impact this may have on ISP projections.

7.2 System security developments

There are system security considerations beyond just ensuring there is sufficient MW capacity from generation and transmission networks.[44] These aspects must be considered to ensure power system developments are operationally adequate, and are also secure and reliable.

As conventional synchronous generation retires, the suite of services such as system strength, inertia, frequency control and voltage control will need to continue to be closely monitored and studied.

[43] AEMO, RIS International Review, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Future-Energy-Systems/2019/AEMO-RIS-International-Review-Oct-19.pdf.

[44] AEMO, Power System Requirements, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

Co-ordination and locational optimisation for the acquisition of these services will be an important consideration as the power system transitions to higher levels of inverter-based resources within REZs.

7.2.1 Forecast power system degradation

System strength

System strength is a measure of the ability of a power system to remain stable under normal conditions and to return to a steady state condition following a system disturbance.[45]

Because some types of generation, including most solar and wind generators currently being developed and built, have not been designed to provide inherent contribution to system strength, REZs can be susceptible to low system strength conditions. Low system strength can impact the stability and dynamics of generating systems' control systems and the ability of the power system to remain in stable operation. Section Appendix 8 provides detail on REZs that are most susceptible to low system strength.

Based on projections provided in this ISP, many renewable developments contemplated in the 2020s are likely to require some level of system strength remediation for their connection, and from the 2030s onwards, most renewable developments would be expected to require system strength remediation. When developing REZs, system strength planning can benefit from economies of scale – coordinated solutions to providing system strength, that generators contribute towards, are expected to be more economic than multiple small-scale solutions developed at each wind or solar farm[46].

As covered in Section 7.2.2, AEMO has published guidelines with regards to system strength and mitigation requirements for new generation connections[47]. TNSPs are also required to maintain minimum fault levels at specified nodes within their networks. Should a shortfall be identified by AEMO, the TNSP must procure system strength services to maintain the fault levels determined by AEMO. AEMO has published methodologies and assessments relating to TNSP responsibilities in maintaining minimum fault levels at specific fault level nodes[48].

As renewable energy continues to displace conventional generation, it will become increasingly important for TNSPs to coordinate system strength solutions. REZs that are strategically designed with system strength in mind will benefit from economies of scale to achieve optimal investment outcomes.

Consequence of low system strength

The increasing integration of inverter-based resources across the NEM has implications for the engineering design of the future transmission system. As clusters of inverter-based resources 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.

- **Steady state voltage management** – in systems with low system strength, greater deviations in voltages occur due to disturbances. Larger voltage step changes can occur with the switching in/out of reactive devices which could breach system standards. A lack of reactive capability due to reduced synchronous plant online can lead to difficulty in maintaining secure operating voltages. For example, high voltages can occur during light load periods.
- **Voltage dip** – in a weak network area, voltage dips are deeper, more widespread, and can last longer than in a strong network. For example, the transient voltage dip resulting from a short circuit event will be more

[45] A system disturbance is an unplanned contingency on the power system, such as a high-voltage network fault (i.e. short-circuit) or an unplanned generator or large load disconnection.

[46] Section 4.3.2 of AEMO's 2017 Victorian Annual Planning Report included a worked example that demonstrated the benefits of system strength planning, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/VAPR/2017/2017-VICTORIAN-ANNUAL-PLANNING-REPORT.pdf.

[47] AEMO. System Strength Impact Assessment Guidelines, at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Strength-Impact-Assessment-Guidelines.

[48] AEMO. System Strength Requirements Methodology, 2018 System Strength Requirements & Fault Level Shortfalls, at http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/System-Security-Market-Frameworks-Review.

severe, more widespread, and slower to recover in a weak system than in a strong system. This condition will generally last until the network fault is cleared by protection systems.

- **Fault ride-through** – the ability of generators to maintain stable operation following a fault is an important aspect of power system security. Inverter-based resources have minimum fault level requirements – if they are not met, then their associated control systems cannot be relied upon to operate in a stable manner. Also, during a network fault, inverter-based resources tend to reduce their active power generation and supply reactive power. In a weak system, where the impact of the network fault is widespread, a large amount of inverter-based resources can enter fault ride-through during the brief period before a fault is isolated, resulting in a power imbalance.
- **Power quality** – for the same consumer demand, voltage harmonics and imbalance are higher in weak systems than in strong systems. This can result in large over-voltages lasting for several seconds, potentially exceeding the withstand capability of local generation. Because synchronous generators dampen harmonics and voltage imbalance, displacement of synchronous generators with inverter-based resources diminishes power quality.
- **Operation of protection** – the trend of decreasing system strength will result in fault current being reduced, which makes it more difficult for protection systems to detect and isolate faults, and can also result in higher likelihood of protection maloperation[49].

7.2.2 System strength outlook

In the NEM, the division of responsibilities for the provision of system strength are as follows:

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[50] defines the process AEMO must apply to determine the system strength requirement at each node.

The local TNSP is required to provide system strength services to meet the minimum three phase fault levels at relevant fault level nodes if AEMO has declared a shortfall.

A connecting generator is required to implement or fund system strength remediation, such that its connection (or altered connection) does not have an adverse impact on system strength, assessed in accordance with AEMO's system strength impact assessment guidelines.

The initial system strength requirements determined by AEMO in 2018 are currently under review, with detailed Electromagnetic Transient (EMT) studies now being utilised for all regions to refine the fault level requirements. Once these studies are finalised, the system strength shortfall projections will be also be updated, and any shortfalls will be declared.

Available fault levels

AEMO uses the Available Fault Level calculation methodology[51] to perform high level system strength impact assessments (see Figure 152), and uses a more comprehensive System Strength Requirements Methodology[52] for determining system strength requirements at fault level nodes (e.g. the following sections).

Snapshot periods from the market modelling outputs with low levels of synchronous generation online have been analysed for snapshot years across the NEM. Figure 150 demonstrates graphically areas already with low system strength, and also projects where system strength is expected to decrease.

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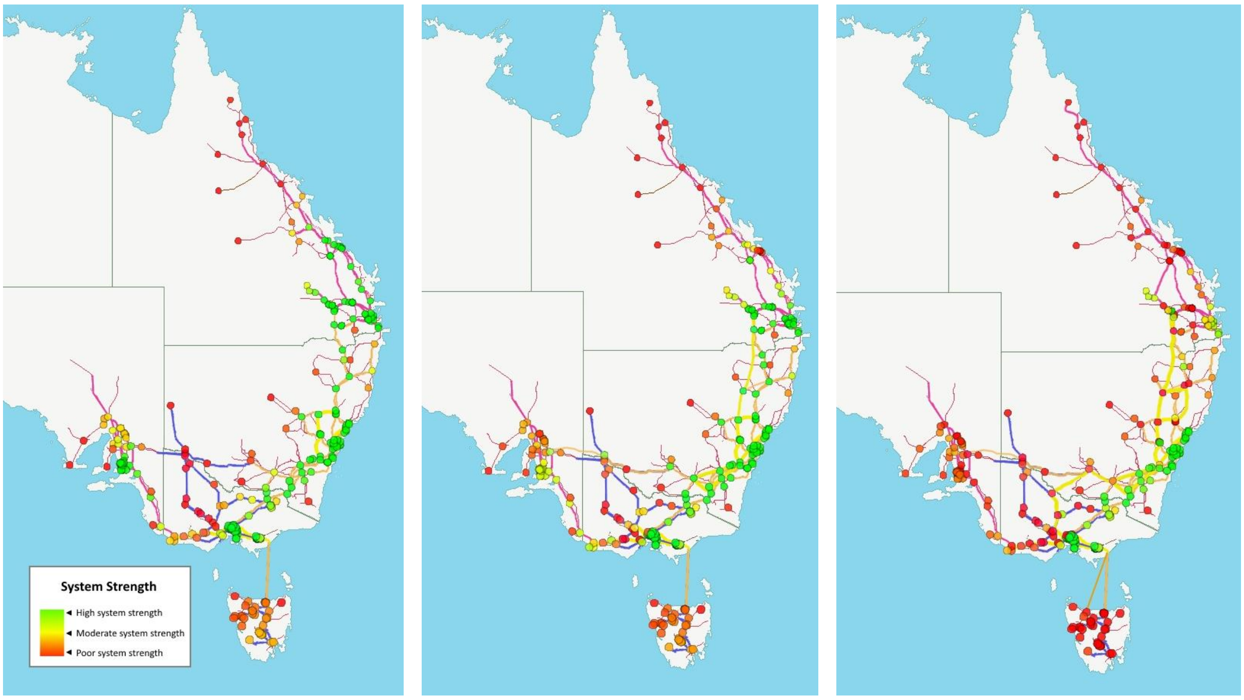
[49] Protection maloperation can result in additional generation tripping during power system disturbances, loss of load due to maloperation of network equipment, and public safety risks if faults are not cleared.

[50] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

[51] AEMO. System Strength Impact Assessment Guidelines, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Impact_Assessment_Guidelines_PUBLISHED.pdf

[52] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

Figure 150 NEM-wide system strength outlook 2020-21 (left), 2029-30 (middle), 2039-40 (right)



Results for 2020-21 demonstrate the areas with existing low system strength such as Western Victoria, South West New South Wales, northern Queensland, and Tasmania.

In the 2029-30 results, there is a forecast reduction in system strength in the Adelaide area as gas plant is no longer required to be directed on for system strength, but the system strength requirements are instead expected to be met by the new synchronous condensers at Robertstown and Davenport 275 kV substations.

The 330 kV transmission lines, as well as the synchronous condensers associated with Project EnergyConnect at Buronga and Darlington Point, are shown to improve system strength around Western Victoria and South West New South Wales. The Western Victoria network upgrades also improve the system strength in Western Victoria, demonstrating the importance of taking into account network upgrades for system strength assessments.

In the 2039-40 results, system strength in central and southern Queensland is projected to reduce as coal generation retirements occur. This is also the case for New South Wales, particularly around the Armidale and Wellington 330 kV substations.

Available fault levels in the Latrobe Valley are forecast to remain high, even though the Yallourn Power Station units are projected to have retired by that point. It should be noted that although available fault levels are high, there could still be a requirement for the TNSP to mitigate any reduction in fault levels following synchronous plant retirement.

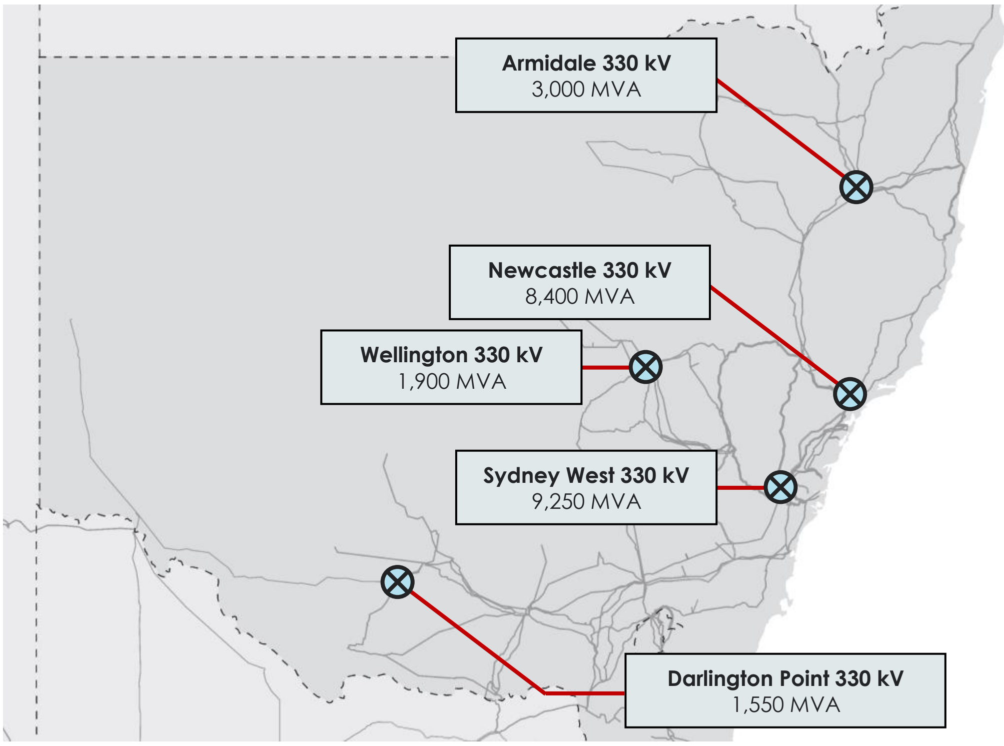
High levels of new generation are forecast to lead to low system strength emerging or worsening in South West Victoria, Northern New South Wales, Southern Queensland, and Tasmania.

Co-ordination and optimisation of requirements for TNSPs to maintain fault levels at the defined fault level nodes, and fault level mitigation requirements for inverter-based generation will be an important consideration for REZs.

New South Wales system strength outlook

AEMO has determined the following fault level nodes for New South Wales. They represent a metropolitan load centre, a synchronous generation centre, areas with high inverter-based resources and areas electrically remote from synchronous generation. . The System Strength Requirements Methodology[53] outlines the process for determining the system strength requirement at each node.

Figure 151 New South Wales system strength (fault level) requirements



The ISP system strength assessments for New South Wales are outlined in Table 25. These studies are based on the 2018 system strength requirements[54] which are currently under review. These studies have found that:

- The proposed Project EnergyConnect (see Section 6.1.2) is projected to improve system strength at the Darlington Point fault level node, because it includes synchronous condensers at Buronga and Darlington Point.
- Following the exit of Vales Point, Bayswater, and Eraring Power Stations, there is a projected shortfall at the Sydney West, Newcastle, and Wellington fault level nodes.

Table 25 New South Wales projected system strength

Fault level node	Duration Curve	Current requirements met			Comment
		Currently	Up to 2025	Up to 2040	
Armidale 330 kV	Figure 152	Yes	Yes	Yes	No shortfall projected within 5 years. Increases following transmission network upgrades to QNI
Sydney West 330 kV	Figure 153	Yes	Yes	3,000 MVA potential shortfall †	No shortfall projected within 5 years. Shortfall by 2040 due to coal generation retirements

[53] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

[54] AEMO. System Strength Requirements & Fault Level Shortfalls, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

Fault level node	Duration Curve	Current requirements met			Comment
		Currently	Up to 2025	Up to 2040	
Wellington 330 kV	Figure 154	Yes	Yes	250 MVA potential shortfall †	No shortfall projected within 5 years. Shortfall by 2040 due to coal generation retirements
Newcastle 330 kV	Figure 155	Yes	Yes	3,000 MVA potential shortfall †	No shortfall projected within 5 years. Shortfall by 2040 due to coal generation retirements
Darlington Pt 330 kV	Figure 156	Yes	Yes	Yes	No shortfall projected within 5 years. Increases when Project EnergyConnect is commissioned in 2023-24

† Although AEMO projects that a shortfall may arise before 2040, a fault level shortfall is not formally declared at this stage.

The following figures show the projected fault level duration curves for each fault level node in New South Wales, highlighting:

- A forecast step increase at Darlington Point when Project EnergyConnect is commissioned in 2023-24, because of the new synchronous condensers.
- A projected step increase at Armidale when the QNI and REZ upgrades are commissioned.
- A forecast trend of decreasing system strength across New South Wales due to the retirement of synchronous generation and the transition to inverter-based resources.

Figure 152 Projected Armidale 330 kV fault level duration curves

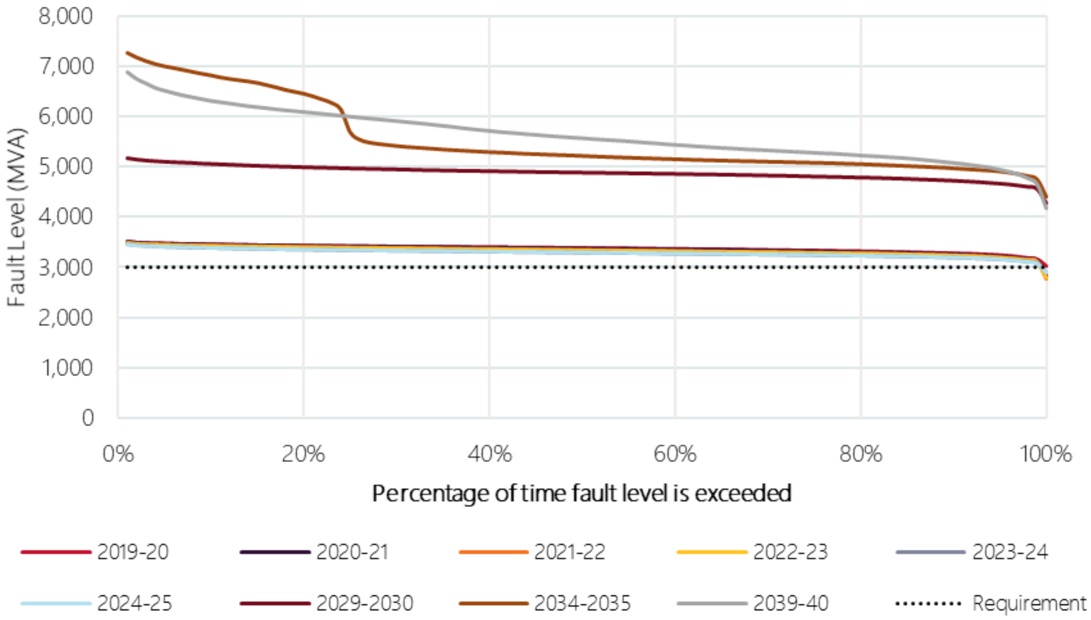


Figure 153 Projected Sydney West 330 kV fault level duration curves

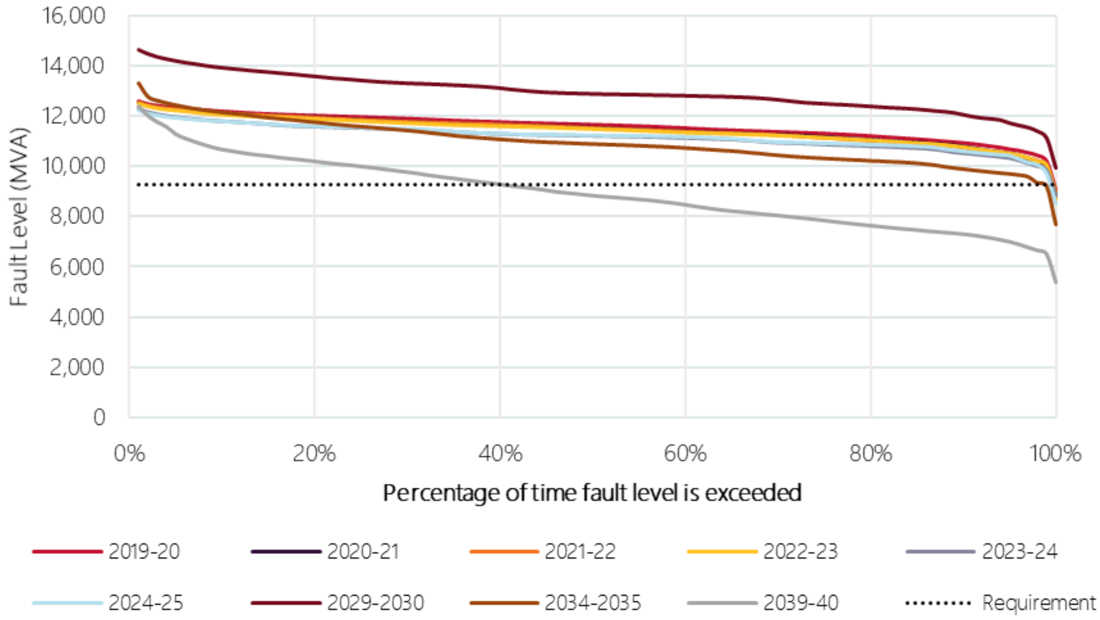


Figure 154 Projected Wellington 330 kV fault level duration curves

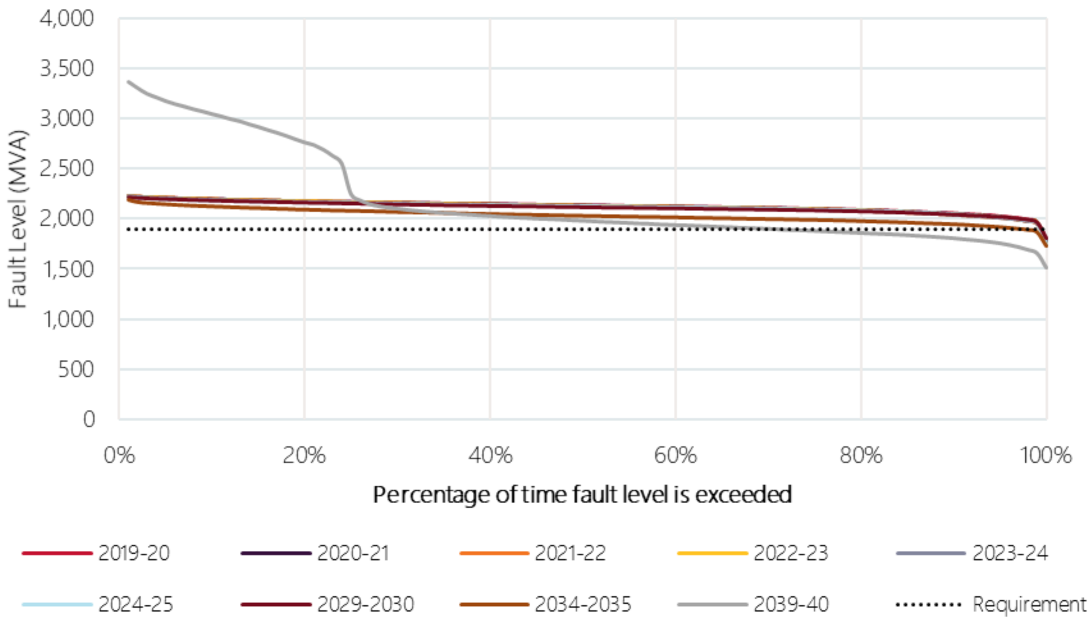


Figure 155 Projected Newcastle 330 kV fault level duration curves

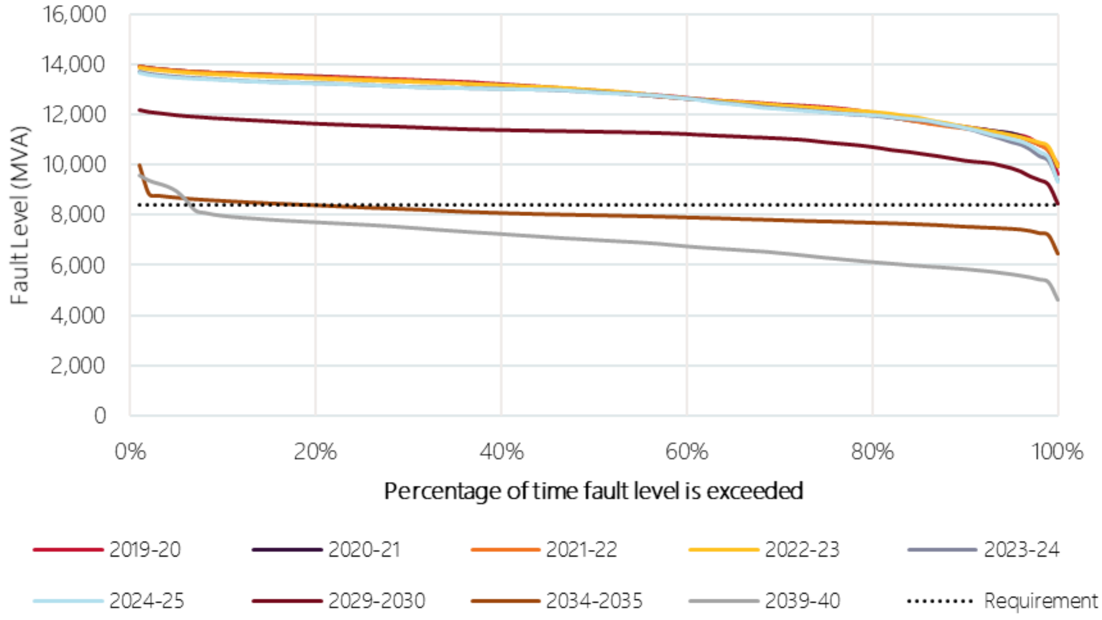
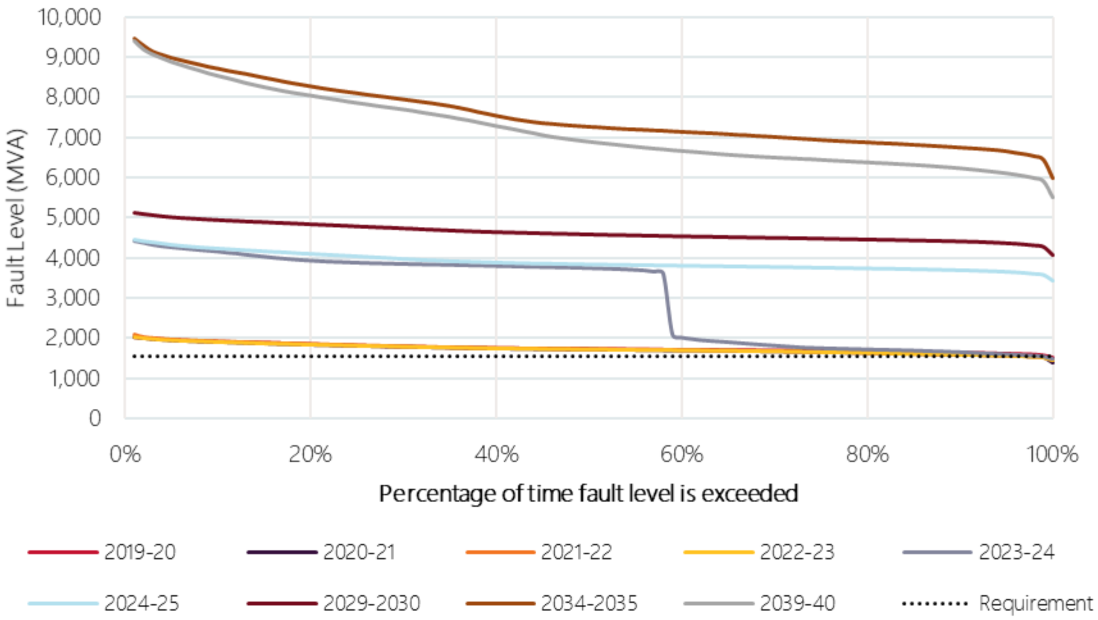


Figure 156 Projected Darlington Point 330 kV fault level duration curves

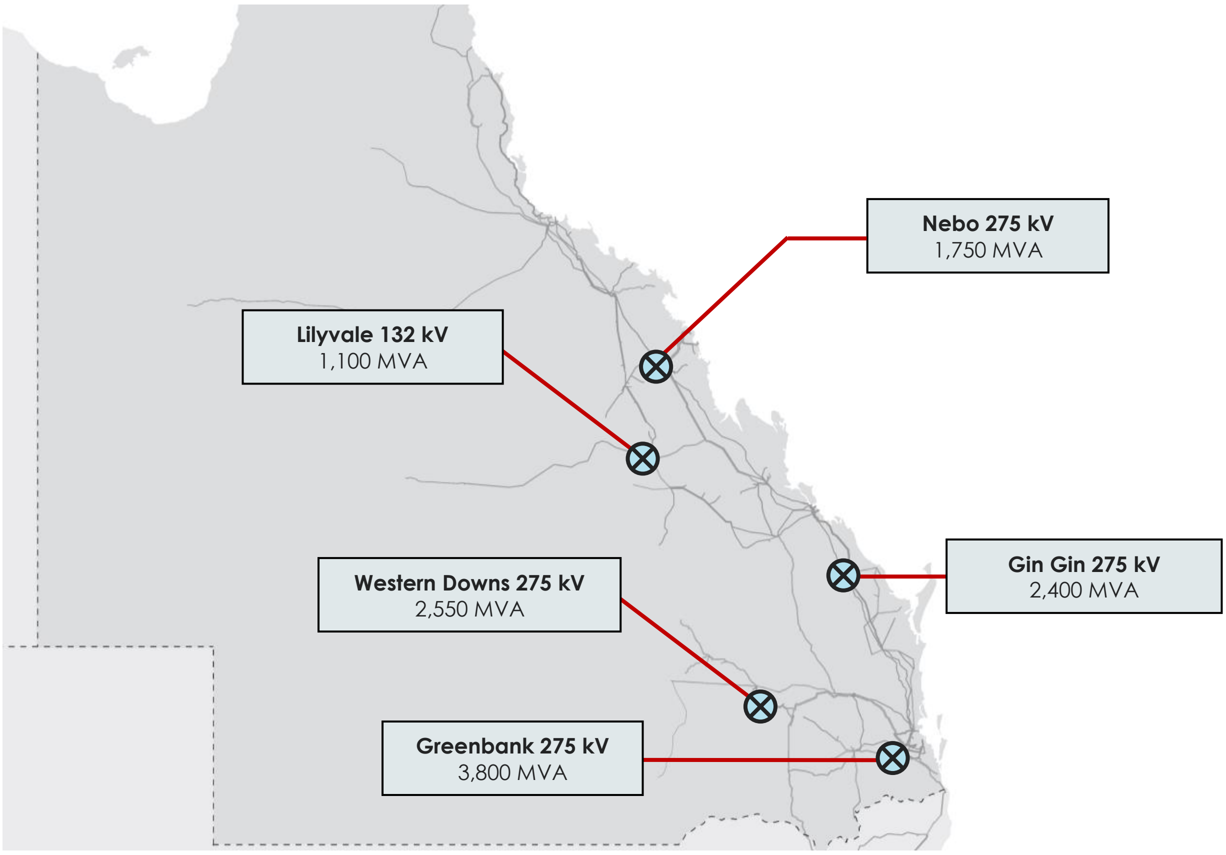


Queensland system strength outlook

AEMO has determined the following fault level nodes for Queensland. Together they represent a metropolitan load centre, a synchronous generation centre, areas with high inverter-based resources, and areas electrically remote from synchronous generation. The System Strength Requirements Methodology[55] outlines the process for determining the system strength requirement at each node.

[55] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

Figure 157 Queensland system strength (fault level) requirements



The ISP system strength assessments for Queensland are in Table 26. These studies are based on the 2018 system strength requirements[56] which are currently under review. After synchronous coal generation retires in Queensland, system strength shortfalls are projected at Greenbank and Gin Gin by 2040.

Table 26 Queensland projected system strength

Fault level node	Duration Curve	Current requirements met			Comment
		Currently	Up to 2025	Up to 2040	
Western Downs 275 kV	Figure 158	Yes	Yes	Yes	No shortfall projected within 5 years.
Greenbank 275 kV	Figure 159	Yes	Yes	Yes	No shortfall projected within 5 years.
Nebo 275 kV	Figure 160	Yes	Yes	Yes	No shortfall projected within 5 years.
Gin Gin 275 kV	Figure 161	Yes	250 MVA potential shortfall†	500 MVA potential shortfall ‡	No shortfall projected within 5 years. Projected shortfall by 2040 due to coal generation retirements
Lilyvale 132 kV	Figure 162	Yes	Yes	Yes	No shortfall projected within 5 years.

† Detailed EMT studies currently in progress to confirm Queensland fault level requirements.
‡ Although AEMO projects that a shortfall may arise before 2040, a fault level shortfall is not formally declared at this stage.

[56] AEMO. System Strength Requirements & Fault Level Shortfalls, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

The following figures show the projected fault level duration curves for each fault level node in Queensland, highlighting a forecast step increase at Western Downs following the commissioning of QNI in 2030-31, and at Nebo following the commissioning of pumped hydro at Walkamin in 2030-31. Across Queensland, there is a projected trend of decreasing system strength due to the retirement of synchronous generation and the transition to inverter-based resources.

Figure 158 Projected Western Downs 275 kV fault level duration curves

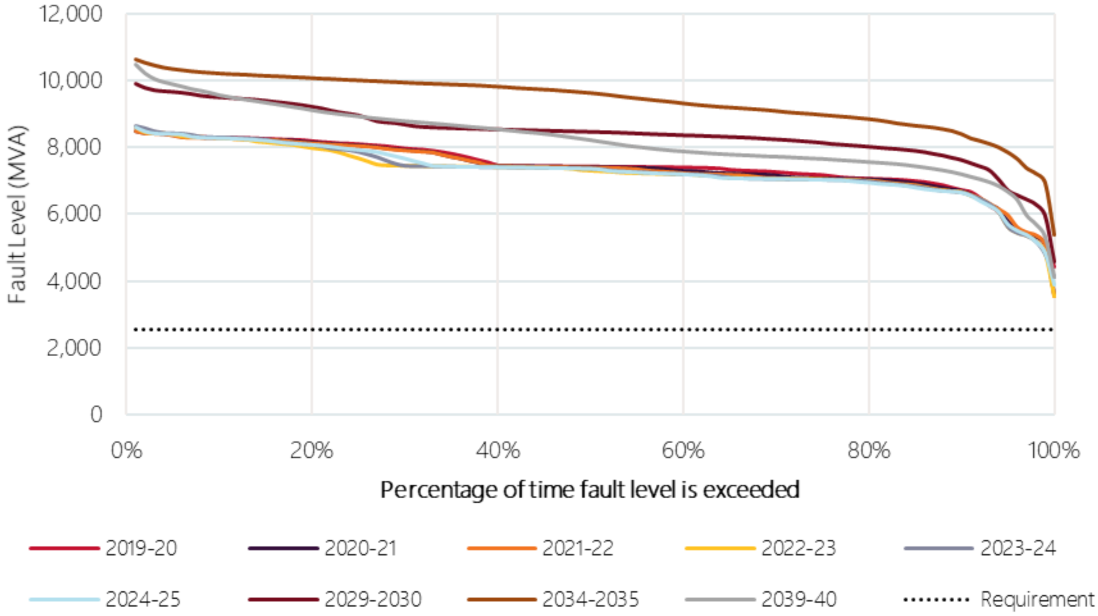


Figure 159 Projected Greenbank 275 kV fault level duration curves

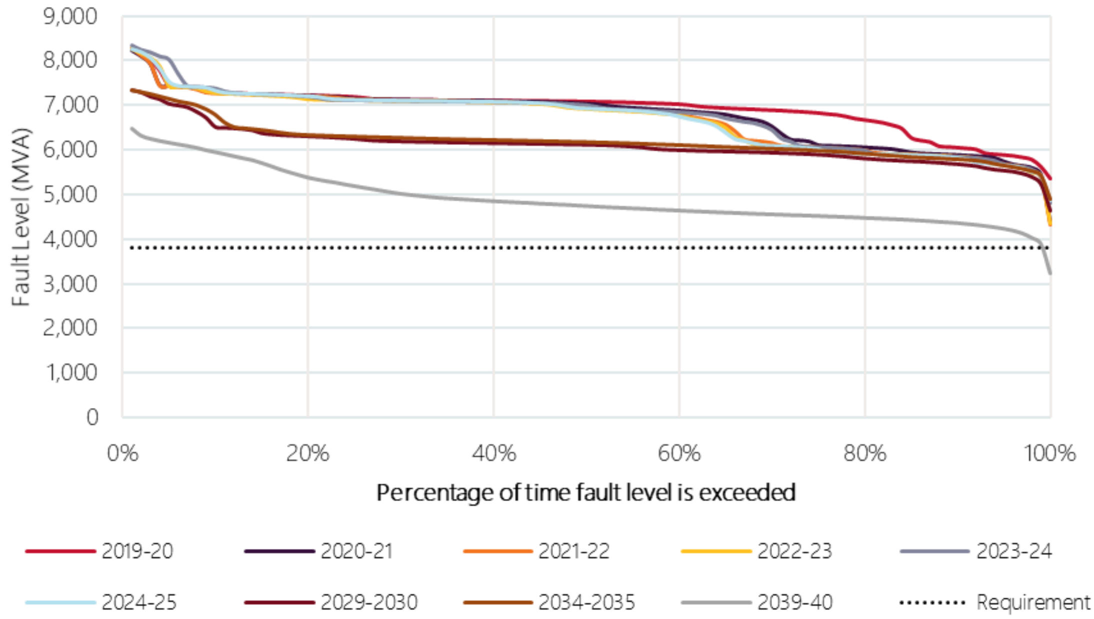


Figure 160 Projected Nebo 275 kV fault level duration curves

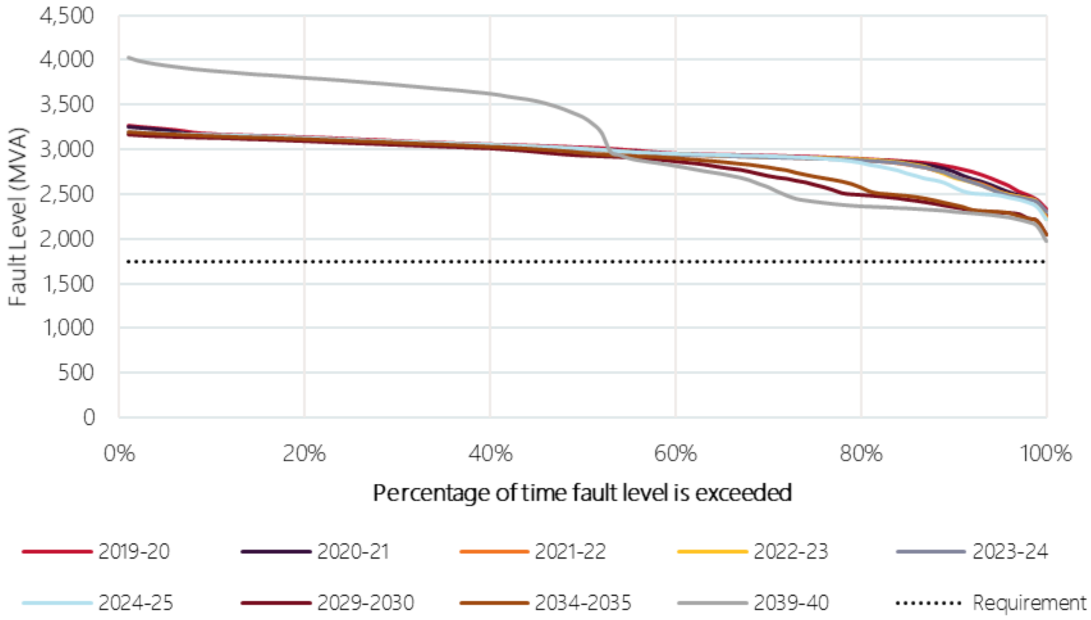


Figure 161 Projected Gin Gin 275 kV fault level duration curves

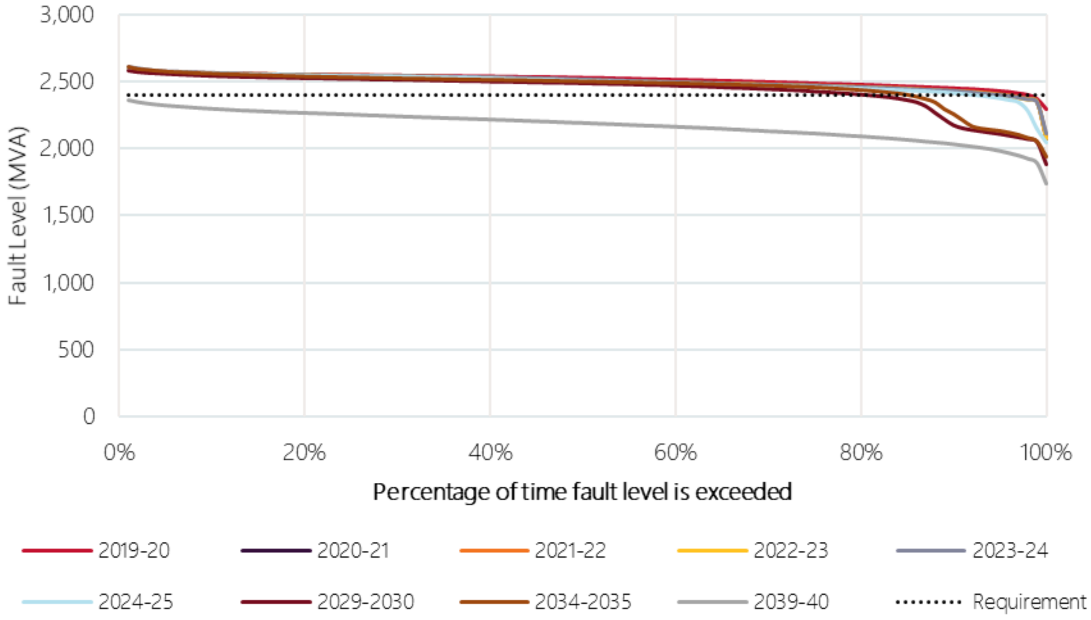
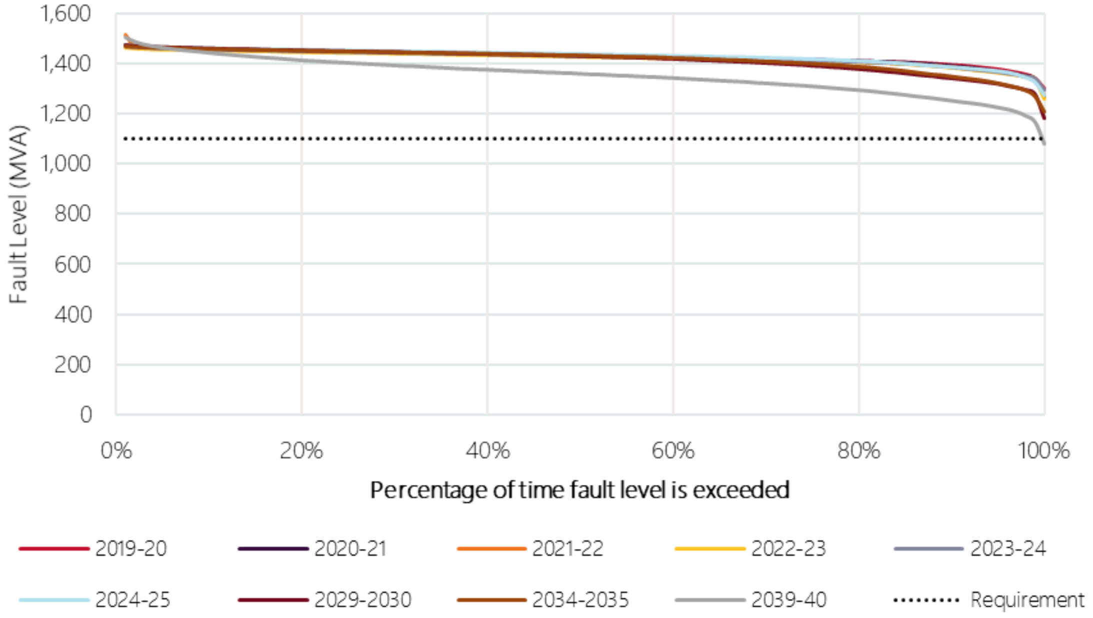


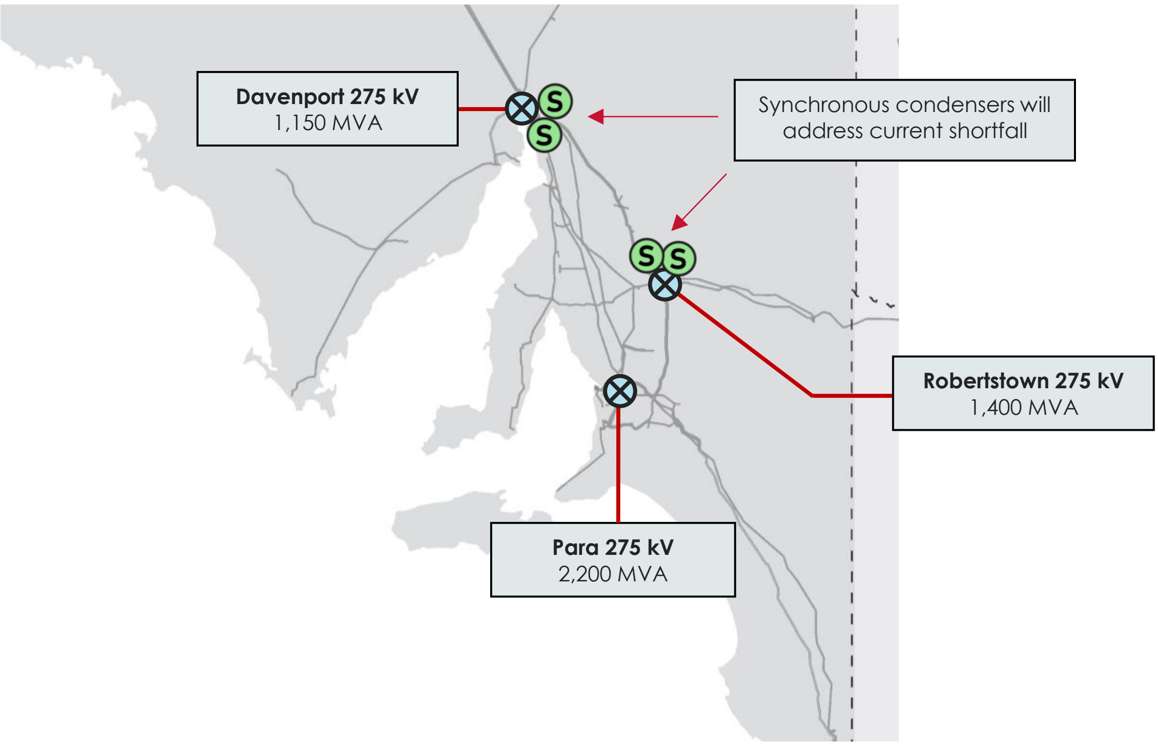
Figure 162 Projected Lilyvale 132 kV fault level duration curves



South Australia system strength outlook

AEMO has determined the following fault level nodes for South Australia. They represent a metropolitan load centre, a synchronous generation centre, areas with high inverter-based resources and areas electrically remote from synchronous generation. The System Strength Requirements Methodology[57] outlines the process for determining the system strength requirement at each node.

Figure 163 South Australia system strength (fault level) requirements



[57] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

The ISP system strength assessments for South Australia are in Table 27. These studies are based on the 2018 system strength requirements[58] which are currently under review. These studies have found that:

- AEMO is currently intervening in the market to ensure the system strength requirements in South Australia[59] will be met on a day-to-day basis.
- The new synchronous condensers at Davenport and Robertstown in 2020-21 are projected to address the current fault level shortfall.

Table 27 South Australian projected system strength

Fault level node	Duration Curve	Current requirements met			Comment
		Currently †	Up to 2025	Up to 2040	
Davenport 275 kV	Figure 164	Shortfall	Yes	Yes	The current shortfall will be addressed when synchronous condensers are installed at Davenport and Robertstown (see section 6.1.1).
Para 275 kV	Figure 165	Yes	Yes	Yes	No shortfall projected within 5 years.
Robertstown 275 kV	Figure 166	Yes	Yes	Yes	No shortfall projected within 5 years. Fault levels increase following synchronous condenser installation in 2020-21

† Requirements currently met by use of generation directions, which are included in the market modelling.

The following figures show the projected fault level duration curves for each fault level node in South Australia, highlighting a forecast step increase across South Australia when the new synchronous condensers are commissioned in 2020-21, and also at Robertstown when Project EnergyConnect is commissioned in 2023-24. The projected system strength shows that requirements are expected to be met in the future.

58 AEMO. System Strength Requirements & Fault Level Shortfalls, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

59 AEMO. Limits Advice, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2019/Transfer-Limit-Advice-System-Strength.pdf.

Figure 164 Projected Davenport 275 kV fault level duration curves

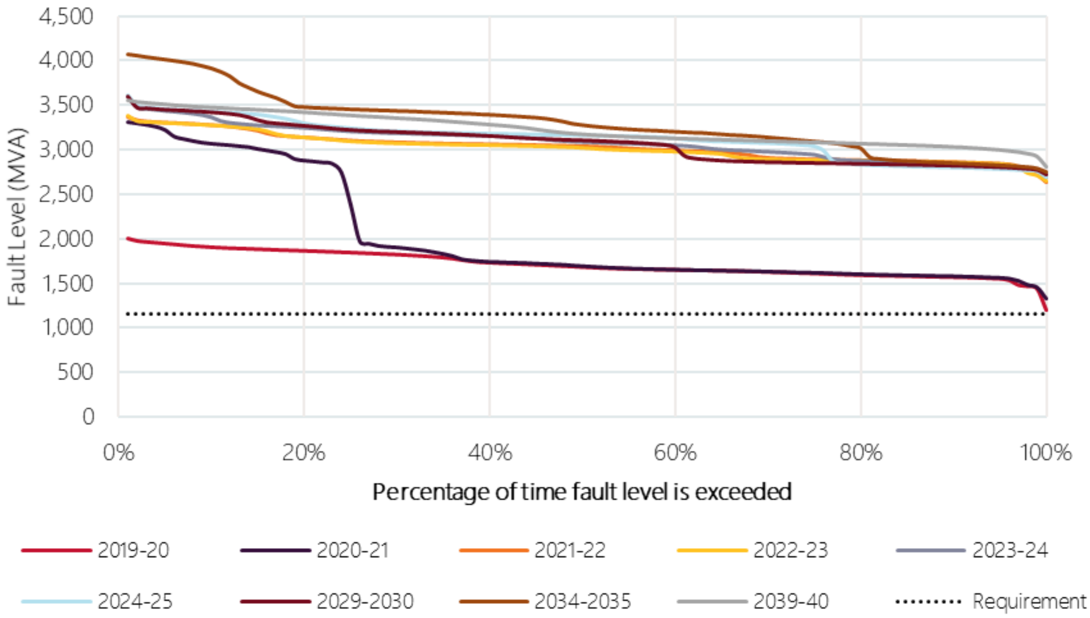


Figure 165 Projected Para 275 kV fault level duration curves

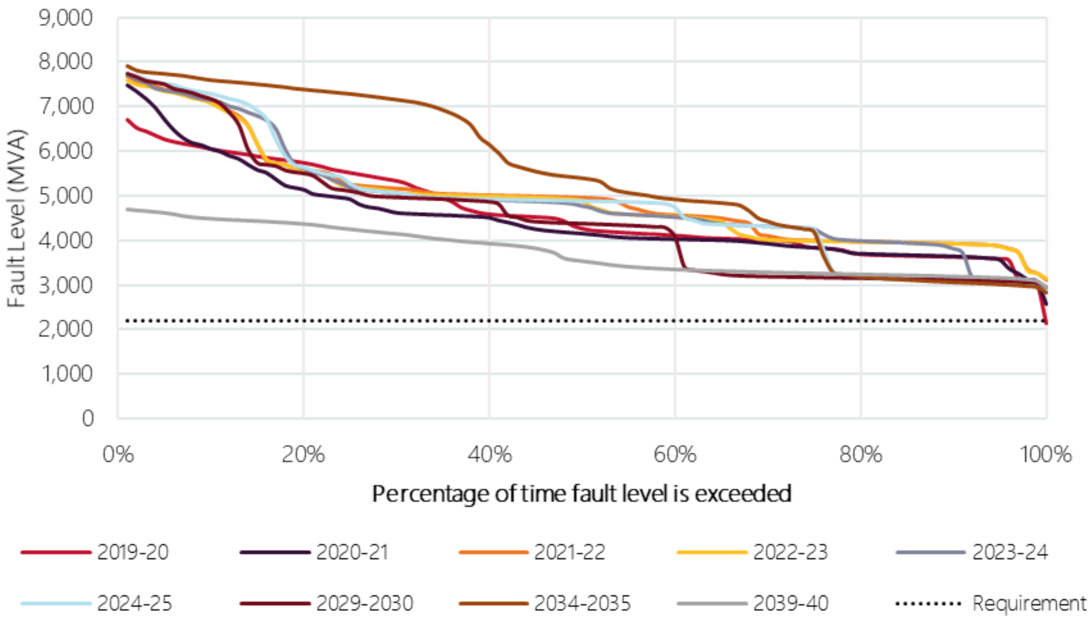
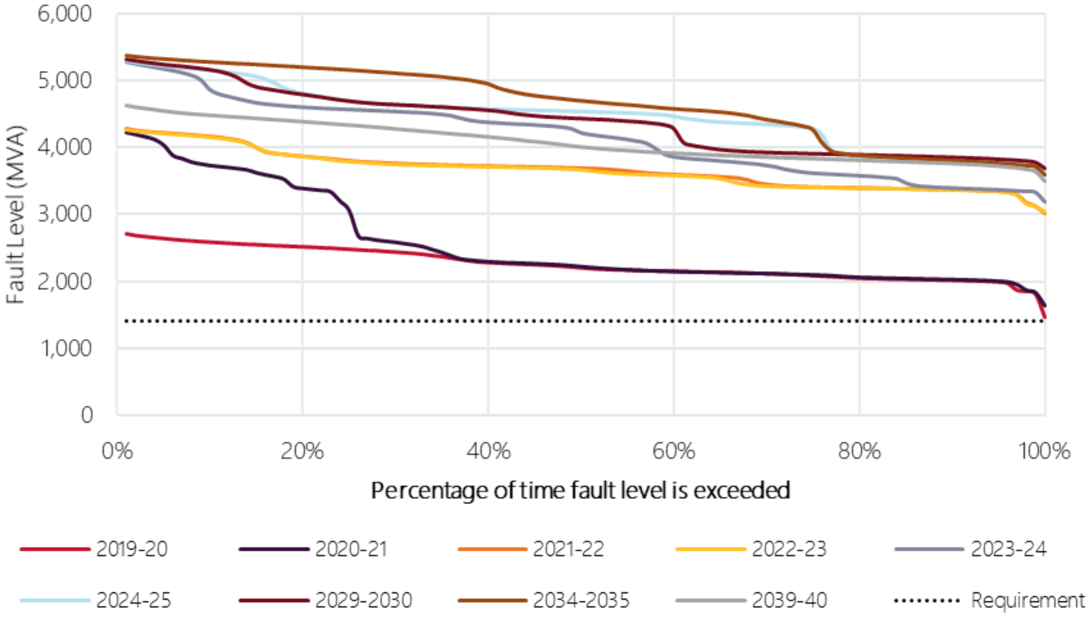


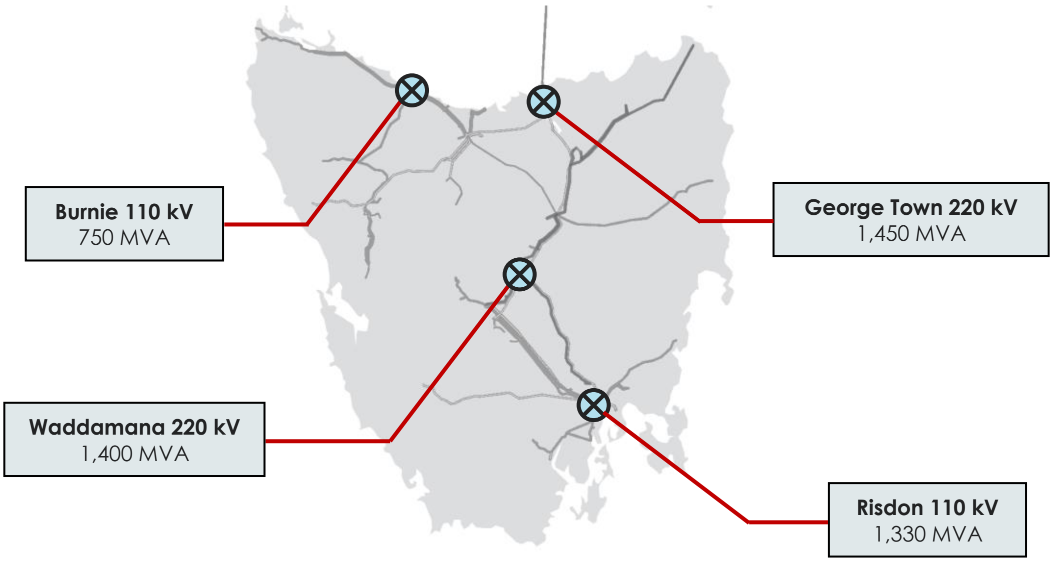
Figure 166 Projected Robertstown 275 kV fault level duration curves



Tasmania system strength outlook

AEMO has determined the following fault level nodes for Tasmania. They represent a metropolitan load centre, a synchronous generation centre, areas with high inverter-based resources, and areas electrically remote from synchronous generation. The System Strength Requirements Methodology[60] outlines the process for determining the system strength requirement at each node.

Figure 167 Tasmanian system strength (fault level) requirements



[60] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

The ISP system strength assessments for Tasmania are in Table 28. An inertia and fault level shortfall was declared for Tasmania in November 2019[61]. TasNetworks is currently reviewing the most economic way to meet this gap by April 2020.

The fault level projections do not include any contribution from hydro plant being operated in synchronous condenser mode. These studies are based on the 2018 system strength requirements[62] which are currently under review.

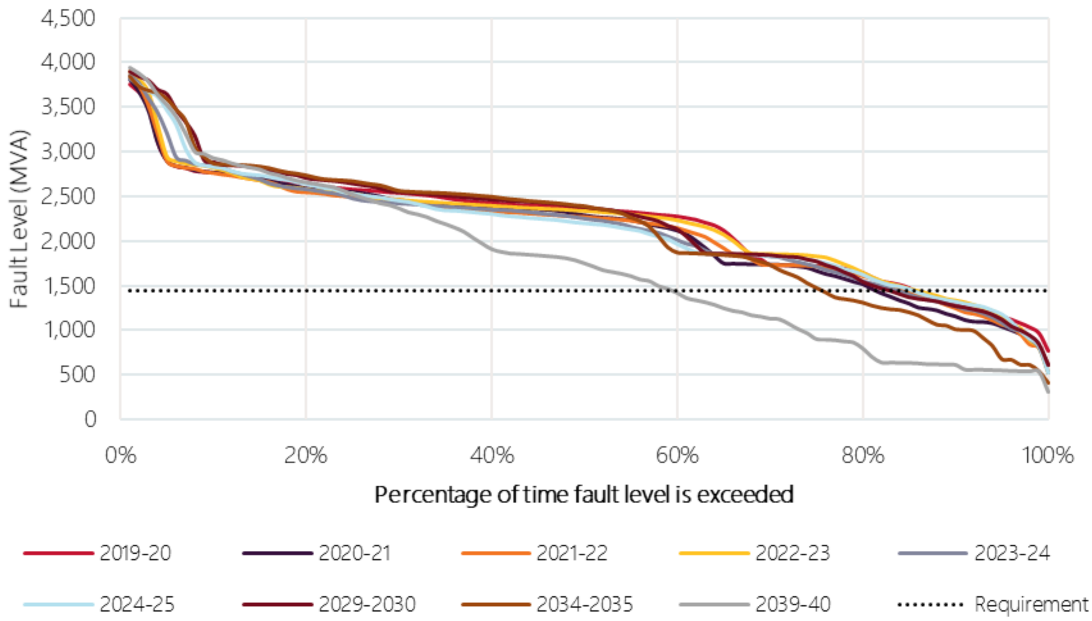
Table 28 Tasmanian projected system strength

Fault level node	Duration Curve	Current requirements met			Comment
		Currently	Up to 2025	Up to 2040	
George Town 220 kV	Figure 168	Shortfall	Shortfall	Shortfall	Shortfall declared in November 2019†.
Risdon 110 kV	Figure 169	Shortfall	Shortfall	Shortfall	Shortfall declared in November 2019†.
Waddamana 220 kV	Figure 170	Shortfall	Shortfall	Shortfall	Shortfall declared in November 2019†.
Burnie 110 kV	Figure 171	Shortfall	Shortfall	Shortfall	Shortfall declared in November 2019†.

† AEMO. Notice of Inertia and Fault Level Shortfalls in Tasmania, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Notice-of-Inertia-Fault-Level-Shortfalls-Tasmania-Nov-2019.pdf.

The following figures show the projected fault level duration curves for each fault level node in Tasmania. All the figures show a current shortfall, and worsening system strength into the future as inverter-based resources displace synchronous generation.

Figure 168 Projected George Town 220 kV fault level duration curves



[61] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Notice-of-Inertia-Fault-Level-Shortfalls-Tasmania-Nov-2019.pdf.

[62] AEMO. System Strength Requirements & Fault Level Shortfalls, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

Figure 169 Projected Risdon 110 kV fault level duration curves

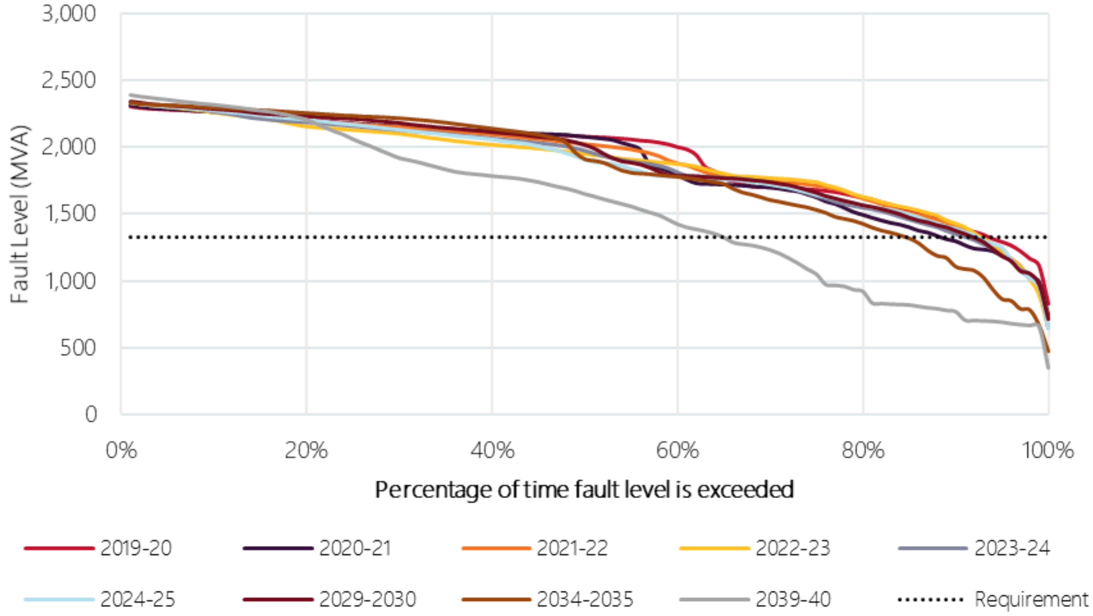


Figure 170 Projected Waddamana 220 kV fault level duration curves

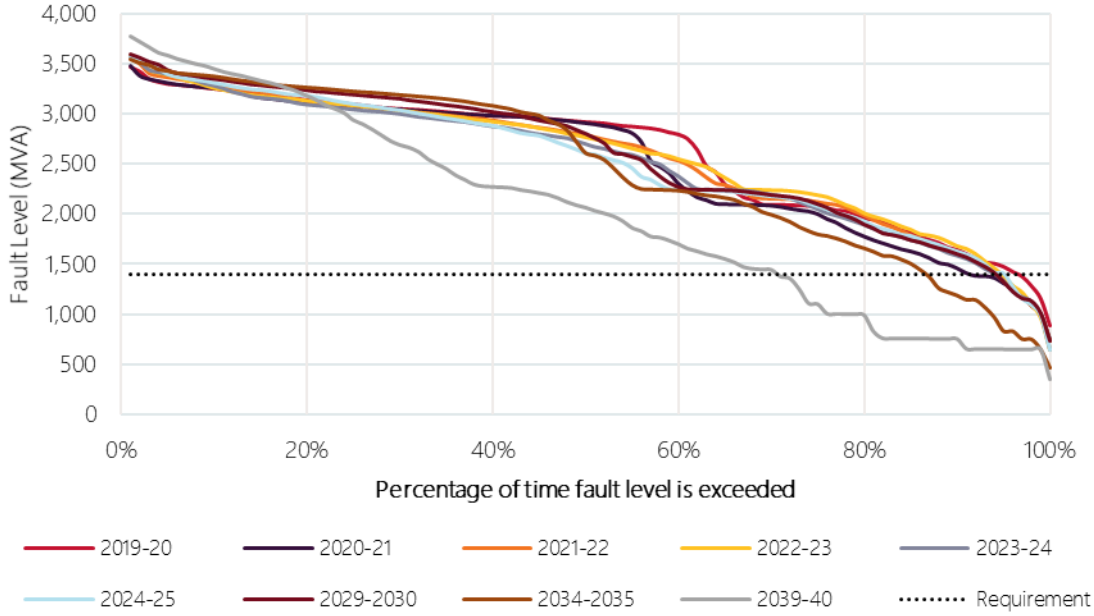
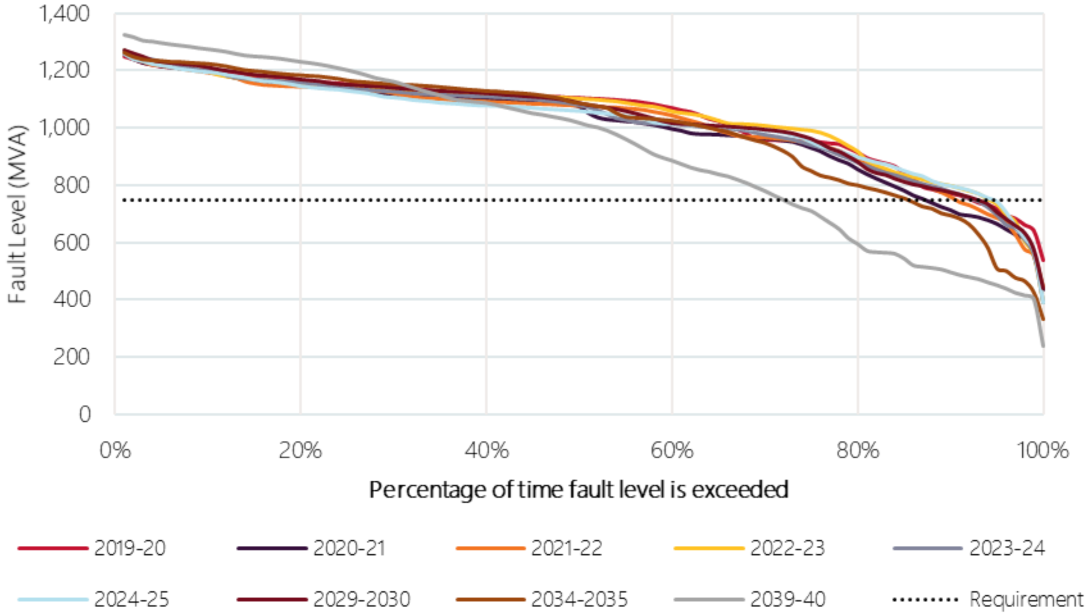


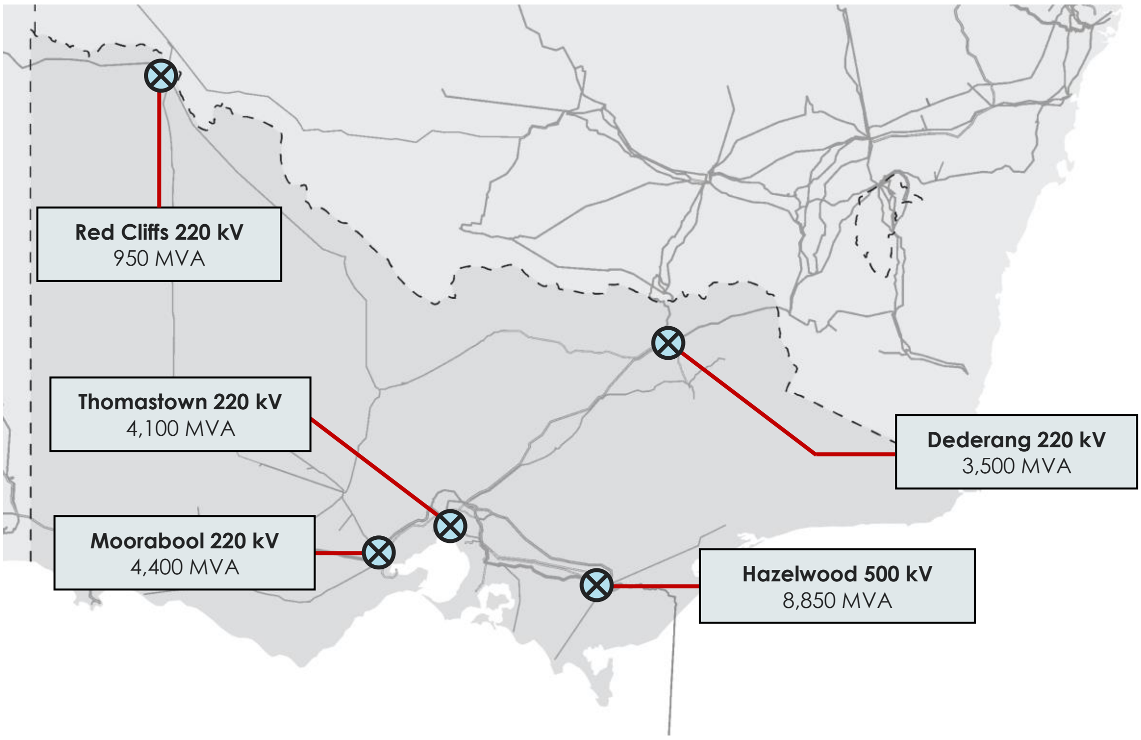
Figure 171 Projected Burnie 110 kV fault level duration curves



Victoria system strength outlook

AEMO has determined the following fault level nodes for Victoria. They represent the metropolitan load centre, a synchronous generation centre, areas with high inverter-based resources, and areas electrically remote from synchronous generation. The System Strength Requirements Methodology[63] outlines the process for determining the system strength requirement at each node.

Figure 172 Victorian system strength (fault level) requirements



[63] At http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

The ISP system strength assessments for Victoria are outlined in Table 29. This analysis was based on the 2018 system strength requirements[64] for all nodes except the Red Cliffs fault-level node, for which recent EMT studies have been used to update requirements. The outcomes of this analysis to date are as follows:

- Recently completed detailed EMT studies into the Victorian system strength requirements have indicated the need for an increase to the fault level requirements at the Red Cliffs fault level node from 600 MVA to 950 MVA.
- The proposed Project EnergyConnect (see Section 6.1.2) is projected to significantly improve system strength at the Red Cliffs fault level node, because it includes synchronous condensers at Buronga and Darlington Point.
- Following the closure of Yallourn Power Station (announced by EnergyAustralia to be staged between 2029 and 2032[65]), a shortfall is projected at the Hazelwood fault level node. Sufficient fault level is required at this node to ensure stable operation of the Basslink HVDC interconnector.

At the time of developing this Draft ISP, Project EnergyConnect was pending approval by the AER and had not been committed. AEMO is currently investigating alternative options to new synchronous condensors to address any projected shortfalls , considering the likelihood of Project EnergyConnect being approved and its potential benefit towards resolving these shortfalls. A formal notice declaring a fault-level shortfall and initiating action by the responsible TNSP is expected to be made in the near future once this analysis is completed.

Table 29 Victorian projected system strength

Fault level node	Duration Curve	Current requirements met			Comment
		Currently	Up to 2025	Up to 2040	
Red Cliffs 220 kV	Figure 173 Figure 174	Projected shortfall of 312 MVA	Yes	Yes	A current shortfall is projected; studies are progressing to determine the impact on the shortfall of Project EnergyConnect should it be commissioned in 2023-24.
Thomastown 220 kV	Figure 175	Yes	Yes	Yes	No shortfall projected within 5 years.
Moorabool 220 kV	Figure 176	Yes	Yes	Yes	No shortfall projected within 5 years.
Dederang 220 kV	Figure 177	Yes	Yes	Yes	No shortfall projected within 5 years.
Hazelwood 500 kV	Figure 178	Yes	Yes	500 MVA potential shortfall †	No shortfall projected within 5 years. When Yallourn Power Station retires there is expected to be a shortfall. Further studies and possible solutions are required as the closure date approaches.

† Although AEMO projects that a shortfall may arise before 2040, a fault level shortfall at Hazelwood is not formally declared at this stage.

The following figures show the projected fault level duration curves for each fault level node in Victoria, highlighting:

- A current shortfall is projected at the Red Cliffs node.

[64] AEMO. System Strength Requirements & Fault Level Shortfalls, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

[65] AEMO. Generating Unit Expected Closure Year, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

- A project forecast step increase in fault-level at the Red Cliffs node in 2023-24 resulting from Project EnergyConnect, assuming it is operational at that time.
- A projected shortfall at Hazelwood after Yallourn retires in 2029-31.
- Projected system strength also decreasing at the other nodes as inverter-based resources displace synchronous generation, but the requirements are still met.

Figure 173 Projected Red Cliffs 220 kV fault level duration curves, prior to Project EnergyConnect commissioning

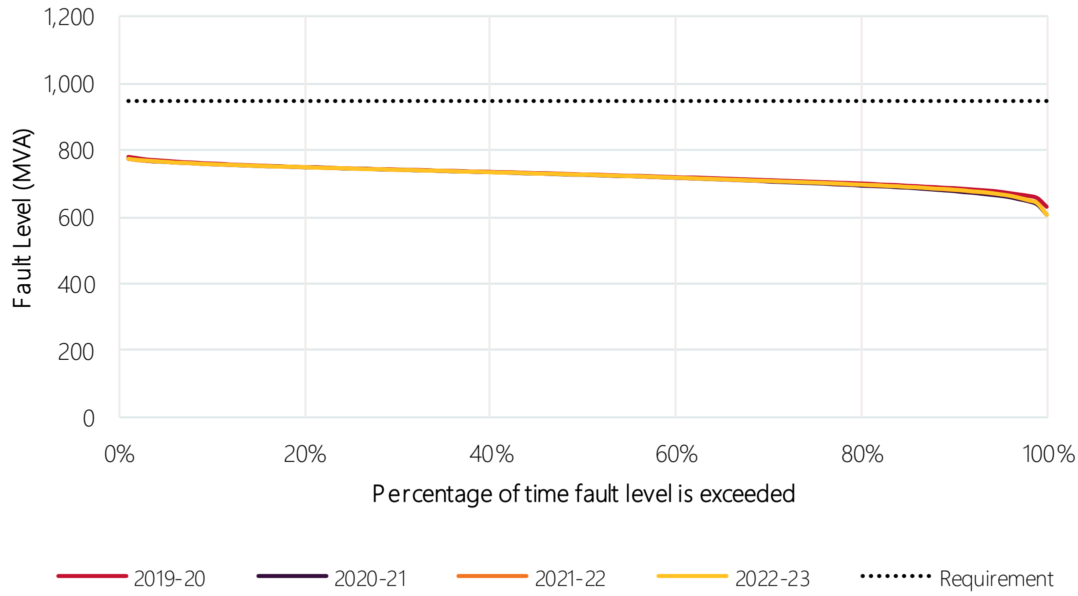


Figure 174 Projected Red Cliffs 220 kV fault level duration curves, including after Project EnergyConnect commissioning

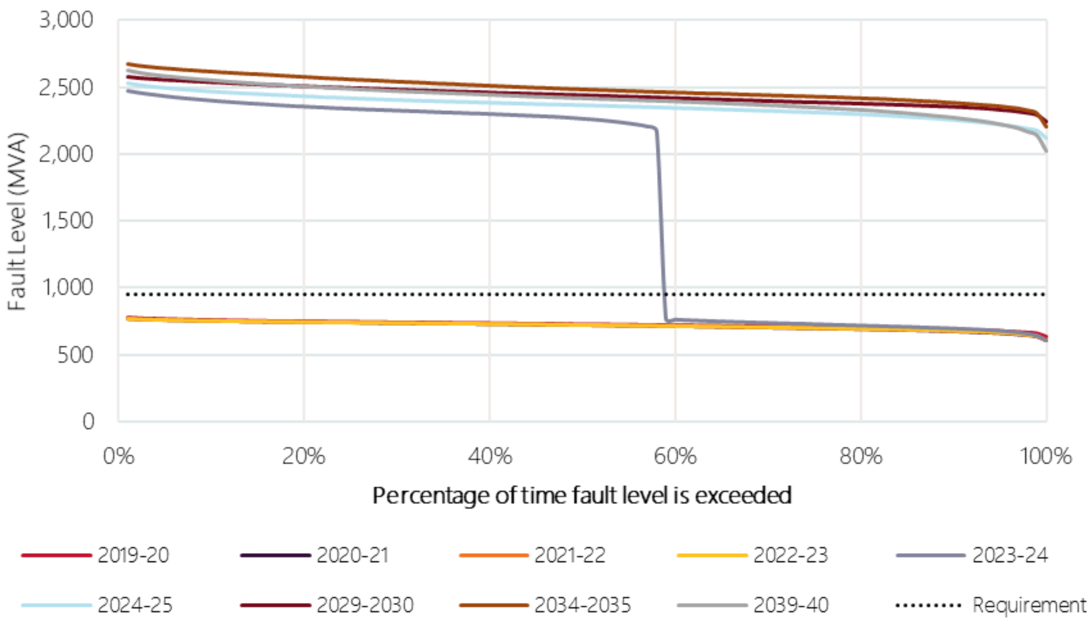


Figure 175 Projected Thomastown 220 kV fault level duration curves

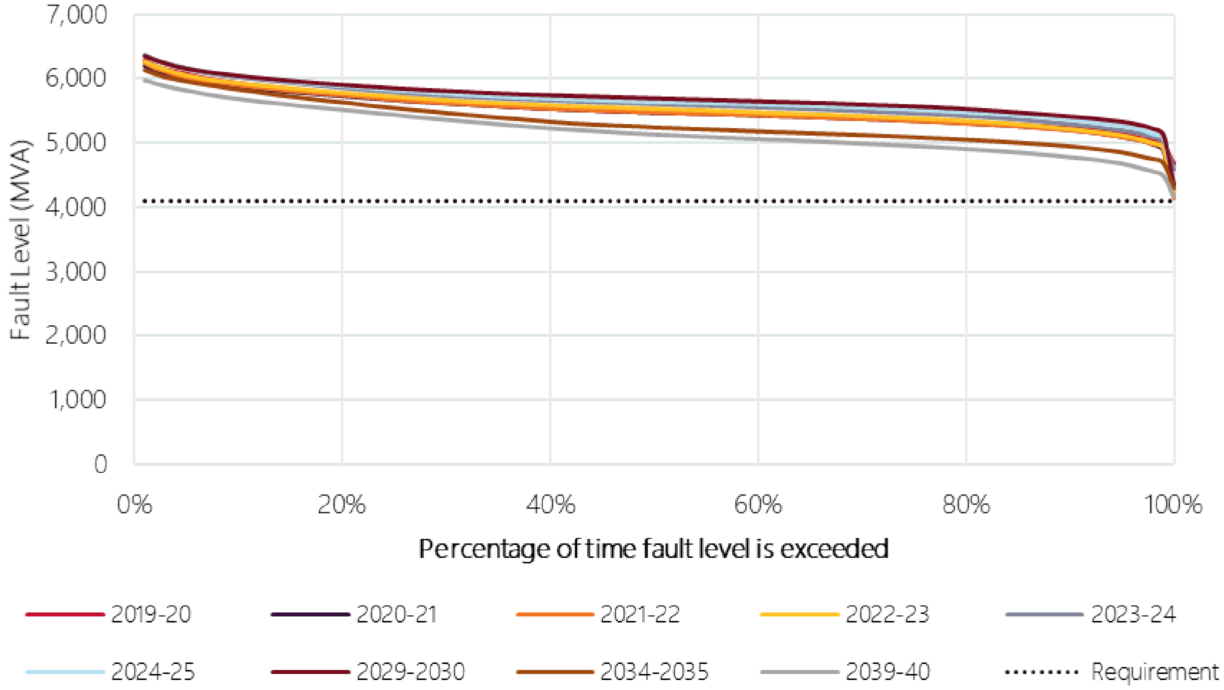


Figure 176 Projected Moorabool 220 kV fault level duration curves

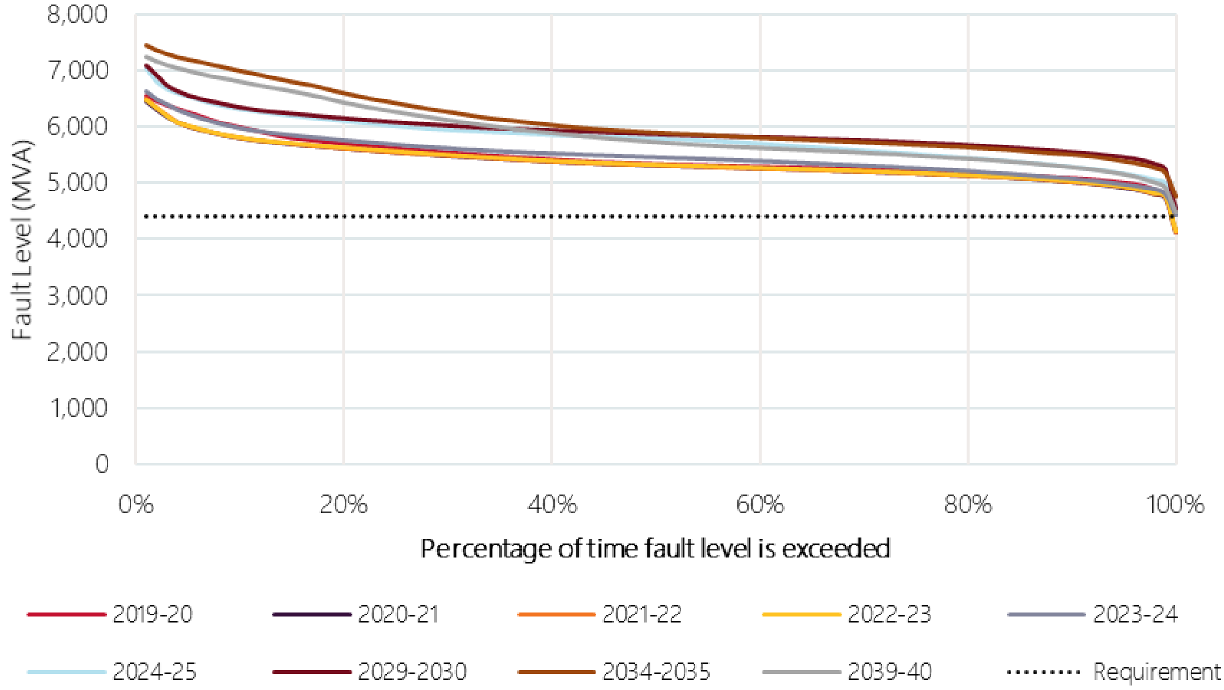


Figure 177 Projected Dederang 220 kV fault level duration curves

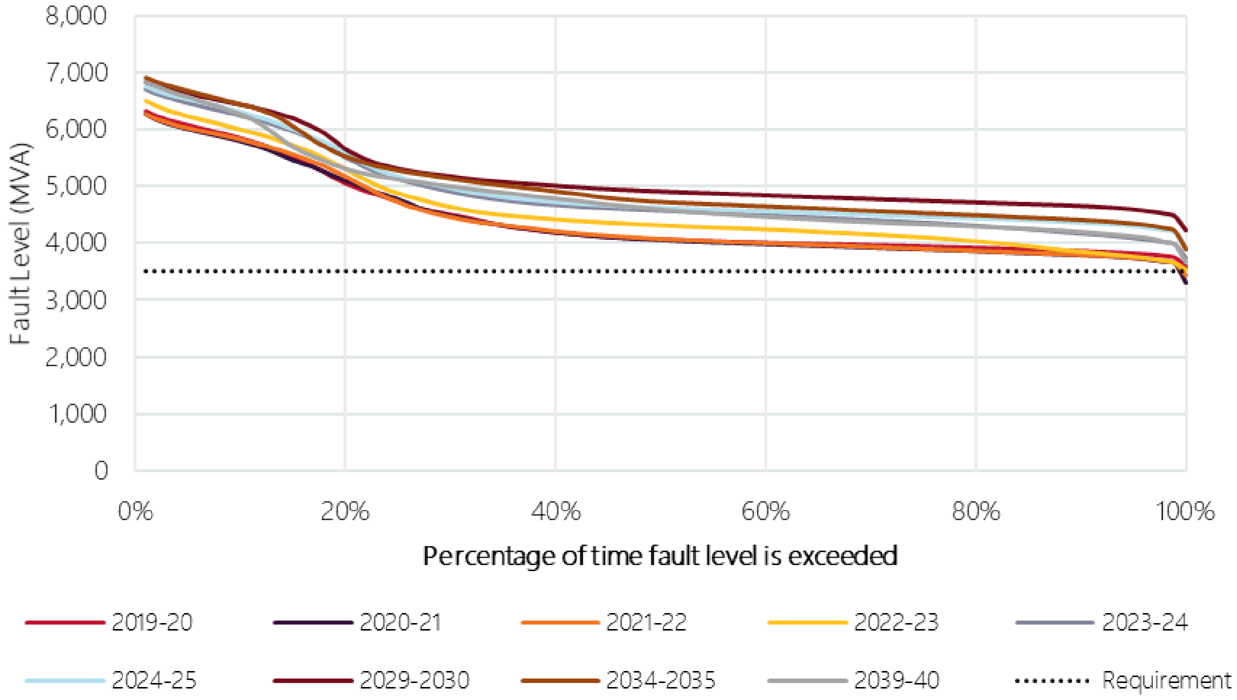
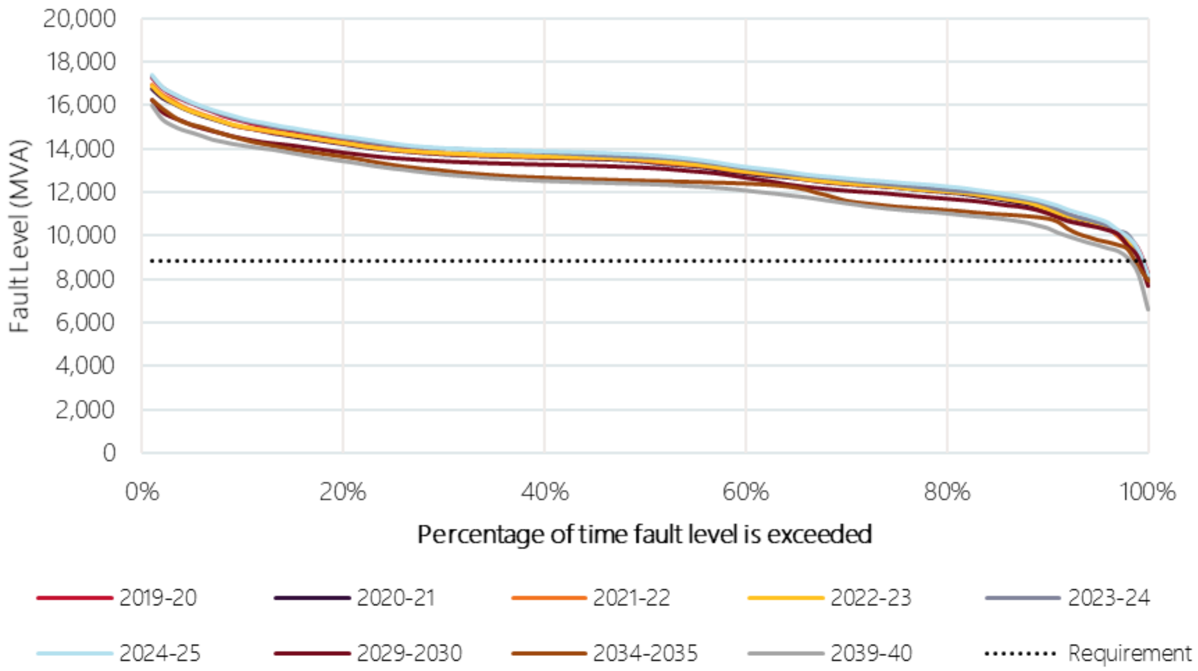


Figure 178 Projected Hazelwood 500 kV fault level duration curves



7.2.3 Inertia outlook

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.

The NER also require that AEMO assess and declare a shortfall to enable the TNSP to procure inertia, and that once declared, the TNSP must procure it by the agreed timing.

AEMO is required to operate the power system to meet these requirements using services provided by the local TNSP. In 2018, AEMO determined the two levels of inertia for each NEM region that must be available for dispatch when a region is at credible risk of being islanded:

- The Minimum Threshold Level of Inertia is the minimum level of inertia required to operate an islanded region in a satisfactory operating state.
- The Secure Operating Level of Inertia (SOLI) is the minimum level of inertia required to operate the islanded region in a secure operating state.

The Minimum Threshold of Inertia is required to be provided by synchronous sources (synchronous generators, synchronous condensers), while the additional inertia to then meet the SOLI can be provided by fast frequency response (FFR).

As coal plant retires, or operates less frequently, it is often replaced with inverter-based resources such as wind farms and solar farms, and the levels of inertia in the NEM reduce.

Results from the Central scenario (using Nash-Cournot bidding) have been assessed. Typical inertia values have been assigned to new generation planted by the market model,

In the five-year outlook to 2024-25, no further inertia gaps are anticipated, based on the definition of a "gap" under the current Rule frameworks. However, these requirements are solely focused on regional requirements when the region is at risk of islanding, or operating as an islanded system. Large amounts of inverter-based resources (both VRE and DER) are projected to replace the energy and capacity from synchronous generation such as coal plant when it retires. This will lead to reducing synchronous inertia across the NEM overall. This means that need for minimum levels of inertia services for system security may require new market arrangements, such as system-wide levels of inertia.

The requirements for minimum levels of regional inertia and frequency control services during periods of high output from inverter-based resources are currently under review as part of AEMO's Renewable Integration Studies (RIS)[66]. This will be further explored in the RIS and as part of the 2020 Final ISP.

NEM mainland inertia outlook

The Inertia Requirements define the minimum levels of inertia required to operate each NEM region as an island. These defined levels of inertia are only required to be online when a region is at risk of islanding, or islanded. While islanded, the frequency operating standards (FOS) allow the frequency to deviate between 49.0 hertz (Hz) and 51.0 Hz for the largest credible contingency, and the inertia requirements have been calculated on this basis.

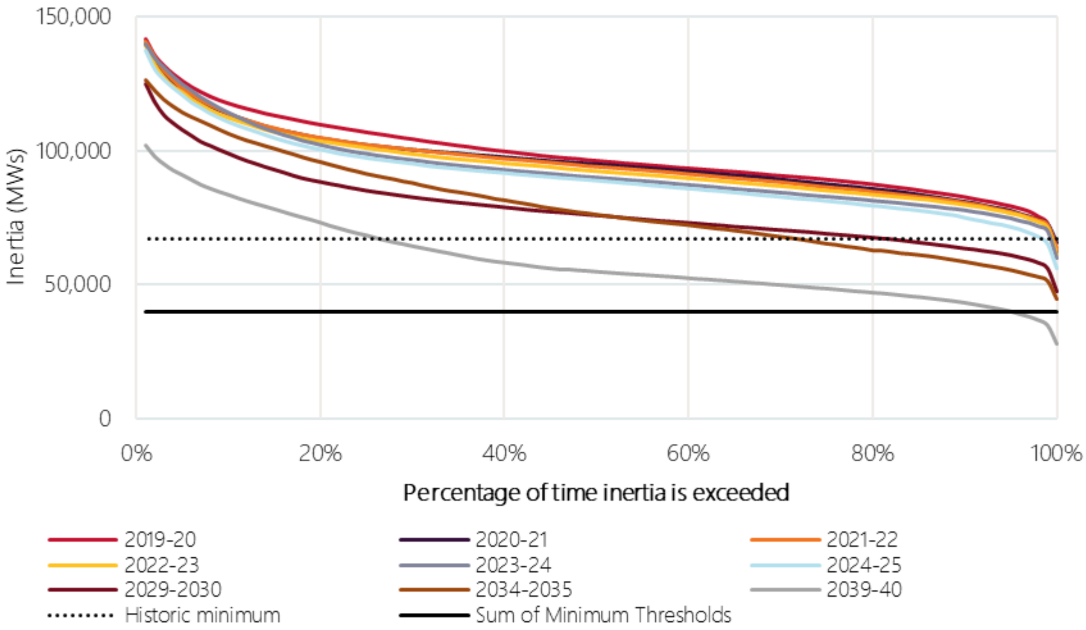
While NEM regions are interconnected, the FOS require that the frequency be maintained between 49.5 Hz and 50.5 Hz for the largest credible contingency. This is a more stringent requirement, and can only be maintained with sufficient levels of FCAS and inertia online. As coal units retire, total inertia reduces across the NEM, and the FCAS required is anticipated to increase.

Approximately only a third of the inertia being retired is projected to be replaced by inertia from new pumped hydro projects (18,000 MW.s by 2040[67]). Dispatch results show at the minimum inertia periods indicated below, pumped hydro is largely not generating or pumping, so could be made available as Inertia Support services if operated in synchronous condenser mode. The following figure shows the projected mainland inertia over the coming 20 years.

[66] AEMO. Renewable Integration Study, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Future-Energy-Systems/Renewable-Integration-Study.

[67] Total inertia available from new pumped hydro, using typical inertia values and assumption of half of the plant being inverter connected. This could require operation in synchronous condenser mode with inertia support contracts.

Figure 179 NEM mainland inertia outlook (Tasmania excluded)



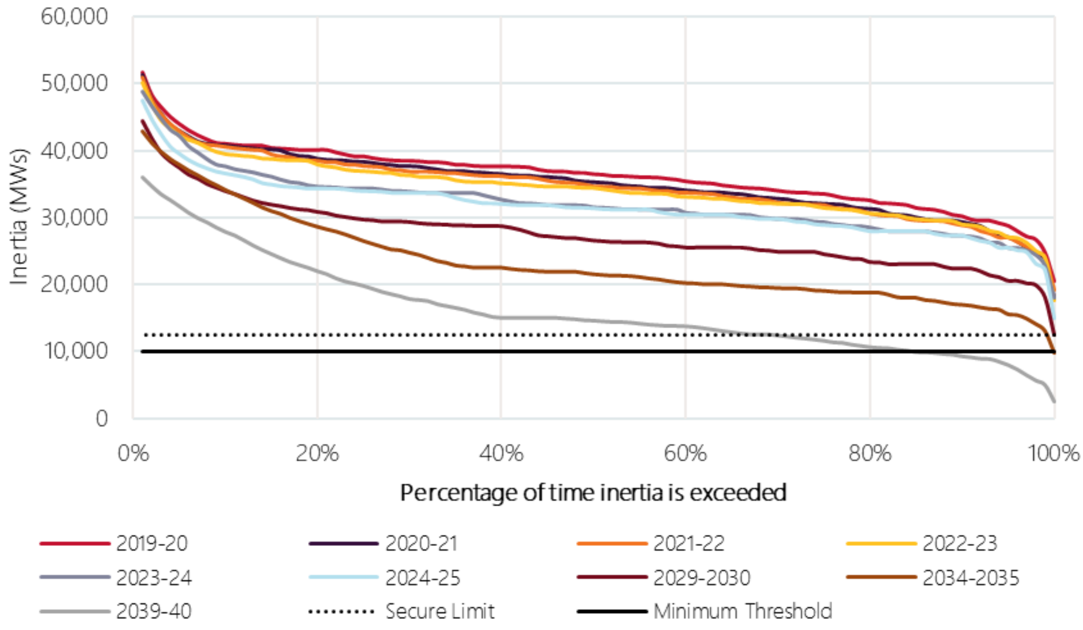
There are anticipated to be system strength shortfalls needing to be addressed by the respective TNSPs as synchronous plant retire. As occurred in South Australia, inertia requirements should also be considered when addressing fault level shortfalls. For example, the addition of flywheels to any synchronous condenser solutions can be accommodated with marginal cost increases.

New South Wales inertia outlook

As significant levels of coal plant retirement occur, the inertia available in New South Wales is forecast to reduce. There is still projected to be sufficient inertia for the minimum requirements.

If remaining coal plant is able to operate more flexibly (de-synchronise during the middle of the day), or retires earlier than expected, then the inertia online can be expected to reduce earlier than the times shown here.

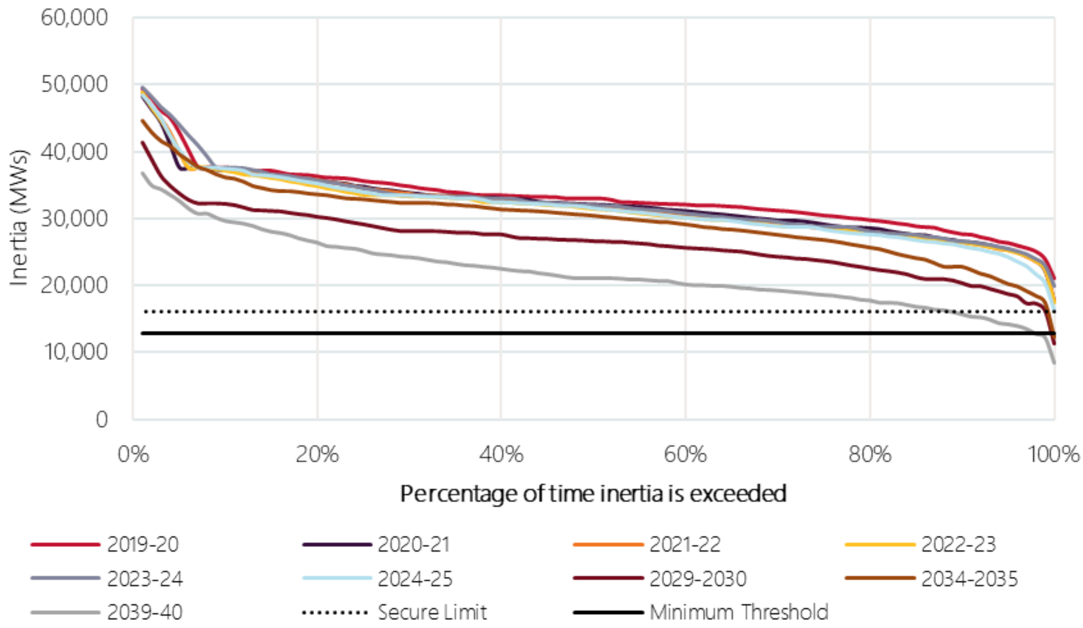
Figure 180 Projected inertia in the New South Wales



Queensland inertia outlook

While some coal plant retirements have been assumed, there is still forecast to be sufficient inertia for the minimum requirements until 2039-40. If remaining coal plant can operate more flexibly (de-synchronise during the middle of the day), or retires earlier than expected, then the inertia online can be expected to reduce earlier than the times shown here.

Figure 181 Projected inertia in the Queensland grid



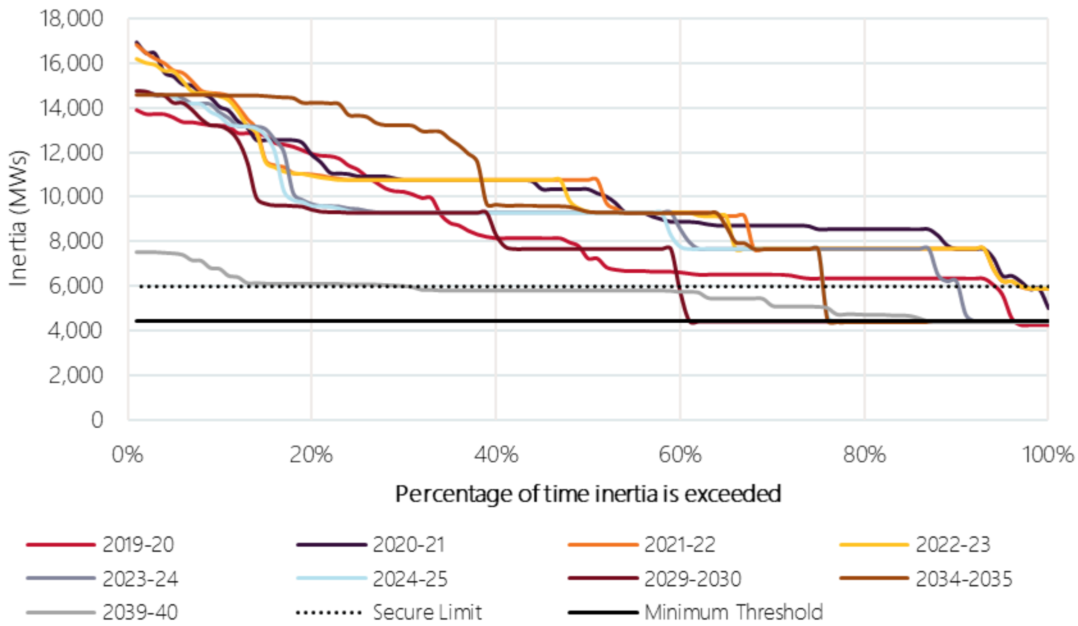
South Australia inertia outlook

AEMO declared a system strength shortfall for South Australia in 2017[68], resulting in ElectraNet procuring four synchronous condensers for installation in the South Australian region.

AEMO has also declared an inertia shortfall for the South Australian region as part of the 2018 NTNDP[69]. To meet this gap, high inertia flywheels have been included in the design of the synchronous condensers being procured to address system strength shortfalls. The results shown above include the 4,400 MW.s inertia to be provided by the synchronous condensers. These results project significant periods after 2024-25 where the only synchronous inertia online is by the synchronous condensers. This occurs after Project EnergyConnect is commissioned, and no gas plant are required to be online. The commissioning of Project EnergyConnect will result in there being four AC circuits to other NEM regions, meaning the risk of having to operate as an island will be significantly reduced.

The inertia requirements for the South Australian region following the commissioning of the new synchronous condensers are currently under review. The update to these requirements is being done in conjunction with proposed changes to regional requirements for primary frequency control[70], and regional frequency control ancillary service requirements.

Figure 182 Projected inertia in the South Australia grid



Tasmania inertia outlook

Tasmania is connected to Victoria by an asynchronous HVDC link, so for the purposes of inertia assessments is considered to be operated as an island at all times.

The results above project the inertia expected to be online from the dispatch of hydro plant. Operation of hydro plant in synchronous condenser mode can be utilised to increase the amount of online synchronous inertia. Results above are consistent with the system strength and inertia gap declared by AEMO for the Tasmanian region in 2019[71].

68 AEMO. Update to the 2016 NTNDP, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Second_Update_to_the_2016_NTNDP.pdf.

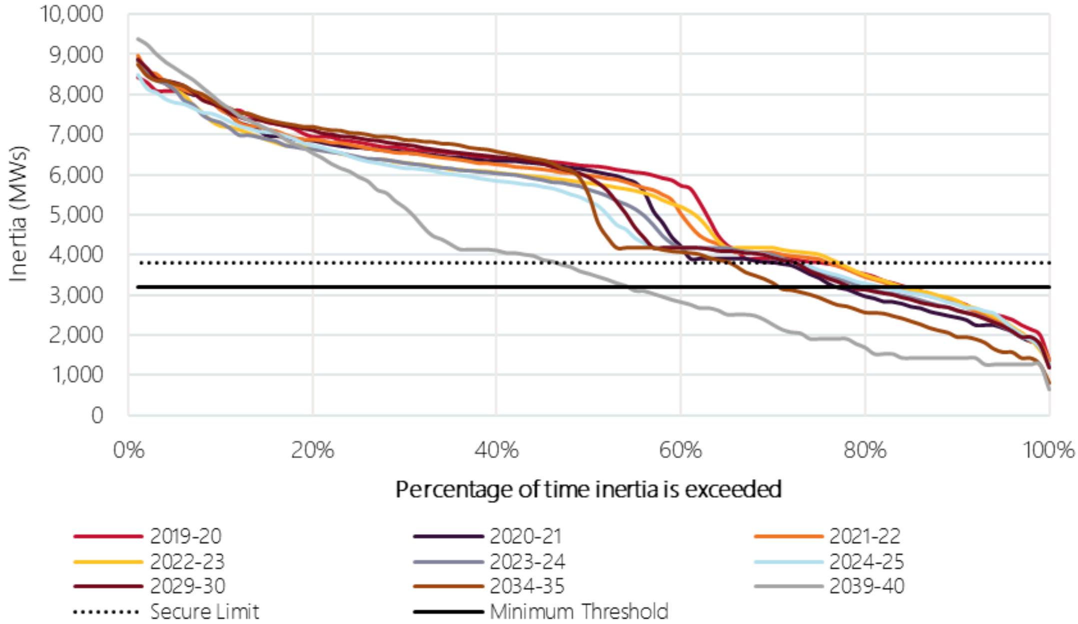
69 AEMO. 2018 NTNDP, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/2018/2018-NTNDP.pdf.

70 AEMO, Mandatory primary frequency response, at https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response

71 AEMO. Notice of Fault Level and Inertia Shortfall, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Notice-of-Inertia-Fault-Level-Shortfalls-Tasmania-Nov-2019.pdf.

TasNetworks is currently reviewing the most economical way to meet this gap by April 2020.

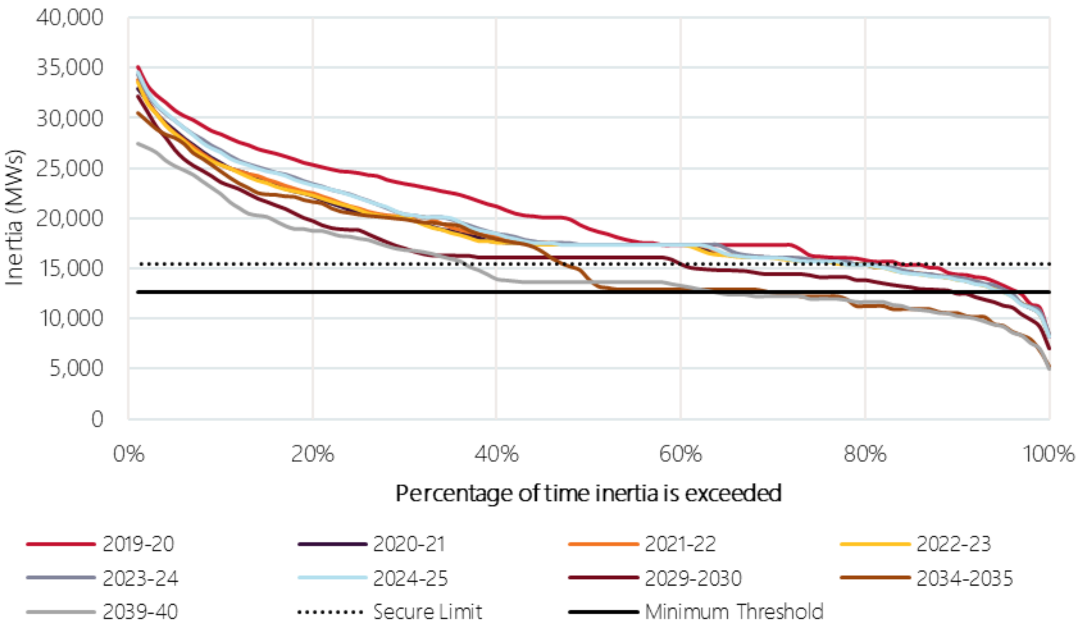
Figure 183 Projected inertia in the Tasmania grid



Victoria inertia outlook

While the inertia dispatched in Victoria is forecast to be below the minimum threshold for significant periods, when assessing risk of islanding occurring there should be consideration of the number of AC interconnector circuits to other NEM regions. Victoria will effectively share inertia with other NEM regions such as New South Wales and South Australia.

Figure 184 Projected inertia in the Victoria grid



Appendix 8. Renewable Energy Zones

AEMO has identified and mapped the areas across Eastern Australia as candidates for Renewable Energy Zones (REZ). REZs are areas in the NEM where clusters of large scale renewable energy can be developed to promote the economies of scale in high-resource areas and capture geographic and technological diversity in renewable resources. This appendix provides updated detail on those 35 candidate REZs.

8.1 Integrating large volumes of variable renewable energy

8.1.1 Network and non-network requirements in the future power system

Transmission connection in the NEM is currently open access. That means, subject to meeting connection standards and if necessary remediating system strength impacts, a participant is free to connect to any part of the transmission network. Existing generators and generator projects under development in an area face the risk of the network being constrained if available generation exceeds the capacity of the transmission network to securely transport the energy across any part of the network. Generators in congested areas may also face restrictions on operation caused by low system strength or be affected by marginal losses without some network augmentation.

If the transmission network required to support a REZ is only designed for known/firmly committed generation projects, the capacity of this network is unlikely to be adequate to handle future generation projects for the REZ. To further exploit the renewable resources in the REZ, additional transmission network augmentation will be required.

An incremental approach to augmenting the network risks an overall higher cost of developing the REZ. For example, it is generally less expensive to build one high capacity transmission line than to build one lower capacity transmission line which is later duplicated.

Effective REZ development could reduce these risks to generators if the development of capacity of the transmission network for a REZ is aligned with the likely renewable energy build in the REZ, with a view to both current and future requirements. This highlights the importance of coordinated staging of generation and transmission development that minimises risks of under- and over-utilisation while ensuring reliability and security of the power system is maintained.

Ways to stage a transmission development include, but are not limited to:

- Acquiring strategic easements ahead of their build.
- Building a double circuit tower but stringing a single circuit initially.
- Developing a substation incrementally but having a footprint that accounts for an ultimate development.

It will be essential in the development of transmission to support REZs that these options are explored, to minimise any stranding risk and maximise option value. In the development of the ISP, AEMO has sought to optimise REZs in conjunction with transmission development to achieve the lowest overall cost of development.

8.1.2 Benefits of the Renewable Energy Zone approach

Resource quality and diversity

An important consideration for large-scale development of renewables in a concentrated area such as a REZ is the diversity of resources within the REZ and across the NEM. High diversity (low correlation) between REZs is valuable because it results in a more consistent generation output overall, which requires less energy storage to support the need for firming.

This analysis shows:

- There is high solar energy correlation across the NEM for all REZs.
- Wind resources in Queensland provide the most diversity to wind generation in other areas. Wind generation in Tasmania is somewhat diverse to wind generation on the mainland – particularly Queensland, New South Wales, and South Australia.
- Wind generation within states is generally highly correlated.

There are five REZs that have low or negative correlation with most of the NEM, meaning they are expected to generate electricity at different times to the rest of the NEM. These five REZs are all situated in Queensland and show good diversity with wind in the other regions of the NEM. These REZs are:

- North Queensland Clean Energy Hub.
- Isaac.
- Fitzroy.
- Darling Downs.
- Barcaldine.

Darling Downs and Fitzroy are considered some of the most strategic REZs in eastern Australia for development in the short to medium term, hence these are good areas to consider for wind development. Wind development in these areas would allow for the diversification of renewable resources across the NEM, and contribute to a firmer resource portfolio across the NEM. Development in these areas would also be impacted less by wind generation in other REZs, as the transmission paths to load centres would be less congested.

Diversity and demand matching

Integrating a large amount of highly correlated variable renewable generation can be more complicated for managing power system reliability than connecting generation whose variations are not correlated. Generation correlation can be influenced by technology, location, and time of day. High levels of correlation – when a lot of nearby variable generation is producing (or not producing) energy at the same time – will increase congestion on the transmission network, and volatility in electricity market dispatch.

There are several key ways to achieve diversity with renewable generation, and improve system efficiency:

- Diversify the type of renewable generation built. For example, wind generation within a REZ is likely to be highly correlated to other wind generation within the same REZ, whereas solar generation is likely to be relatively uncorrelated to wind generation in the same area.
- Diversify the geographical location of where the renewable generation is built. For example, wind generation located in different geographical areas is likely to be less correlated than wind generation within the same geographical area.
- Select REZs where combined output from renewable resources is positively correlated with grid demand.
- Co-develop energy storage and variable renewable generation in the same REZ, to allow the net REZ output to be more correlated with demand or within transmission capacity.

In assessing the REZs for analysis in the ISP, the optimisation considered the correlation of REZ resource with demand.

8.2 REZ identification

In the production of the 2018 ISP, AEMO engaged consultants DNV-GL to provide information on the resource quality for potential REZs. Wind resource quality assessment was based on mesoscale wind flow modelling at a height of 150 m above ground level (typical wind turbine height), while Global Horizontal Irradiance (GHI) and Direct Normal Irradiance (DNI) data from the Bureau of Meteorology (BOM) were used to assess solar resource quality. The work undertaken for the ISP is not intended in any way to replace the specific site assessment of potential wind 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 reso**urce** – a measure of high solar irradiation (above 1,600 kW/m2).
- **Demand matching** – the degree to which the local resources correlate with demand.
- **Electrical network** – the distance to the nearest transmission line.
- **Cadastral parcel density** – an estimate of the average property size.
- **Land cover** – a measure of the vegetation, waterbodies, and urbanisation of areas.
- **Roads** – the distance to the nearest road.
- **Terrain complexity** – a measure of terrain slope.
- **Population density** – the population within the area.
- **Protected areas** – exclusion areas where development is restricted.

Throughout the 2020 Draft ISP consultation, AEMO refined the REZ analysis from the 2018 ISP based on stakeholder feedback.

The following figure shows the results of this analysis, with the highest rating potential areas for development of wind and solar farms in green.

Figure 185 Weighted wind (left) and solar (right) resource areas

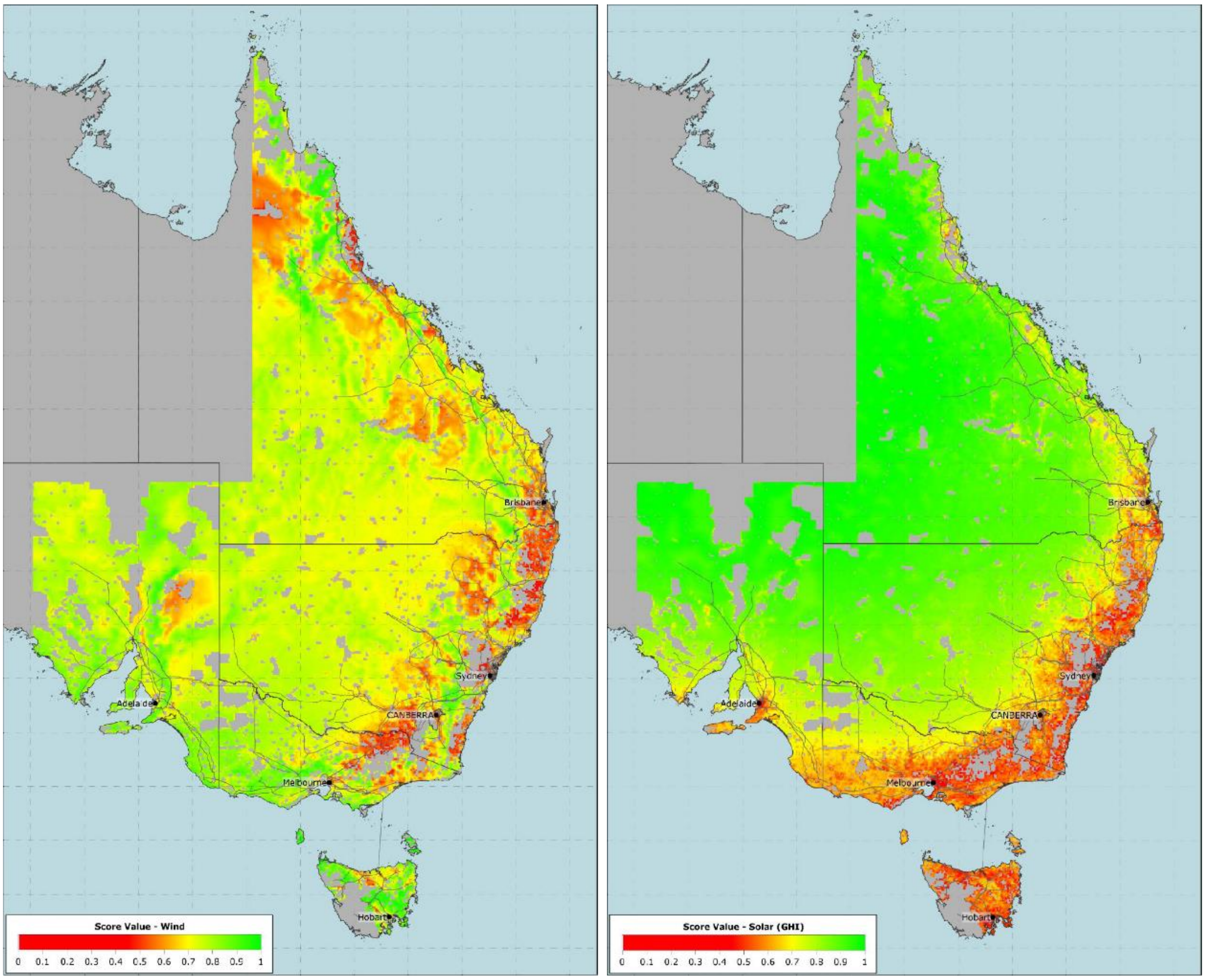
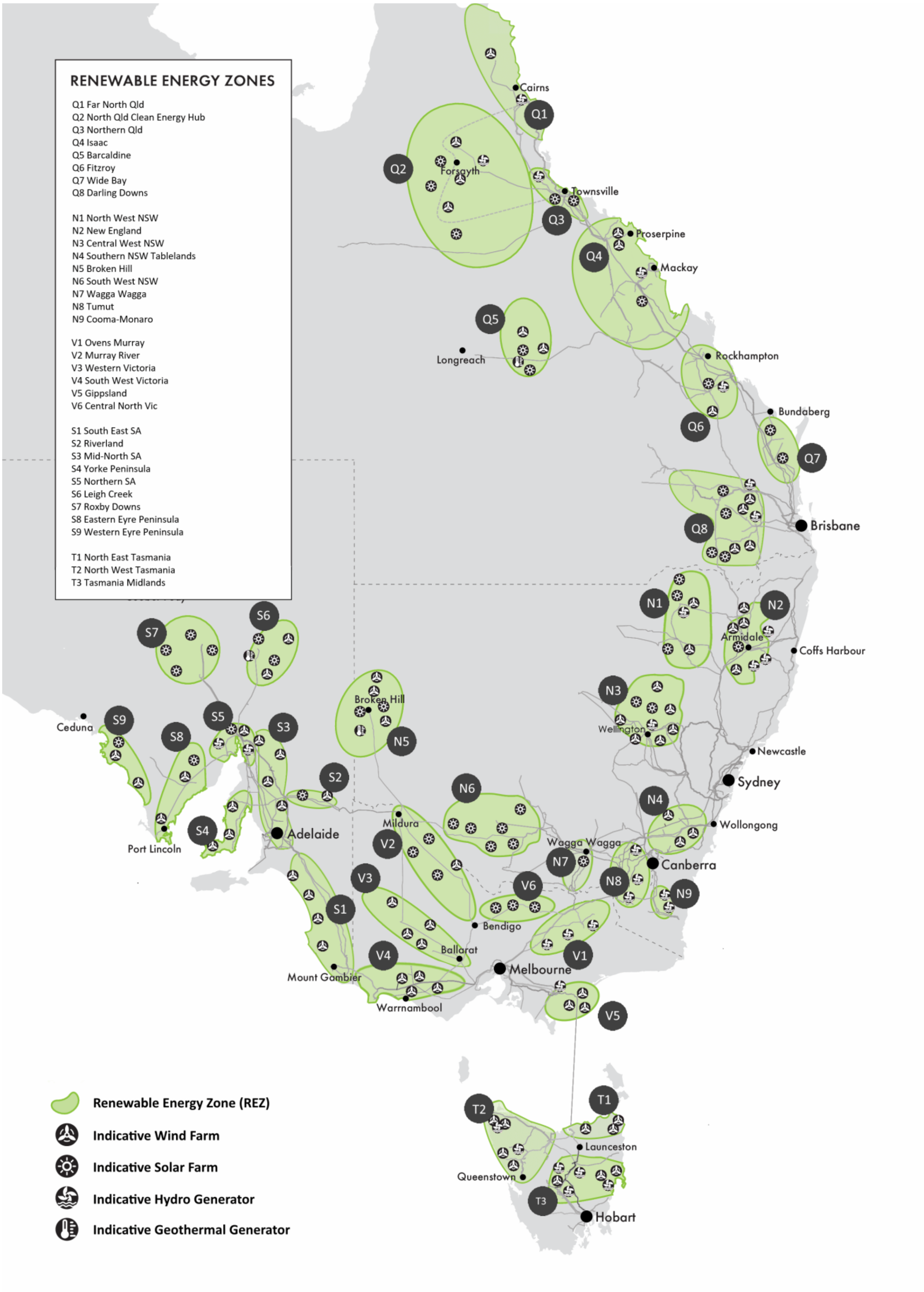


Figure 186 highlights the 2020 Draft ISP Renewable Energy Zone candidates.

After analysis and consultation, the following changes have been implemented to the REZ candidate list since the 2018 ISP:

1. The following new REZs are included in the analysis:
   - Wide Bay in Queensland (Q7).
   - Wagga Wagga in New South Wales (N7).
   - Central North Victoria (V6).
2. The Murray REZ, capturing resources to the west of New South Wales and Victoria has been separated to form the:
   - Murray REZ in Victoria (V2), and
   - South West New South Wales REZ in New South Wales (N6).
3. The New England and Northern New South Wales Tablelands REZs have been combined in the New England REZ (N2).
4. Central New South Wales Tablelands and Central West New South Wales have been refined to form Central West New South Wales (N3).
5. The Far North Queensland REZ has been extended north to include wind resource capacity.

Figure 186 2020 ISP Renewable Energy Zone candidates



8.3 REZ scorecards

The REZ scorecards provide an overview of the characteristics of each REZ so an assessment can be made as the development opportunities. The following explains the criteria in the scorecards.

<table>
<tr><th colspan="2">REZ Report Card Details</th></tr>
<tr><th colspan="2">Renewable Resources</th></tr>
<tr><td rowspan="2">Map Legend</td><td>Indicative generation is shown based on the connection interest in the REZ:
Wind Solar Hydro Geothermal</td></tr>
<tr><td>The green shading shows the indicative geographic area of the Renewable Energy Zone</td></tr>
<tr><td>Resource Quality</td><td>Solar average capacity factor based on 9 reference years
<table>
<tr><td>≥30%</td><td>≥28%</td><td>≥26%</td><td>≥24%</td><td>≥22%</td><td><22%</td></tr>
<tr><td>A</td><td>B</td><td>C</td><td>D</td><td>E</td><td>F</td></tr>
</table>
Wind average capacity factor based on 9 reference years
<table>
<tr><td>≥45%</td><td>≥40%</td><td>≥35%</td><td>≥30%</td><td><30</td></tr>
<tr><td>A</td><td>B</td><td>C</td><td>D</td><td>E</td></tr>
</table>
Correlation between demand describes whether the REZ resources are available at the same time as the regional demand, using a statistical correlation factor. A higher correlation represents that the resource is more available at regional demand.
<table>
<tr><td>≥0.3</td><td>≥0.15</td><td>≥0.0</td><td>≥-0.15</td><td><-0.3</td></tr>
<tr><td>A</td><td>B</td><td>C</td><td>D</td><td>E</td></tr>
</table></td></tr>
<tr><td>Renewable Potential</td><td>Estimated potential REZ size in MW based on the geographical size and resource quality in the REZ</td></tr>
<tr><th colspan="2">Variable Generation Outlook</th></tr>
<tr><td>Scenario</td><td>Long term market simulations of different scenarios named Central, Slow Change, Fast Change, Step Change and High DER.</td></tr>
<tr><td>Existing / Committed Generation</td><td>The existing and commited generation as of the 8th of August 2019 measured in MW.</td></tr>
<tr><td>Project variable generation</td><td>The long term market simulations projected variable generation outlook for Solar and Wind generation at different time intervals across all scenarios.</td></tr>
<tr><th colspan="2">Pumped Hydro</th></tr>
<tr><td>Projected pumped hydro</td><td>The long term market simulations projected generation outlook for pumped hydro generation at different time intervals across all scenarios.</td></tr>
<tr><th colspan="2">Network Capability</th></tr>
</table>

<table>
<tr><td>Hosting Capacity (MW)</td><td colspan="4">The approximate scale of additional generation (MW) that can be transported from the REZ to the load centre, taking into account network limitations (excluding system strength), diversity of resources and the REZs current/exisitng committed generation as of the 8th of August 2019. For any REZ augmentation options, the figure listed as the hosting capacity is the increase in hosting capacity provided by the augmenation.</td></tr>
<tr><td>Loss Factor Robustness</td><td colspan="4">The sensitivity of MLF to addititional generation inside the REZ. The measure used is the additional generation (MW) that can be added before the MLF changes by -0.05
<table>
<tr><td>≥1000</td><td>≥750</td><td>≥500</td><td>≥250</td><td>≤250</td><td>None</td></tr>
<tr><td>A</td><td>B</td><td>C</td><td>D</td><td>E</td><td>F</td></tr>
</table></td></tr>
<tr><td colspan="5">Available Fault level</td></tr>
<tr><td>Scenario</td><td>< 2022</td><td>2022 to 2030</td><td>2030-35</td><td>Post 2035</td></tr>
<tr><td></td><td colspan="4">Available Fault Level calculations have been performed in order to indicate when fault level remediation may be required in the REZ. An assumed short circuit ratio of 3 has been used for these calculations, which may be considered conservative especially for the later years.

The methodology used for calculating Available Fault Level is outlined in Appendix Section 9.8.

'OK' represents zones where there is still headroom for additonal generation connection to at least one bus in the zone, 'At Limit' where it is unlikely that further generation can be connected without remediation being required, and 'Remediation likely required' indicates where available fault levels are insufficient for the projected levels of generation. Where significant remediation is potentially required and it is expected a co-ordinated optimised solution would be beneficial '>500 MVA' has been noted.</td></tr>
</table>

8.3.1 Q1 – Far North Queensland

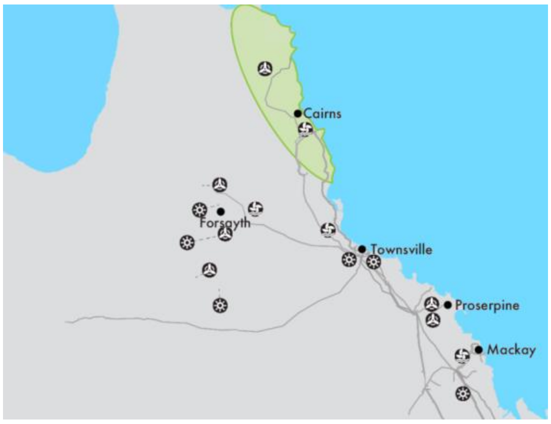
Summary

Far North Queensland is located at the most Northerly section of Powerlink's network.

It has excellent wind and moderate solar resources. Q1 contains two hydro generators at Barron Gorge and Kareeya, with a capacity of 152 MWs. Two renewable generation projects were commissioned since the 2018 ISP - Lakeland Solar & Storage (12 MW) and Mt Emerald Wind Farm (180 MW).

Far North Queensland has a moderate 275 kV network connection however, its distance makes it prone to losses with the addition of generation.

AEMO recommends the installation of dedicated wind monitoring equipment or partnering with interested parties to measure the wind potential and quantify its potential in greater detail to inform future assessment.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	C			A		
Renewable Potential (MW)	1,100			2,400		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	D	D	D

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
Scenario	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central						700	700	1,700
Step						1,500	1,500	2,300
High DER	10	The modelling outcomes, for all scenarios, did not project additional solar generation for this REZ			180	700	700	1,600
Fast						700	900	1,800
Slow						-	-	600

Pumped Hydro

Far North Queensland has good potential pumped hydro locations just north of Cairns and towards the North East around Desailly. The transmission network near this location are weak and upgrades would be required to accommodate large scale pumped hydro. There is also potential pumped hydro locations near Herberton within proximity of the Walkamin/Woree – Chalumbin 275 kV lines.

*Pumped Hydro for Queensland (MW)			
	Projected		
	2022-30	2030-35	> 2035
Central	-	1,200	2,900
Step	300	1,850	3,000
High DER	-	-	1,350
Fast	-	1,550	3,500

	Slow	-	-	-

*Not REZ specific but for Queensland

Network Capability

	Description	Approximate Hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	Connection is via the 275 kV network from Ross- Chalumbin-Walkamin-Woree	700 MW		E
Upgrade Option 1	To increase capacity of the 275 kV network: • Rebuild the double circuit Ross-Chalumbin 275 kV line at a higher capacity (possibility timed with asset replacement). To connect generation in the Northern Part of Far North Queensland requires: • A new substation to the North of the zone around the Lakeland area • A new single/double circuit Walkamin – Lakeland 275 kV line • A new single/double circuit Walkamin – Chalumbin 275 kV line	+600 MW	~$480 to $780 million	-
Upgrade Option 2	To increase capacity of the 275 kV network: • Rebuild the double circuit Ross-Chalumbin 275 kV line at a higher capacity (possibility timed with asset replacement). To connect generation interest within the REZ, dependent on the location of interest: • A new substation North of Millstream • Turn in Woree – Chalumbin 275 kV line • A new single/double circuit Chalumbin – Millstream 275 kV line	+600 MW	~$295 to $445 million	-
Upgrade Option 3	To increase capacity of the 275 kV network: • Rebuild the double circuit Ross – Chalumbin 275 kV line at a higher capacity (possibility timed with asset replacement) • A new 275 kV single circuit Ross – Chalumbin 275 kV line • Uprate the lower rated Ross – Strathmore 275 kV line To connect generation interest within the REZ, dependant on location of interest: • A new substation north of Millstream • Turn in Woree – Chalumbin 275 kV line • A new single/double circuit Chalumbin – Millstream 275 kV line • A new substation to the North of the zone around the Lakeland area • A new single/double circuit Walkamin – Lakeland 275 kV line • A new single/double circuit Walkamin – Chalumbin 275 kV line	+1,200 to 1,500 MW	$745 to $1,260 million	-

Available Fault Level

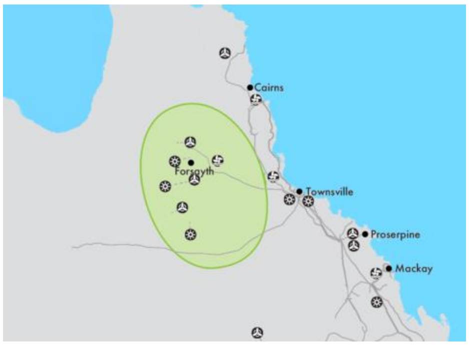
Scenario	< 2022	2022 to 2030	2030-35	Post 2035
Central	At limit	At limit	Remediation > 500 MVA likely required	Remediation > 500 MVA likely required

8.3.2 Q2 – North Queensland Clean Energy Hub

Summary

North Queensland Clean Energy Hub is located in North West Queensland. It has excellent solar and wind resources. The existing 132 kV line to the North Queensland Clean Energy Hub from Ross cannot accommodate any large-scale generation developments. Significant transmission infrastructure would be required to connect large scale generation in this area which would include building a 200 km long double/single circuit line.

One renewable generation project has been commissioned since the 2018 ISP – Kidston Solar Project Phase 1 (50 MW), and two additional projects have been committed -Hughenden Sun Farm (18 MW) and Kennedy Energy Park Phase 1 (60 MW).



Renewable Resources

Resource	Solar			Wind		
Resource Quality	A			A		
Renewable Potential (MW)	8000			18,600		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	D	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	83	The modelling outcomes, for all scenarios, did not project additional solar generation for this REZ.			43.2	There is no existing or committed wind generation in this REZ. The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ.		
Step								
High DER								
Fast								
Slow								

Pumped Hydro

North Queensland Clean Energy Hub REZ has not been identified as having an abundance of potential pumped hydro capability. There is currently interest to develop a 250 MW pumped hydro scheme at Kidston. This proposed pumped hydro scheme suggests converting the Kidston Gold mine upper and lower reservoirs into a pumped hydro scheme. In order to connect the pumped hydro scheme additional transmission infrastructure is required.

Network Capability

	Description	Approximate Hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	Connection is via a single 132 kV line Ross-Kidston-George Town.	-		F
Upgrade Option 1	• Establish a new 275 kV substation near Kidston • Establish a new substation mid-point on Ross – Chalumbin 275 kV line • Turn both Ross – Chalumbin 275 kV lines into the new substation • Connect Kidston to the substation mid-point between Ross and Chalumbin with a double circuit 275 kV line	+800 MW	$230 to $420 million	E

	• Upgrades between the new mid-point substation and Ross would be required if Q1 REZ is also developed			

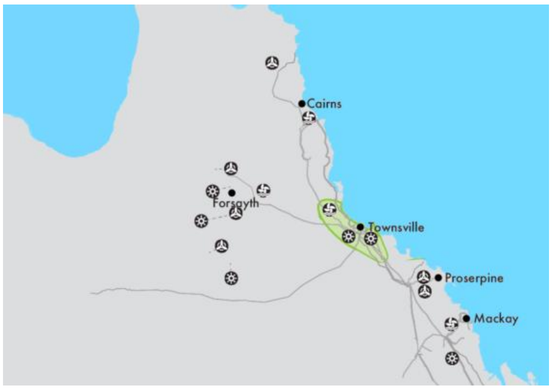
Available Fault Level				
	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	At limit	At limit	At limit	At limit

8.3.3 Q3 – Northern Queensland

Summary

The North Queensland REZ includes Townsville and the surrounding area. It has good quality solar and wind resources and is close to the 275 kV corridor. Clare Solar Farm (150 MW), Ross River Solar Farm (116 MW), and Sun Metals Solar Farm (125 MW) are operational.

The existing 275 kV network has good capacity, but this is shared with the REZs in North and Central Queensland. Even though there is good network capacity, the MLF will decline sharply due to the distance from major load centres. The potential for pumped hydro generation has been identified in the North Queensland REZ. Storing excess solar generation in pumped hydro would relieve network thermal capacity between NQ and CQ.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	B			B		
Renewable Potential (MW)	3,400			-		
	2020	2030	2040	2020	2030	2040
Demand Correlation	F	F	F	C	B	B

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	424	The modelling outcomes, for all scenarios, did not project additional solar generation for this REZ.			There is no existing or committed wind generation in this REZ. The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ.			
Step								
High DER								
Fast								
Slow								

Pumped Hydro

North Queensland has good potential pumped hydro locations to the North East (Near the Ross-Chalumbin 275 kV lines) and just east of Townsville.

Network Capability

	Description	Approximate Hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	The current network connects to Far North QLD via the 2 x Ross–Chalumbin 275 kV lines and to Strathmore via 3 x Ross–Strathmore 275 kV lines. There is also an integrated 132 kV network around Ross. The current hosting capacity of 1200-1300 MW is for all generation Q1, Q2 and Q3.	1,200 to 1,300 MW	-	D
Upgrade Option	• Upgrade lower rated Ross – Strathmore 275 kV line	600 MW	$10 to $15 million	-

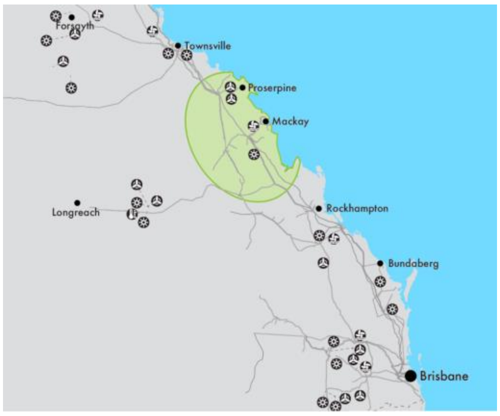
Upgrade Option 2	• Augment the 275 kV network between Ross – Strathmore – Nebo by building an additional 275 kV line	~1,000 MW	~$165 to $305 million	-
Available Fault Level				
	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	Remediation likely required	Remediation likely required	Remediation > 500 MVA likely required	Remediation > 500 MVA likely required

8.3.4 Q4 – Isaac

Summary

Isaac REZ has excellent wind and good solar resources covering Collinsville and Mackay. Daydream Solar Farm (167.75 MW), Hayman Solar Farm (57.75 MW), Collinsville PV (42.5 MW), and Emerald Solar Farm (72 MW) is operational whilst Hamilton Solar Farm (57.5 MW), Lilyvale (100 MW) and Rugby Run (65 MW) are committed.

The existing 275 kV network has spare capacity, but this is shared with the REZs in North and Central Queensland.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	B			A		
Renewable Potential (MW)	6,900			3,800		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	B	B	A

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central						-	-	1,000
Step						1,000	1,000	1,000
High DER	562	The modelling outcomes, for all scenarios, did not project additional solar generation for this REZ				-	-	1,000
Fast						600	1,000	1,000
Slow						-	-	-

Pumped Hydro

There are numerous potential pumped hydro locations to the North East and South East of Nebo. With large variable generation projected for North and Central Queensland, strategic development of large scale storage could defer some transmission augmentations.

	*Pumped Hydro for Queensland (MW		
	Projected		
	2022-30	2030-35	> 2035
Central	-	1,200	2,950
Step	300	1,850	3,000
High DER	-	-	1,350
Fast	-	1,550	3,500
Slow	-	-	-

*Not REZ specific but for Queensland				

Network Capability

	Description	Approximate Hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	275 kV and 132 kV circuits pass through this REZ. The hosting capacity along this corridor is approximately 2000 to 2500 MW which includes any generation in Q1, Q2, Q3, Q4 and Q5.	2,000 to 2,500 MW	-	B
Upgrade Option 1	• Rebuild the Bouldercombe–Calliope River and the Bouldercombe–Raglan–Larcom Creek–Calliope River as a high capacity double circuit line (May be possible to bring forward end of life condition replacement) • A new double circuit Calvale – Larcom Creek 275 kV line • 275/132 kV Calliope River Transformer	+1,200 MW	$160 to $300 million*	-

*Cost assumes full cost of the full rebuild (and not the cost of the bring forward)

Available Fault Level

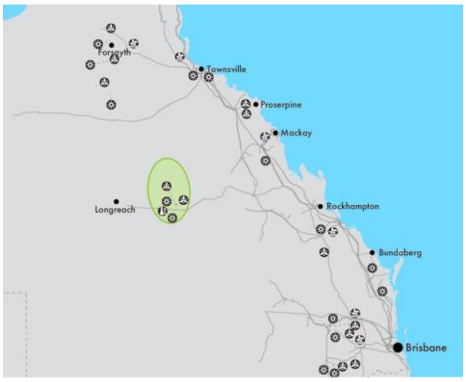
	< 2022	2022 to 2030	2030-35	Post 2035
Central	OK	OK	At limit	Remediation > 500 MVA likely required

8.3.5 Q5 – Barcaldine

Summary

The Barcaldine REZ is in Central Queensland. This REZ has excellent solar resources, moderate wind resources. The existing network is very weak and significant upgrades must take place before this level of new generation can connect.

The existing 350 km 132 kV line to Barcaldine cannot support any large-scale generation developments. A possible investment option is to build a double circuit 275 kV line from the main backbone at Lilyvale extending inland to Barcaldine. Even after this upgrade, the MLFs will decline sharply because the generation is located a significant distance from load.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	A			C		
Renewable Potential (MW)	8,000			3,900		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	D	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central Step High DER Fast Slow	44	The modelling outcomes, for all scenarios, did not project additional solar generation for this REZ			There is no existing or committed wind generation in this REZ. The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ			

Pumped Hydro

Barcaldine REZ has not been identified as having good or an abundance of potential pumped hydro capability

Network Capability

	Description	Approximate Hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	Connection is via a 132 kV line from Lilyvale to Barcaldine via Clermont. A total line length of approximately 350 km.	0 MW		F
Upgrade Option	• Build a double circuit 330 to 350 km 275 kV line to connect the Barcaldine REZ to Lilyvale	+700 MW	$318 to $590 million	

Available Fault Level

	< 2022	2022 to 2030	2030-35	Post 2035
Central	OK	OK	OK	At limit

8.3.6 Q6 – Fitzroy

Summary

The Fitzroy REZ is in Central Queensland and covers a strong part of the network where Gladstone and Callide generators are connections. This REZ has moderate solar and wind resources.

Currently the limitation for connection within this REZ and REZ Q1 to Q4 is limited by the cut set CS-SQ, due to voltage and transient stability. This is projected to limit total generation connected North of this cut set to 2,000-2,500 MW. This limit could be increased by the exit of Callide B (expected in the late 2020s) and Gladstone (in the mid-late 2030s).

Renewable Resources

Resource	Solar			Wind		
Resource Quality	B			B		
Renewable Potential (MW)	7,700			3,500		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	B	B	B

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central		1,500	1,500	1,500		300	300	900
Step		-	-	-		900	900	900
High DER	-	1,800	1,800	1,800	-	-	-	900
Fast		-	-	-		600	900	900
Slow		-	-	-		-	-	-

Pumped Hydro

Potential pumped hydro locations have been identified near Bouldercombe and Calvale. There is a significant projection in Solar and Wind generation North of the CQ-SQ cut set. Significant transmission build would be required to accomodate such large projection in generation. Having pumped hydro in this location or any location in the north of Queensland would assist to reduce the new development project. Fitzroy is a good location, storage here would assist to firm up the solar generation projected under the Central scenario.

*Pumped Hydro for Queensland (MW			
	Projected		
	2022-30	2030-35	> 2035
Central	-	1,200	2,900
Step	300	1,850	3,000
High DER	-	-	1,350
Fast	-	1,550	3,500
Slow	-	-	-

*Not REZ specific but for Queensland

Network Capability				
	Description	**Approximate Hosting capacity**	**Upgrade cost**	**Loss Factor Robustness**
Existing	Currently this REZ is connected via a meshed 275 kV network ranging between Bouldercombe, Gladstone and Callide/Calvale.	~2,000-2,500 MW		A
Upgrade Option	• Turn the Calvale – Halys 275 kV lines into a new substation at Auburn River. This substation is midway between Calvale and Halys and expected to increase the transient stability limit by 300 MW	+300 MW	$26 to $48 million	A
Upgrade Option 2	• Build a double circuit 275 kV line from Calvale to Wandoan South	+900 MW	$226 to $420 million	A

Available Fault Level				
	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	OK	OK	OK	Remediation > 500 MVA likely required

8.3.7 Q7 – Wide Bay

Summary

Due to significant interest in and around the wide bay area, and after consultation, Wide Bay has been included as a REZ in the Draft 2020 ISP. The wide bay area has moderate solar resources with Childers (56 MW) and Susan River Solar Farm (75 MW) operational within this zone.

Renewable Resources

Resource	Solar			Wind		
Resource Quality	C			D		
Renewable Potential (MW)	2,200			1,100		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	B	B	B

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	131	-	-	500	There is no existing or committed wind generation in this REZ. The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ			
Step		500	500	500				
High DER		-	-	500				
Fast		-	500	500				
Slow		-	-	-				

Pumped Hydro

Wide Bay REZ has not be identified as having good or an abundance of potential pumped hydro capability

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	Current connection of this REZ is via the 275 kV lines between Woolooga, South Pine, Woolooga and Gin Gin. There is also significant 132 kV lines in the REZ.	500 MW	-	-

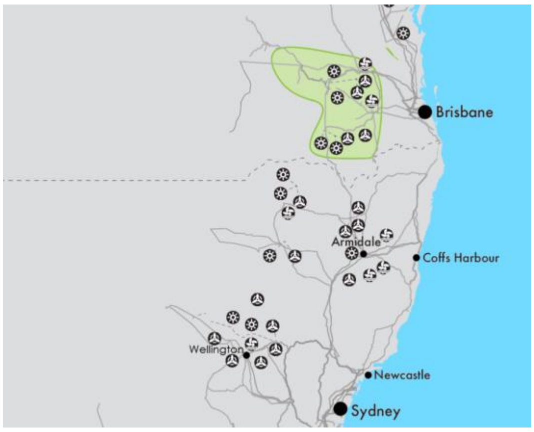
Available Fault Level

	< 2022	2022 to 2030	2030-35	Post 2035
Central	OK	OK	OK	OK

8.3.8 Q8 – Darling Downs

Summary

The Darling Downs REZ covers a wide area in the South-West Queensland. The network is strong with good potential to connect renewable generation. Wind and solar resources are good. Darling Downs REZ is situated close to the Brisbane load centre and has good access to the New South Wales – Queensland interconnector.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	B			B		
Renewable Potential (MW)	7,700			5,800		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	C	B	B

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	417	1,500	1,500	3,600	453	1,400	1,400	1,400
Step		1,000	3,800	7,700		3,000	3,000	4,100
High DER		1,400	1,400	3,500		900	900	1,400
Fast		400	2,600	6,400		-	1,400	3,300
Slow		-	-	-		-	-	-

Pumped Hydro

Large scale solar and wind generation is projected in the Darling Downs area. Darling Downs has good access to the Brisbane load centre as well as the load in New South Wales via the Queensland to New South Wales interconnector. Storage in this location would be beneficial to help firm the solar generation projected across all scenarios except for the slow change.

*Pumped Hydro for Queensland (MW)			
	Projected		
	2022-30	2030-35	> 2035
Central	-	1,200	2,900
Step	300	1,850	3,000
High DER	-	-	1,350
Fast	-	1,550	3,500
Slow	-	-	-

*Not REZ specific but for Queensland				
Network Capability				
	Description	**Approximate hosting capacity**	**Upgrade cost**	**Loss Factor Robustness**
Existing	This is the only REZ in Queensland that has access to the transmission network at 330 kV. The Darling Downs REZ also connects to the Brisbane load centre via 3 x 275 kV lines – one from Middle Ridge to Greenbank, one from Tarong to Blackwall and one from Tarong to South Pine.	3,000 MW		B
Upgrade Stage 1	Plans to increase the hosting capacity of this network involve increasing connection between Queensland and New South Wales. QNI 2E (Group 2 Project) Increases capacity within Darling Downs by 1,000 MW with the following works: • Single circuit 500 kV from Wollar to Gunnedah/Narrabri site to West of Dumaresq to Bulli Creek to Western Downs • New 330 kV single circuit line from Gunnedah/Narrabri site to Uralla or Armidale • New 330 kV single circuit line from West Dumaresq to Dumaresq • Establish new 500/330 kV substations at Gunnedah/Narrabri site and new site West of Dumaresq (West Dumaresq) • One 550/330kV 1500 MVA transformer at Gunnedah/Narrabri site • One 500/330 kV 1500 MVA transformer at west of Dumaresq • One 500/330 kV 1500 MVA transformer at Bulli Creek • Two 500/275 kV 1000 MVA transformers at Western Downs • Install static and dynamic compensation at Wollar, Gunnedah/Narrabri, West Dumaresq, Bulli Creek and/or Western Downs	+1,000 MW	Costed with QNI 2E	A
Upgrade Stage 2	QNI 3E further increases the capacity to connect generation in this zone: • Additional single circuit 500 kV line from Wollar to Gunnedah/Narrabri site to West of Dumaresq to Bulli Creek to Western Downs • One 550/330kV 1,500 MVA transformer at Gunnedah/Narrabri site	+1,000 MW	Costed with QNI 3E	A

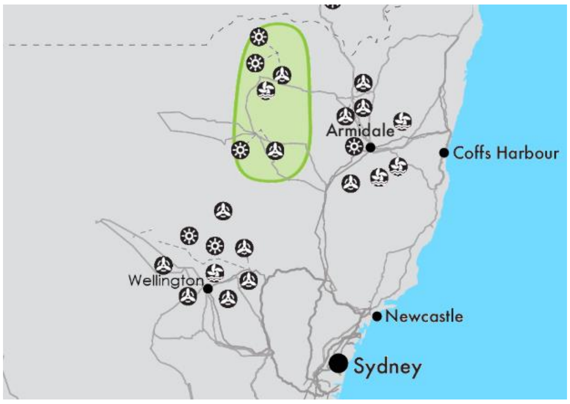
Available Fault Level				
	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	OK	OK	OK	Remediation > 500 MVA likely required

8.3.9 N1 – North West New South Wales

Summary

The North West New South Wales REZ is situated to the west of Armidale, Tamworth and Dumaresq. This REZ encompasses the 132 kV network between Armidale and Tamworth towards Inverell, Moree, Narrabri and Gunnedah. The existing 132 kV network is weak and would require significant network upgrades to accommodate large scale variable renewable energy greater than the current hosting capacity of 100 MW.

Since the 2018 ISP, there has been no additional committed and commissioned renewable generation projects. The preferred QNI augmentation, QNI 2E and 3E which are group 2 and group 3 projects respectively, increases the hosting capacity within this REZ. In three of the scenarios, the solar resource capacity is fully utilised within this zone.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	A			D		
Renewable Potential (MW)	6,500			-		
Demand Correlation	2020	2030	2040	2020	2030	2040
	E	E	E	D	D	D

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	56	100	2,100	6,500	There is no existing or committed wind generation in this REZ. The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ			
Step		1,900	3,700	6,500				
High DER		-	1,100	6,500				
Fast		1,000	2,300	6,500				
Slow		-	-	1,100				

Pumped Hydro

North West New South Wales has some identified potential pumped hydro location about 30 km west of Narrabri. There are also good locations in and around Tamworth. With such large scale solar projected for North West New South Wales, a need for large-scale storage is created to firm supply and reduce the transmisison infrastructure required to facilitate the transfer of this generation to the load centres.

*Pumped Hydro for New South Wales (MW)			
	Projected		
	2022-30	2030-35	> 2035
Central	-	1,400	3,800
Step	-	675	2,500
High DER	-	-	1,300
Fast	-	1,300	3,100
Slow	-	-	230

*Not REZ specific but for New South Wales. It is additional to the pumped hydro of Snowy Hydro 2.0 which is committed in all scenarios.

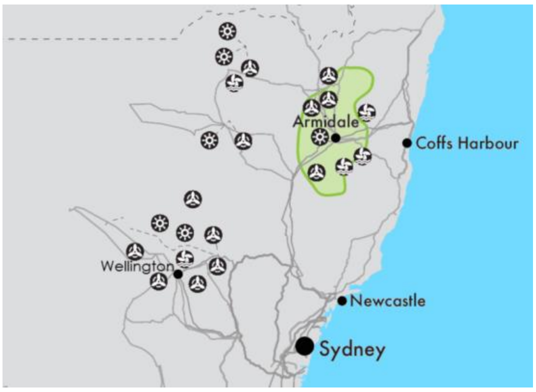
Network Capability				
	Description	**Approximate hosting capacity**	**Upgrade cost**	**Loss Factor Robustness**
Existing	The existing 132 kV network extends from Armidale – Inverell – Moree – Narrabri – Gunnedah back to Tamworth, and has a hosting capacity of approximately 100 MW.	100 MW	-	F
Upgrade Option 1	• Establish a new 330 kV substation at Gunnedah • A new double circuit Wollar-Gunnedah 330 kV line • A new double circuit Gunnedah-Tamworth 330 kV line • 330/132 kV transformation at Gunnedah	+1,350 MW	$276 to $510 million	-
Upgrade Option 2	• Establish a new 500/330 kV substation at Gunnedah • A single circuit Gunnedah – Wollar 500 kV line • A new double circuit Gunnedah-Tamworth 330 kV line	+1,000 MW	$333 to $618 million	-
Upgrade option 4	This option looks at extending out towards more solar interest (it does not increase the capacity of the corridor): • Establish a new 500/330 kV substation at Narrabri • A single circuit Gunnedah – Narrabri 330 kV line or • Establish a new 500/330 kV substation at Gunnedah	N/A	$132 to $244 million	-
Upgrade Option 5	This option looks at build around QNI minor (2E) and QNI Large (3E) to incorporate growth in N1 and N2: Stage 1: • 2 x 500/330 kV 1500 MVA transformers at Gunnedah/Narrabri • A new double circuit Gunnedah-Narrabri 330 kV line (dependant on connection interest in the area) • Uprate Armidale – Tamworth 330 kV lines 85 and 86 • Establish a new Uralla 500/330 kV substation • Turn both Armidale – Tamworth 330 kV lines 85 and 86 into Uralla • A new double circuit Uralla – Bayswater 500 kV line (route passing nearby Walcha), with one side strung • Power flow controllers on the Uralla – Tamworth 330 kV line • A new single circuit Gunnedah/Narrabri 500 kV line • 2 x 500/330 kV 1,500 MVA Uralla transformers • 1 x 500/330 kV 1,500 MVA Bayswater transformer Stage 2: • Third single circuit Gunnedah/Narrabri-Bayswater/Wollar 500 kV line • 2x 500/330 kV transformers at Gunnedah/Narrabri • String other side of Uralla – Bayswater 500 kV line • A new Walcha 500/330 kV Substation (Dependant on connection interest in the area) • Cut Uralla – Bayswater 500 kV line into Walcha • 2 x 500/330 kV 1500 MVA Walcha transformer	+8,000 MW	$1,110 to $2,550 million	-

Available Fault Level				
	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	OK	OK	Remediation required	Remediation > 500 MVA likely required

8.3.10 N2 – New England

Summary

The New England REZ, previously known as Northern New South Wales Tablelands, was identified by the New South Wales government as one of three potential priority renewable energy zones in the New South Wales Government Electricity Strategy. This REZ has moderate to good wind and solar resources in close proximity to the 330 kV network. The connection of additional generation in this zone may compete with generation from Queensland via the New South Wales – Queensland 330 kV interconnector. Three of the larger Queensland to New South Wales interconnector options, QNI 2, QNI 3B and QNI 3C increases the capacity for the connection of renewable energy within this zone. No further renewable generation has been committed or commissioned since the 2018 ISP.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	C			C		
Renewable Potential (MW)	3,500			7,400		
Demand Correlation	2020	2030	2040	2020	2030	2040
	D	E	E	D	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	-	-	300	300	462	-	-	3,500
Step		300	300	1,500		1,300	1,900	6,300
High DER		-	300	300		-	-	1,800
Fast		300	300	300		-	1,000	4,900
Slow		-	-	300		-	-	-

Pumped Hydro

New England REZ has good potential for pumped hydro. The pumped hydro resources are situated close to the 330 kV network – just east of Armidale and Uralla. There is also significant pumped hydro resources along the Armidale – Coffs Harbour 330 kV line. Given the large project solar and wind generation for the New England, North West New South Wales and Darling Downs REZ, a need for large scale storage under some scenarios for New South Wales is also required. Strategic development of pumped hydro in the New England and North West New South Wales could assist to not only firm up on the VRE but also defer or reduce the size of the transmission augmentations required.

*Pumped Hydro for New South Wales (MW)			
	Projected		
	2022-30	2030-35	> 2035
Central	-	1,400	3,800
Step	-	675	2,500
High DER	-	-	1,300
Fast	-	1,300	3,100
Slow	-	-	230

*Not REZ specific but for New South Wale, it is additional to the pumped hydro of Snowy Hydro 2.0 which is committed in all scenarios

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	The existing 330 kV network can support around 300 MW of new connections in and around Armidale 330 kV substation	300 MW	-	B
Upgrade Option 1	Uprate Armidale – Tamworth 330 kV line 85 and 86. It is assumed that the Tamworth–Muswellbrook–Liddell and Liddell–Tamworth 330 kV lines have been uprated as part of QNI minor augmentation.	+300 MW	$70 to $130 million	B
Upgrade Option 1	• Establish a new Uralla 330 kV substation • Turn Armidale – Tamworth 330 kV lines 85 and 86 into Uralla • A new double circuit Uralla – Bayswater 330 kV line • Uprate Armidale – Tamworth 330 kV line 85 and 86	+1,000 MW	$197 to $366 million	
Upgrade Option 2	• Establish a new Uralla 500/330 kV substation • Turn Armidale – Tamworth 330 kV lines 85 and 86 into Uralla • A new single circuit Uralla – Bayswater 500 kV line • Uprate Armidale – Tamworth 500 kV line 85 and 86	+1,000 MW	$288 to $534 million	
Upgrade Option 3	• Establish a new Uralla 500/330 kV substation • Turn Armidale – Tamworth 330 kV lines 85 and 86 into Uralla • A new Double circuit Uralla – Bayswater 500 kV line • Power flow controllers on Uralla – Tamworth 330 kV lines • Uprate Armidale – Tamworth 500 kV line 85 and 86	+1,000 MW	$374 to $694 million	
Upgrade Option 3	Stage 1: • 2 x 500/330 kV 1500 MVA transformers at Gunnedah/Narrabri • A new double circuit Gunnedah-Narrabri 330 kV line (dependant on connection interest in the area) • Uprate Armidale–Tamworth 330 kV lines 85 and 86 • Establish a new Uralla 500/330 kV substation • Turn Armidale – Tamworth 330 kV lines 85 and 86 into Uralla • A new double circuit Uralla – Bayswater 500 kV line (route passing nearby Walcha), with one side strung • Power flow controllers on the Uralla – Tamworth 330 kV line • A new single circuit Gunnedah/Narrabri 500 kV line • 2 x 500/330 kV 1500 MVA Uralla transformers • 1 x 500/330 kV 1500 MVA Bayswater transformer Stage 2: • Third single circuit Gunnedah/Narrabri – Wollar 500 kV line • 2x 500/330 kV transformers at Gunnedah/Narrabri • String other side of Uralla – Bayswater 500 kV line • A new Walcha 500/330 kV Substation (Dependant on connection interest in the area) • Cut Uralla – Bayswater 500 kV line into Walcha • 2 x 500/330 kV 1500 MVA Walcha transformers	+8,000 MW	$1,110 to $2,550 million	

Available Fault Level

	< 2022	2022 to 2030	2030-35	Post 2035
Central	OK	OK	OK	Remediation > 500 MVA likely required

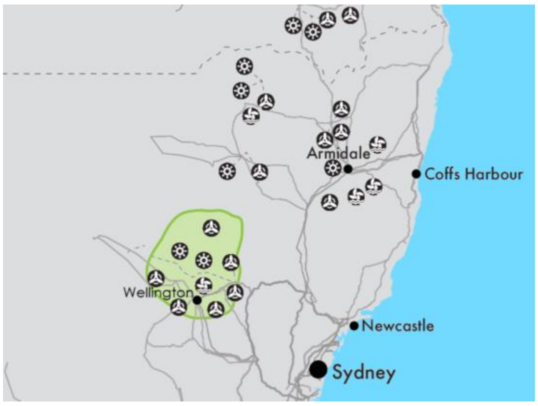
8.3.11 N3 – Central West New South Wales

Summary

The Central West REZ is electrically close to the Sydney load centre and has moderate wind and solar resources. Currently there is more than 700 MW of commissioned and committed generation within Central West REZ, the majority of this generation being from solar energy.

The Central West REZ has been identified by the New South Wales Government as the state's first pilot REZ – expected to unlock 3,000 MW of new renewable generation within New South Wales[72].

As the New South Wales Electricity Strategy was announced just prior to completion of this Draft ISP it has not been fully considered in this ISP. Subject to further policy detail becoming available, AEMO intends to assess the impact of this policy in the Final 2020 ISP.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	C			C		
Renewable Potential (MW)	7,200			3,000		
Demand Correlation	2020	2030	2040	2020	2030	2040
	E	F	F	D	D	D

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	665	-	700	2,800	53	-	20	800
Step		100	100	3,100		800	800	800
High DER		-	700	700		-	-	800
Fast		700	700	2,600		-	800	800
Slow		-	-	700		-	-	-

Pumped Hydro

By 2040 in each scenario, the projected solar generation for Central West is between 700 and 3,900 MW. The Central West New South Wales REZ has good pumped hydro resources situated predominately to the North West of the Wellington-Piper 330 kV line. Developing pumped hydro in this zone would assist to increase the hosting capacity of solar generation within the network if strategically located.

*Pumped Hydro for New South Wales (MW)			
	Projected		
	2022-30	2030-35	> 2035
Central	-	1,400	3,800
Step	-	675	2,500
High DER	-	-	1,300
Fast	-	1,300	3,100
Slow	-	-	230

*Not REZ specific but for New South Wale, it is additional to the pumped hydro of Snowy Hydro 2.0 which is committed in all scenarios

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

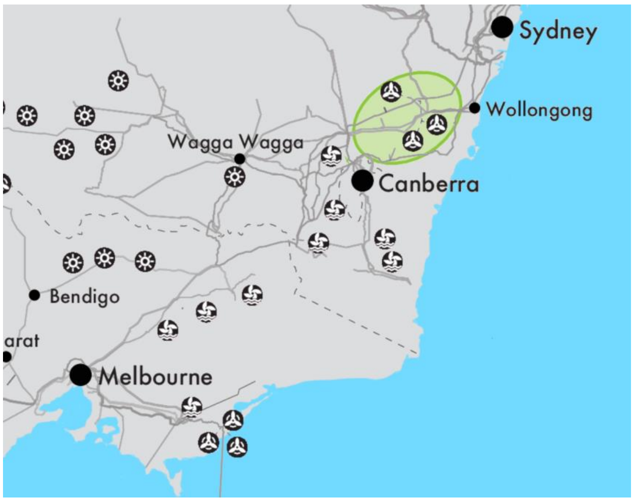
Network Capability				
	Description	**Approximate hosting capacity**	**Upgrade cost**	**Loss Factor Robustness**
Existing	The Central West REZ is connected via a 330 kV circuit between Wellington-Wollar and Wellington-Mount Piper. A 132 kV network connects Wellington, Mount Piper and Yass. There is also a 132 kV network that extends from Wellington to Dubbo	700 MW	-	A
Upgrade Option 1	• Establish 330 kV switchgear at Wollar • Install a 500/330 kV 1,143 MVA transformer at Wollar	+700 MW	$24 to $44 million	A
Upgrade Option 2	Additional to Option 1 above, develop a Central West Hub: • A new Central West Hub 330 kV substation • A new double circuit Wollar–Central Hub 330 kV line • A new Central West Hub–Wellington 330 kV line • 500/330 kV 1,143 MVA Wollar transformer	+1,000 MW	$299 to $555 million	A
Upgrade Option 3	For the connection of large scale wind within the Central West REZ: • Establish a new 500/330 kV substation near wind interest within Liverpool ranges • 2 x 500/330 kV 1,500 MVA transformers • A new double circuit Wollar-Liverpool Ranges 500 kV line • Cut-in Bayswater–Mount Piper 500 kV line 5A3 into Wollar if not yet done as part of QNI augmentation • Third Bayswater 500/330/33 kV 1500 MVA transformer • Third Mt Piper – Wallerawang 330 kV line	+2,000 MW	$229 to $425 million	-

Available Fault Level				
	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	OK	OK	OK	Remediation > 500 MVA likely required

8.3.12 N4 – Southern New South Wales Tablelands

Summary

Southern New South Wales Tablelands REZ has excellent wind resources. There is currently just over 640 MW of renewable generation installed within this zone – over 630 MW of which is wind generation. Southern New South Wales Tablelands has one of the highest wind capacity factors within New South Wales. However, there has been significant opposition from the community within this area for the connection of any additional wind generation, and the proposed extension of Crookwell 3 Wind farm was rejected by the New South Wales Independent Planning Commission[73].



Renewable Resources

Resource	Solar			Wind		
Resource Quality	D			B		
Renewable Potential (MW)	-			-		
Demand Correlation	2020	2030	2040	2020	2030	2040
	E	E	F	C	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	10	The modelling outcomes, for all scenarios, did not project additional Solar generation for this REZ			643	The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ		
Step								
High DER								
Fast								
Slow								

Pumped Hydro

Southern New South Wales has identified pumped hydro locations close to the 330 kV network between Marulan and Dapto.

*Pumped Hydro for New South Wales (MW)			
	Projected		
	2022-30	2030-35	> 2035
Central	-	1,400	3,800
Step	-	675	2,500
High DER	-	-	1,300
Fast	-	1,300	3,100

[73] New South Wales Independent Planning Commission, Statement of reasons for decisions Crookwell 3 Wind Farm (SSD 6695) available at, https://www.ipcn.nsw.gov.au/resources/pac/media/files/pac/projects/2015/02/crookwell-iii-wind-farm/determination/crookwell-3-wind-farm-ssd-6695--statement-of-reasons.pdf

	Slow	-	-	230

*Not REZ specific but for New South Wale, it is additional to the pumped hydro of Snowy Hydro 2.0 which is committed in all scenarios

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	This REZ is close to four 330 kV transmission lines and two 500 kV transmission lines supporting Sydney. The existing network could support approximately 1,000 MW of new connections.	1,000 MW	-	A

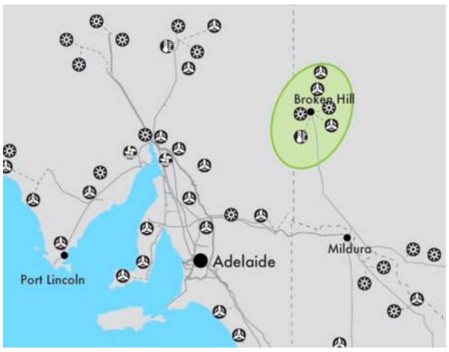
Available Fault Level

	< 2022	2022 to 2030	2030-35	Post 2035
Central	OK	OK	OK	OK

8.3.13 N5 – Broken Hill

Summary

Broken Hill REZ has good wind and solar resources but is connected to the New South Wales grid via a 220 kV line from Buronga with an approximate length of 270 km. The current capacity of this 220 kV line is utilised by the existing solar, wind and gas generation in the area. With little local load and the long distance of the generation to the load central, the MLF for this REZ is one of the worst in the NEM.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	A			C		
Renewable Potential (MW)	8,000			5,100		
Demand Correlation	2020	2030	2040	2020	2030	2040
	E	F	F	E	E	E

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	53	The modelling outcomes, for all scenarios, did not project additional solar generation for this REZ			199	The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ		
Step								
High DER								
Fast								
Slow								

Pumped Hydro

Broken Hill REZ has not been identified as having significant potential pumped hydro capability.

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	Broken Hill REZ is connected via a 270 km 220 kV line from Buronga to Broken Hill	-		E
Upgrade Option 1	• A new double circuit Broken Hill–Bannaby 500 kV line	+3,500 MW	$1,640 to $3,040 million	-

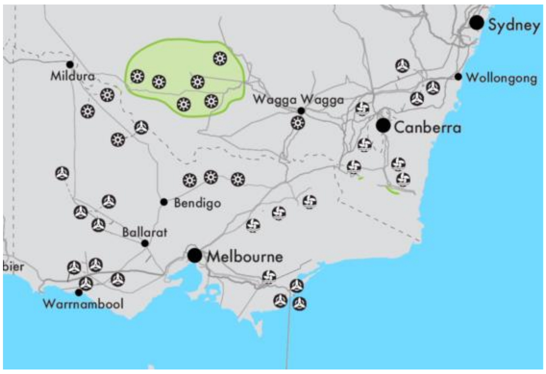
Available Fault Level

	< 2022	2022 to 2030	2030-35	Post 2035
Central	Remediation likely required	Remediation likely required	Remediation likely required	Remediation likely required

8.3.14 N6 – South West New South Wales

Summary

In the 2018 ISP, the South West New South Wales REZ formed part of the Murry River REZ which covered the western part of New South Wales and Victoria. The New South Wales portion of the Murray River REZ now forms the South West New South Wales REZ. This zone has over 1,000 MW of generation currently in service or committed and has good solar resources. For any further large scale renewable generation to connect in this area, additional transmission infrastructure would be required to get the generation from this REZ to the Sydney load centre. The capacity within this REZ will be improved by the proposed New South Wales and South Australia interconnector – Energy Connect as well as with the proposed development of HumeLink, both of which are Group 1 transmission augmentation projects.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	B			D		
Renewable Potential (MW)	4,000			4,300		
Demand Correlation	2020	2030	2040	2020	2030	2040
	E	F	F	D	D	D

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	1,060	-	1,600	1,600	There is no existing or committed wind generation in this REZ. The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ			
Step		1,600	1,600	1,600				
High DER		-	400	1,600				
Fast		600	1,600	1,600				
Slow		-	-	600				

Pumped Hydro

South West New South Wales REZ has not been identified as having significant potential pumped hydro capability.

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	The 220 kV network within this REZ is weak and currently has no spare hosting capacity to connect large scale renewable energy.	-	-	-
Upgrade Option 1	VNI West Option 7 (Group 1 Project) • New 500 kV double circuit line between North Ballarat–Bendigo–Kerang–Darlington Point–Wagga • 2 x 500/220 kV 1,000 MVA transformers at Kerang and at Bendigo • 2 x 500/330 kV transformers at Darlington Point	+1,000 MW	As part of VNI West	-

Upgrade Option 2	• Rebuild existing Darlington Point-Wagga 330 kV line to high capacity twin olive conductor • Second new Darlington Pt-Wagga-330 kV line • New Wagga 500/330kV substation • 2 x Wagga 500/330/33kV 1,500 MVA transformers • A new single circuit Wagga-Bannaby 500 kV Line	+1,400 MW	$368 to $684 million	

Available Fault Level

	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	At limit	At limit	Remediation > 500 MVA likely required	Remediation > 500 MVA likely required

8.3.15 N7 – Wagga Wagga

Summary

The Wagga Wagga REZ is a new addition to the New South Wales REZ. The need to identify this area as a REZ has been driven via significant interest in the area. This REZ extends North of Wagga and south past Hume. Bomen Solar Farm of 121 MW is committed as well as a few other proposed solar projects in the area. The proposed HumeLink project, which is a Group 1 transmission project, will increase the hosting capacity of variable renewable generation within this REZ.

Renewable Resources

Resource	Solar			Wind		
Resource Quality	C			E		
Renewable Potential (MW)	1,100			1,100		
Demand Correlation	2020	2030	2040	2020	2030	2040
	E	F	F	D	D	D

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	121	-	500	500	There is no existing or committed wind generation in this REZ. The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ.			
Step		500	500	500				
High DER		-	500	500				
Fast		500	500	500				
Slow		-	-	500				

Pumped Hydro

Wagga Wagga REZ has not be identified as having significant potential pumped hydro capability.

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	There is no additional hosting capacity on the 330 kV and 132 kV network around Wagga Wagga.	-	-	-
Upgrade Option 2	HumeLink (Group 1 Project): • A new 500 kV single circuit from Maragle to Bannaby • A new 500 kV single circuit from Maragle to Wagga Wagga • A new 500 kV single circuit from Wagga Wagga to Bannaby • Cut-in Lower Tumut-Upper Tumut 330 kV line at Maragle • Three 500/330 kV 1500 MVA transformers at Maragle • One 500/330 kV 1500 MVA transformer at Wagga Wagga	+500 MW	As part of HumeLink	-

	• Power flow controller on Bannaby-Sydney West 330 kV line			
Upgrade Option 3	• New Wagga 500/330kV substation • 2 x Wagga 500/330/33kV 1,500 MVA transformers • A new single circuit Wagga-Bannaby 500 kV Line	+1,400 MW	$340 to $635 million	-

Available Fault Level

	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	OK	OK	OK	OK

8.3.16 N8 – Tumut

Summary

The Tumut REZ, a Group 1 REZ expansion project, has been identified due to the potential for additional pumped hydro generation, such as Snowy 2.0. The proposed HumeLink, a group 1 transmission project currently undergoing a RIT-T, will enable the connection of 2,040 MW (Snowy 2.0) of pumped hydro generation within this area.

Renewable Resources

Resource	Solar	Wind
Resource Quality	-	-
Renewable Potential (MW)	-	-
Demand Correlation	-	-

Variable Renewable Energy Outlook

<table>
<tr><th></th><th colspan="4">Solar PV (MW)</th><th colspan="4">Wind (MW)</th></tr>
<tr><th></th><th>Existing / committed</th><th colspan="3">Projected</th><th>Existing / committed</th><th colspan="3">Projected</th></tr>
<tr><th></th><th>< 2022</th><th>2022-30</th><th>2030-35</th><th>> 2035</th><th>< 2022</th><th>2022-30</th><th>2030-35</th><th>> 2035</th></tr>
<tr><td>Central</td><td colspan="4" rowspan="5">There is no existing or committed solar generation in this REZ. The modelling outcomes, for all scenarios, did not project additional solar generation for this REZ</td><td colspan="4" rowspan="5">There is no existing or committed wind generation in this REZ. The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ</td></tr>
<tr><td>Step</td></tr>
<tr><td>High DER</td></tr>
<tr><td>Fast</td></tr>
<tr><td>Slow</td></tr>
</table>

Pumped Hydro

Tumut REZ has excellent pumped hydro resources.. Snowy 2.0 has been considered committed across all scenarios with the timing around 2025. To facilitate the additional pumped hydro wihtin this area, the Humelink RIT-T (Group 1 transmission project) is currently underway. This proposes the addition of 500 kV transmission between Wagga, Tumut area and Bannaby. In late February 2019, the Government approved Snowy 2.0 as part of its plan to support renewable energy transformation delivering affordable, reliable power.

<table>
<tr><th colspan="4">Pumped Hydro (MW)</th></tr>
<tr><th colspan="4">Committed Snowy 2.0</th></tr>
<tr><th></th><th>2022-30</th><th>2030-35</th><th>> 2035</th></tr>
<tr><td>Central</td><td>2,040</td><td>2,040</td><td>2,040</td></tr>
<tr><td>Step</td><td>2,040</td><td>2,040</td><td>2,040</td></tr>
<tr><td>High DER</td><td>2,040</td><td>2,040</td><td>2,040</td></tr>
<tr><td>Fast</td><td>2,040</td><td>2,040</td><td>2,040</td></tr>
<tr><td>Slow</td><td>2,040</td><td>2,040</td><td>2,040</td></tr>
</table>

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	Currently the 330 kV transmission network around lower and upper Tumut is congested during peak demand periods. A careful balance of generation from the existing hydro units and flow between Victoria and New South Wales is required to prevent overloads within this area.	-	-	A
Upgrade option 1	HumeLink (Group 1): • A new single circuit Maragle-Bannaby 500 kV line • A new single circuit Maragle-Wagga Wagga 500 kV line • A new single circuit Wagga Wagga-Bannaby 500 kV line • Cut-in Lower Tumut-Upper Tumut 330 kV line at Maragle • Three 500/330 kV 1,500 MVA transformers at Maragle • One 500/330 kV 1,500 MVA transformer at Wagga Wagga • Power flow controller on Bannaby-Sydney West 330 kV line	+2,040	Part of HumeLink	A

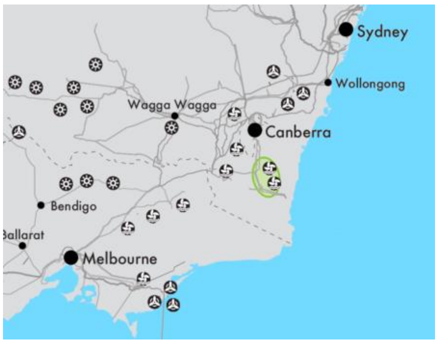
Available Fault Level

	< 2022	2022 to 2030	2030-35	Post 2035
Central	OK	OK	OK	OK

8.3.17 N9 – Cooma Monaro

Summary

The Cooma Monaro REZ has been identified for its pumped hydro potential. This REZ has moderate to good quality wind. Boco Rock wind farm (113 MW) has been commissioned since the 2018 ISP.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	D			C		
Renewable Potential (MW)	-			300		
Demand Correlation	2020	2030	2040	2020	2030	2040
	E	E	F	D	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	There is no existing or committed solar generation in this REZ. The modelling outcomes, for all scenarios, did not project additional solar generation for this REZ				113	-	100	200
Step						200	300	300
High DER						-	-	300
Fast						-	300	300
Slow						-	-	-

Pumped Hydro

Cooma Monaro REZ was identified due to its pump hydro capacity. The network connection at Cooma Monaro is weak with only 132 kV connection. To accommodate any large scale pumped hydro this network would need to be augmented.

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	The existing 132 kV network connecting Cooma Monaro REZ to Canberra, Williamsdale and Munyang can accommodate an additional 200 MW of generation	200 MW		E
Upgrade option 1	• Establish a new substation close to wind or pumped hydro storage	+300 MW	$48 to $90 million	-

	• A new double circuit 132 kV line from the new station to Williamsdale/Canberra			

Available Fault Level				
	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	OK	OK	At limit	Remediation likely required

8.3.18 V1 – Ovens Murray

Summary

The Ovens Murray REZ has been identified due to this REZ having good pumped hydro resources. There is currently 770 MW of installed hydro generation within this zone. Good potential pumped hydro locations within this zone and the proximity of this REZ to good solar resources, makes Ovens Murray a good candidate for meeting the pumped hydro needs within Victoria.

Renewable Resources

Resource	Solar	Wind
Resource Quality	-	-
Renewable Potential (MW)	-	-
Demand Correlation	-	-

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	There is no existing or committed solar generation in this REZ. The modelling outcomes, for all scenarios, did not project additional solar generation for this REZ.				There is no existing or committed wind generation in this REZ. The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ.			
Step								
High DER								
Fast								
Slow								

Pumped Hydro

Ovens Murray and Gippsland REZs have been highlighted as having potential for significant pumped hydro generation. Ovens Murry is connected to the Victoria load centre via two 330 kV lines from Dederang to South Morang. It also lies on the interconnector flow path between New South Wales and Victoria.

*Pumped Hydro for Victoria (MW)			
	Projected		
	2022-30	2030-35	> 2035
Central	-	300	1,550
Step	450	450	600
High DER	-	-	-
Fast	-	400	850
Slow	-	-	1,250

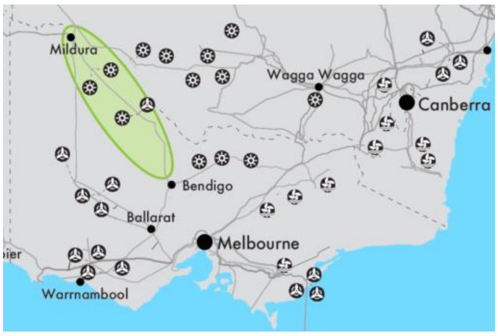
Available Fault Level

	< 2022	2022 to 2030	2030-35	Post 2035
Central	OK	OK	OK	OK

8.3.19 V2 – Murray River

Summary

In the 2018 ISP, the Murray River REZ spanned over New South Wales towards Darlington Point. The New South Wales portion of Murray River is now defined as South West New South Wales REZ, and the Victorian portion of the REZ remains at Murray River. Murray River REZ has moderate wind and solar resources. The existing 220 kV network between Bendigo and Red Cliffs is electrically weak, with MLFs declining sharply as new generators connect. Capacity in Murray River is improved with the uprating of the Red Cliffs – Wemen – Kerang 220 kV line Murray REZ has been included in group 1 augmentation projects. The proposed new interconnector between New South Wales and South Australia (Project EnergyConnect) will improve capacity within Murray REZ, and with VNI West under option 6.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	C			D		
Renewable Potential (MW)	1,100			-		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	D	D	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central		700	1,100	1,100				
Step		1,100	1,100	1,100				
High DER	628	700	1,100	1,100	There is no existing or committed wind generation in this REZ. The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ			
Fast		400	1,100	1,100				
Slow		100	100	400				

Pumped Hydro

This REZ is not considered to have potential for significant pumped hydro generation.

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	Murray REZ, which has no spare hosting capacity, is connected via a weak 220 kV line from Bendigo–Kerang–Wemen–Red Cliffs	0 MW		E
Upgrade Option 1	Extend the Murray REZ hosting capacity by augmenting the 220 kV network: • A new double circuit Red Cliffs–Kerang 220 kV line • A new double circuit Kerang–Bendigo 220 kV line	+1,200 MW	$330 to $610 million	-

	• A new double circuit Bendigo – Moorabool/North Ballarat 220 kV line • A new Moorabool or North Ballarat 500/220 kV 1000 MVA transformer			
Upgrade Option 2	Extend Murray REZ with new augmentation between New South Wales and Victoria – VNI option 7 (Group 1): • New 500 kV double circuit line between North Ballarat–Bendigo–Kerang–Darlington Point–Wagga • 2 x 500/220 kV 1000 MVA transformers at Kerang and at Bendigo • 2 x 500/330 kV transformers at Darlington Point • 1 x 500/330 kV transformer at Wagga	+2,000 MW	As part of VNI 7	-
Upgrade Option 3	500 kV network augmentation to Kerang, applied if VNI West Option 7 is not chosen: • A new 500 kV double circuit line between North Ballarat–Bendigo–Kerang • 2 x 500/220 kV 1000 MVA transformers at Kerang and at Bendigo • A new double/single circuit Kerang – Wemen – Red Cliffs 220 kV line	+1,500 MW*	$570 to $1,100 million	-

*Augmentation hosting capacity dependant on generation within Western Victoria, Central North Victoria, and South West Victoria

Available Fault Level

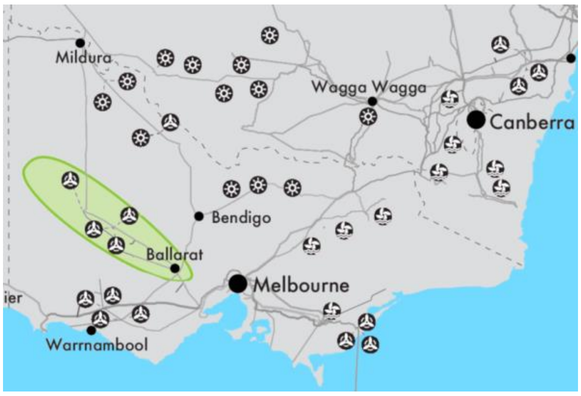
	< 2022	2022 to 2030	2030-35	Post 2035
Central	Remediation likely required	Remediation likely required	Remediation likely required	Remediation > 500 MVA likely required

8.3.20 V3 – Western Victoria

Summary

The Western Victoria REZ has excellent wind resources, with the existing and committed renewable generation within this REZ exceeding 1 GW all of which is from wind generation. The current network is constrained and cannot support any further connection of renewable generation without transmission augmentation. AEMO has just completed the Western Victoria RIT-T, it has been highlighted as a committed project, with the preferred option to expand generation within this zone as follows:

- A new North Ballarat Terminal Station
- A new 220 kV double circuit North Ballarat – Bulgana (Via Waubra) line
- A new 500 kV double circuit Sydenham – North Ballarat line
- 2 x 500/220 kV 1000 MVA transformers at North Ballarat



Renewable Resources

Resource	Solar			Wind		
Resource Quality	D			B		
Renewable Potential (MW)	400			2,800		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	D	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central		-	-	400		1,100	1,100	1,100
Step		400	400	400		700	700	1,100
High DER	-	100	100	400	1,027	700	700	700
Fast		-	400	400		400	700	1,100
Slow		-	-	-		200	200	500

Pumped Hydro

This REZ is not considered to have potential for significant pumped hydro generation.

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	The hosting capacity within Western Victoria REZ will be approximately 450 MW after completion of the committed projects.	450 MW		D
Upgrade Option 1	Increase capacity to Western Victoria with increased connection between New South Wales and Victoria (Group 1):	+1,000 MW	Part of VNI West	

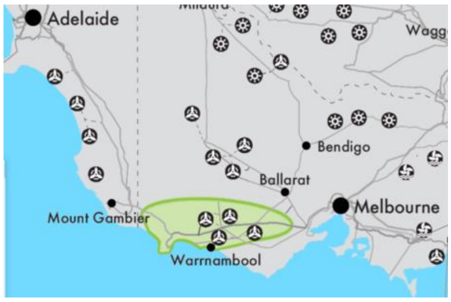
	1. VNI option 6: • Two 500 kV lines from North Ballarat to Shepparton • Two 500 kV lines from Shepparton to Wagga Wagga • Two 500/220 kV 1,000 MVA transformers at Shepparton • One additional 500/330 kV 1500 MVA transformer at Wagga Wagga • Power flow controllers to prevent overloading on 330 kV lines between Upper/Lower Tumut and South Morang. Possible locations are on the Murray–Lower Tumut and Lower Tumut–Wagga 330 kV lines. Alternatively, on both Murray–Dederang and Wodonga–Dederang 330 kV lines. • Additional reactive plant at North Ballarat, Shepparton and Wagga Wagga. 2. VNI option 7: • Two 500 kV lines from North Ballarat to Bendigo • Two 500 kV lines from Bendigo to Kerang • Two 500 kV lines from Kerang to Darlington Point • Two 500 kV lines from Darlington Point to Wagga Wagga • Two 500/220 kV 1000 MVA transformers at each of Bendigo and Kerang Terminal Stations • Two 500/330 kV 1500 MVA transformers at Darlington Point • One additional 500/330 kV 1500 MVA transformer at Wagga Wagga • Power flow controllers to prevent overloading on 330 kV lines between Upper/Lower Tumut and South Morang. Possible locations are on the Murray–Lower Tumut and Lower Tumut–Wagga 330 kV lines. Alternatively, on both Murray–Dederang and Wodonga–Dederang 330 kV lines. • Additional reactive plant at Bendigo, Kerang, Darlington Point and Wagga Wagga.			

Available Fault Level				
	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	Remediation likely required	Remediation likely required	Remediation likely required	Remediation > 500 MVA likely required

8.3.21 V4 – South West Victoria

Summary

The South West REZ has moderate to good wind resource within proximity to the 500 kV and the 220 kV networks in the area. Currently the 220 kV network is congested, however there is still approximately 750 MW of hosting capacity remaining on the 500 kV network. There are several large wind farms are already in service including Macarthur (420 MW) and Portland (149 MW).



Renewable Resources

Resource	Solar			Wind		
Resource Quality	E			C		
Renewable Potential (MW)	-			3,900		
Demand Correlation	2020	2030	2040	2020	2030	2040
	E	F	F	D	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	There is no existing or committed solar generation in this REZ. The modelling outcomes, for all scenarios, did not project additional solar generation for this REZ.				1005	1,000	1,000	1,000
Step						800	800	3,500
High DER						1,000	1,000	1,100
Fast						-	500	2,000
Slow						-	-	-

Pumped Hydro

This REZ is not considered to have potential for significant pumped hydro generation.

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	The current hosting capacity of 750 MW within this REZ is on the 500 kV network between Moorabool and Heywood. The 220 kV and 66 kV network between Moorabool and Terang is currently congested	750 MW		C
Upgrade Option 1	Extend Gippsland hosting capacity by firming current Moorabool to Mortlake 500 kV line: Stage 1: • A new 500 kV single circuit Moorabool–Mortlake 500 kV line	+2,200 MW	$260 to $480 million	

	Stage 2 • A new 500 kV single circuit Moorabool–Sydenham 500 kV line Or Extend Gippsland with 500 kV towards Western Victoria (Assuming Western Victoria is in service) • A new single circuit Mortlake–North Ballarat 500 kV line			

Available Fault Level

	< 2022	2022 to 2030	2030-35	Post 2035
Central	OK	OK	Remediation > 500 MVA likely required	Remediation > 500 MVA likely required

8.3.22 V5 – Gippsland

Summary

Two wind farms are in service within the Gippsland REZ, Bald Hill wind farm (106 MW) and Wonthaggi wind farm (12 MW). Furthermore, there is currently significant wind generation interest in this area, including a large offshore wind farm of 2,000 MW. Due to the strong 500 kV backbone of this REZ, significant generation can be accommodated within this REZ. Which is further increase with the retirements of coal fired generation within this area.

Renewable Resources

Resource	Solar			Wind		
Resource Quality	D			D (on-shore) B (off-shore)		
Renewable Potential (MW)	-			2,000 (on-shore) 4,000 (off-shore)		
Demand Correlation	2020	2030	2040	2020	2030	2040
	E	F	F	C	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	There is no existing or committed solar generation in this REZ. The modelling outcomes, for all scenarios, did not project additional solar generation for this REZ				118	There is no existing or committed wind generation in this REZ. The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ		
Step								
High DER								
Fast								
Slow								

Pumped Hydro

Ovens Murray and Gippsland REZs have been highlighted as having potential for significant pumped hydro generation within Victoria. Gippsland REZ has a strong 500 kV network connecting coal fired power station to the Melbourne load centre as well as interconnecters to Tasmania via Basslink. Due to the good network capacity, Gippsland REZ is a good candidate for pumped hydro generation. The modelling outcomes for pumped hydro within Victoria is tabulated, with this pumped hydro being distributed between the Ovens Murray and the Gippsland REZ.

*Pumped Hydro for Victoria (MW)			
	Projected		
	2022-30	2030-35	> 2035
Central	-	300	1,550
Step	450	450	600
High DER	-	-	-
Fast	-	400	850
Slow	-	-	1,250

*Not specific to REZ but for Victoria

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	There is significant 500 kV and 220 kV network connecting the Gippsland REZ to the Melbourne load centre.	2,000 MW	-	A
Upgrade Option 1	Upgrades for Gippsland are not considered as there is sufficient hosting capacity available within this REZ to accommodate the wind resource. The hosting capacity is then further expected to increase with retirements of Loyang and Yallourn coal -fired stations			

Available Fault Level

	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	OK	OK	OK	OK

8.3.23 V6 – Central North Victoria

Summary

The Central North Victoria REZ, after careful assessment and consultation was included in the Draft 2020 ISP as a Group 1 REZ expansion candidate.

This REZ has moderate wind and solar resources. Additional to the currently committed Solar farm Numurkah (100 MW), the solar generation applications exceed 300 MW whilst the enquiries within this zone exceeds 2.5 GW.

The VNI West project is recommended to upgrade transfer capability between Victoria and New South Wales via Kerang or Shepparton. This would increase the ability for renewable generation to connect within this zone significantly.

Renewable Resources

Resource	Solar			Wind		
Resource Quality	C			D		
Renewable Potential (MW)	1,900			1,600		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	D	D	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central		200	200	400		400	400	400
Step		400	400	400		400	400	400
High DER	100	-	-	-	-	400	400	400
Fast		-	-	-		-	-	400
Slow		-	-	-		-	-	-

Pumped Hydro

This REZ is not considered to have potential for significant pumped hydro generation.

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	The current hosting capacity of the 220 kV network between Dederang–Glenrowan–Shepparton–Bendigo is 800 MW.	800 MW		-
Upgrade Option 1	Extend Central North Victoria with additional 220 kV lines: • A new double circuit North Ballarat – Bendigo 220 kV line • A new double circuit Bendigo–Shepparton 220 kV line	+600 MW	$150 to $285 million	-

Upgrade Option 2	Extend Central North Victoria with additional 220 kV lines, this option assumed Western Victoria Augmentation in service: • A new double circuit North Ballarat – Bendigo 220 kV line • A new double circuit Bendigo–Shepparton 220 kV line • A new double circuit Shepparton–Glenrowan 220 kV line	+800 MW	$211 to $392 million	-
Upgrade Option 3	Extend Central North Victoria with a combination of 500 kV and 220 kV integration: • A new double circuit North Ballarat – Shepparton 500 kV line • A new double circuit Shepparton–Glenrowan 220 kV line • 2 x 500/220 kV 1,500 MVA transformation at Shepparton	+1500 to 1,700 MW	$390 to $720 million	-
Upgrade Option 4	Increase capacity to Central North Victoria REZ with increased connection between New South Wales and Victoria (Group 1): 1. VNI option 6: • Two 500 kV lines from North Ballarat to Shepparton • Two 500 kV lines from Shepparton to Wagga Wagga • Two 500/220 kV 1,000 MVA transformers at Shepparton • One additional 500/330 kV 1500 MVA transformer at Wagga Wagga • Power flow controllers to prevent overloading on 330 kV lines between Upper/Lower Tumut and South Morang. Possible locations are on the Murray–Lower Tumut and Lower Tumut–Wagga 330 kV lines. Alternatively, on both Murray–Dederang and Wodonga–Dederang 330 kV lines.	+2,000 MW	Part of VNI West	-

Available Fault Level

	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	OK	OK	At limit	Remediation likely required

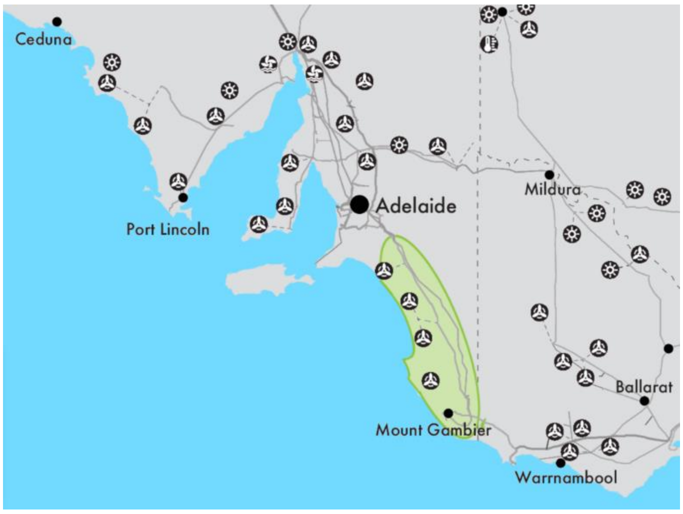
8.3.24 S1 – South East SA

Summary

The South-East South Australia REZ has good wind resources. Over 300 MW of wind farms at Canunda and Lake Bonney are in service.

This REZ lies on the major 275 kV path linking South Australia with Victoria. The existing network can only effectively accommodate a small amount of additional generation.

The MLF is sensitive to additional generation because the REZ is not close to any major load centres.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	D			C		
Renewable Potential (MW)	100			3,200		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	C	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	95	The modelling outcomes, for all scenarios, did not project additional solar generation for this REZ			325	-	100	800
Step						100	100	800
High DER						-	-	800
Fast						-	300	800
Slow						-	-	500

Pumped Hydro

This REZ is not considered to have potential for significant pumped hydro generation.

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness

Existing	Presently the network capacity is limited – any additional generation would effectively be competing with the flows on the Heywood Interconnector	55 MW	-	D
Upgrade Option 1	Install an additional 275 kV line by stringing the vacant circuit between Tailem Bend and Tungkillo, including any additional reactive support required.	+400-600 MW	$20 to $80 million	D/C
Available Fault Level				
	< 2022	2022 to 2030	2030-35	Post 2035
Central	OK	OK	OK	Remediation > 500 MVA likely required

8.3.25 S2 – Riverland

Summary

The Riverland REZ is on the South Australian side of the proposed Energy Connect route. It has moderate quality wind and solar resources. There is minimal existing renewable generation in the zone.

Prior to EnergyConnect, approximately 200 MW can be connected. Once Project EnergyConnect is commissioned (2024), approximately 1,000 MW can be accommodated. Additional generation beyond 1,200 MW is not practical without extensive network upgrades.

Renewable Resources

Resource	Solar			Wind		
Resource Quality	B			E		
Renewable Potential (MW)	4,000			1,400		
Demand Correlation	**2020**	**2030**	**2040**	**2020**	**2030**	**2040**
	F	F	F	C	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	**Projected**			**Existing / committed**	**Projected**		
	< 2022	**2022-30**	**2030-35**	**> 2035**	**< 2022**	**2022-30**	**2030-35**	**> 2035**
Central		-	1,200	1,200				
Step		1,200	1,200	1,200				
High DER	-	-	1,100	1,200	There is no existing or committed wind generation in this REZ. The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ			
Fast		400	1,200	1,200				
Slow		-	-	1,200				

Pumped Hydro

This REZ is not considered to have potential for significant pumped hydro generation.

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	Presently the network capacity is limited, any additional generation would effectively be competing with the flows on the Heywood Interconnector.	200 MW	-	E
Upgrade Option 1	Energy Connect provides an additional 330 kV connection option for this REZ.	+800 MW to 1,000 MW	Provided through Energy Connect	-

Available Fault Level

	< 2022	2022 to 2030	2030-35	Post 2035

Central	OK	OK	Remediation > 500 MVA likely required	Remediation > 500 MVA likely required

8.3.26 S3 – Mid-North SA

Summary

The Mid-North South Australia REZ has good wind and moderate solar resources. There are several major wind farms totalling 795 MW in service, including Hallett, Hornsdale, North Brown Hill, and Waterloo. The 100 MW/129 MWh Hornsdale battery storage is also located in this REZ.

Four 275 kV circuits pass through the REZ, and about 1,000 MW additional generation can be accommodated in these 275 kV circuits. However the network is configured, any generation north and west of this REZ contributes to this 1,000 MW limit, hence this forms part of the aggregate limit for South Australia which is an improvement in the methodology and applies to S3, S5, S6, S7, S8.

Mid North REZ has been identified as a Group 3 Transmission Augmentation Project.

The MLF is moderately robust to additional generation connections.

Renewable Resources

Resource	Solar			Wind		
Resource Quality	C			C		
Renewable Potential (MW)	600			4,600		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	C	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	There is no existing or committed solar generation in this REZ. The modelling outcomes, for all scenarios, did not project additional solar generation for this REZ				970	-	50	1,200
Step						1,200	1,200	1,200
High DER						-	50	1,200
Fast						100	600	1,200
Slow						-	-	50

Pumped Hydro

REZ is not considered to have potential for significant pumped hydro generation.

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	The present network is limited by the 275 kV lines which supply the Adelaide load centre and provide a transfer path to the Heywood interconnector and the future Project EnergyConnect interconnector.	1,000 MW		C

Upgrade 2	When the combination of generation in S3, S5, S6, S7, S8 and S9 >1000 MW the following upgrade is required: • Rebuild Davenport – Brinkworth – Templers West – Para 275 kV line as a high capacity double circuit line. Reconfigure the 132 kV network in the mid north region balance flows.	+1,100 MW	$265 to $475 million	-

Available Fault Level

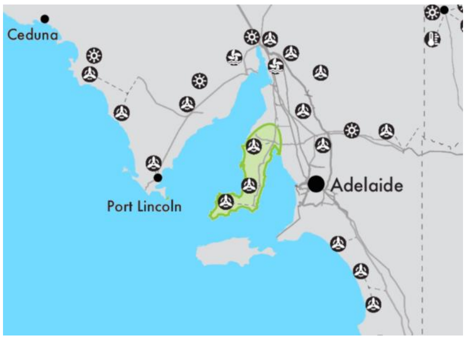
	< 2022	2022 to 2030	2030-35	Post 2035
Central	At limit	OK	OK	Remediation > 500 MVA likely required

8.3.27 S4 – Yorke Peninsula

Summary

The Yorke Peninsula REZ has good quality wind resources. The wind farms at Snowtown (99 MW and 270 MW) and Wattle Point (90 MW) are located within this REZ.

A single 132 kV line extends from Hummocks to Wattle Point (towards end of Yorke Peninsula). It can only support an additional 50 MW capacity of new generator connections before upgrading would be necessary.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	C			C		
Renewable Potential (MW)	-			1,400		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	C	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	There is no existing or committed solar generation in this REZ. The modelling outcomes, for all scenarios, did not project additional solar generation for this REZ.				460	-	-	300
Step						-	-	400
High DER						-	-	200
Fast						-	-	400
Slow						-	-	-

Pumped Hydro

This REZ is not considered to have potential for significant pumped hydro generation.

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	Presently the network capacity is limited by the single 132 kV circuit	0 MW	-	F
Upgrade Option 1	Increase capacity to Yorke Peninsula: • Build a double circuit 132 kV line from Blythe West into Yorke Peninsula (location would be dependent on wind connection interest) • Establish a 132 kV substation at Blythe West with 275/132 kV transformation	+400 to 450 MW	$70 to $130 million	-

Upgrade option 2	• Establish a 275 kV substation near connection interest in Yorke Peninsula • Build a single circuit 275 kV line from Blythe West into Yorke Peninsula (location would be dependent on wind connection interest)	+600 to 700 MW	$78 to $145 million	-

Available Fault Level

	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	At limit	At limit	OK	Remediation likely required

8.3.28 S5 – Northern SA

Summary

The Northern South Australia REZ has good wind and moderate solar resources. Bungala Solar (220 MW) and Lincoln Gap Wind (126 MW) are currently committed projects. Over 1,100 MW of new generation has been proposed, with a diverse mix of solar thermal, wind, solar PV, and pumped hydro

About 1,000 MW additional generation can be accommodated in this REZ. However, additional new generation in this zone is subject to new generation connection in the remaining REZs in the North South Australia region. This REZ is part of the South Australia group constraint involving S3, S5, S6, S7, S8 <1,000 MW.

The REZ is close to the major load centre at Adelaide and the MLFs are very robust.

Renewable Resources

Resource	Solar			Wind		
Resource Quality	B			C		
Renewable Potential (MW)	3000			200		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	C	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	220	The modelling outcomes, for all scenarios, did not project additional solar generation for this REZ.			126	The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ.		
Step								
High DER								
Fast								
Slow								

Pumped Hydro

This REZ has good hydro potential in terms of location and network opportunities. This is a candidate for some or all of the projected pumped hydro located in South Australia and could defer the size or timing of a network augmentation if located and sized appropriately.

Pumped Hydro (MW) for South Australia			
	Projected		
	2022-30	2030-35	> 2035
Central	-	-	700
Step	-	-	200
High DER	-	-	-
Fast	-	-	550
Slow	-	-	300

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	The current 275 kV network around Davenport and Cultana can accommodate approximately 1,000 MW	1,000[74]	-	B
Upgrade Option 1	• Uprate the existing Davenport–Cultana 275 kV line	+200 MW	$2.7 to $5 million	B
Upgrade Option 2	• A new double circuit Davenport–Cultana 275 kV line	+800 MW	$55 to-$100 million	-
Upgrade Option 3	Additional to the above augmentation when the combination of generation in S3, S5, S6, S7, S8 and S9 >1,000 MW the following upgrade is required: • Rebuild Davenport – Brinkworth – Templers West – Para 275 kV line as a high capacity double circuit line. Reconfigure the 132 kV network in the mid north region balance flows	+1,100 MW	$265 to $475 million	-
Available Fault Level				
	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	Remediation likely required	OK	OK	Remediation likely required

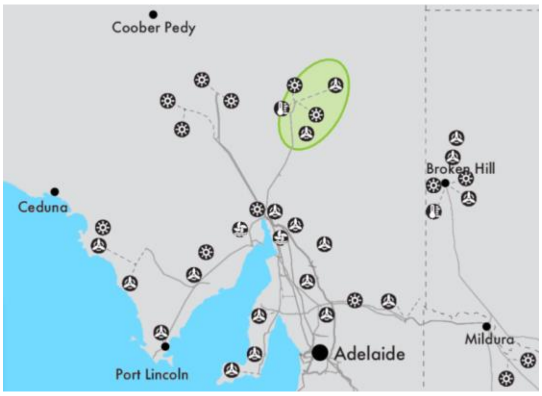
[74] This is part of the South Australia group constraint.

8.3.29 S6 – Leigh Creek

Summary

The Leigh Creek REZ is located a few hundred kilometres north of Davenport. It has excellent solar resources and good wind resources. There has also been high level discussion about the potential for geothermal in the REZ.

The REZ is currently supplied with a single 132 kV line that does not have any spare capacity. A possible augmentation could involve extending the 275 kV network from Davenport to this REZ. The MLF would still decline rapidly with new generation, due to the distance from any major load.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	A			B		
Renewable Potential (MW)	6,500			2,400		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	C	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	There is no existing or committed solar generation in this REZ. The modelling outcomes, for all scenarios, did not project additional solar generation for this REZ				There is no existing or committed wind generation in this REZ. The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ			
Step								
High DER								
Fast								
Slow								

Pumped Hydro

This REZ has good hydro potential in terms of location. This is a candidate for some, or all of the MW of Pumped Hydro located in South Australia, however it is not well placed to defer network augmentations.

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	Single circuit 132 kV line between Davenport and Leigh Creek	0	-	F
Upgrade 1	• Establish a 275 kV substation near connection interest • A new double circuit Davenport – Leigh Creek 275 kV line	+1,000 MW	$170 to $310 million	E

Upgrade 2	Additional to the above augmentation when the combination of generation in S3, S5, S6, S7, S8 and S9 >1000 MW the following upgrade is required: • Rebuild Davenport – Brinkworth – Templers West – Para 275 kV line as a high capacity double circuit line. Reconfigure the 132 kV network in the mid north region balance flows	+1,100 MW	$265 to $475 million	-
Available Fault Level				
	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	At limit	At limit	Remediation likely required	Remediation likely required

8.3.30 S7 – Roxby Downs

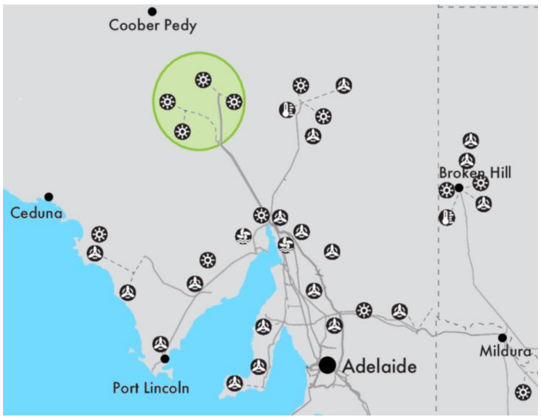
Summary

The Roxby Downs REZ is located a few hundred kilometres north-west of Davenport. It has excellent solar resources. The only significant load in the area is at the Olympic Dam.

This REZ is currently connected with a 132 kV line and privately owned 275 kV line from Davenport. ElectraNet is in the process extending the 275 kV system to develop a new 275 / 132 kV connection point at Mount Gunson South to service OZ Minerals' new and existing mines in the area.

The MLF in this area is likely to decline rapidly with new generation connections due to the distance from any major load.

This REZ is part of the South Australia group constraint.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	A			D		
Renewable Potential (MW)	3,400			-		
Demand Correlation	**2020**	**2030**	**2040**	**2020**	**2030**	**2040**
	F	F	F	C	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	**Projected**			**Existing / committed**	**Projected**		
	< 2022	**2022-30**	**2030-35**	**> 2035**	**< 2022**	**2022-30**	**2030-35**	**> 2035**
Central	-	100	960	960	There is no existing or committed wind generation in this REZ. The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ.			
Step		-	300	960				
High DER		-	960	960				
Fast		900	900	900				
Slow				960				

Pumped Hydro

This REZ is not considered to have potential for significant pumped hydro generation.

Network Capability

	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	The existing network together with a new 275 kV line between Davenport and Mount Gunson South, has a hosting capacity of 960 MW	960 MW	-	E
Upgrade1	• 275 kV substation at Roxby Downs	+1,000 MW	$210 to $387 million	E

	• 260 km double circuit 275 kV line from Davenport to Roxby Downs			
Upgrade 2	Following the above augmentation when the combination of generation in S3, S5, S6, S7, S8 and S9 >1000 MW the following upgrade is required: • Rebuild Davenport – Brinkworth – Templers West – Para 275 kV line as a high capacity double circuit line. Reconfigure the 132 kV network in the mid north region balance flows	+1,100 MW	$265 to $475 million	-

Available Fault Level

	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	At limit	At limit	Remediation > 500 MVA likely required	Remediation > 500 MVA likely required

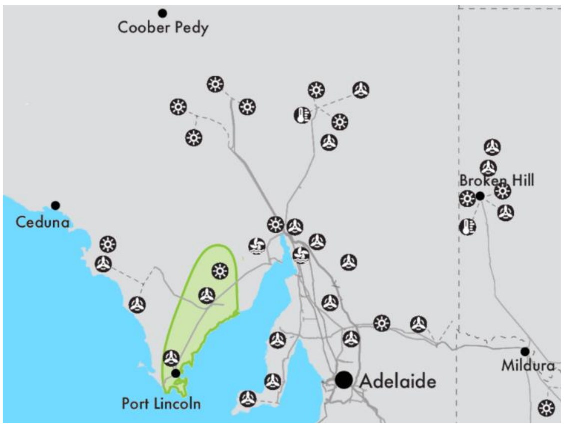
8.3.31 S8 – Eastern Eyre Peninsula

Summary

The Eastern Eyre Peninsula REZ has good wind resources. Wind farms in service include Cathedral Rocks (66 MW) and Mt Millar (70 MW) wind farms. ElectraNet has completed the Eyre Peninsula Electricity Supply RIT-T for transmission development to support this area. The AER has determined that the preferred option satisfies the requirements of the RIT-T.

The REZ is currently supplied by a single 132 kV line extending 250 km south of Cultana. The outcome of the Eyre Peninsula Electricity Supply RIT-T will see the replacement the existing Cultana–Yadnarie–Port Lincoln 132 kV single circuit line with a new double circuit line 132 kV line built at 275 kV.

The MLF is likely to decline rapidly with any additional generation. Even with upgrading the network halfway along the Peninsula to 275 kV and augmenting the remaining 132 kV lines, the MLF does not become much stronger.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	C			C		
Renewable Potential (MW)	5,000			2,300		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	C	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	There is no existing or committed solar generation in this REZ. The modelling outcomes, for all scenarios, did not project additional solar generation for this REZ				133	There is no existing or committed wind generation in this REZ. The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ		
Step								
High DER								
Fast								
Slow								

Pumped Hydro

This REZ is not considered to have potential for significant pumped hydro generation.

Network Capability

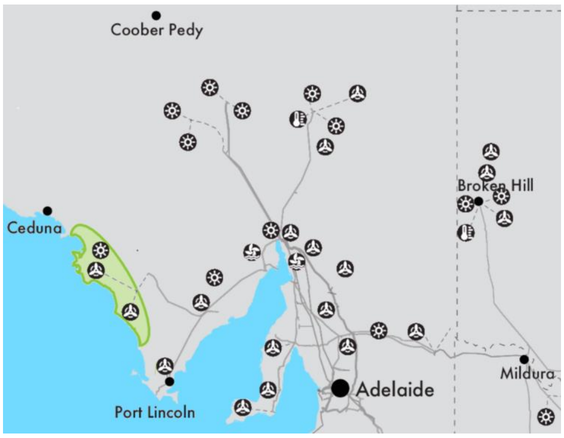
	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	This REZ is connected via 132 kV network from Cultana to Port Lincoln, including the committed rebuild of the 132 kV line from Cultana–Yadnarie–Port Lincoln as a double circuit line.	470 MW*	-	F

Upgrade	Upgrade the Cultana–Yadnarie 132 kV line to operate at 275 kV by: • Establishing a 275 kV substation at Yadnarie • 275/132 kV transformation	+300 MW	$30 to $55 million	D
* Includes network capacity gained from the committed Eyre Peninsula Electricity Supply RIT-T				
Available Fault Level				
	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	At limit	At limit	At limit	At limit

8.3.32 S9 – Western Eyre Peninsula

Summary

The Western Eyre Peninsula REZ shares the same supply as the Eastern Eyre Peninsula. It has good wind resources and moderate solar resources. There are currently no generators connected in the REZ.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	B			C		
Renewable Potential (MW)	4,000			1,500		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	C	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	There is no existing or committed PV generation in this REZ. The modelling outcomes, for all scenarios, did not project additional PV generation for this REZ.				There is no existing or committed wind generation in this REZ. The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ			
Step								
High DER								
Fast								
Slow								

This REZ is not considered to have potential for significant pumped hydro generation.

Network Capability

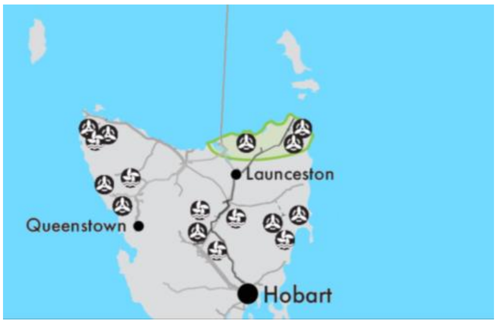
	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	This REZ is connected via the existing 132 kV network from Cultana to Port Lincoln.	0	-	F
Upgrade	Upgrade the Cultana–Yadnarie 132 kV line to operate at 275 kV by: • Establishing a 275 kV substation at Yadnarie	+300 to 500 MW*	$140 to $260 million	E

	• 275/132 kV transformation Build a double circuit 275 kV line from Yadnarie to Elliston.			
*Augmentation hosting capacity dependant on generation within Eastern Eyre Peninsula, additional augmentation may be required between Yadnarie and Cultana.				
Available Fault Level				
	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	At limit	At limit	At limit	At limit

8.3.33 T1 – North East Tasmania

Summary

The North East Tasmania REZ has one wind farm of 168 MW (Musselroe Wind Farm) in service. This REZ has been extended in the Draft 2020 ISP to encompass George Town. As more inverter based generators connect within this area, the fault level at George Town is likely to deteriorate. To ensure stable operation of Basslink HVDC interconnector, a sufficient three phase fault level needs to be maintained. In November 2019, AEMO declared a fault level shortfall for Tasmania, including George Town in this shortfall.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	D			B		
Renewable Potential (MW)	-			1,400		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	C	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	There is no existing or committed PV generation in this REZ. The modelling outcomes, for all scenarios, did not project additional PV generation for this REZ.				168	The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ.		
Step								
High DER								
Fast								
Slow								

Pumped Hydro

This REZ is not considered to have potential for significant pumped hydro generation.

Network Capability

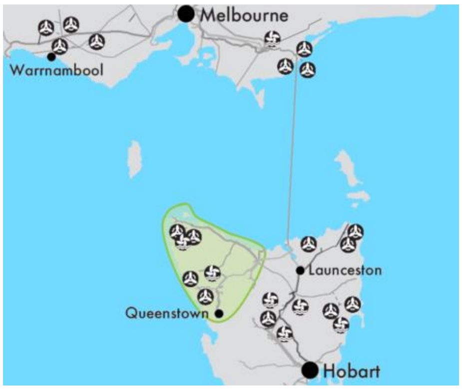
	Description	Approximate hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	Approximately 250 MW of hosting capacity still remains in and around the 220 kV network at Georgetown.	250 MW		F
Upgrade Option 1	Location of generation would drive the route and substation locations for the expansion of this zone: • A new substation towards the far North East of the zone (dependant on generation interest) • A new double circuit 220 kV line from George Town to the new substation	+800 MW	$95 to $180 million	-

Available Fault Level				
	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	OK	OK	Remediation > 500 MVA likely required	Remediation > 500 MVA likely required

8.3.34 T2 – North West Tasmania

Summary

With good wind resources, a significant portion of proposed new wind capacity in Tasmania is located within the North West. The North West REZ covers the North West and the West coast. It has also extended towards Sheffield since the 2018 ISP. The REZ has two load centres, one at Burnie and one at Sheffield. The North West Tasmania REZ is a favourable connection point for Marinus Link



Renewable Resources

Resource	Solar			Wind		
Resource Quality	E			A		
Renewable Potential (MW)	150			5,000		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	C	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central		-	-	-	252	There is no existing or committed wind generation in this REZ. The modelling outcomes, for all scenarios, did not project additional wind generation for this REZ.		
Step		-	-	200				
High DER		-	-	-				
Fast		-	-	-				
Slow		-	-	-				

Pumped Hydro

North West Tasmania REZ has high potential to host pumped hydro storage. Hydro Tasmania has announced the most promising sites for the development of pumped hydro. All three sites are located within the North West REZ, two connecting around Sheffield and the third around Farrel.

	Pumped Hydro (MW)		
	Projected		
	2022-30	2030-35	> 2035
Central	-	-	-
Step	-	200	450
High DER	-	-	50
Fast	-	-	-
Slow	-	-	-

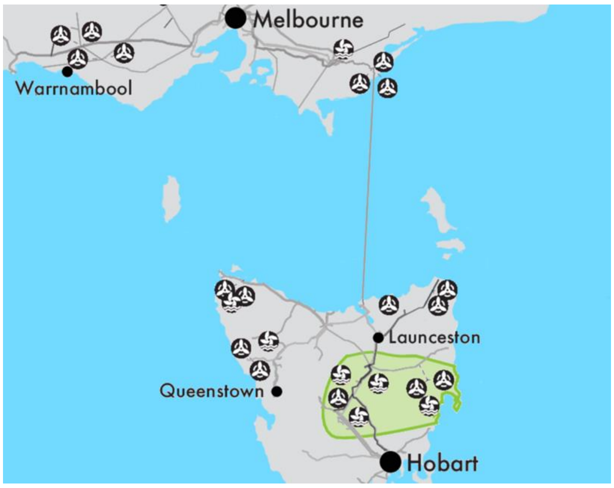
Network Capability				
	Description	**Approximate hosting capacity**	**Upgrade cost**	**Loss Factor Robustness**
Existing	There is currently no additional spare capacity available on the 110 kV circuits west of Burnie. There is still approximately 340 MW of spare capacity on the 220 kV network from Sheffield.	340 MW	-	E
Upgrade Option 1	To allow for connection in the North West Tasmania the circuit between Burnie and Hampshire will need to be upgraded: • A new double circuit Burnie-Sheffield 220 kV line	-	$56 to $105 million	
Upgrade Option 2	In addition to upgrade 1, the following upgrade can increase the capacity to connect renewables near Hampshire: • A new double circuit Burnie-Hampshire 220 kV line	+800 MW	$50 to $95 million	
Upgrade Option 3	In addition to upgrade 1, the following upgrade can increase the capacity to connect renewables in the far north west: • A new double circuit Burnie–West Montague 220 kV line or • A new double circuit Hampshire – West Montague 220 kV line	+800 MW	$105 to $190 million	

Available Fault Level				
	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	OK	At limit	At limit	Remediation > 500 MVA likely required

8.3.35 T3 – Tasmania Midlands

Summary

The Tasmania Midlands REZ has one of the best wind capacities within the NEM, and also has good pumped hydro resources. It is located close to major load centres at Hobart. The double circuit Palmerston–Waddamana–Liapootah and Waddamana–Lindisfarne 220 kV line pass through this REZ. Cattle Hill wind farm (144 MW) is the only committed variable generation within this zone. Additional to transmission network limitations within Tasmania, as more generation connects, export to the mainland becomes a limiting factor.



Renewable Resources

Resource	Solar			Wind		
Resource Quality	E			A		
Renewable Potential (MW)	-			3,400		
Demand Correlation	2020	2030	2040	2020	2030	2040
	F	F	F	C	C	C

Variable Renewable Energy Outlook

	Solar PV (MW)				Wind (MW)			
	Existing / committed	Projected			Existing / committed	Projected		
	< 2022	2022-30	2030-35	> 2035	< 2022	2022-30	2030-35	> 2035
Central	There is no existing or committed PV generation in this REZ. The modelling outcomes, for all scenarios, did not project additional PV generation for this REZ.				144	50	300	900
Step						2,100	2,500	2,700
High DER						0	300	900
Fast						600	600	900
Slow						-	-	-

Pumped Hydro

The Tasmania Midlands REZ has potential to host pumped hydro storage. Hydro Tasmania has not included any pumped hydro options in the Midlands REZ in its latest review of promising pumped hydro sites.

Network Capability

	Description	Hosting capacity	Upgrade cost	Loss Factor Robustness
Existing	The existing 220 kV network which extends from Palmerston to Waddamana to Liapootah and from	~480 MW	-	E

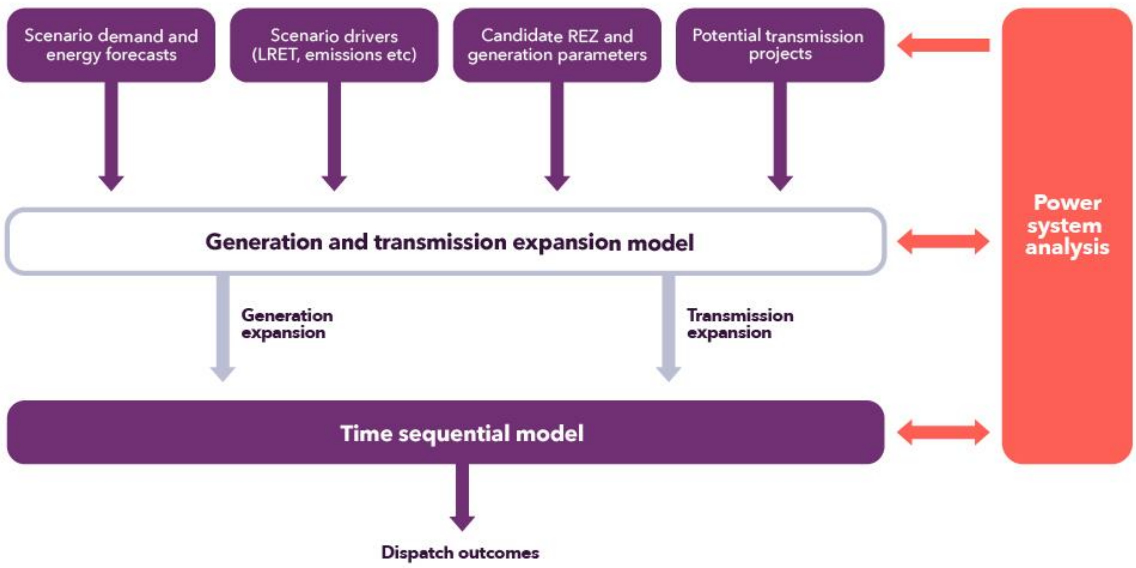
	Waddamana to Lindisfarne has a hosting capacity of approximately 480 MW.			
Upgrade Option 1	To increase capacity within the Tasmania Midlands REZ the following is proposed: • A new double circuit Palmerston – Sheffield 220 kV line • A new double circuit Palmerston – Waddamana 220 kV line	~800 MW	$140M - $260M	
Upgrade Option 2	The development of Marinus Link (Group 3 Project) will increase the hosting capacity within this REZ: • A 750 MW HVDC interconnector using voltage source • area with a converter technology and monopole configuration. Converter stations are proposed to be located in the Burnie area in Tasmania and the Hazelwood area in Victoria. • A new 220 kV switching station in the Burnie area adjacent to the converter station; • A new double circuit Burnie–Sheffield double-circuit 220 kV line and the decommissioning of the existing 220 kV single-circuit transmission line in this corridor; • A new double-circuit Palmerston–Sheffield 220 kV line and the decommissioning of the existing 220 kV single-circuit transmission line in this corridor; • 500 kV connection asset for connection of converter station in Hazelwood 500 kV connection to Hazelwood 500 kV terminal station.	~560 MW	Part of Marinus Link	
Available Fault Level				
	< 2022	**2022 to 2030**	**2030-35**	**Post 2035**
Central	OK	At limit	Remediation > 500 MVA likely required	Remediation > 500 MVA likely required

Appendix 9. ISP methodologies

Modelling the increasingly complex energy ecosystem requires new, innovative techniques. This required AEMO to adopt a multi-staged modelling approach, with each stage helping to build a more complete analysis of the strengths and weaknesses of various future grid development options. The approach used in this 2020 Draft ISP builds on the 2018 ISP modelling approach using similar tools, and continues to combine economic modelling and power system engineering to ensure the ISP objectives are achieved.

Figure 189 below summarises this integrated approach.

Figure 187 Multi-phase integrated modelling approach



This Appendix provides an overview of the methodologies used. AEMO has published detailed information on the demand forecasting and market methodology separately[75].

9.1 ISP economic modelling approach

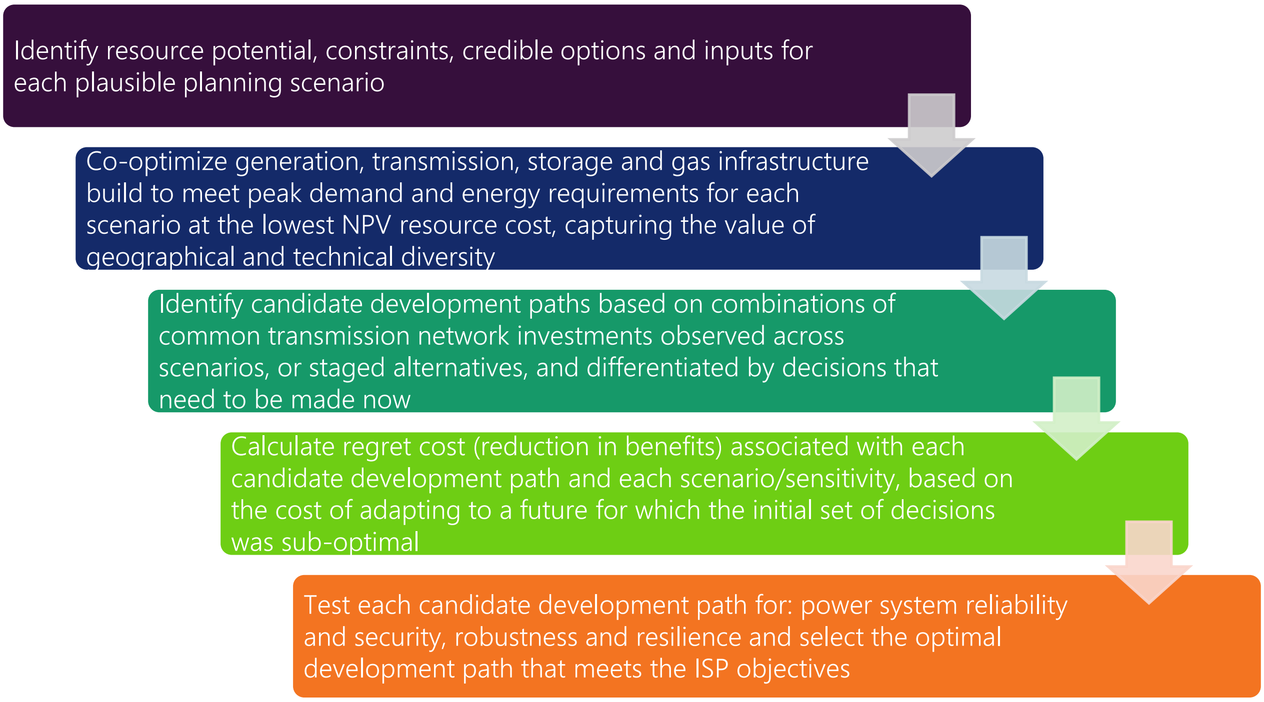
Energy Exemplar's PLEXOS Integrated Energy Model is the key software platform utilised by AEMO to conduct economic modelling for this ISP (the ISP Model).

The ISP Model sought to find the optimal mix of gas and electricity infrastructure investment and operation which meets the future power system needs at lowest cost for consumers across the NEM. The initial analysis focused on identifying the optimal solution for each scenario and progressively moved to finding the overall

[75] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

plan which delivered market benefits to consumers based on best information available, while also maintaining flexibility to adapt as new information comes to hand.

Figure 188 Summary of modelling approach – the ISP Model



The modelling approach required extensive computation as it considered a broad set of investment choices in generation, transmission, and storage across regions and zones through the plan timeframe.

The ISP Model considered:

- Availability of gas reserves, resources, and pipeline capacities – these influence the cost and availability of gas and consequently the viability of future GPG to supply electricity consumption in volume.
- Maximum renewable energy potential and constraints in each region – the quality of the renewable resource, potential quality degradation as more generation is co-located, existing spare transmission capacity, and cost to augment the existing capacity all influence the value of a given location and REZ. Where new interconnector routes pass by REZs and effectively encompass the intra-regional transmission augmentation required to access the REZ generation, this value was captured by removing any REZ transmission congestion.
- Diurnal and seasonal weather patterns by REZ – the hour-by-hour profile of expected output for each renewable generation technology is related to the REZ in which it is located. AEMO used historical weather observations to capture observed solar and wind variability at each REZ, to take account of diversity as an important input to the overall optimisation.
- Minimum synchronous generation constraints – where synchronous generation is required to maintain power system security, constraints have been imposed on the modelling. In turn, these constraints are removed in instances where new interconnector options would alleviate these power system security concerns.
- Levels of DER co-ordination – utilising these resources to meet system needs, rather than operating passively, can make the overall system more efficient, flexible, and affordable. The volume of DER and level of DER co-ordination (in the form of VPP) was an input assumption that was varied for each scenario.

The first step of the ISP Model was to find the combination of investments for each scenario that delivers reliable and secure electricity supply at the least cost to consumers. This combination reflects input assumptions and the broad set of investment choices in generation, transmission, and storage identified across regions and zones. AEMO has completed over 1,000 long term expansion models (DLT and IM) to identify the best development paths, across 5 scenarios and multiple sensitivities.

Certain interconnection options and combinations of options were consistently seen to be part of the least-cost solution as each scenario was modelled. Importantly, some interconnector developments were selected by the model under all scenarios, with immediate effect. These interconnector investment decisions common to all scenarios formed the basis for developing a number of "candidate development paths". All the candidate development paths included both headline interconnection upgrades between NEM regions and a range of smaller upgrades within regions to relieve constraints and support the integration of new generation.

For each candidate development path, and each scenario, the future generation mix was re-evaluated in detailed long-term modelling, assuming that generation and storage investment decisions would be influenced by future grid expansion. The resulting net present value (NPV) of resource costs was used to compare between candidate plans to develop the lowest cost pathway for each scenario.

The final step in the ISP Model was hourly modelling of snapshot years, using detailed transmission constraint sets, and considering unit commitment and bidding behaviour. This step was undertaken to verify whether the candidate development paths met the reliability and system security requirements (see Appendix 3)

The robustness and option value of each candidate development path were tested using regret analysis, discussed below.

Cost benefit analysis

Thoughtful development of the transmission network has the potential to deliver cost savings to end consumers by improving efficiency of the existing generation fleet, deferring or reducing the need for new generation and storage investment and reducing the cost of accessing renewable energy resources.

To assess this value in each scenario, the investment and production costs for each candidate plan were compared on an NPV[76] basis against a case with no additional inter-regional transmission developments. In this counterfactual, no new interconnector transmission development is required, although additional transmission is still needed within regions to connect new renewable generation and/or storage. Without intra-regional transmission investment to connect new local generation to load centres, the analysis projects there would be insufficient energy accessible to replace the retiring coal fleet.

Key market benefits considered when comparing the candidate development pathway against the counterfactual include:

- Capital deferral benefits (transmission and generation).
- Productive efficiency gains through fuel and operating cost savings.

Details of the market benefits projected for the optimal development pathway under each scenario are reported in Appendix 5.2.

Least worst regret analysis

Finding the least-cost development path in each scenario is only a first step, because we do not know which scenario will eventuate. Some decisions will be beneficial to energy users in some scenarios and costly in others. We need to find the 'least regret' set of actions that will still deliver the expected benefits to consumers. Put another way, of all the worst-cost outcomes that could arise if the environment shifts from one scenario to another, we are looking for the least worst-cost outcome of all.

[76] The discount rate used to calculate the NPV of costs and benefits was 5.9% (in real terms), except for in the Slow Change scenario which used a discount rate of 7.9% (in real terms).

The process for determining this is repeated for all scenarios:

- Identify the set of investment decisions (D1) that should would be made now with perfect foresight to ensure that the assets are operational when needed in the first scenario. AEMO's modelling suite (see Box 2) would calculate the total system costs of that decision (C1).
- If those investment decisions are made but a different scenario unfolds, further investment decisions would be needed to adapt. The modelling would then optimise the adapted plan and recalculate the total system costs (C2).
- The 'regret cost' of the original investment in the second scenario is then the loss of total system benefits (R1=C1-C2).
- Repeating steps 2 and 3 across all scenarios and sensitivities gives you a range of regret costs (R1….Rn), revealing W1 as the worst of the possible regret costs for the investment set D1.
- AEMO's modelling suite repeats this process concurrently for each combination of scenarios and sensitivities, identifying the range of worst regret costs for all initial investment sets (W1……Wn).
- The set of decisions with the least worst regret cost in the range (W1 …. Wn) become part of the optimal development pathway.

The optimal development pathway represents the most efficient plan that would transition the electricity industry to reliable and secure future, taking into account policy settings, at lowest cost to consumers. This combination of credible transmission, generation, storage and DER options:

- Meets power system needs for reliability and security,
- Achieves positive net market benefits under the Central scenario, and
- Minimises regrets across all scenarios and sensitivities.

Additional unquantified benefits

The modelling undertaken for the ISP focused on minimising the total resource costs. This provides a conservative estimate of the potential benefits of the identified network investment. In addition to lowering the total resource cost, increasing the transfer capacity of the network could also provide:

- Greater operational flexibility to deal with plant outages and weather events. The ISP modelling process only optimised outcomes under 'system normal' conditions.
- A level of resilience against climate change and extreme events (or sudden shocks, such as unplanned coal closures) which can impose high costs on consumers and society.
- More choice and competition.
- Scalability, providing the option to extend or increase capacity over time as the future becomes more certain and the industry transforms.
- Lower costs for ancillary services (services the power system needs to operate securely, such as frequency control services).

It is also important to recognise that the modelling considered resource costs, not prices to consumers. An informed and efficient competitive market should see the lower resource costs reflected in lower consumer prices. Increased transfer capacity of the system and a reduction in congestion, or the risk of congestion, should also increase competition, reduce the cost impact of network outages, and result in more efficient pricing.

Consideration has been given to the resilience of the system, and a checklist of additional value from the various alternatives under consideration has been qualitatively assessed.

9.2 Hydrogen as a new potential resource in the energy mix

While much research has been carried out on the potential uses of hydrogen within the broader global energy landscape, and work has been done in Australia both at state and federal level to initiate discussions on this topic, policy and direction are at this time still unclear. Relevant recent work includes:

- The National Hydrogen Roadmap[77] by CSIRO.
- The Future of Hydrogen report[78] by the IEA.
- Gas Vision 2050 by Energy Networks Australia and the Australian Pipelines and Gas Association[79].
- More particularly, the recent release (during preparation of this Draft ISP) of the National Hydrogen Strategy, led by Alan Finkel[80].

The National Hydrogen Strategy provides a summary of the state plans, and a medium to long-term vision for the use of hydrogen across the Australian economy. The strategy lays out an adaptive pathway for the hydrogen industry, identifying early 'no-regret' actions that can be taken now, and other actions that can be planned for possible future implementation. It also makes a series of recommendations for consideration by all Australian governments. These have not yet been acted upon with policy and are under active review.

As policy is still being developed, and the industry is only at the early stages of research and development with a very broad range of potential outcomes, this Draft ISP was not able to incorporate quantitative analysis of the potential use of hydrogen within the Australian energy system.

Aspects of the ISP modelling that may change in a future where hydrogen is widely used (subject to cost competitiveness) include:

- Transport – the trade-off between conventional petrol/diesel/gas vehicles, EVs and hydrogen fuel-cell vehicles will impact the use of electricity for EV charging.
- Power system security – flexible power generation via GTs to provide the ability to recover from contingency events, and to maintain system within required operability specifications.
- Power system reliability – large-scale storage of hydrogen could provide firm dispatchable capacity via GT or CCGT technology, initially as a blend in existing natural gas systems, and later as 100% hydrogen, as technology develops further. This could be done over intra-day or seasonal timeframes, depending on the scale of storage available, and could become an alternative to pumped hydro. Demand response using electrolysers could also contribute to reliability.
- Domestic Heating – hydrogen from renewables could be blended into natural gas distribution pipelines to offset emissions, at low concentrations, which will impact on gas usage profiles.
- Industrial heating – there will be a trade-off between use of natural gas/electricity and hydrogen (potentially blended with natural gas) for industrial heating loads.
- Emissions – the scale and rate of take-up of hydrogen-related technology and energy paths will affect the predicted emissions profiles for the country in future years, and is likely to be closely linked to changes in governmental emissions policies.
- Energy export – The international market for low-emission energy may drive a demand for export of hydrogen or related derivatives (such as ammonia). Depending on the relative locations of the generation and export facilities, and the pathways used to transfer energy between the two, there may be changing demands on the electricity or gas grids.

[77] Bruce S, Temminghoff M, Hayward J, Schmidt E, Munnings C, Palfreyman D, Hartley P. 2018. National Hydrogen Roadmap. CSIRO, Australia.

[78] International Energy Agency. 2019. The Future of Hydrogen.

[79] ENA/APGA. 2019. Gas Vision 2050.

[80] Commonwealth of Australia. 2019. Australia's National Hydrogen Strategy. COAG Energy Council.

9.3 Renewable energy zone methodologies

AEMO considered a range of requirements for the selection of REZs. This section presents the methodology applied to determine resource quality, potential wind and solar generation capacity, transmission investment to develop REZs, projected network losses, and diversity of renewable generation within the region and across REZs.

9.3.1 Resource quality

In 2017, AEMO engaged consultants DNV-GL to provide information on the resource quality for potential REZs. Wind resource quality assessment was based on mesoscale wind flow modelling at a height of 150 m above ground level (typical wind turbine height), while Global Horizontal Irradiance (GHI) and Direct Normal Irradiance (DNI) data from the Bureau of Meteorology (BOM) were used to assess solar resource quality.

AEMO identified wind speeds and solar GHI values inside each of the REZs. This data was used to determine grading of resource quality. For wind generators, the 10% Probability of Exceedance (POE) resource was taken to determine the relative REZ quality, since 50% POE (median) values did not produce enough differentiation between all the different regions. For solar, 50% POE values of GHI were taken to determine the grade. The 50% POE GHI values produced sufficient variation between all the REZs to give a meaningful relative grade for solar generation.

9.3.2 Network capacity and transmission investment

AEMO undertook high level network studies to identify additional generation that can be accommodated within the existing network and that may be enabled by interconnectors developed near or through REZs.

AEMO then developed a cost estimate of the transmission network expansion required to connect REZs and converted this estimate to a cost per megawatt for each REZ.

The cost per megawatt for each REZ was then applied within the ISP market modelling, within the IM and DLT models, as a simple linear cost for development of REZs beyond existing transmission connection capabilities. In this way, each REZ may provide 'free' connection capacity up to existing assumed transmission capabilities. The market model can then expand intra-regional connections to improve transmission access to REZs if the cost of that access is outweighed by the benefits associated with the increased renewable generation that it enables.

9.3.3 Projected network losses

Projected network losses were determined based on the methodology described in AEMO's Forward-Looking Transmission Loss Factors[81]. In particular:

- A complete year of historical data has been used as a reference.
- Generators representing the REZ were added at connection points.
- Future wind and solar generation and load traces, which were developed PLEXOS® market simulations, were applied.
- Marginal loss factors (MLFs) were calculated for those connection points representing the REZ.

A grading method was used to categorise the average value of current MLF at connection points inside REZs (initial loss factor) and sensitivity of MLFs to additional generation inside REZs (Loss factor robustness). The measure used is the additional generation (MW) that can be added before the MLF drops by 0.05. The following table presents grading applied to differentiate REZs based on loss factors.

[81] AEMO. Methodology for Calculating Forward-Looking Transmission Loss Factors, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries.

9.4 Network augmentation methodologies

AEMO considered various augmentation options to increase inter-regional and intra-regional transfer capability to support projected demand from different generation planting scenarios. This included increasing capability of the existing networks, new transmission lines and alternative technologies. Non-network options are detailed in Section 9.5. This section describes the different technologies and factors AEMO considered when choosing inter-regional and intra-regional network augmentation options.

9.4.1 Increasing transfer capability of existing transmission asset

The capability of an existing transmission network can be increased by:

- Switching reconfiguration to balance or reduce the overloaded element.
- Application of real-time ratings for transmission lines.
- Control schemes to reduce generation and load immediately following a contingency.
- Uprating of transmission lines.
- Adding transformers.
- Adding reactive plant.

Switching reconfiguration

Depending on the load and generation pattern, potentially some transmission lines or transformers could become overloaded at certain periods. During that period, switching reconfiguration could reduce potential overload and thus assist to increase transmission capability.

Real-time ratings

The variables that affect transmission line thermal capability most are ambient temperature, wind speed, wind direction, and solar radiation. Static line ratings can be adjusted for real-time ambient variables rather than for seasonal maximum ratings. Real-time ratings are typically higher than static ratings under favourable ambient conditions.

Line monitors and weather measurement devices to measure ambient temperature and wind speed can be used to determine rating of the line in real time. Cost estimates to implement real-time ratings are less expensive and Network Service Providers are best placed to identify the location of real-time measurements and integrate the measurements into their rating calculation.

Control schemes

The transmission network is planned to operate within the thermal capacity of transmission lines, transformers, and other plant. The current carrying capacity of transmission plant is generally defined in terms of a maximum temperature that the equipment can sustain without plant damage or in the case of transmission lines, the necessary critical clearances to the ground being maintained.

A sudden loading increase will not increase the transmission line temperature instantaneously, but the temperature will increase exponentially, with a time constant generally less than 15 minutes due to the low mass of metal involved. In such cases, it is possible to provide special control schemes to take advantage of the thermal inertia of transmission plant in order to load them beyond their continuous rating for a short time. Facilities must be in place to remove the overload and operate the plant within its continuous rating within a given short time.

Line uprating

Transmission lines may be thermally limited by primary plant connection at the substation or secondary equipment of the line than the line itself. In such cases, the circuit rating can be increased by replacement of connection plant and switch gears. Changing the settings of secondary plant, such as metering and protection, or replacement of these plant, can increase circuit ratings. These are normally less expensive than uprating the line.

In the case of conductor uprating, the main approaches include:

- Increase maximum allowable conductor temperature.
- Re-conductor the line on the existing towers.

Increase maximum allowable conductor temperature

This involves increasing the ground clearance to allow operation of the line up to or within the conductor maximum temperature. Ground clearance can be increased by re-tensioning the conductors, moving suspension clamps higher, increasing the overall height of the tower, adding new structures in long spans, or land profiling.

Re-conductor

This involves replacement of existing conductors with higher rating conductors. This uprating would require a review and possible replacement or reinforcement of existing structures. Replacement of the original line conductor with high temperature low sag (HTLS), would allow substantial increase in the line rating by increasing the maximum allowable conductor temperature without changing the structure or requiring physical structure modifications to increase ground clearances.

Power transformers

Transformers are used where different operating voltages need to interface. As well as transforming the voltage, they also introduce impedance between the systems, controlling fault currents to safe levels. Additional power transformers are needed to increase the transfer capability from one voltage level to another voltage level.

Power transformers can be specified with on load tap changers (OLTC). These types of transformers can regulate the secondary side voltage as per operational staff instructions or by an automatic control system.

Reactive power plant

Reactive power plant in an AC power system is necessary to balance the reactive power and operate the system within the voltage and stability limits. There are two main types of reactive plant.

Static reactive power plant.

Dynamic reactive power plant.

Static reactive power plant

Shunt reactors

At times of light load, network can experience high voltages due to excess capacitive reactive power. Also, HVAC cables have a high capacitance and shunt reactors are used to regulate voltages. Shunt reactors used to compensate for the capacitive reactive power is ac transmission networks, regulating network voltage. Shunt reactors can be permanently or with a dedicated circuit breaker connected to line or at a substation. The circuit breaker connection will provide an operational flexibility to switch on or off the shunt reactor and, thus efficient control of network voltages.

Shunt capacitors

Shunt capacitors provide reactive power to ensure the voltage remains within operational limits. They can be connected permanently or with a dedicated circuit breaker to the network. The circuit breaker connection will provide an operational flexibility to switch on or off the shunt capacitor and, thus efficient control of network voltages.

Static capacitor banks are used for steady state voltage control and can be part of a substation voltage control scheme, coordinated with other voltage control devices such as transformer tap-changer control and shunt reactors. A shunt capacitor bank can increase transfer capability and reduce real power losses. The reactive power delivered by the shunt capacitor is proportional to the square of the terminal voltage and, hence during low voltage conditions reactive power support from shunt capacitor drops.

Dynamic reactive power plant

Static Var Compensator (SVC)

An SVC is a power electronic application with shunt connected capacitor and reactor whose output is adjusted to exchange reactive power with the network to maintain or control network voltages continuously.

An SVC will typically regulate and control the voltage to the required set point under normal steady state and contingency conditions and thereby provide dynamic, fast response reactive power following system contingencies. In addition, an SVC can also increase transfer capability, mitigate active power oscillations and prevent over voltages at loss of load.

It typically includes:

- Thyristor controlled reactor.
- Thyristor switched capacitor.
- Harmonic filter.
- Mechanically switched capacitor bank or reactor bank.

At the limit of minimum or maximum susceptance, a SVC behaves like a fixed capacitor or an inductor. When a SVC operates as shunt capacitor, its output reduces with low voltages.

STATCOM

A STATCOM is a voltage-source converter-based device, which converts a DC input voltage into an AC output voltage to compensate the active and reactive needs of the system. It is a fast-acting device which can produce or consume reactive power more quickly than an SVC.

A STATCOM has better characteristics than an SVC. When the system voltage drops sufficiently to force the STATCOM output to its ceiling, its maximum reactive power output will not be affected by the voltage magnitude.

STATCOMs are more suitable on weak networks, as the reactive compensation capability of SVCs reduces more significantly than STATCOMs below nominal voltage ratings. STATCOMs with reduced ratings can be integrated with fixed reactors and capacitor banks to provide a lower cost solution than a fully rated STATCOM alone.

Synchronous condensers

A synchronous condenser operates in a similar way to large synchronous generators or motors. It contains a synchronous motor whose shaft is not directly connected to anything but spins freely and is able to adjust technical conditions on the power system. Synchronous condensers are source of system strength, reactive power and inertia. Additional fly wheels can be added to the synchronous condenser to increase the inertia.

It can control network voltages continuously.

Series capacitors

Series compensation (SC) is typically used in long transmission lines where increased power flow, increased system stability or power oscillation damping is required. The maximum active power that can be transferred over a power line is inversely proportional to the series reactance of the line. Series compensation reduces reactance of a transmission line. Hence by compensating the series reactance using a series capacitor, higher active power transfer is achieved. Since the output of series capacitor is proportional to the line current, it will partly balance the voltage drop caused by the reactance of the line. Series capacitors also improve load sharing between parallel lines.

Amount of series compensation (or percentage of series compensation relative to line reactance) is influenced by any interference of sub synchronous resonance (SSR). There are two main types of series compensation:

- Fixed series capacitors.
- Thyristor controlled series capacitors.

Thyristor controlled series capacitors can smooth control of power flow and enhance mitigation of SSR.

9.4.2 Transmission line technologies

There are two distinct types of transmission technology that are currently in use to transfer electricity in the power system.

- High voltage alternating current (HVAC) transmission.
- High voltage direct current (HVDC) transmission.

HVAC transmission

The electrical power system is based on alternating current (AC) generation, transmission, and distribution because it has historically represented the most economical way of delivering power to consumers. The economic benefits are largely due to the use of transformers to match the efficiency of high voltage transmission with the convenience and safety of low voltage generation and demand.

In general, AC networks can be extended by adding more circuits or tied together with circuits of sufficiently large capacity. In principle, there is no limit to the geographical extent of an AC network if generation and demand are evenly distributed throughout the network.

An advantage of using AC transmission technology for inter-regional connections and network expansion to remote areas is the ability to accommodate new generation along the route with relatively low cost.

However, long distance AC transmission lines require reactive power compensation to avoid stability problems. The addition of renewable generation or storage, which are mostly variable and inverter-based technologies, along the AC transmission line could require system strength support. Any additional synchronous condensers or alternative technologies which provide system strength along the route would likely reduce the need for additional reactive power compensation.

HVDC transmission

High Voltage Direct Current (HVDC) technology transmits power by first converting it from AC to DC at the rectifier converter station, transmitting DC power through overhead lines or cables to the inverter station, and then converting back to AC. The high cost of these AC/DC converters currently limits the opportunities for widespread application of HVDC technology in the ISP's development plans, due to the need to for multiple stations to connect VRE. However, there are some specific purposes where HVDC could be used, including:

- Long distance point to point overhead transmission where HVDC schemes can operate stably over long distances without the need for expensive reactive power compensation (as required by AC transmission). In addition, HVDC transmission lines require fewer conductors and have fewer losses than AC transmission lines of similar voltage and power ratings.
- Long underground or submarine cable connections (for example, the proposed new cables for Marinus Link).
- Joining power systems of different frequencies (for example, 50 Hz and 60 Hz).
- Augmenting the AC network without increasing fault current levels.

There are two HVDC converter technologies available in the market:

- Line commutated converters (LCC).
- Voltage source converters (VSC).

Line commutated converters (LCC)

LCC technology, commonly known as HVDC Classic, has been in operation for over 50 years. This technology has been employed to transfer power over long distance overhead transmission lines or submarine interconnectors.

LCC uses thyristor-based technology with controllable turn-on capability at the converter stations. The thyristors are triggered to switch on with a gate pulse and remain in that condition until the next zero current crossing. LCC achieves its control by regulating firing angles at converter stations. The current direction does not change, and power reversal from one station to another is carried out by a change of polarity of voltage at both converter stations. For LCC operation, the converters require strong AC systems and rely on network voltage for commutation.

LCC technology can be used to transfer large amounts of power. Basslink, the HVDC interconnector between Victoria and Tasmania, uses LCC technology.

Voltage source converters (VSC)

HVDC VSC technology is a newer technology made possible by the development of high-power electronic switches such as insulated-gate bipolar transistors (IGBT). Rather than relying on the network voltage for commutation, the IGBTs are switched on and off under the direction of a control system to develop an AC and DC voltage waveform. The polarity of voltage does not change and current direction changes to change power direction from one station to another. It can operate under weaker AC systems and it has greater operational flexibility, independent active and reactive power control and black start functionality.

The Murraylink HVDC connection between Victoria and South Australia, and the Directlink HVDC connection between New South Wales and Queensland, use VSC technology.

LCC technology can transfer higher amounts of power than VSC technology. Research is ongoing into the use of VSC to transfer higher amounts of power.[82]

New transmission line development

Several factors need to be considered to when developing a plan for new transmission. For high level planning studies, these include route selection, transmission technology selection, transmission voltage selection, choice of single or double circuits, transmission losses, staging of transmission development, and costs.

Route selection

There are number of factors to be considered on route selection of new transmission lines. These include route diversity, facilitating the connection of generation along the route, and sensitive areas to avoid, and a range of local community and planning considerations.

Route diversity

Some transmission line sections may run through areas that are associated with low probability risks that could have a high impact on the reliability of the transmission scheme. For example, if the line runs through an area that is prone to bush fires then two lines in the same route would be less reliable than each line on diverse routes. A route diversity from the existing interconnectors would harden the grid against extreme climate conditions. However, route diversity will increase the cost of the transmission scheme.

[82] IEEE Power and Energy Magazine – May/June 2019. Current Trends in dc – Voltage Source Converters, at https://ieeexplore.ieee.org/document/8694095/.

Facilitating the connection of other generation

There may be significant overall economic benefits in selecting a transmission route that runs through areas that have potential for future generation development (or demand development). The time and cost associated with consenting and building a long transmission line tend to inhibit remote generation development. Consequently, the additional cost of a longer route that enables other generation may help to make the transmission scheme commercially more viable and more justifiable in the consenting process.

Given that a number of REZs were identified across the NEM, an interconnector route through REZs would open up connection of renewable generation/storage in these REZs.

Urban and ecologically or culturally sensitive areas

There are generally objections to routing transmission lines through or near existing urban areas or ecologically sensitive or culturally sensitive areas. Sensitive areas would include:

- Protected areas.
- Scenic areas associated with tourism.
- Heritage sites.
- Lakes and shoreline.

Avoiding these areas could significantly increase the length of the transmission line, which would increase costs due to:

- Additional towers and conductor.
- Additional easement length.
- Additional losses.
- Additional reactive compensation for AC transmission.

Conductor resistive (I^2R) Losses

Transmission line losses are usually dominated by conductor I^2R losses. Adding more conductors reduces the resistance and losses by an inverse factor whilst increasing voltage reduces current and losses by an inverse squared factor. Consequently, as the transmission distance increases, it becomes more economic to select a higher voltage to minimize losses.

Increasing the operating voltage increases the cost of the towers due to the increased air clearance required to withstand over-voltages.

Typical I^2R losses for an AC or HVDC transmission scheme of 1,000 km are about 4% - 8% at rated load.

High temperature low sag (HTLS) conductors

In recent years, a new type of bare overhead conductor known as Aluminium Conductor Composite Core (ACCC) became available in the market. It is a type of high-temperature low-sag (HTLS) overhead line conductor. While the ACCC Conductor is capable of carrying twice the current of conventional steel reinforced conductors, its lighter weight core allows the use of approximately 30 percent more conductive aluminium which serves to reduce line losses. The added aluminium content serves to reduce electrical resistance – under any load condition – and the reduced thermal sag allows it to carry more current without violating sag limits[83].

Staging transmission capacity

If the REZ generation is being implemented in stages or inter-regional transfer capacity needed in stages, then it may be economic to stage the transmission capacity to match the generation or import/export levels.

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[83] CTC Global. https://www.ctcglobal.com/

This may have cost benefits if there are several years between the implementation of generation or interconnector stages, or if there is uncertainty regarding the ultimate development of the remote generation.

AC transmission schemes can be staged by:

1. Constructing the line for operation at high voltage (say 500 kV) but initially operating at a lower voltage (say 330 kV) to match the voltage of the connection point in the shared network. This allows the cost of the 500/330 kV transformers to be deferred. Ultimate operation at 500 kV will provide lower losses and higher transmission capacity.
2. Initially stringing a double circuit line with only one circuit can lower the initial capital cost by about 25%. The overall line capacity can be doubled by later stringing the second circuit at a deferred cost.

HVDC transmission schemes can also be staged by :

1. Constructing an HVDC bipole line but initially operating as a monopole allows the cost of the second stage converters to be deferred, and initial losses can be halved by paralleling the conductors. Alternatively, the cost of the second pole conductor can be deferred.
2. Converters can be added in either parallel or series with the original converters allowing either current or voltage upgrades. The design of the transmission line will need to allow for these upgrades.

9.4.3 Alternative network technologies

Power flow controllers

Power flow on individual AC transmission lines is usually not directly controlled. When power flows from one point to another along parallel flow paths, the amount of power on an individual line is a function of its fixed impedance. This can lead to the power being unevenly shared between the lines. Inter-regional transfer capability can thus be limited because one line on the flow path is at its limit while another is under-utilised.

To increase transfer capability, power flow controllers can be used to shift power from an over-utilised line to under-utilised lines. Power flow controllers are an alternative option to building additional transmission lines. Two different power flow controller technologies are described in the following sections.

Phase shift transformer

Phase shift transformers are a mature technology normally connected in series with a transmission line. They create a phase shift in the voltage angle between the primary and secondary side of the transformer. Power flow is proportional to the sine of the voltage angle difference across the transformer. Power flow can thus be controlled through the phase shift transformer and the line connected in series with the phase shift transformer.

Modular power flow controller

A modular power flow controller is a power electronics-based device that is installed in series with a transmission line. It controls power flow along the line by modifying the apparent series impedance of the line by injecting a series sinusoidal voltage waveform in quadrature to the line current. Adjusting the magnitude of the voltage injection allows the impedance to be controlled and to operate either inductive or capacitive mode. In the inductive mode, power flow through a transmission line is reduced and in the capacitive mode power flow through a transmission line is increased.

Modular power flow controllers provide the functionality of series capacitors or series reactor without the risk of sub-synchronous resonance with series capacitors or the constant VAR consumption of series reactors. It uses modular units which can be mounted individually on a transmission line or at a substation.

9.5 Non-network options

Non network solutions are an alternative to network augmentation solutions. There are several broad kinds of non-network solutions:

- Load curtailment.
- Local generation.
- Energy storage.
- Virtual transmission lines.

The following items briefly describe each non-network solution and outline how this Draft ISP has considered them. AEMO welcomes feedback from stakeholders during the consultation phase on how the consideration of non-network solutions can be improved.

Load curtailment

Load curtailment is where the consumer agrees to reduce usage. Transmission network can experience high loading during times of high demand on hot summer afternoon or cold winter days. Load reduction at times of high loading would avoid transmission augmentation.

The ISP methodology has assumed a realistic amount of voluntary load curtailment.

Local generation

Local generation near load centres can reduce transmission network loading, hence avoid or defer transmission augmentation.

If generators are not on line, a contractual arrangement could provide services like reactive power, system strength or inertia. This is a non-network option and would assist to increase transmission capability.

The ISP methodology is optimising the placement of generators in the networks and thus optimises local generation, where economically feasible.

Energy storage

Due to the variable nature of wind and solar power generation, the power system can experience excess or shortage of generation in relation to load. Energy storage can store energy at times of excess generation in the grid and release at the time of generation shortage to meet the load.

There are two main types of energy storage:

- Battery energy storage.
- Pumped hydro energy storage.

Location of pumped hydro energy storage is site-specific. Battery energy storage can be located anywhere in the system, subject to availability of land and environmental approvals.

The major expansions in transmission capacity for interconnections are about transferring very large quantities of energy and capacity, well beyond the scope or economics of batteries. A targeted use of storage may be justified in specific cases, such as firming options within REZ for supporting VRE or as part of the transmission solution to reduce the costs in development of transmission or provide staging of network augmentation. The basis of the need for major interconnection and network expansion to connect REZs is driven by the need for very large increases in transfer capacity between regions to access very large development of VRE across the NEM, to replace exiting coal stations. Batteries alone are not considered to be an economic replacement for this scale and duration of need.

The ISP methodology has tested and optimised the use of batteries compared to transmission investments in its analysis.

Virtual transmission

A virtual transmission concept is a use of storage at both ends of a transmission line, which is likely to be a constraining element. Immediately following a contingency, the sending end storage absorb the power and the receiving end storage release the same amount of power minus the line losses. Thus, avoiding any overload on remaining parallel transmission lines. This operation of placing energy storage on a transmission line and operating it to inject or absorb real power, mimicking transmission line flows is an alternative to uprate, replace or new line to be built.

A similar concept is applicable to increase the transient or voltage stability limits. Following a fault on a line or trip of a generator, the sending end storage can absorb power and receiving end storage release power to the network, thus increasing the pre-contingency transfer levels.

The ISP methodology has tested a number of virtual transmission concepts and has concluded that these are not yet but may very well in future be a viable alternative to traditional transmission infrastructure.

9.6 Approach to power system analysis

Thermal capacity of transmission asset

The power flow through a transmission element is limited to its maximum thermal capacity .

Network Service Providers provide transmission line and transformer ratings for different ambient temperature, seasons, months, day or night:

Normal ratings are applied for pre-contingent conditions.

Contingency ratings are applied for post-contingent conditions.

Short-term ratings are applied for post contingency conditions, if an operational solution is available to bring the line loading below the normal rating within the allowed time.

The determination of maximum transfer levels based on thermal capacity is undertaken using PSSE.

Voltage stability

Voltage stability refers to maintaining stable voltage control following the most severe credible contingency event or any protected event. Assessment of voltage stability covers the following requirements:

A margin from the point of voltage collapse. This margin (expressed as a capacitive reactive power in MVAr) must not be less than 1% of the maximum fault level (in MVA) at the connection point. However, a higher margin would be applicable if advised by relevant Network Service Provider.[84]

Voltages are to be within limits. At all times, the steady state voltage magnitudes must remain between 90% and 110% of the nominal voltage, unless

Different voltage levels are applicable under contractual obligations with connected parties,

The highest voltage capability of plant is lower than 110% of nominal voltage.

The determination of voltage stability limit is done using PSS/E.

Transient stability

Transient stability refers to maintaining the power system in synchronism and remaining stable following any credible contingency event or protected event. Transient stability is assessed on the basis of rotor angle swings following a contingency. This contingency can be trip of a generating unit or customer load, or an outage of a transmission element. As per NER requirements, in the case of transmission lines at operating voltage 220 kV and above, transient stability is assessed on the basis of the rotor angle swings following the

[84] NER Version 124. Clause S5.1.8.

application of a single circuit two-phase-to-ground solid fault at the most critical location that is cleared by the faster of the two protection systems (with intertrip systems assumed in service where installed)[85].

The determination of transient stability limit is undertaken using PSS/E.

Oscillatory stability

Oscillatory stability refers to maintaining the power system in synchronism and remaining stable in the absence of any contingency event, for any level of inter-regional or intra-regional power transfer up to the applicable operational limit; or following any credible contingency event or protected event. Oscillatory instability differs from transient instability in that oscillatory instability arises more slowly due to adverse interactions between different control and stabilisation systems, whereas transient instability occurs due to synchronous generators suddenly losing synchronism with the network due to accelerating or decelerating in response to an imbalance in electrical and mechanical power during a fault.

As per NER requirements, damping of power system oscillations is assessed to determine the power transfer limit. Power system damping is considered adequate if after the most critical credible contingency event or any protected event, simulations calibrated against past performance indicate that the halving time of the least damped electromechanical mode of oscillation is not more than five seconds.

The determination of oscillatory limit is undertaken using Mudpack and PSS/E.

9.7 Interconnections, network options and assessments

The roles of the transmission network include supplying load from geographically dispersed generation, to providing interconnection between regions to access low fuel cost resources and to enhance system security and reliability. This section describes

- Inter-regional network constraints which limits transfer capability.
- How transmission network options are developed to increase transfer capability both between regions, and between generators (such as those located within a REZ) and load centres.

9.7.1 Representation of interconnectors

In the NEM, interconnectors are defined between the regional boundaries and transfer capability across these interconnectors is limited by transmission plant thermal capacity, voltage stability, transient stability and oscillatory stability. The capability across interconnectors at any particular time is dependent on a number of factors, including demand levels, generation dispatch, status and availability of transmission equipment, and operating conditions of the network. In real-time operation, the actual transfer limits of interconnectors are determined by constraint equations[86]. There are many constraint equations represented in the NEM operation.

In AEMO's ISP Model, each of the five NEM regions represented by a node at its regional reference node (RRN) and inter-regional transfer between the regions are represented between these RRNs. A notional maximum transfer limit at the time of maximum demand in the importing region is represented as interconnector capacity between RRNs, which presented in the Planning Input and Assumptions Workbook[87]. Table 30 presents NEM definition of interconnectors and LT model representation of interconnectors.

[85] NER Version 124. Clause S5.1.2.1

[86] Constraint equations are the mathematical representations that AEMO uses to model power system limitations and FCAS requirements in NEMDE.

[87] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

Table 30 NEM interconnector definitions

Interconnector	Definition of interconnector in NEM operations	Interconnector representation in PLEXOS LT model
Queensland to New South Wales (QNI)	• Two 330 kV lines between Bulli Creek in Queensland and Dumaresq in New South Wales.	South Pine in Queensland and Sydney West in New South Wales
Queensland to New South Wales (DirectLink)	• Two 110 kV lines between Mudgeeraba in Queensland and Terranora in New South Wales.	South Pine in Queensland and Sydney West in New South Wales
Victoria to New South Wales	• The 330 kV line between Murray and Upper Tumut. • The 330 kV line between Murray and Lower Tumut. • The 330 kV line between Jindera and Wodonga. • The 220 kV line between Buronga and Red Cliffs. • The 132 kV bus tie at Guthega (which is normally open).	Thomastown in Victoria and Sydney West in New South Wales.
Victoria to South Australia (Heywood)	• Two 275 kV lines between Heywood in Victoria and South East in South Australia.	Thomastown in Victoria and Torrens Island in South Australia.
Victoria to South Australia (Murraylink)	• HVDC cable between Red Cliffs in Victoria and Monash in South Australia.	Thomastown in Victoria and Torrens Island in South Australia.
Victoria-Tasmania (Basslink)	• HVDC cable between Loy Yang in Victoria and George Town in Tasmania.	Thomastown in Victoria and Georgetown in Tasmania.

For ISP modelling of hour-by-hour simulation studies (ST simulations), a full NEM transmission network was represented, with constraint equations which are similar to NEM Dispatch Engine (NEMDE) constraint equations. These constraint equations take into account all the network limits.

9.7.2 Inter-regional network constraints

This section describes the interconnectors in the NEM today and provides detail on the factors that limit their capacity. For details on options to improve interconnector capacity, see Section 6.1.

New South Wales – Queensland Interconnector

The Queensland to New South Wales Interconnector (QNI) is defined as the flows across the two 330 kV lines between Dumaresq in New South Wales and Bulli Creek in Queensland. The transfer capability across QNI is limited by transmission line thermal capacity, voltage stability, transient stability and oscillatory stability. The capability across QNI at any particular time is dependent on a number of factors, including demand levels, generation dispatch, status and availability of transmission equipment, and operating conditions of the network.

For intact system operation, the transfer from New South Wales to Queensland is mainly limited by the following constraints:

- Thermal capacity of the 330 kV lines between Liddell and Tamworth.
- Voltage collapse on loss of the largest Queensland unit or trip of the Liddell–Muswellbrook 330 kV line.
- Transient stability associated with transmission line faults in the Hunter Valley.
- Oscillatory stability upper limit of 700 MW.

For intact system operation, the transfer from Queensland to New South Wales is mainly limited by the following constraints:

- Stability limits for faults on either Sapphire to Armidale or Armidale to Dumaresq line.
- Thermal capacity of the 330 kV lines within northern New South Wales.
- Oscillatory stability upper limit of 1,200 MW.

The nominal transfer capacity of QNI is highly dependent on the output of Sapphire wind generation.

Parallel to QNI, the Terranora interconnector provides interconnector capacity across the two 110 kV lines from Mudgeeraba in Queensland to Terranora in New South Wales.

Terranora is connected to the rest of the electricity network in New South Wales via the direct current (DC) link known as Directlink. This was commissioned in 2000 and formed the first transmission connection between New South Wales and Queensland. Directlink has three pairs of bipolar DC transmission cables. Each pair has a 60 MW maximum capacity, giving Directlink a total rating of 180 MW.

Victoria – New South Wales Interconnector

The Victoria to New South Wales interconnector is defined as the flow across:

- The 330 kV line between Murray and Upper Tumut (65).
- The 330 kV line between Murray and Lower Tumut (66).
- The 330 kV line between Jindera and Wodonga (060).
- The 220 kV line between Buronga and Red Cliffs (0X1).
- The 132 kV bus tie at Guthega (which is normally open).

This interconnector came into operation on 1 July 2008 as part of the Snowy region abolition and replaced the previous "SNOWY1" and "V-SN" interconnectors. The interconnection between NSW and Victoria was commissioned at the same time as the Snowy Hydro scheme. The Wodonga and Buronga lines were added later as a part of strengthening the electricity supply to western NSW and north-west Victoria.

The transfer capability between Victoria and New South Wales is limited by transmission line thermal capacity, voltage stability, and transient stability. The capability across Victorina and New South Wales interconnector at any particular time is dependent on a number of factors, including demand levels, generation dispatch, status and availability of transmission equipment, and operating conditions of the network.

For intact system operation, transfer from Victoria to New South Wales is mainly limited by following:

- Thermal overloads on:
  - South Morang 500/330 kV F2 transformer.
  - South Morang–Dederang 330 kV circuits.
  - Dederang–Mount Beauty 220 kV circuits.
  - Murray–Upper Tumut/Lower Tumut 330 kV lines.
  - Lower Tumut/Upper Tumut¬–Canberra/Yass 330 kV lines.
  - Yass–Marulan 330 kV lines.
  - Dapto–Sydney South 330 kV line.
  - Dapto–Marulan 330 kV line.
  - Kangaroo Valley–Dapto 330 kV line.
  - Bannaby–Sydney West 330 kV line.
- Transient stability limit for a fault and trip of a Hazelwood to South Morang 500 kV line.
- Voltage stability limit for loss of largest load in Victoria.

- Voltage stability limit for loss of a 330 kV line between Upper/Lower Tumut and Canberra/Yass.

For intact system operation, transfer from New South Wales to Victoria is mainly limited by following:

- Thermal overloads on:
  - Murray–Dederang 330 kV lines.
  - Dederang–South Morang 330 kV lines.
  - Eildon–Thomastown 220 kV line.
- Voltage collapse for loss of the largest Victorian generator or Basslink at high import levels into Victoria from Tasmania.

The nominal transfer capacity of the Victoria – New South Wales interconnector is highly dependent on the output of Murray generators for transfer from New South Wales to Victoria and Lower/Upper Tumut generators for transfer from Victoria to New South Wales.

Victoria – South Australia

The Victoria to South Australia interconnector (Heywood Interconnector) is defined as the flow across the 275 kV lines between Heywood substation in Victoria and South East substation in South Australia. This interconnector was originally commissioned in 1989 as a connection from the western 500 kV network in Victoria (at Heywood near the Portland smelters) to the nearest 275 kV substation at Para, South Australia. It includes a number of connections to the parallel 132 kV network in south-eastern South Australia.

The transfer capability between Victoria and South Australia via Heywood is limited by transformer thermal capacity, voltage stability, transient stability, and rate of change of frequency. The capability across the Victoria – South Australia Heywood interconnector at any particular time is dependent on a number of factors, including demand levels, generation dispatch, status and availability of transmission equipment, and operating conditions of the network.

For intact system operation, transfer from Victoria to South Australia is mainly limited by the following constraints:

- Transient stability for loss of the largest South Australian generator.
- Limiting rate of change of frequency to 3 Hz/second for loss of both Heywood to South East 275 kV lines.
- Transient stability for fault and trip of a Hazelwood to South Morang 500 kV line.
- Transient stability for fault and trip of a South East-Tailem bend 275 kV line.
- Voltage stability for fault and trip of a South East-Tailem bend 275 kV line.
- Thermal overload on the South Morang 500/330 kV transformer.

Parallel to the Heywood interconnector is Murraylink. Murraylink is defined as the flow across the DC cable between Red Cliffs in Victoria and Monash in South Australia. It is a 220 MW DC cable that was commissioned in 2002. Runback schemes in South Australia and Victoria were commissioned along with Murraylink, and these handle many of the thermal issues in the Riverland of South Australia and western Victorian 220 kV.

Tasmania – Victoria Interconnector (Basslink)

Basslink is defined as the flow across the DC cable between George Town in Tasmania and Loy Yang in Victoria. It was commissioned in early 2006 after Tasmania joined the NEM. The commissioning included the undersea DC cable, converter stations and several control schemes in Tasmania. Unlike the other DC lines in the NEM, Basslink has a frequency controller and is able to transfer frequency control ancillary services (FCAS) between Victoria and Tasmania.

The transfer capability between Tasmania and Victoria (Basslink) is mainly limited by the HVDC submarine cable thermal capacity.

The system protection scheme (SPS) is in place to meet the Basslink transfer capability and meet the system security requirements. These SPSs are frequency control special protection scheme (FCSPS) and network control special protection scheme (NCSPS) and have following main functions:

- The FCSPS automatically interrupts Tasmanian generating units or load blocks in the event of a sudden interruption to Basslink transfers either under export or import conditions in order to maintain frequency in Tasmania within standard; and
- The NCSPS automatically interrupts Tasmanian generating units in the event of a sudden disconnection of specified 220 kV and 110 kV transmission circuits in order to remove overloads on the circuits remaining in service.

Without the SPS and generating unit and load block interruption services in place, Basslink transfers will be substantially limited.

Contractual arrangement

If generators are not on line, a contractual arrangement could provide services like reactive power, system strength or inertia. This is a non-network option and would assist to increase transmission capability.

9.7.3 Cost estimates

Cost estimates of transmission networks projects which are currently undergoing RIT-T by TNSPs were obtained from TNSPs' RIT-T reports as at available in August 2019. AEMO undertook a review of TNSPs' cost estimates based on AEMO's in house price estimates, and TNSPs' cost estimates are within the planning estimate of AEMO's assessment. All capital cost estimates are indicative with a ±30% range, unless otherwise noted.

AEMO's price book capital estimates include 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

A 5% of overall capital cost has been allowed for land and easement and a 1% of capital cost was assumed as operation and maintenance cost.

9.8 System strength

System strength is an inherent power system characteristic – a measure of its stability under all reasonably possible operating conditions. The ISP assesses future system strength and identifies shortfalls with two measures:

- Synchronous three phase fault level.
- Available fault level.

Both measures are established and currently used in the NEM for system strength.

Synchronous three phase fault level

Definition and current use in the NEM

The synchronous three phase fault level is measured in MVA and calculated by only including fault contributions from synchronous machines. It is calculated under system normal conditions, and also under credible line or transformer contingencies.

It is a helpful measure for system strength, because it can be used to assess the correct operation of protection systems, the size of voltage deviations due to static voltage control devices, such as switched inductors or capacitors, and the stable operation of existing generation. Fault current is used as a proxy for the level of inertia, fault current, synchronising torque, and other synchronous characteristics which a power system needs. However, it cannot be used as the only metric for all system strength needs, which require detailed EMT type simulations to fully quantify.

TNSPs have a responsibility under the NER to maintain a minimum synchronous three phase fault level at defined fault level nodes within their network. If there is a shortfall, the TNSP must pay for remediation.

The System Strength Requirements Methodology document[88] details the fault level calculation method to be used, defines the fault level nodes in each region, and specifies the minimum fault level requirement at each of these nodes.

Calculation method in the ISP

The ISP uses the same methodology and requirements to report on potential future shortfalls and possible solutions. The synchronous three phase fault level was calculated in the ISP as follows:

1. The status of all synchronous units (on/off) was extracted from the market modelling outputs for each half-hour interval, using the Central scenario with Nash-Cournot bidding.
2. The status was applied to the PSS/E network model.
   - The model assumed typical parameters for projected new synchronous plant such as gas peaking, CCGT, and pumped hydro. For pumped hydro, half the plant was assumed synchronous and half was assumed inverter-based.
   - The model included future TNSP synchronous condensers and network upgrades.
   - The model did not assume any system strength mitigation with future inverter-based resources.
3. All inverter-based resources were switched off.
4. The fault level was then calculated at each fault level node using PSS/E.
5. The process was repeated for each half-hour market modelling interval to produce annual fault level node duration curves.

System strength shortfalls are identified when the synchronous three phase fault level falls below the existing minimum fault level requirements for more than 1% of the period.

Available fault level

Definition and current use in the NEM

The available fault level is measured in MVA and defined as the actual synchronous three phase fault level minus the required synchronous three phase fault level specified by the manufacturer of inverter based resources.

It is a helpful measure for system strength because it assesses whether the control systems of inverter based resources will operate correctly. It is considered superior to a Weighted Short Circuit Ratio (SCR), because the

[88] AEMO. System Strength Requirements, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

calculation includes the impact of surrounding inverter-based resources and also their relative electrical distances.

AEMO assesses the impact on system strength of each new generation connection application. There must continue to be sufficient system strength for the stable operation of the network following the new connection. AEMO uses the available fault level calculation to perform this high level system strength impact assessment, and in determining if a full impact assessment using EMT studies will be required.

If AEMO finds there would be a shortfall after the new connection, the new applicant may be required to provide system strength mitigation. This could be additional equipment or schemes in the applicant's plant, or the applicant paying for a TNSP to perform additional works on the network.

The System Strength Impact Assessment Guidelines[89] describe the assessment process and the methodology for determining available fault level.

Calculation method in the ISP

The ISP used the same methodology to report on potential future shortfalls and possible solutions. The available fault level was calculated in the ISP as follows:

1. The status of all synchronous units (on/off) was extracted from the market modelling outputs for each half-hour interval, using the Central scenario with Nash-Cournot bidding.
2. The status was applied to the PSS/E network model.
   - The model assumed typical parameters for projected new synchronous plant such as gas peaking, CCGT, and pumped hydro. For pumped hydro, half the plant was assumed synchronous and half was assumed inverter-based.
   - The model included future TNSP synchronous condensers and network upgrades.
   - The model did not assume any system strength mitigation with future inverter based resources.
3. The impedance of inverter-based resources was modified according to its minimum required SCR (assumed to be 3) and its unit MW capacity.
4. Two fault levels for each node were calculated using PSS/E: three phase synchronous fault level (S_SG) and total fault level including both synchronous and inverter-based resources (S_TOTAL).
5. Available fault level (AFL) was calculated for each node: AFL = $2S_{SG}-S_{TOTAL}$.
6. The process was repeated for each half-hour market modelling interval to produce annual fault level node duration curves.

System strength shortfalls are identified when the available fault level becomes negative.

System strength shortfalls in the ISP

Possible solutions

When a shortfall is found, using either the synchronous three phase fault level or the available fault level, possible solutions are:

- Conversion of retiring synchronous plant to synchronous condensers.
- Contracts with synchronous units with existing generation to remain online (or delay early retirement).
- Contracts with synchronous units to come online in synchronous condenser mode.
- Installation of new synchronous condensers.
- Additional AC transmission.

[89] AEMO. System Strength Impact Assessment Guidelines, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Impact_Assessment_Guidelines_PUBLISHED.pdf.

- Connection of new synchronous generation (for example, temporary plant for interim solutions).
- If only marginal, reduced impedances, such as connection transformers.
- Improved control systems such as grid forming inverters[90].
- Control schemes, if significant numbers of other nearby proponents have not already installed similar schemes.

Future improvement for the ISP

System strength shortfalls also interact with other issues such as:

Timing of synchronous generator retirements.

Timing of network upgrades, such as interconnectors or REZ requirements.

Inertia mitigation.

An overall holistic review of potential solutions and timings could be performed to the minimise total cost. This requires that when solutions and costs are identified, these additional costs or solutions are included in subsequent generation planting optimisations to determine any impact on the outcomes.

9.9 Marginal Loss Factors

Energy is lost as it travels through the transmission network, and these losses increase as more generation connects in locations that are distant from load centres. In the NEM, Marginal Loss Factors (MLFs) are applied to market settlements, adjusting payments to reflect the impact of incremental energy transfer losses. MLFs are used to adjust the price of electricity in a NEM region, relative to the regional reference node[91], 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 generation certificates (LGCs) created if accredited under the Federal Large-scale Renewable Energy Target (LRET).

Increasing generation within a REZ is likely to increase losses between the REZ and the regional reference node, decreasing the MLFs for the REZ. The MLFs attributable to generators located in some REZs will be more sensitive to change as a result of new connecting generators than other REZs, particularly where they are distant from major load centres and interconnection is relatively weak.

Investors in new generation are concerned about the effect of decreased MLFs on their potential returns, and the uncertainty of how MLFs can vary from one year to the next. Generators in locations that are strongly connected to major load centres have MLFs that are less likely to change over time.

For a generator, an MLF represents the amount of electricity delivered to the regional reference node for a marginal (next MW) increase in generation; for a load, the MLF represents the amount of power that would need to be generated at the regional reference node for a marginal (next MW) increase in demand. In simple terms, a higher MLF is good for a generator's revenue, while a lower MLF is good for a load (as it means it is not paying for energy lost before it reaches the load). MLFs will change over time, most often decreasing as additional generation connects in an area.

A range of factors affect how much the MLF will change:

- **Transmission and distribution network** – if new generation is added at an electrically distant connection point, the MLF decreases more than if it had been added to a connection point in close proximity to the high-voltage network.

[90] Currently there is a low level of experience in costs and performance of grid forming converters, and as such generation planting outcomes assume costs for grid following inverter options only.

[91] The reference point (or designated reference node) for setting a region's wholesale electricity price.

- **Generation profile in the area** – if new generation is only running at the same times other nearby generators are also running, the MLF decreases more. For example, solar generators in an area all produce power at the same time, so adding more of this type of generator will decrease the MLF more than if a different technology generator was added.
- **Load profile in the area** – if new generation mainly produces power at times when there is light load in the area, the decrease in MLF will be greater.
- **Intra-regional and inter-regional flows** – wider trends affecting MLFs include decreasing consumption, increasing distributed generation, changing industrial loads, and retiring generators.

For example, the planned connection of over 1,200 MW of new solar generation in north and central Queensland led to MLFs falling by up to 12% from the 2017-18 financial year to 2018-19.

In addition to new generator connections, a number of other events can cause large changes in power flow across the transmission network, and corresponding large changes in MLF. These include:

- **Retirement of generation** – the retirement of Northern Power Station in South Australia in 2016 caused power flow from Victoria to South Australia to increase, contributing to MLFs in south-east South Australia falling by around 6%. The retirement of Hazelwood Power Station in Victoria in 2017 resulted in increased power flow south from Queensland and New South Wales, contributing to northern New South Wales loss factors reducing around 5%.
- **Change in fuel mix** – the availability of cheap "ramp" gas in Queensland in 2014 and 2015 led to an increase in GPG in southern Queensland. This caused increased power flow from Queensland to New South Wales, contributing to MLFs in northern New South Wales falling by up to 10%.
- **Changes in electrical load** – the closure of the Point Henry Aluminium Smelter in Victoria in 2014 contributed to MLFs in the area falling around 2.5%.

The projected increase in development of renewable generation across the NEM will result in changes to network flow patterns, the network itself where augmentations or new interconnection is undertaken, to network losses as different parts of the network are utilised in different ways, and resultant MLFs will change.

In this analysis, AEMO modelled the transmission system and its losses. AEMO studied each candidate REZ to assess the sensitivity of its MLF to increased renewable generation, based on the existing network. The results are only to be used as a guide to determine how sensitive each proposed REZ would be to changes in MLF.

The studies considered each REZ individually, using historical snapshots. Various levels of renewable generation were connected in the model to represent the REZ, then an MLF was calculated. The MLFs calculated are only indicative as they are not based on applying the full Forward Looking Loss Factor Methodology[92] set out in the Rules and procedures. The studies used existing electrical system strength and the existing generation and load profiles, and AEMO included consideration of some proposed network augmentations.

Effect of energy storage on MLFs

The effect of energy storage on the MLF depends on how well its charging and discharging profiles correlate with the generation profile and load profile. The MLF of a site would improve if the energy storage is charging at times when the generation of the REZ is high and the local area load is low. For example, co-locating a battery with a solar farm could not only assist in shifting the output to times when needed, but could also improve the MLF for the site.

[92] AEMO. Methodology for Calculating Forward-Looking Transmission Loss Factors, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries.

9.10 Generator project commitment criteria

AEMO applies strict commitment criteria for generation projects to ensure that the supply outlook adequately reflects the status of existing, announced, and proposed projects. AEMO models the forecast period with all committed or committed* projects included, in addition to the additional resources that form part of the ISP development opportunities discussed in Section 3.2.

The project commitment criteria are described in greater detail in AEMO's Generation Information releases[93]. To summarise, the following criteria are used.

Table 31 Generation commitment criteria

Criterion name	Description
Site	The project proponent has purchased / settled / acquired (or commenced legal proceedings to purchase / settle / acquire) land for the construction of the project.
Major components	Contracts for the supply and construction of major plant or equipment components (such as generating units, turbines, boilers, transmission towers, conductors, and terminal station equipment) have been finalised and executed, including any provisions for cancellation payments.
Planning and Approvals	The proponent has obtained all required planning consents, construction approvals, connection contracts (including approval of proposed negotiated Generator Performance Standards from AEMO under clause 5.3.4A of the National Electricity Rules), and licences, including completion and acceptance of any necessary environmental impact statements.
Finance	The financing arrangements for the proposal, including any debt plans, must have been concluded and contracts executed.
Date	Construction of the proposal must either have commenced or a firm commencement date must have been set. Commercial use date for full operation must have been set.

In applying these criteria, the following status descriptions summarise the relative advancement and maturity of the projects.

Table 32 Generation project commitment status descriptions

Commitment Status	Description
Committed	Projects that will proceed, with known timing, satisfying all five of the commitment criteria. That is, all categories are green.
Committed*	Projects that qualify as "Advanced" and where construction or installation has also commenced. Typically, Committed* projects are included in sensitivity analysis for MLF calculations and in the base case for reliability assessments.
Advanced	Projects that are highly likely to proceed, satisfying Site, Finance and Date criteria plus either Planning or Components criteria. Progress towards meeting the final criteria is also evidenced.
Maturing	Projects that have progressed with site, planning applications, and finance arrangements, but not to the point that they can be classified as advanced. Maturing projects may be explicitly included in scenario analysis to assess future reliability or market impacts and are tested for economic efficiency in capacity outlook modelling.

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

Commitment Status	Description
Emerging	Projects with financing arrangements, but site/planning approvals/construction is uncertain, and development is strongly subject to changes in policy or commercial environment. These projects may be explicitly included in scenario analysis to assess future market impacts, and are tested for economic efficiency in capacity outlook modelling. However, a higher weighted average cost of capital will be assumed to reflect greater development uncertainty compared to proposed projects.
Publicly announced	These projects have been announced publicly, but do not yet have any finance arrangements in place. Costs and capabilities of these projects are developed using recently-completed projects and projections of cost components such as raw material supply and labour.

Appendix 10. Next steps towards Final 2020 ISP

Due to the sheer volume of modelling and analysis work that was carried out to produce the Draft ISP, it was necessary to prioritise certain aspects of the ISP modelling and writing, including response to some of the feedback suggestions that were received during the October 2019 workshop.

Areas which were not able to be included in the Draft ISP, and which will be considered for inclusion in the Final ISP, include:

- A high level summary for policy-makers.
- More in depth power system analysis of all scenarios (not just Central), including system strength and loss factor robustness.
- Validation of cost benefit analysis using ST modelling that has a more granular temporal representation and includes system normal transmission constraints.
- Extension of detailed cost benefit analysis to 2050 (if computationally possible). To date, the carbon budgets have been considered out to 2050 at a high level (in the first phase of AEMO's ISP Model), but the more detailed DLT and ST modelling has only been run to 2042.
- More detailed analysis of the impact of the New South Wales Electricity Strategy.