AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Draft 2020 Integrated System Plan

12 December 2019

For the National Electricity Market

Important notice

PURPOSE

AEMO publishes this Draft 2020 Integrated System Plan (Draft ISP) 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

This Draft ISP document contains 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. This Draft ISP does not include all of the information that an investor, participant or potential participant in the national electricity market might require, and does not amount to a recommendation of any investment.

Anyone proposing to use the information in this Draft ISP should independently verify and check its accuracy, completeness and suitability for purpose, and obtain independent and specific advice from appropriate experts.

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Invitation to engage

The first Integrated System Plan (ISP) was prepared by AEMO and endorsed by the COAG Energy Council in 2018. It has since guided industry and government on the investments needed for an affordable, secure and reliable energy future, while meeting prescribed emissions trajectories.

With the ISP to be updated every two years, AEMO is pleased to present the Draft ISP for 2020 (Draft ISP), which responds to the latest technology, economic, policy and system developments.

The Draft ISP serves its regulatory purposes of informing decision makers about the power system and its development and triggering the processes for actionable ISP projects.

It does so by offering a robust, dynamic, transparent and actionable roadmap for eastern Australia's power system, one that maximises market benefits through the potential complexities and uncertainties of the next 20 years.

This roadmap calls for nationally significant and essential investments in the electricity system to ensure the system meets its security and reliability requirements with the least cost and lowest regret to consumers. As these actions typically have long lead times, this draft roadmap presents clear signposts for decision making as the future unfolds.

While this roadmap provides guidance on many critically important questions relating to Australia's energy transition, market and regulatory reforms are also needed for the ISP to achieve its objectives. The Energy Security Board (ESB) and market bodies are exploring the reforms needed to attract investment and optimise bidding of resources, including demand based resources. The COAG Energy Council has also requested the ESB to review the cost allocation models that govern recovery of network investment, to ensure fair treatment of consumers throughout the NEM.

The final ISP will only serve its essential national purpose if it draws on constructive and critical input from all parties who may be affected by it.

AEMO has consulted widely over the past year in preparing this Draft ISP, and is relying again on your contribution as we prepare the Final ISP.

We encourage you to read the Draft ISP carefully, and engage with us through the consultation process. Please come to our major public forums on 3-5 February 2020 and make a written submission by 21 February 2020.

The planned consultation process is summarised on page 16 below, and set out in full in Part E of this Draft ISP.

We look forward to hearing your comments and contributions.

Yours sincerely,

Audrey Zibelman
Chief Executive Officer and Managing Director

A roadmap to guide Australia's energy transition

[Executive summary]

The 2020 ISP provides an actionable roadmap for eastern Australia's power system that maximises market benefits through a transition period of complexity and potential uncertainty.

A. The ISP is a whole-of-system plan to maximise net market benefits and deliver low-cost, secure and reliable energy through a complex range of plausible energy futures.

B. With extensive stakeholder engagement, AEMO has developed the Draft ISP using cost-benefit analysis and least-regret scenario modelling, covering five scenarios and six sensitivities.

C. This analysis has identified the investments needed for Australia's future energy system: in distributed energy resources (DER)[1], variable renewable energy (VRE)[2], supporting dispatchable resources and power system services, and the National Electricity Market (NEM) transmission grid.

D. The Draft ISP sets out the optimal development path for Australians to enjoy an affordable, secure and reliable energy future, the signposts at which that path may need to change course, and the options we may then have. It identifies the actionable ISP projects and other initiatives that are needed immediately, shortly or in the future.

Stakeholder consultation including public workshops and submissions will be completed by 21 February 2020[3], following which AEMO will finalise the 2020 ISP by mid-2020, alongside the Energy Security Board's (ESB's) development of the ISP Rules[4].

A A dynamic, whole-of-system roadmap is needed for Australia's energy transition

The ISP is a whole-of-system plan "that efficiently achieves power system needs … in the long-term interests of the consumers of electricity"[5]. As its planning horizon is at least 20 years, it must do so through Australia's energy transition. It provides a least-regret, dynamic, resilient and transparent roadmap for the NEM, one that is founded on rigorous cost-benefit analysis and that meets the cost, security, reliability and emissions expectations of energy consumers while also increasing system resilience to be able to better deal with future challenges. It will serve the broad purpose of informing market participants and policy decision makers, and its specific purpose of identifying actionable ISP projects.

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[1] Including rooftop PV, batteries, and other resources at the customer level

[2] Including solar, wind, battery and other energy resources.at the utility level

[3] Consultation on non-network options will be open until 13 March 2020

[4] While the ESB's actionable ISP rules are still in draft form, AEMO has developed this Draft ISP with the aim to satisfy the draft rules

[5] Clause 5.22.2(a) Draft ISP Rules

Its scope is the whole NEM power system over the next 20 years, including emerging innovations in consumer-owned DER, virtual power plants (VPPs), large-scale generation, energy storage, networks, and coupled sectors such as gas, water and the electrification of transport. However, hydrogen, nuclear generation and energy distribution are outside its scope for this draft.[6]

Its guiding objective is to achieve power system needs while optimising net market benefits.[7] The system needs include system reliability, system security and government emissions and renewable energy policies. If these outcomes are achieved at low long-term system cost – measured by whole-of-system cost-benefit analysis and incorporating construction, operation and compliance costs[8] – it will maximise net market benefits in the long-term interests of consumers.

It must do so recognising the risks to consumers of investments made in times where there are multiple uncertainties surrounding technological evolution, policy choices and economic development, to name but a few.[9] The NEM is a highly complex system. Change is certain in the economic, trade, security, policy and technology environments in which it operates. Yet energy investments must be made, as Australian consumers rely on them for their economic and physical wellbeing. If essential investments are delayed or aborted, domestic and industrial consumers will face increased costs and risks – or increased costs if unnecessary investments proceed.

The ISP must therefore be a transparent, dynamic roadmap. The ISP creates this roadmap by using whole-of system cost-benefit analysis to identify an initial least-regret path. It then enhances the optionality of this path to create signposts and decision points to ensure the roadmap is resilient as economic, physical and policy environments change. Such an ISP fulfils two purposes. It will

1. Trigger the processes for the regulatory investment test for transmission (RIT-T) process for actionable ISP projects (which it does in Part D), and[10]
2. Inform policy makers, investors, consumers, researchers and other energy stakeholders about the projects and opportunities that are needed to build and operate Australia's future power system.

B Scenario modelling is needed to meet the ISP's objective

AEMO uses scenario modelling and cost-benefit analysis to determine the most efficient ways to achieve power system needs through the energy transition, in the long-term interests of consumers. The approach complies with the intent of the Australian Energy Regulator's (AER's) proposed *Cost-Benefit Analysis Guidelines* for the ISP and regulatory investment tests.[11]

The ISP approach is based on four key elements:

- **ISP assumptions and scenarios agreed through consultation.** AEMO has consulted extensively with industry, academia, government, developers and consumer representatives, culminating in our *Forecasting and Planning Scenarios, Inputs and Assumptions Report* in August 2019.

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[6] See Section A1 for the rationale and further detail

[7] Clause 5.22.2(a) Draft ISP Rules

[8] Clause 5.22.8(d) Draft ISP Rules

[9] Clause 5.22.5(e)(1) Draft ISP Rules

[10] Clause 5.22.2(b)(1) Draft ISP Rules

[11] AER Issues Paper: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable

- **Scenarios and sensitivities span all plausible operating environments.** The Draft ISP continues to project a profound transition to a NEM of diverse renewable, gas-powered and distributed generation, supported by energy storage and network solutions.
  - Consultations agreed on five scenarios that trace different paces of that transition. In the Central scenario, the pace is determined by market forces and current federal and state government policies. The other scenarios are variations in the pace of the transition – a Slow Change scenario in which economic growth and emission reductions slow, a High DER scenario with more rapid consumer adoption of distributed energy resources, a Fast Change scenario with greater investment in grid-scale technology, and a Step Change scenario where both consumer-led and technology-led transitions occur in the midst of aggressive global decarbonisation.
  - All scenarios are then affected by sensitivities identified through the consultation process, around earlier retirement of existing generators, Snowy 2.0 delays, an early commitment to the Battery of the Nation (BOTN) project in Tasmania, a possible end to the Queensland Renewable Energy Target (QRET) policy, a closure of a large industrial load in Victoria or Tasmania, and early development of VRE in the Central West New South Wales Renewable Energy Zone (REZ)**.**
- **Deep integrated modelling of both economic and power systems.** This modelling uses cost-benefit analysis to determine the least-regret set of investment decisions that meet all ISP objectives through those scenarios. Those five sets of investment decisions are then tested across all scenarios and sensitivities. All sets of decisions must accept some 'regrets' or sunk costs if a different scenario unfolds. The modelling assesses the costs and benefits of different development paths under each scenario in order to reveal the least-regret set of decisions, that form the ISP's optimal development path.
- **A preference for keeping options open through timely preparation and flexible design choices.** The ISP aims to identify investments that are valuable under multiple future scenarios. For example, low-cost early development work can be taken without committing to the full project, or transmission lines can be designed as double circuit, but strung initially as single circuit. Investing early in this way, and being prepared for events such as an early plant closure, carries considerably less reliability risk and consumer costs than investing too late.

This approach supports realistic, transparent decision-making, because it identifies and compares the risks in each scenario, without having to ascribe probabilities to either the scenarios or events. However, in some circumstances it is still useful to consider what the relative probability of a particular scenario or event may be, to ensure it is not unduly influencing recommendations.

C The ISP modelling offers a future least-regret energy system

The ISP modelling confirms that the least-cost and-regret transition of the NEM is from a *centralised* coal-fired generation system to a *highly diverse* portfolio dominated by DER and VRE, supported by dispatchable resources and enhanced grid and service capabilities to ensure the power system can reliably meet demand at all times.

By 2040:

1. **Distributed energy generation capacity is expected to double or even triple.** Residential, industrial and commercial consumers are expected to continue to invest heavily in distributed PV,

with increasing interest in battery storage and load management. Depending on the scenario and subject to technical requirements, the AEMO modelling projects DER could provide 13% to 22% of total underlying annual NEM energy consumption[12] by 2040. With these higher levels of DER, dedicated management practices and protocols will be needed to maintain system security, backed by changes to rules, regulations and standards. New DER installations will increasingly need to have sufficient interoperability capabilities so they can be controlled when required for power system security. AEMO is currently investigating the maximum levels of uncontrollable energy that the system can accomodate while remaining secure.

2. **Over 30 GW of new grid-scale renewables is needed** in all but the Slow Change scenario. This is to replace the approximately 15 GW or 63% of Australia's coal-fired generation that will reach the end of its technical life and so likely retire by 2040. More renewables are required to replace conventional generators because of their naturally lower capacity factor, which has been fully accounted for in this technical and economic analysis. To ensure a gradual, orderly transition, there must be sufficient new generation in place before each major plant exits. Allowing for the strong growth in DER, Australia will still need an additional 34 GW of new VRE in the Central scenario, above what is already committed, 30 GW for High DER, 37 GW for Fast Change or 47 GW for Step Change, much of it built in REZs. In the Slow Change scenario, only 4 GW would be needed by 2040.
3. **5-21 GW of new dispatchable resources are needed in support.** To firm up the inherently variable distributed and large-scale renewable generation, we will need new flexible, dispatchable resources: utility-scale pumped hydro or battery storage, distributed batteries participating as VPP, and demand side participation (DSP). New flexible gas generators could also play a greater role if gas prices materially reduce.
4. **Power system services are critical to support these three sets of energy resources.** Innovative power system services will be needed that span voltage control, system strength, frequency management, power system inertia and dispatchability.
5. **The transmission grid itself needs targeted augmentation to balance resources and unlock REZs**. While over 30 GW of new VRE may be required by 2040, the existing network only has an estimated connection capacity for 13 GW in areas with favourable renewable resources. Strategically placed interconnectors and REZs, coupled with energy storage, will be the most cost-effective way to add capacity and balance variable resources across the whole NEM.

The NEM will draw on a technological mix that may diversify even further as other technologies, such as hydrogen, mature. This diverse portfolio will cost less than replacing the exiting generators with new thermal generation to deliver the energy and peak capacity needed, and simultaneously reduce emissions significantly.

D The ISP lays out the optimal development path to that future

Based on the least-regret approach to the cost-benefit analysis of all potential developments, AEMO has identfied the optimal development path in accordance with the draft ISP Rules. Based on the

[12] Total annual underlying NEM energy consumption, including rooftop PV, and PVNSG (commercial-scale PV, behind-the-meter and <30 MW per installation). The level of instantaneous uncontrolled power that will need to be operationally managed at times of DER peak export will be much higher.

optimal path, AEMO has identified the actions that need to happen now, next and in future for a secure and reliable energy transition.

1. **Selection of the ISP's optimal development path.** From five similar candidates[13], AEMO has identifed the optimal development path, that comprises projects to augment the transmission grid (committed, recommended, and actionable ISP projects) and ISP development opportunities (resources, non-network solutions, and power system security needs).

   This optimal development path is depicted in the Figure 1 map on page 14 below.

2. **Projects to augment the transmission grid[14].** In all, the ISP identifies over 15 projects to augment the transmission grid, which have been selected from a large range of possible options. These projects fall into three time-related groupings to achieve power system needs through a complex, energy sector transition.

   – **Group 1 – Priority grid projects**. These projects are critical to address cost, security and reliability issues. They are to commence immediately after the publication of the final 2020 ISP, if not already underway. They fall into three categories:

     ○ **Already committed projects**:

       ▪ **South Australia system strength remediation** and

       ▪ **Western Victoria Transmission Network Project.**

     ○ **Actionable ISP projects (as defined in the draft ISP rules)**:

       ▪ **Queensland to NSW Interconnector (QNI) minor** and **Victoria to NSW Interconnector (VNI) minor** upgrades to existing interconnections between New South Wales with Queensland and Victoria, respectively. Both projects are currently undergoing their regulatory approval processes. Completion of **QNI Minor** is expected **in 2021-22,** 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 should be delivered **by 2026-27**.

     ○ **Recommended project (but not yet 'actionable' under draft ISP rules)**:

       ▪ **Marinus Link 'shovel-ready' works** – 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'. This low-cost, low-regret investment would allow more time for further

[13] There are differences in the composition and size of the supply side resources, depending on which scenario and which development path apply. The detailed modelling results are set out in the Generation and Transmission Outlook spreadsheets published in conjunction with the Draft ISP.

[14] All dates are indicative, and on a financial year basis. For example, 2023-24 represents the financial year ending June 2024.

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.

- **Group 2 – Near-term grid projects.** These are important projects that require actions in the near future and at the latest prior to the publication of the 2022 ISP to reduce costs, enhance system resilience and optionality. This Draft ISP has identified one actionable ISP project in Group 2, the **QNI medium** interconnector upgrade, which should be delivered **by 2028-29** with an option of accelerating delivery to 2026-27 should the Step Change scenario emerge.
- **Group 3 – Future grid augmentation projects** that provide valuable future options for Australia's energy system, but with time at least until the 2022 ISP before final decisions on actionability and/or investment must be made. This allows time to further investigate and refine these options. The following potential investments should be further assessed and developed in the leadup to the 2022 ISP, to be published by June 2022:
  - **Marinus Link**, which proposes connecting Victoria to Tasmania with a second, and potentially third, HVDC cable, and supporting AC transmission.
  - **Queensland grid reinforcements**, which would consist of one or more of the following options: Larger QNI upgrade; augmentation to the northern Queensland network to support REZ development; upgrade of network from Central to Southern Queensland; reinforcement of the network around Gladstone.
  - **New South Wales grid reinforcements**, which would reinforce the network supporting Sydney, Newcastle and Wollongong.
  - **Network required to support REZ expansions**, which would include various augmentations in regions projected from the late 2020s to support REZs to replace exiting coal power stations, including augmentation of northern New South Wales network[15] if the larger upgrade of QNI does not proceed.

3. **ISP development opportunities in Renewable Energy Zones**

   Development of additional VRE in REZs across the NEM will occur in three overlapping phases of development. These phases should be coordinated with recommended augmentations of the network and system strength remediation.[16] These opportunities will take advantage of additional network capability provided by new interconnectors where possible, as this is often the least cost way of establishing REZ. However, some opportunities also require specific augmentation of the transmission network. The following table lists the REZ development opportunities.

[15] Note that this timing does not include the impact of the New South Wales Electricity Strategy, which aims to develop 3 GW of VRE in the Central West REZ with associated transmission infrastructure by 2028. This plan was announced just prior to completion of this Draft ISP. Subject to further policy detail becoming available, AEMO intends to assess the impact of this policy in the Final 2020 ISP.

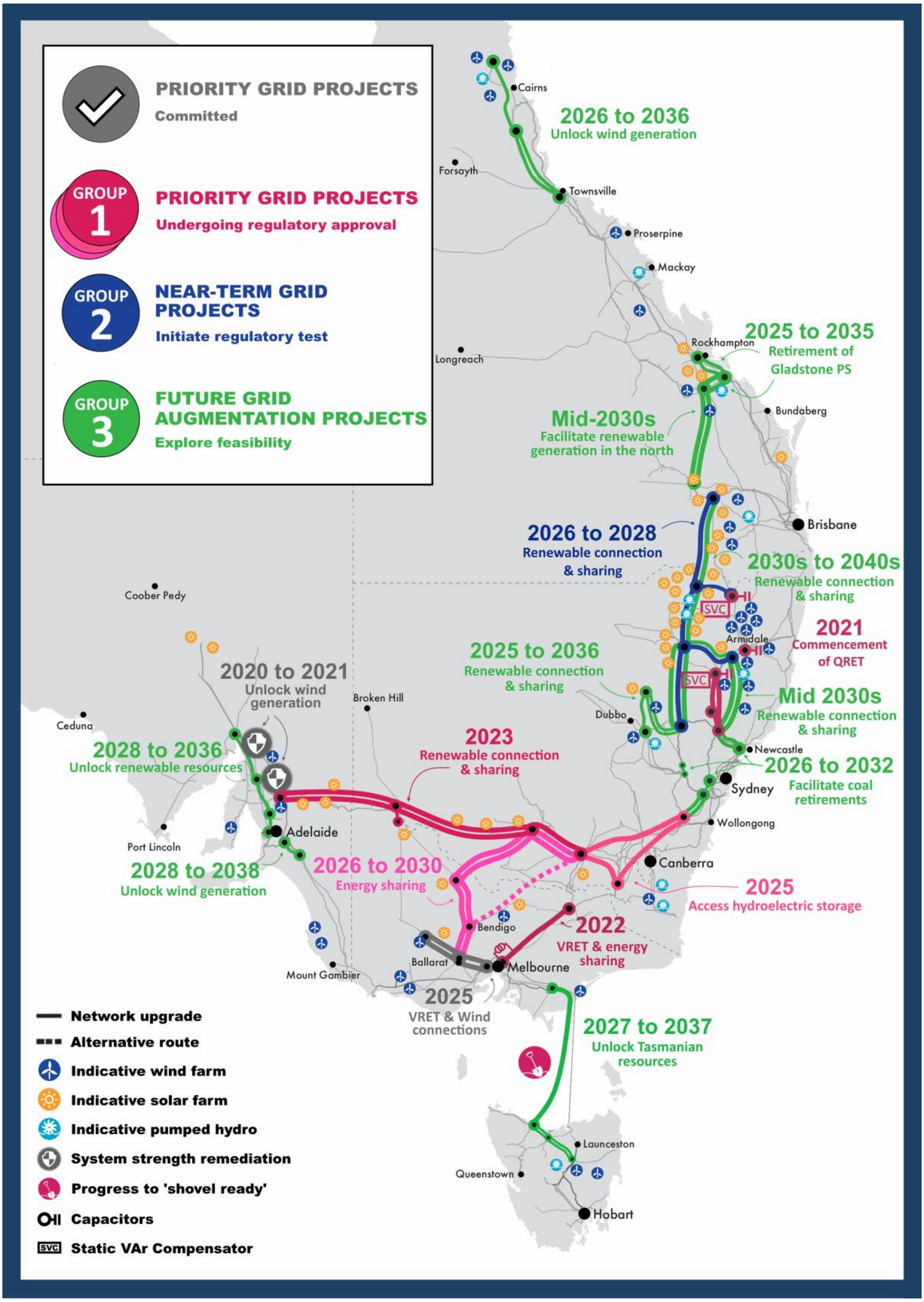
[16] The limits to renewables, and the requirements to realise these limits, are defined in Part D of this report, and in detailed scorecards in Appendix 8

Table 1 ISP development opportunities – REZs

Phases of REZ Development	REZ
Phase 1 To help meet regional RETs (such as VRET and QRET) and other policy initiatives (such as the NSW Electricity Strategy) until those schemes are complete and/or where there is good access to existing network capacity with good system strength, good resource potential, and alignment with community interests.	**Queensland:** Darling Downs (wind and solar), Fitzroy (wind and solar), and initial development of Far North Queensland (wind) **New South Wales:** Initial medium level development of Central West (wind and solar) **South Australia:** Roxby Downs (solar) **Victoria:** Western Victoria (wind) and South West Victoria (wind), Central North Victoria (wind).
Phase 2 To replace energy provided by retiring coal-fired generators – announced to occur from the late 2020s and/or where additional development is supported by the recommended transmission projects in Group 1 and 2 of the optimal development path.	**Queensland**: Larger development of Darling Downs (wind and solar), supported by QNI medium development **New South Wales**: North West (wind and solar), South West (solar), and Wagga Wagga (solar), supported by expansions including QNI Medium, Project EnergyConnect, HumeLink, VNI West and associated works. **Victoria**: Murray River (solar), supported by VNI West and Project EnergyConnect **South Australia**: Riverland (solar), supported by Project EnergyConnect, **Tasmania**: Midlands (wind), supported by Marinus Link
Phase 3 To accompany recommended group 3 transmission projects that are being developed specifically to support them.	**Queensland**: Larger development of Far North Queensland (wind), Isaac (solar), and larger development of Fitzroy (wind and solar) **New South Wales**: Larger development of Central West (wind and solar), New England (wind and solar), and North West (wind and solar) **South Australia**: Roxby Downs (solar), Mid-North (wind), and South East (wind)

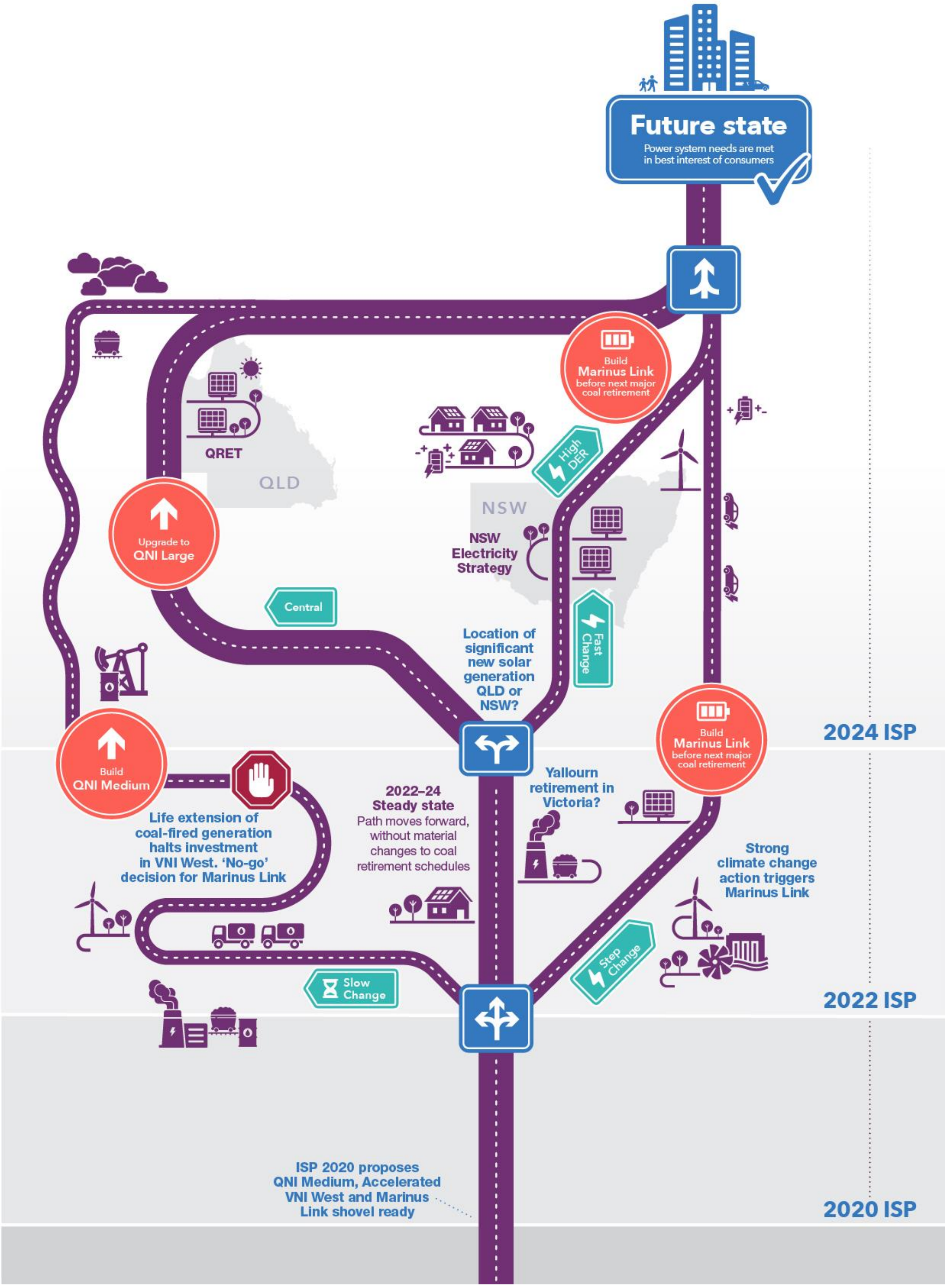
4. **Complementary regulatory and market reforms.**
   - **DER technical and market integration should commence immediately**. This includes uplifting operational tools to operate in a high DER world, ensuring visibility across the DER ecosystem to support decision making, and uplifting standards and protocols to improve the performance, capability and cyber-security of DER, across the energy system and in line with international best practice. AEMO is currently undertaking a Renewable Integration Study to define requirements for integration of renewables in the future power system. This study will also provide insights into the reforms needed to support DER. Without urgent and well targeted reforms, the high levels of DER projected in this ISP would not be achievable and limits may have to be imposed on DER instead, which would be a sub-optimal outcome for Australia.
   - **Market reforms currently being reviewed should be pursued**. The ISP's low-cost, low-regret development path will only be achieved and can only translate into consumer benefits through market arrangements that encourage the optimal use of existing resources and give appropriate signals for further investment. Market design needs to recognise and reward not just the provision of energy, but the increasing value of flexibility and dispatchability in complementing and firming variable generation as well as providing other system security services currently provided by the existing generators scheduled to retire.

Figure 1 The development paths for the NEM in the Draft 2020 ISP[17]



[17] All dates are indicative, and on a financial year basis. For example, 2023-24 represents the financial year ending June 2024.

Figure 2 Dynamic roadmap with choices to be acted on at significant decision points



The Draft ISP and its consultation

From mid-2020, the development and implementation of the ISP will be a regulated requirement under the National Electricity Rules: see Figure 3 below.

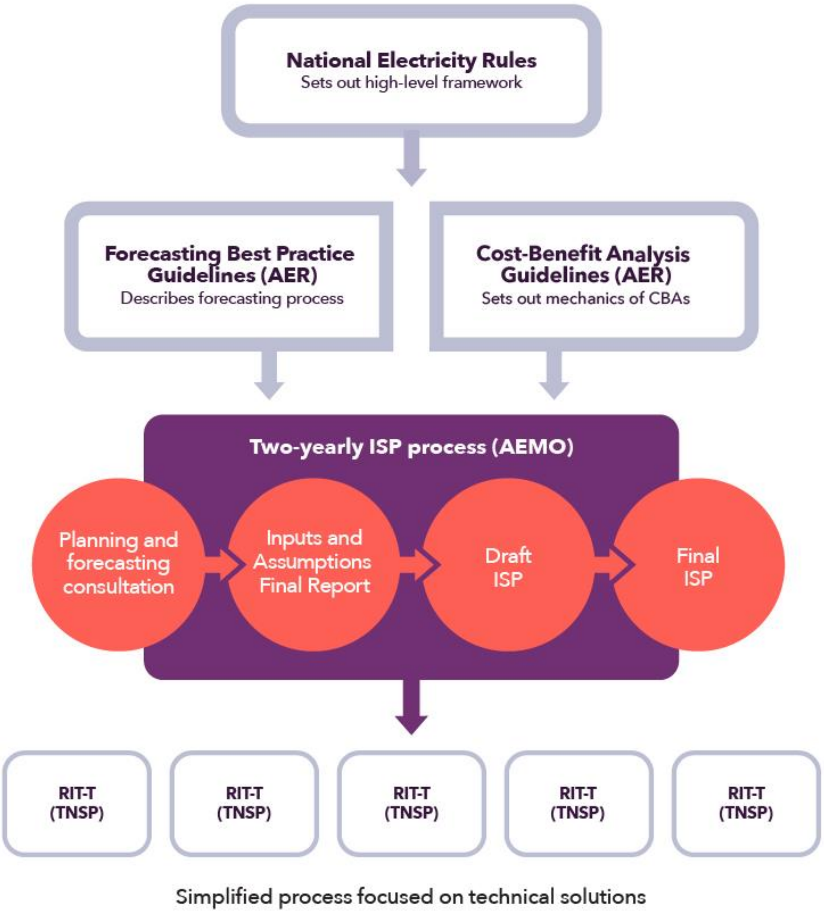
To achieve a smooth transition, AEMO has aligned its analysis and work with the current draft of the ISP Rules, being developed concurrently by the ESB. This alignment includes the completed Inputs, Assumptions and Scenarios work (see Section A1), the content of this draft Plan, consultation on the Draft ISP 2020 (Section E1) and the call for non-network options (Section E2).

While full details are in Part E, the major dates of that consultation are:

1. AEMO will hold public forums on the Draft ISP on 3-5 February 2020.
2. Written submissions will be accepted until 21 February 2020.
3. AEMO may hold further information sessions in February and March 2020.
4. The deadline for submissions on both the QNI Medium call for non-network options and the VNI West Project Specification Consultation Report (PSCR) is 13 March 2020.

In parallel, AEMO has commenced consultation on inputs and assumptions for other forecasting and planning work in 2020. Submissions are called for by 7 February 2020.

Figure 3 The regulatory context of the Draft ISP



Part A
A dynamic roadmap is needed for Australia's complex energy transition

Australia's energy sector faces a profound, complex and accelerating transition. As its traditional generators retire, Australia must invest in a modern energy system with significant consumer-led distributed energy resources (DER) and utility-scale variable renewable energy (VRE), supported by sufficient dispatchable resources.

The high probability of shifts in future technologies, behaviours, and business models, not to mention the complexity of the system itself, means that a single pre-determined path is not sufficient or robust. Instead, the ISP[18] provides a comprehensive guide to decision makers to support least-regret decisions as the environment itself changes.

This Part A frames the challenge for the ISP:

- Its scope is the whole National Electricity Market (NEM) power system
- Its guiding objective is to achieve power system needs while maximising net market benefits
- It must do so recognising the risks to consumers of investments made in uncertain times[19]
- The Draft ISP must therefore be a robust, transparent and dynamic roadmap.

Such an ISP will fulfil its broad purpose of informing power system decision makers about the power system and its development, and its specific purpose of triggering the process for the regulatory investment test for transmission for actionable ISP projects. This is set out in in Part D of this Draft ISP.[20]

A1 The ISP covers the whole NEM power system

The ISP goes much further than traditional models for planning future power systems. These have been based on large-scale power stations located around fuel centres supplying remote load centres through large-scale transmission, which is how the physical assets that comprise the current NEM were designed and built. Now, the ISP must optimise a power system that includes consumer-led DER investments in addition to electricity transmission, storage and generation investments and demand side response.

To optimise that system, the ISP must consider the full range of energy services required to integrate new technologies, including the vital system security services. It considers alternatives to traditional models of supply and demand, looking at localised options to avoid the use of network where feasible and economic.

[18] The term "ISP" refers to both the broader role of the ISP once made and the current Draft ISP under development.

[19] Clause 5.22.5(e)(1) Draft ISP Rules

[20] Clause 5.22.2(b)(1) Draft ISP Rules

As the ISP focuses 20 years into the future and beyond, it draws not only on existing technologies but anticipates innovation in consumer-owned DER, in virtual power plants (VPPs), in large-scale generation, in energy storage and in networks. It will also anticipate the impact of parallel shifts in connected sectors such as gas and the electrification of transport.

Hydrogen is not deeply explored in this Draft ISP. Hydrogen has the exciting potential to become an alternative energy storage technology and a new export commodity for Australia. Australia's recently released national hydrogen strategy[21] will be considered in the development of the Final 2020 ISP, which will provide a high-level analysis of how some of Australia's energy storage needs could be complemented by hydrogen once it is economically competitive. This analysis will also touch on the implications if a large-scale hydrogen export industry emerges towards the end of the ISP outlook period. Hydrogen may also be a viable alternative to decarbonising the gas and transport industry. As policy, economic and technological change progresses, it will be included in future ISPs in more detail.

Two areas that remain beyond the scope of this Draft ISP are energy distribution and nuclear generation. The costs and limitations of the distribution network in delivering the Draft ISP require further work and will be considered more deeply in the whole-of-system analysis in future ISPs. Nuclear has not been considered given current legislative prohibitions for domestic electricity production.

A2 Achieving power system needs while maximising net market benefits

The Draft ISP spans both market and consumer-led investments, seeking to achieve the reliability, security and public policy needs of the power system, in the long-term interests of electricity consumers. Those interests are best served by securing low, long-term system costs. These will maximise the benefits to consumers, assuming an efficient market.

A2.1 The reliability, security and public policy needs of the power system

The Draft ISP must achieve the power system needs of reliability, security, public policy objectives and their supporting system standards. Table 2 below summarises how these needs can be secured, and impacts assessed. These calculations are relevant to the net consumer benefits that the Draft ISP is seeking to maximise.

- **Reliability** means meeting consumer demand under normal operating conditions. It does not guarantee that all customer demand will be met at all times, as doing so would be prohibitively expensive. It means there must be enough generation, demand response and network capacity in the system to meet the energy needs of consumers to the economic levels defined by the reliability standard. A failure of reliability will lead to involuntary load shedding at levels that compromise public confidence and value as well as create health and safety risks.
- **System security** means ensuring that vital power system attributes such as frequency, voltage and system strength remain within safe limits. This is critical to the physical operation of a power system, and to avoid the potential for widespread interruption of electricity supply. This also minimises the risk of damage to the physical assets of the power system and in consumer/business premises, through large excursions in voltage or frequency. If the system is not planned to take

[21] www.industry.gov.au/data-and-publications/australias-national-hydrogen-strategy

account of these risks, it may not have the resilience to recover from contingency events, or consumers may be left paying for costly alternatives including emergency supplies and ad hoc interventions.

- **Public policy requirements** are the existing state and federal policies on emission reduction affecting the energy sector, including regulated, state-based renewable energy targets (RETs). Due to the already low cost of renewables and their firming options, and their projected future reductions, the ISP projects that the lowest cost replacements for emissions-intensive generation is a portfolio of renewable, storage, gas powered generation (GPG), DSP and network resources. With the Draft ISP projecting consumer demand from the grid to remain relatively flat, as emissions intensive generation is replaced with low emissions alternatives (VRE and DER), the ISP projects that a large amount of emissions reduction will be achieved through the natural market-led development of the NEM.[22] However, the Draft ISP shows that faster and deeper emissions reductions would require targeted direction by the governments of Australia.

Table 2 Power system needs

Need	Component	Secured by	Method of assessing need	Risk if need is not met
Reliability	**System adequacy**	Bulk energy and Strategic reserves	Assessing unserved energy under each alternate development path, converted to a cost using the latest estimate of value of customer reliability.	Involuntary load shedding (blackouts) as supply does not meet demand
		Transmission		Blackouts on transmission overload
		Operating reserves		Blackouts on supply disruption
		System restoration	Assessing the ability to restart after disruption	Extended blackouts
	Demand side participation	DER optimisasation	System productivity and efficiency through load shaping	Load shaping and optimisation, and unnecessary generation and network investment
Security	**Frequency stability**	Grid formation Inertial response Primary and secondary frequency control	Assessing additional services required for a secure and reliable power system	Ancillary services costs
	Voltage stability	Slow+Fast response voltage controls System strength		
Public policy requirements	**Emission reduction**	Changing generation mix, merit order dispatch and thermal generation retirements	Assessing least cost mix of investment and production decisions to meet specified NEM emission targets	Failure to meet public policy objectives
	RETs	New VRE and DER development	Assessing efficient investment needed to meet targets.	

[22] AEMO, Forecasting and Planning Scenarios, Inputs and Assumptions Report, 2019

A2.2 Maximising the net market benefits by minimising the system's long-term cost

AEMO uses long-term total system cost as its primary measure of what is in the interest of consumers. The alternative, market outcomes such as wholesale or consumer prices, are the product of total system cost and of effective market design. While total system cost can be modelled accurately based on input assumptions, market design may change over the ISP 20-year analysis period and over the typical lifetime of energy assets. The Draft ISP necessarily assumes that regulatory standards and obligations and market design are aligned to attract cost-effective investment, and adapt to support low total system cost, translating into the best outcome for consumers over time.

Table 3 Minimising total long-term system cost

Benefit	Secured by	Identified by	Costs avoided
Low operation cost	Low marginal cost	Cost of fuel, other operating costs, plant maintenance and plant start-up	Higher cost
	Efficient generation	Co-optimising future generation and transmission build (and retirement) timings and calculating the fuel costs associated with this generation mix.	Greater fuel consumption
	Efficient storage and transmission	Assessing additional generation costs effectively wasted due to network losses under each alternate development path.	Network losses
Low capital cost	Deferred capital	Time value of money	Capital expenditure
	Optimal investment size	Total generation and transmission costs, compared to counterfactual	Capital expenditure
Option value	Least-regrets modelling	Assessing risks and regret of an investment (or lack of) based on an assumed future that doesn't play out.	Lost options/flexibility

The Draft ISP considers the whole of the power system, including all fuel, generation, transmission, storage and network service elements.[23] Total system costs include all capital, operating and compliance costs of those elements[24], as well as any options lost in making a decision. The cost of a decision must also include any negative impact on desirable network or consumer benefits. For example, a decision that leads to consumers having to limit their desired energy use reduces the consumer benefit of on-demand energy use.

The classes of costs and benefits modelled in the Draft ISP are aligned with the categories in RIT-Ts.

A3 Balancing the risks and costs of making decisions in uncertain times

It would be relatively simple and certain to optimise cost, reliability and security if our energy system and its operating environment were also simple and certain. Yet the NEM is a complex system and external influences change its operating environment frequently. The Draft ISP must therefore be both

[23] Clause 5.22.8(c)(i) Draft ISP Rules

[24] Clause 5.22.8(a) Draft ISP Rules

dynamic and transparent. A dynamic ISP can guide market participants when the operating environment changes; a transparent ISP gives participants confidence in that guidance, particularly when they must keep options open or accept sunk costs.

A3.1 Complexity and uncertainty are unavoidable

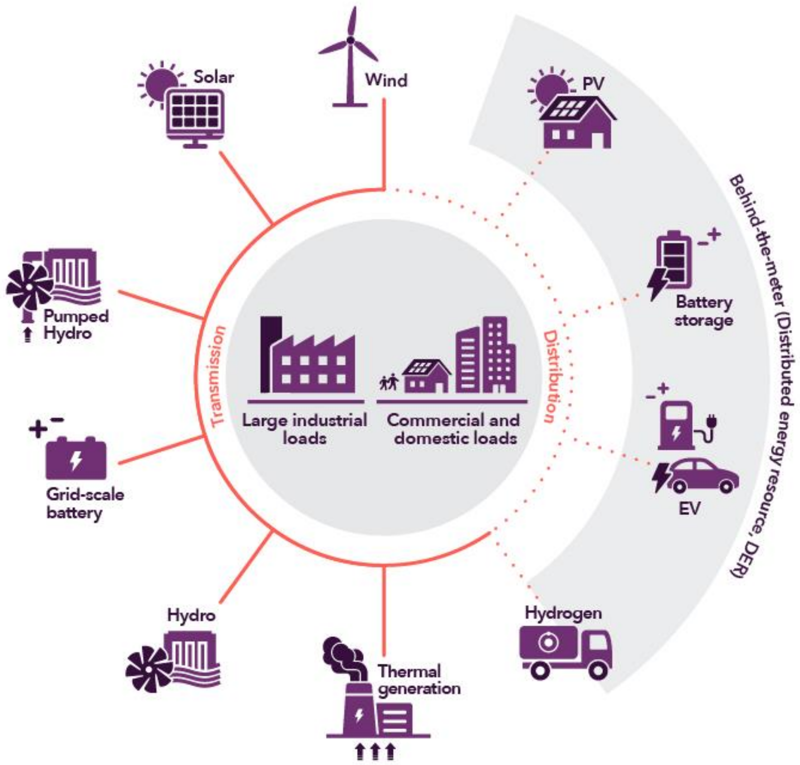
The Draft ISP aims to take into account:

- complex and interdependent factors in the physical system, and
- changes in the future economic, trade, security, policy and technology environments.

The complexities include the rapid introduction of increasing levels of consumer-driven DER, satisfying the critical operational needs for the power system, arrangements to replace exiting generators and deploy replacement resources ahead of, or in alignment with, those exits, low-cost but variable resources, storage, transmission investments, climate change impacts, and increasingly scarce system services.

The first major complexity is the interaction between behind-the-meter and grid-scale supply: see Figure 4. Consumers are increasingly managing their demand, and investing in DER, batteries and now electric vehicles. Digital controls and falling costs are making these assets easier and cheaper to adopt. Consumers can now take advantage of new business models offering VPPs. Each decision changes how and when the NEM will deliver energy. As consumers install rooftop PV, the level of uncontrolled energy in the system increases, and as batteries and EVs charge and discharge, the demand profile for grid-supplied energy shifts, which in turn influences how generators operate and increases the value of flexible generation and storage.

Figure 4 Overview of power system showing interactions between grid and behind-the-meter energy supply



The second major complexity for the Draft ISP is forecasting when existing black and brown coal plants will either reduce generation or shut down. The owners of these assets will make their decisions based on a range of commercial factors, and in the context of energy and climate change policies, market arrangements, competing technologies, and social and investor licences. The Draft ISP's objective is to maintain power system reliability and security throughout this transition.

Large thermal assets have been fundamental to the design, construction, and operation of both the physical power systems and the NEM, so the development path to replace them is fundamental in the design of future market arrangements for the NEM. While individual VRE plants may be quick to build, they are dispersed across the country, often in weak areas of the grid. At the scale and combination projected by the Draft ISP to replace the outgoing thermal assets, they will require supporting infrastructure such as network capacity and system services to maintain system reliability and security. As individual VRE are not all developed at the same time, delivery of large-scale network access with long development lead times can be a challenging coordination task.

An accelerating complexity is achieving system resilience against a broad array of extreme weather and climate impacts. System resilience is enhanced through fuel diversity, geographic diversity and strategic redundancy. Given the increasing likelihood of extreme events, maintaining static levels of system redundancy will increase costs and risks for consumers, suggesting an incentive for earlier investment timing.

The potential changes to the power system's operating environment are just as daunting as the complexities. As noted above, the energy system must be secure and reliable enough to withstand variable consumer demand and unplanned events. More changes are likely in the economic, trade, security, policy and technology environments in which the energy system operates. Australia's economy may shift towards or away from energy-intensive sectors. An emerging global hydrogen economy may offer Australia strong growth in a new energy-intensive export industry. Limits on international free trade may dampen demand for our existing energy-intensive exports, as may global security risks. Federal and state policies may restrict the availability of natural gas, or set targets for renewable energy or emissions.

A3.2 Yet investments must be made, balancing the risks of early and late action

The replacement of large-scale coal-fired power stations involves large-scale investments and deployment of new infrastructure, with long lead times and complex integration with the rest of the power system. Decisions on what and when to invest must be wise, for the consumer, the investor, and for the energy system itself. It is hard enough for investors to make such decisions within the complexity of the power system. A changing environment makes it even harder. Yet Australian consumers rely on these decisions being made for their economic and physical wellbeing. If decisions are delayed or aborted, domestic and industrial consumers will face increased costs and risks.

The Draft ISP assumes generation investments will be guided by a well-functioning market that has appropriate signals to guide timely investments. In support of that market, the Draft ISP aims to help identify, assess and reduce as many of the associated investment risks as possible, and offers guidance for when the operating environment changes.

These generation investments also rely on the critical enabling role of the network. The Draft ISP recommends specific transmission investments that in the long run are both desirable and least-regret. For any investment, there is the risk of over- or under-spend, and the resulting costs and risks are ultimately borne by consumers. To assess the risk exposure of over-investment in transmission infrastructure, the Draft ISP compares all potential development against the "counterfactual" of no further investment in that asset class.

The question then becomes *when* a decision on a desirable investment is needed, in the face of uncertainty. This is particularly challenging for investments with long lead times, a common dilemma for large-scale infrastructure investment, including transmission. Investing too early may lock the NEM into a development path that will be regretted in the future, possibly increasing consumers' costs. However, making decisions too late can lead to late delivery of essential infrastructure, with potentially severe consequences such as extreme price events and/or load shedding, when physical assets are simply not available to serve consumer needs. Late transmission investment can also drive higher costs to customers in the form of investments in relatively expensive forms of generation to address short term reliability gaps.

The Draft ISP assesses the asymmetry between investing early, which for the right investment is typically lower cost, and investing late. Careful analysis of the risk asymmetry helps to guide whether investments should be 'just in case' or 'just in time'.

A4 A robust, transparent, dynamic roadmap for Australia's energy transition

To meet its objectives, the Draft ISP uses a cost benefit analysis to determine a robust and transparent plan for future development of the NEM. However, a single static development path or plan will not do the job, even if it appears optimal in 2020. Instead, the Draft ISP provides a *roadmap* that shows:

- the initial optimal development path for Australia's future energy system, as proposed in the Draft ISP Rules
- the signposts at which that path may need to change course as economic, physical and policy environments change, and the options we may then have.

The ISP roadmap must be robust, to underpin secure, reliable, low-cost energy from the outset. It must be dynamic, given the complexity of the energy system and its changing operating environment. And it must be transparent in both process and outcomes, to give participants confidence in its guidance.

The concept of a 'dynamic' roadmap may not be common in policy planning, yet it is common in making decisions on capital investments. At regular intervals or when a particular signpost is reached, the roadmap is updated to changes in the economic, physical and policy environments.

The concept of 'least-regret' decision-making is a strategic approach to managing future risks and outcomes of good and poor choices. Under uncertainty, investors typcially consider any potential regrets from their decisions, and seek to reduce those regrets as far as practicable. The Draft ISP must similarly consider any potential regrets on behalf of consumers. For example, an investment to upgrade a transmission line to serve a power station may no longer be needed if that power station closes earlier than expected. These regrets translate to additional costs or lost opportunity, and, in the worst case, a stranded asset. All these outcomes will increase costs to the consumer.

To minimise these regrets, decision-makers can choose to invest now in the option with the least downside risk, or defer investment until there is more certainty, or stage investment or select options that retain flexibility, or invest as well in a way that hedges their major investment.

Part B
Scenario modelling to meet the objective of an ISP

AEMO uses scenario modelling and cost-benefit analysis to determine economically efficient ways to provide reliable and secure energy to consumers through the energy transition. Exploring scenarios helps assess the future risks, opportunities, and development needs in the energy industry, in the long-term interests of consumers.

Scenario modelling does not set out to suggest that any one scenario is more likely or more preferred than others. Rather, it looks for insights into how our energy system may robustly meet our energy needs through the transition. To do so, the selected scenarios must cover a broad range of plausible operating environments for the energy sector, and the potential changes in those environments, in an internally consistent way.

Part B sets out how AEMO has used scenario modelling to determine the least-regret, low cost development path to meet the NEM's reliability, security and emissions expectations. It covers:

- the ISP options and assumptions that have been agreed through extensive consultation
- the five scenarios (plausible operating environments for the power system), and six sensitivities to be tested, and
- the modelling process AEMO has followed in seeking a least-regret, low-cost development path.

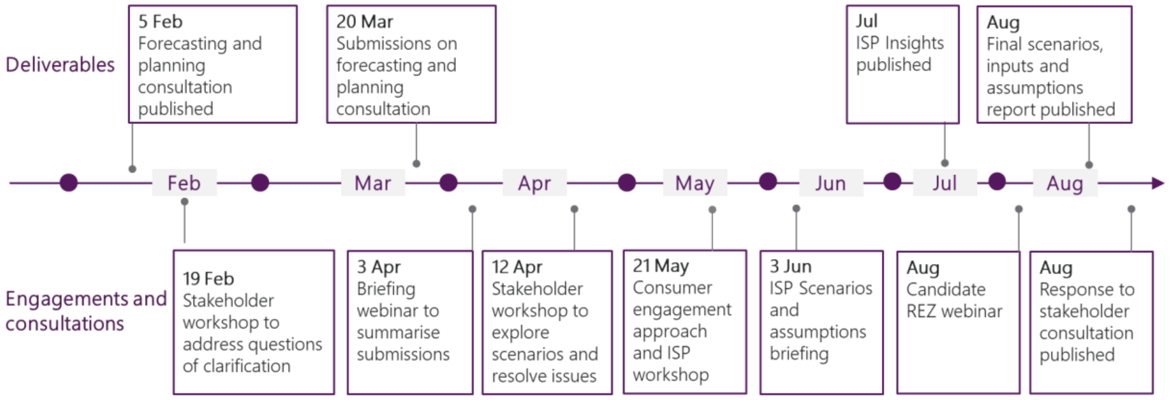
The following Part C summarises the investments needed for Australia's future energy system: in DER, VRE, supporting dispatchable resources and power system services, and the NEM transmission grid, and Part D set out the optimal development path.

B1 ISP options and assumptions have been agreed through consultation

For the 2020 ISP, AEMO has consulted extensively with industry, academia, government, developers and consumer representatives to determine scenarios and associated input assumptions.

AEMO values the input provided through over 25 detailed written submissions, four workshops and numerous stakeholder meetings held since the start of the 2020 ISP process. Overall, this ISP process has involved over 100 stakeholders from the energy industry.

Figure 5 Consultation on scenarios, inputs and assumptions



B1.1 Input detail in Forecasting and Planning Scenarios, Inputs and Assumptions Report

This consultation culminated in the *Forecasting and Planning Scenarios, Inputs and Assumptions Report* published in August 2019[25]. This report is an essential source document for this Draft ISP. It sets out the detail and sources of all the inputs and assumptions on which the Draft ISP relies, including:

- **Demand and supply inputs**, including energy consumption forecasts, electric vehicle adoption, and policy, technical and economic settings that affect energy supply.
- **Generation and storage inputs**, including existing generation assumptions, the uptake of DER, gas and electricity system co-dependencies (allowing for domestic gas use and LNG exports). For generation technology cost options, AEMO partnered with the CSIRO on the GenCost project[26], working collaboratively with industry to annually review and update projections of electricity generation technology costs.
- **System variables** that need to be considered in the analysis, including system security constraints, network losses and Marginal Loss Factors (MLFs), system strength and inertia requirements, and
- **Market modelling** approaches for both gas and electricity markets, including approaches to improve representation of storage modelling, better capture the effects of weather on the system and the need to build greater power system resilience[27]. Improvements in modelling to better assess the revenue sufficiency of existing thermal fleet have also been consulted on.
- **Network development options**, including REZs, interconnector augmentation options and non-network technologies. The REZ options were developed initally with DNV-GL[28] and with wide stakeholder consultation in 2017. For the 2020 ISP, AEMO has refined these candidate REZs against

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[25] AEMO has reported on how that feedback has been taken into account, and provided an Excel workbook containing data inputs: see AEMO 2019 Input and Assumptions workbook v1.1 in the workbook archives.

[26] CSIRO, GenCost 2018 Updated projections of electricity generation technology costs, December 2018

[27] Changes in the future climate, including an increasing number of extreme weather events, can increase stress on the power system, so it is important that the system is resilient to these risks. The Australian Government is providing $6.1 million over three years, from 2018-19, to fund the Electricity Sector Climate Information (ESCI) project. Through this project, CSIRO and Bureau of Meteorology in collaboration with AEMO will deliver specific information and data to the electricity sector to improve the reliability and resilience of the NEM to the risks from climate change and extreme weather. https://www.environment.gov.au/climate-change/adaptation

[28] DNV-GL, Multi-Criteria for Identification of Renewable Energy Zones, April 2018

regional policies and inputs, and each candidate REZ's features and transmission needs are set out in Appendix 8.

- **Transmission project options** were refined in consultation with transmission network service providers (TNSPs) through joint planning and extensive power system engineering, to ensure that robust technical designs were used in the modelling. For major interconnections, many options were assessed encompassing differing routes, design implementation, staging, and alternatives including non-network options. For example, for the major new interconnections between New South Wales and Victoria, and New South Wales and Queensland, over a dozen headline options were assessed covering differing routes, voltages, capacities, non-network optimisation and design options. A full listing of options considered can be found in Appendix 6.

Box 1 below lists the improvements in the 2020 ISP methodology over the 2018 analysis, which have been discussed at and/or been a result of the stakeholder consultation.

Box 1: Process and analysis improvements from ISP 2018

Improvements in the 2020 ISP methodology over the 2018 analysis, discussed at and/or have been a result of the stakeholder consultation

Changes to inputs

- A higher expectation of energy conservation and efficiency has flattened overall energy consumption, generally reduced peak and minimum demand over the outlook period;
- A much wider range of DER uptake is investigated across the Draft 2020 ISP scenarios;
- A more comprehensive assessment of the impact of increasing temperatures on demand, and decreasing rainfall on hydro generation output;
- Coal generators are expected to leave slightly more rapidly than assumed in the 2018 ISP;
- Generation costs have been refined — Gas and Renewable generation costs are slightly lower compared to 2018 while Energy storage costs are slightly higher than 2018. Transmission costs have experienced only minor adjustments;
- A significant number of projects have become committed since the 2018 ISP

Changes to process

- More extensive consultation with stakeholders to establish a set of plausible scenario input assumptions that cover the key uncertain and material variables in a consistent manner.
- Increased transparency in the decision-making framework, explicitly identifying risks under various development paths, and valuing optionality
- Cross-sector collaboration with the transport industry to validate assumptions around transport electrification

Changes to analysis

- Greater recognition of the role energy efficiency can play in reducing total system costs
- More detailed assessment of the value delivered by a portfolio of storage solutions of varying depths
- Incorporation of weather uncertainty in the assessment of costs and benefits
- In-depth assessment of the intra-day operability of the system, and threats to ongoing viability of incumbent generators

- More detailed and in-depth assessments of the requirements to realise and operate the future power system under the projected resource mixes, in particular, the requirements for system security and dispatchability in a system with large amounts of VRE. Included in this are assessments of the infrastructure needs for critical system services (such as system strength), and the costs of these have been factored into projections

B2 Scenarios and sensitivities to span all plausible operating environments

Five scenarios have been developed to cover plausible futures that span differing rates of change in technology development, renewable and distributed generation, decarbonisation policies, and the electrification of other sectors such as transport.

In all scenarios, the Draft ISP continues to project a continuing and profound transition of the NEM over the next two decades. As stated in the 2018 ISP, our energy system is transitioning from one dominated by coal-fired generation to one of diverse renewable and distributed energy generation, supported by energy storage and network solutions. This outcome has been consistently generated by all AEMO and peer iterative modelling since the Finkel Review, and has been adopted and confirmed throughout the consultations.

The difference between the scenarios is in the pace of that transition. To date, the pace of development in new renewable and distributed energy generation has been even faster than anticipated in the 2018 ISP.

B2.1 The Central Scenario and variations in the speed of transition

In the **Central scenario**, the pace of transition is determined by market forces under current federal and state government policies. A policy is current if it is either a commitment made in an international agreement, legislated in Australia, required by regulation, in receipt of material funding from a state or federal government budget, or otherwise if COAG has advised AEMO to incorporate the policy. The Central scenario therefore incorporates[29]:

- the NEM's share of the Federal Government objective of reducing emissions by at least 26% by 2030
- Renewable Energy Targets in Victoria (VRET, 50% by 2030) and Queensland (QRET, 50% by 2030)
- the New South Wales Electricity Strategy[30] (included in Draft ISP as a sensitivity only due to the release of this strategy in only late November 2019)
- the Snowy 2.0 energy storage project, and
- all current state and federal policies impacting DER and energy efficiency (EE) policies.

A potential ISP development path is only considered justified when it is assessed as likely to deliver benefits under the Central scenario.

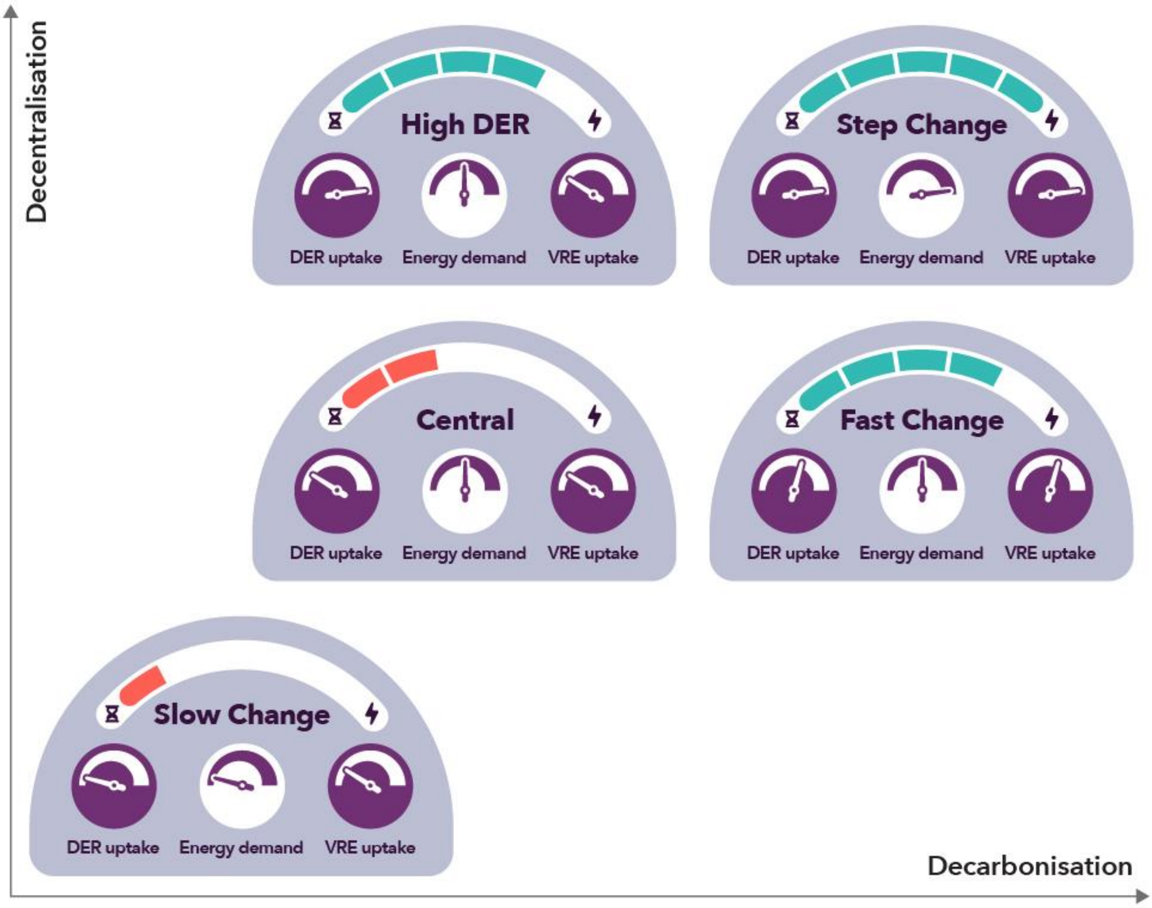
[29] Clause 5.22.3(b) Draft ISP Rules

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

The other scenarios are variations in the pace of the transition – one slower than the Central scenario, and three faster.

- **Slow Change scenario:** a slow-down of the energy transition, characterised by slower changes in technology costs, and low political, commercial, and consumer motivation to make the upfront investments required for significant emissions reduction.
- **High DER scenario**: a more rapid, consumer-led transition, as consumers take control of their energy costs with easy-to-use, interactive technologies, falling costs for DER and electric transport, while existing generators accelerate their exit.
- **Fast Change scenario**: a more rapid technology-led transition, its costs reduced by advancements in grid-scale technology and targeted policy support. Coordinated national and international action to reduce emissions leads to innovation, automation, the accelerated exit of existing generators, and greater electric transport.
- **Step Change scenario:** both consumer-led and technology-led transitions occur in the midst of aggressive global decarbonisation and strong infrastructure commitments.

Figure 6 Comparative rates of decarbonization and decentralization across the five Draft ISP scenarios



B2.2 Additional sensitivities

Additional sensitivities have been used to identify the magnitude of impact of key assumptions and test how well the roadmap can adapt if specific decisions are taken in the near future. Through consultation, AEMO has identified six additional sensitivities, including specific near-term decisions, to complement the scenarios and test the robustness of the power system:

- **Delay of Snowy 2.0:** if the Snowy 2.0 project was delayed unexpectedly without replacement
- **Early retirement of existing generation:** if brown coal power plants reduce generation earlier than submitted retirements, without replacement. A reduction is possible through early retirement, seasonal mothballing or long-term maintenance.
- **Adding Marinus Link to support the Battery of the Nation (BOTN):** To complement Snowy 2.0, the commitment of Marinus Link with 750 MW in 2026-27 and (optionally) a further 750 MW in 2031-32, providing access to existing and new hydro storage options in Tasmania.
- **Excluding the QRET policy.** To test the regional development of renewable resources in Queensland and its impact on New South Wales as well as the impact of this on transmission development.
- **Central West New South Wales REZ:** if the New South Wales Electricity Strategy attracts at least 2 GW of additional VRE in the Central West New South Wales REZ by 2028.
- **Closure of industrial load:** if a large smelter in Victoria closes in the next ten years.

In addition to the scenarios and additional sensitivities, AEMO has tested several assumption uncertainties that may materially influence outcomes. For example, AEMO has run sensitivity analysis on inputs such as future grid-scale battery costs, and the potential for pumped hydro on the mainland: see AEMO's 2019 Scenarios, Inputs and Assumptions Report[31].

B3 Modelling development paths to meet power system needs across all scenarios

AEMO modelled the scenarios and their sensitivities to determine the least-cost development path to achieving power system needs in each individual scenario. Then, AEMO identified the development paths that would be the least-regret development paths across *all* scenarios.

B3.1 Calculating the NPVs of net market benefits using cost-benefit analysis

Through the ISP process, AEMO is identifying identifies the optimal development path that:

- meets power system reliability, security and public policy needs
- achieves positive net market benefits under the Central scenario[32], and
- minimises regrets across all scenarios.[33]

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[31] https://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

[32] Clause 5.22.5(e)(3) Draft ISP Rules

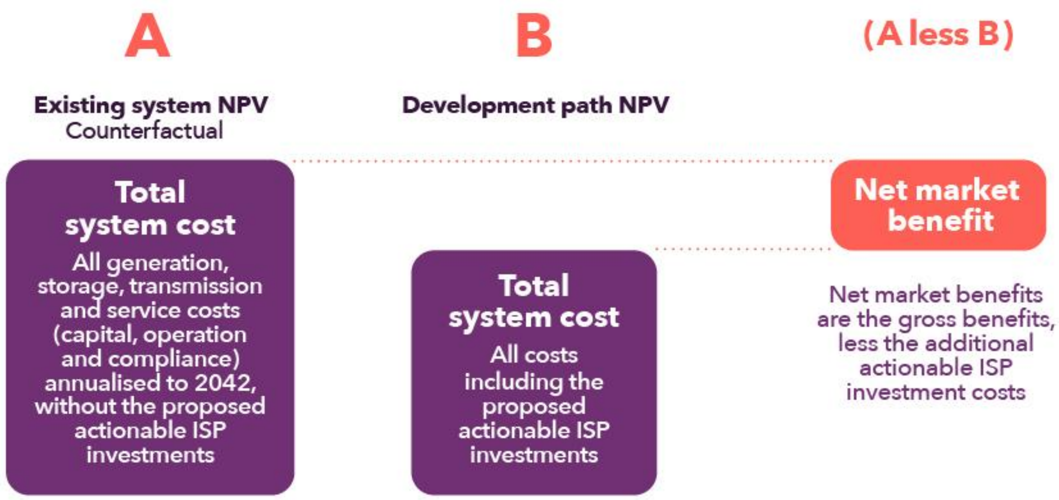
[33] Chosen by AEMO as the best method to select the optimal development path under R.22.5 (e)(2)

To enable the potential development paths to be compared, AEMO's first task is to determine the net present value (NPV) of their net market benefit. That is simply defined as the reduction in their total system cost relative to a counterfactual with no further transmission development: see Figure 7.

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

As shown in Figure 7, when conducting whole-of-system planning, the least cost development path is also the development path that maximises net market benefits. This is because the Draft ISP development path includes generation and storage developments and their fuel costs as well as transmission developments.

Figure 7 Cost-benefit analysis calculation of net market benefits of development paths

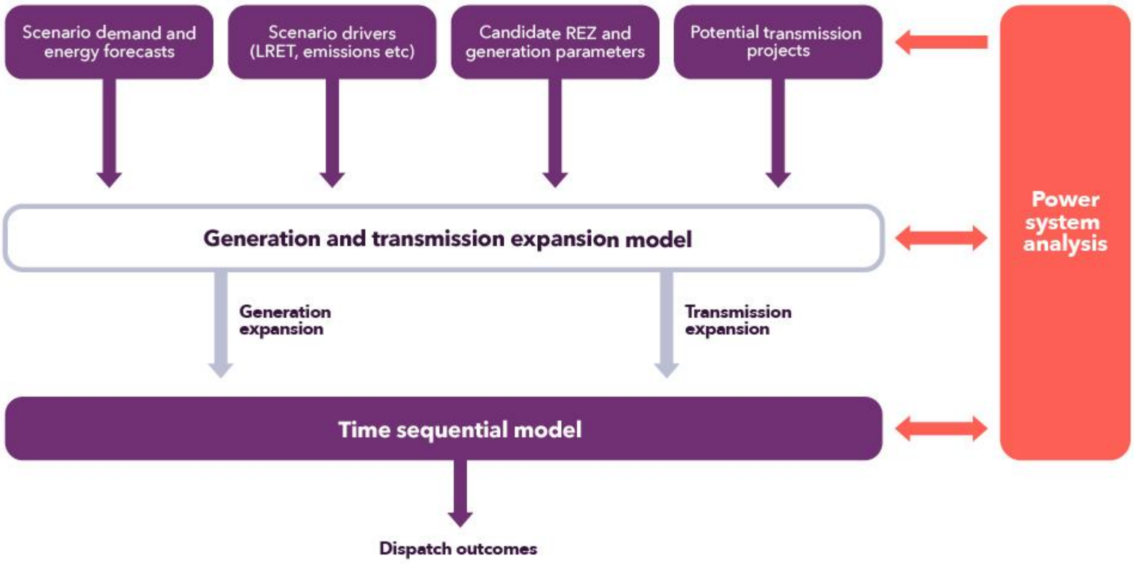


Columns related to the tables in this Draft ISP that detail the cost-benefit analysis of particular projects or development paths

B3.2 Finding the least-cost development path for each scenario

Even within one scenario, there are near-infinite possibilities to mix generation, storage, transmission and DER to meet the cost, security, reliability and emissions expectations. To determine the optimal mix, AEMO ran the multi-phase integrated modelling shown in Figure 8.

Figure 8 Multi-phase integrated modelling to determine the optimal development path for each scenario



The inputs were the scenario and sensitivity options, and the candidate generation, storage, transmission and REZ options – all detailed in the *Forecasting and Planning Scenarios, Inputs and Assumptions Report* and briefly summarised above. In all cases, AEMO also considered counterfactual options – e.g. not to build a future interconnection option – to confirm the optimal investment plan.

AEMO first ran the NEM generation and transmission expansion model (see Box 2 below) to identify the most economic way to meet projected consumer demand. As options for network augmentation were refined, the modelling re-evaluated the generation and storage mix. Eventually, the modelling revealed the lowest-cost (NPV) outcome for the location and staging of resources as well as the optimal evolution of the network configuration.

To verify that these outcomes would deliver the desired system reliability and security performance, they were then tested in a time-sequential model, hour-by-hour in snapshot years, against detailed transmission constraints, unit commitments and bidding behaviour. These results were also tested in a detailed power system model (see Box 2) to ensure system security. Where necessary, the leading outcome for each scenario was iterated in the time-sequential model until the optimal outcome was identified.

Box 2: Models for economic and power system outcomes

For the economic outcomes, AEMO used PLEXOS® software to model the gas, electricity, storage and transmission investment that would minimise the total system cost while meeting reliability and emission expectations. The modelling incorporated:

- Options for energy storage, particularly in combination with variable renewable energy to substitute for retiring coal generators,
- DER co-ordination so that distributed generation and storage could help meet system as well as consumer needs, and

- In the relevant scenarios, 2050 carbon budgets as a hard constraint that must be achieved, leading to year-on-year emission trajectories determined by PLEXOS®. No carbon price is used in any scenario.

For the power system analysis, AEMO relied on PSS/E tools, including loadflows, fault levels, dynamics and reactive power/voltage control. AEMO also applied the outcomes of previous modelling using PSCAD that defined detailed requirements for inertia and other system security services. The modelling considered options for alternative network and non-network infrastructure:

- HVAC was generally preferred for the major ISP projects, designed to share diverse resources across areas and regions. HVDC was generally more expensive due to the multiple convertor stations needed to connect REZs and VRE along the route. HVDC could be used in more targeted areas, such as point-to-point connection of individual VRE projects, or for connections within REZ.
- Targeted application of non-network technologies such modular power flow controllers and other static devices will be critical to optimise power flows in the augmented network. These are detailed in Appendix 9 of this Draft ISP.
- While batteries were considered to offset capacity needs, HVAC solutions were generally preferred as large-scale (1-3 GW) augmentations are needed to provide large-scale transfer capacity and fulfil REZ needs. Batteries should be explored for incremental gains when finalizing the designs of the transmission projects in the RIT-Ts.

B3.3 Selecting the optimal development path across all scenarios

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.

The process for determining this is repeated for all scenarios:

1. Identify the set of investment decisions (D_1) 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 (C_1).
2. 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 (C_2).
3. The 'regret cost' of the original investment in the second scenario is then the increase in total system costs ($R_1=C_1-C_2$) associated with making a suboptimal decision.
4. Repeat steps 2 and 3 across all scenarios and sensitivities to get a range of regret costs (R_1....R_n), revealing W_1 as the worst of the possible regret costs for the investment set D_1.
5. 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 (W_1......W_n).
6. The set of decisions with the least worst regret cost in the range (W1 .... Wn) become part of the optimal development path.

The results of this analysis for candidate development paths are set out in Part C.

This least-regret approach to cost-benefit analysis is preferable to a probability-weighted approach in two respects. First, as the regret costs take into account the adapted plans, the approach selects a path that is flexible as new information becomes available, rather than locking in a single view of the future as may occur under a probability-weighted approach.[34] This approach supports realistic, transparent decision-making, because it identifies and compares the risks in each scenario, rather than distilling outcomes into a single probability-weighted NPV, which tends to obscure the risks of not being prepared for a range of different worlds that may be faced.

Further, it avoids the need to ascribe probabilities to either the scenarios or its events, which inevitably requires a subjective assessment of each scenario's likelihood. It is particularly strong if the analysis is not unduly swayed by either a large benefit or regret in an highly unlikely scenario – possibilities that AEMO has sought to avoid.

[34] TNSPs are required to use a probability-weighted approach under the current RIT-T framework, although AER's Issues Paper on the Cost Benefit Analysis Guidelines contemplates that this may change.

Part C

A future least-regret energy system

The objective of an ISP is to minimise long-term total system costs, thereby maximising benefits in the interest of consumers, while meeting the NEM's reliability, security and emissions expectations. We have set out in Part B our modelling approach to determine a least-regret development path to meet that objective.

We now lay out the results of that modelling, which in effect describes what our power system might look like in 2040 if it is to meet all its expectations, and the investments needed to get there. The individual scenario outcomes are laid out in the double-page Figure 11 below. The years are indicative and are financial years (i.e. 2030 is the financial year 2029-30). Part D, the roadmap itself, reveals the optimal development path, and the staging and approximate timing for investments. In this Part C, all dates are indicative and on a financial year basis.

Across all scenarios, the NEM will evolve from a *centralised* coal-fired generation system, to a highly *diverse* portfolio dominated by DER and VRE, supported by enough dispatchable resources to ensure the power system can reliably meet demand at all times.

In that transition, the ISP development opportunities can be broadly classified as:

1. **Small-scale distributed energy resources (DER) is expected to double, and in some scenarios triple, by 2040**, holding grid demand relatively constant. Residential, industrial and commercial consumers are expected to continue to invest heavily in rooftop PV, with increasing interest in battery storage and load management. Depending on the scenario and subject to technical requirements, the modelling projects that DER could provide 13% to 22% of total underlying annual NEM energy consumption[35] by 2040. With these higher levels of DER. dedicated management practices and protocols will be needed to maintain system security, backed by changes to rules, regulations and standards. New DER installations will increasingly need to have sufficient interoperability capabilities so they can be controlled when required for power system security. AEMO is currently investigating the maximum levels of uncontrollable energy that the system can accomodate and remain secure.
2. **Over 30 GW of new grid-scale renewables (VRE) is needed** in all but the Slow Change scenario, beyond what is already committted. Approximately 15 GW or 63% of Australia's coal-fired generation is set to retire by 2040. To ensure a gradual, orderly transition, there must be sufficient new generation in place before each major plant exits. Allowing for the strong growth in DER, the NEM will need an additional 34 GW of VRE for the Central scenario, 30 GW for High-DER, 37 GW for Fast Change or 47 GW for Step Change, much of it built in REZs. In the Slow Change scenario only 4 GW would be needed, due to lower economic growth combined with delayed retirement of existing generators.

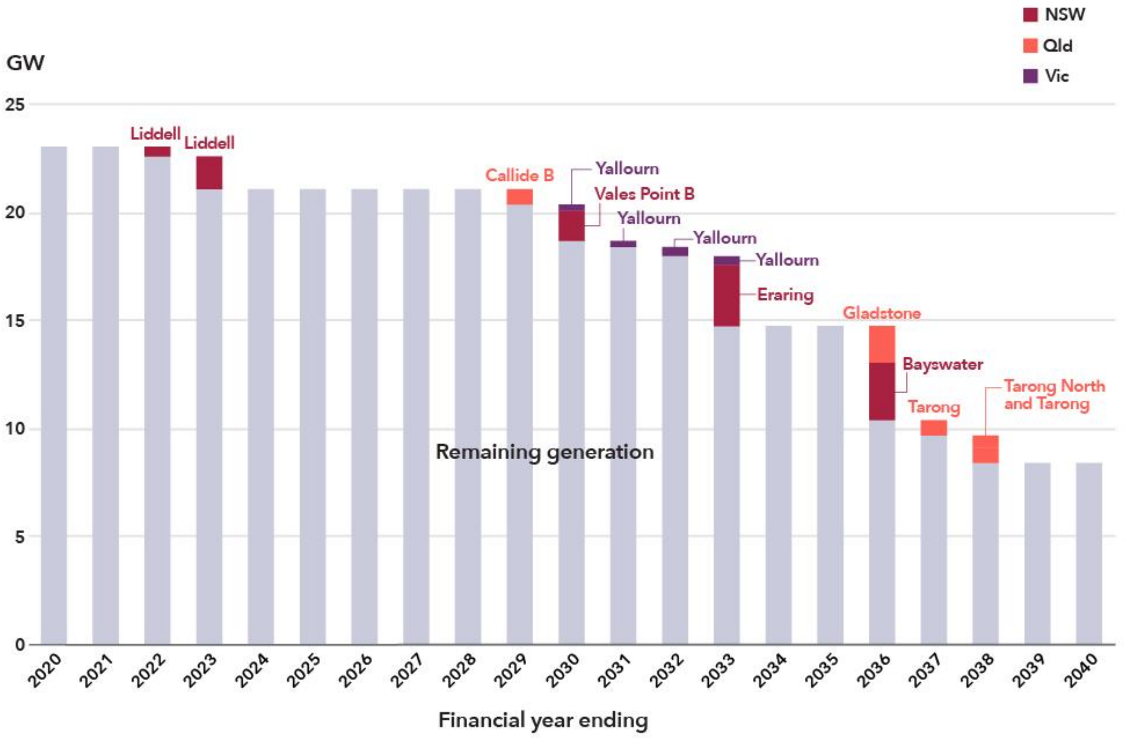
[35] Total annual underlying NEM energy consumption, including rooftop PV, and PVNSG (commercial-scale PV, behind-the-meter and <30 MW per installation). The level of instantaneous uncontrolled power that will need to be operationally managed at times of DER peak export will be much higher.

3. **5-21 GW of new dispatchable resources are needed in support.** To firm up the inherently variable renewables, we will need new flexible, dispatchable resources: utility-scale pumped hydro or battery storage, demand response such as DSP, and distributed batteries participating as VPPs. New flexible gas generators could also play a greater role if gas prices materially reduce.
4. **Investments to provide power system services are critical to enabling the transition.** Innovative power system services will be needed to transform a system that has been dominated by traditional thermal generation with large spinning generators. These services span voltage control, system strength, frequency management, power system inertia and dispatchability. System services will be a critical part of REZs.
5. **The transmission grid needs targeted augmentation to provide capacity, balance resources and unlock Renewable Energy Zones (REZs).** While over 30 GW of new VRE may be required by 2040, the existing network only has an estimated connection capacity for 13 GW within the identified potential REZ. Three types of projects are considered in this Draft ISP to augment the grid: current projects, additional regional interconnections and intraregional augmentations. The most cost-effective way to provide the required connection capacity for VRE is to develop strategically placed interconnectors in conjunction with REZs. Five alternative development paths for these investments are compared in Part D, revealing the optimal development path of the Draft ISP.

The pace of the transition varies by scenario, although the trends are very consistent. Figure 11 illustrates and contrasts the change in installed capacity mix over time for each scenario, shows the broad geographic location of existing, committed and new VRE, and highlights the scale of development in various types of energy storages required. As more coal-fired generation retires (Figure 9), and is replaced with VRE, total installed capacity needs to increase to supply similar levels of consumption. Typically, these VRE technologies require a greater land and network footprint than conventional coal-fired generation and tend to be less variable in aggregate if geographically dispersed. This increases the future value of transmission which facilitates the sharing of surplus low-cost resources across regions and maximises the value of geographic weather diversity.

Ultimately, the NEM will draw on a technologically diverse mix, that may diversify further as other technologies, such as hydrogen, mature. This diverse portfolio will cost less than replacing the existing generators with new thermal generation to deliver the energy and peak capacity needed, and simultaneously reduce emissions significantly, see Figure 10.

Figure 9 Coal-fired generation remaining as power stations retire*



* Based on expected closure years provided by participants as of November 2019. Modelled outcomes vary slightly from these timings and are based on expected closure years reported in August 2019.

Figure 10 Annual electricity sector emissions to 2042

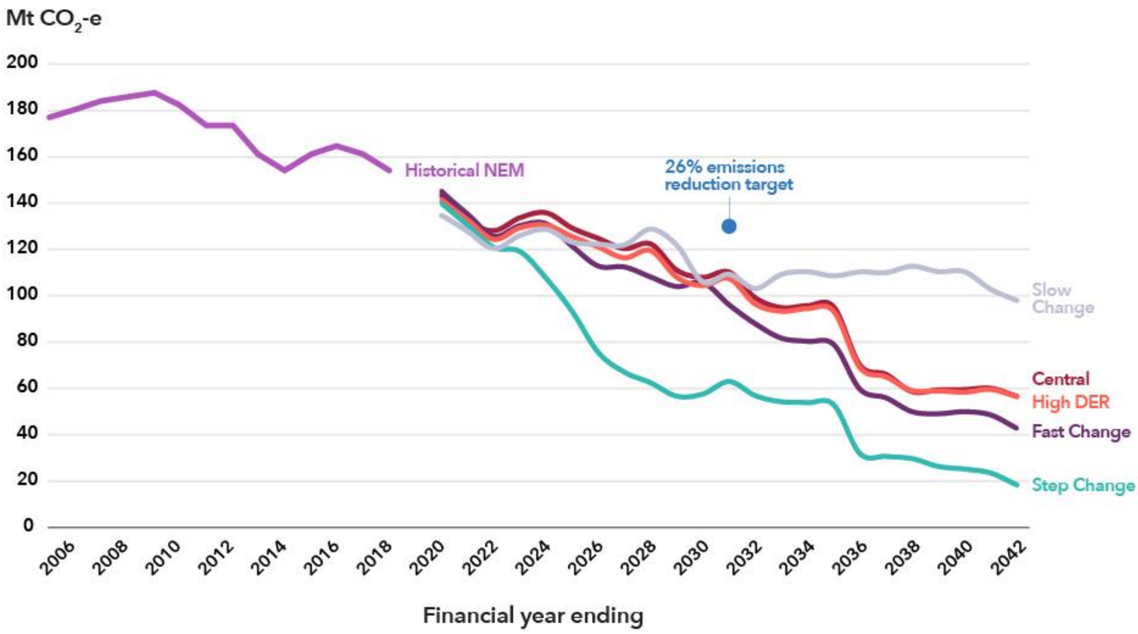
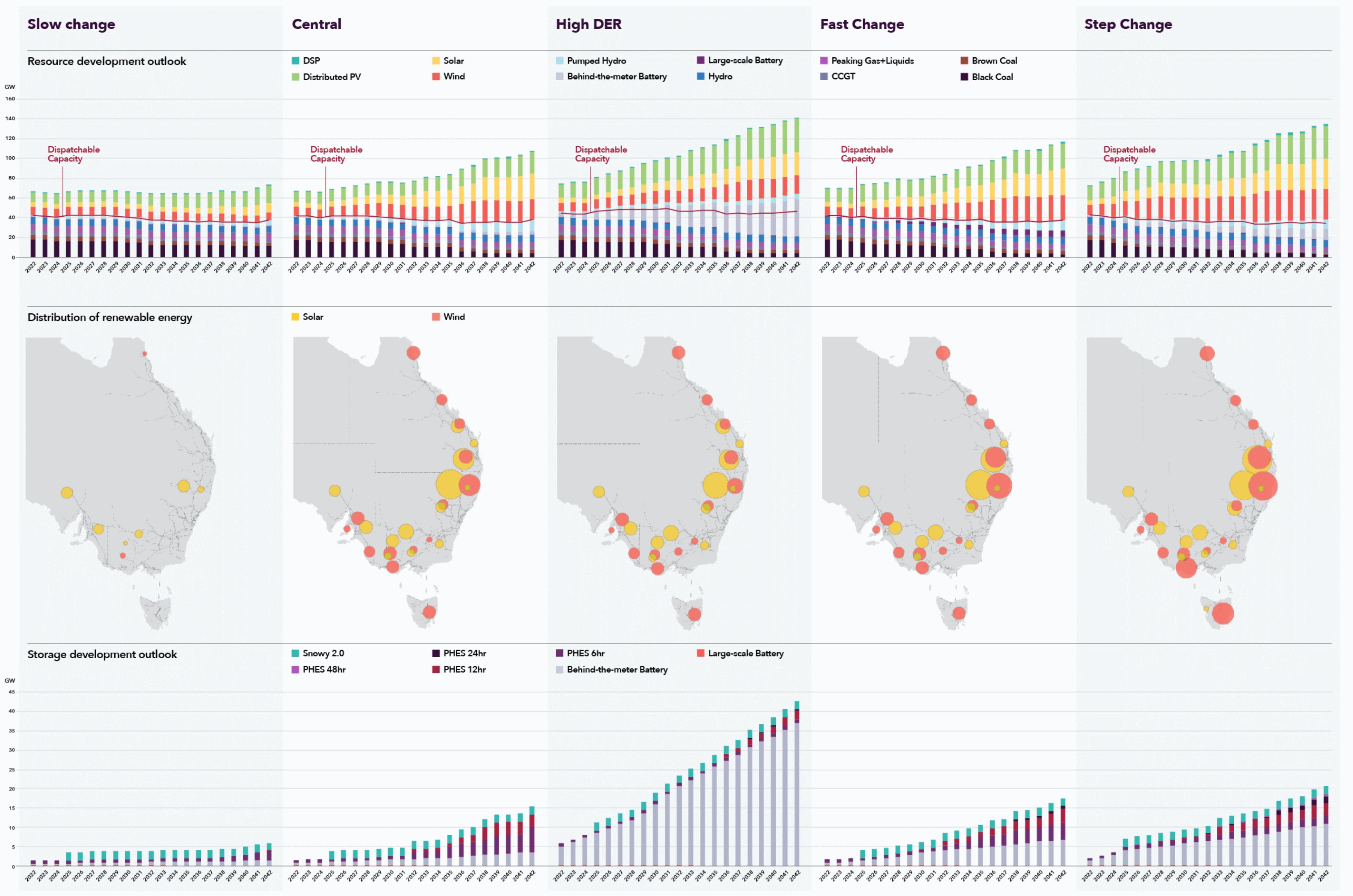


Figure 11 Power system development across five scenarios



C1 Distributed energy resources are expected to double or even triple by 2040

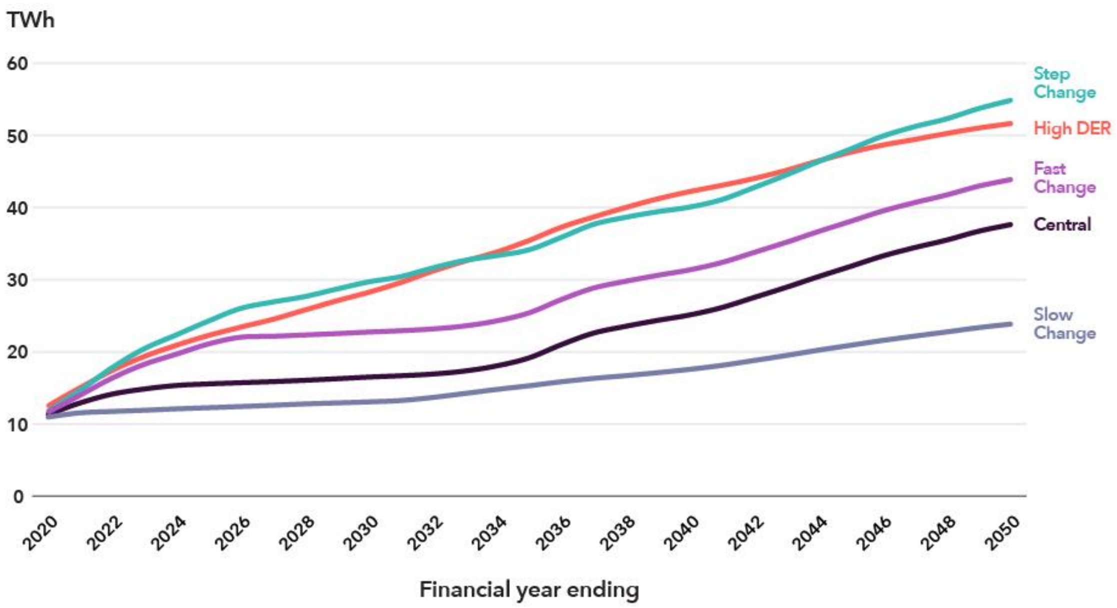
All scenarios expect to see residential, industrial, and commercial consumers continue to invest heavily in rooftop PV, with increasing interest in battery storage and load management. This may bring diverse consumer-led benefits to the wider economy, beyond offering power system flexibility and reducing the demand for grid-scale investment, for example creating employment opportunities in the energy sector and spurring additional market and technology innovation.

C1.1 Growth of DER

At the end of the outlook period AEMO projects that DER could provide up to 13% to 22% of total underlying annual NEM energy consumption[36]. This assumes that the necessary technical and market integration is put in place to ensure DER investments can operate effectively and securely. Realising high levels of DER will require dedicated management practices and protocols, backed by changes to rules, regulations and standards, to secure system security.

The growth in DER is driven primarily by continual installation of rooftop PV on domestic and commercial premises: see Figure 12. Together with energy efficiency and local storage, that growth will keep grid demand held more or less constant over the outlook period, even though the population and economy are growing. In most scenarios, electric vehicles are forecast to have only a small impact on overall NEM demand[37], though we expect local, charging infrastructure and market impacts as their potential is pursued.

Figure 12 Distributed PV generation to 2050[38]



[36] Total annual underlying NEM energy consumption, including rooftop PV, and PVNSG (commercial-scale PV, behind-the-meter and <30 MW per installation). The level of instantaneous uncontrolled power that will need to be operationally managed at times of DER peak export will be much higher.

[37] In the Step Change scenario, EVs account for 8% of NEM consumption by 2040.

[38] Includes PV non-scheduled generation.

However, the relatively constant average demand masks an increase in peak demand (which rises with growing population and economic growth, as well as air-conditioning) which must be covered by additional supply as described in more detail in the following sections. There will also be lower troughs of minimum demand, which means less inertia and other criticial system services from traditional supply, which must also be replaced.

C1.2 Technical and market integration of DER

The Draft ISP assumes that the necessary regulations, standards, digital platforms and distribution-level investments are in place to allow DER investments to contribute to their full potential. This will not happen automatically. A number of technical and market changes will be needed to manage two-way flows, the impacts of DER on faults on the system, peak demand, minimum demand and peak export from DER.

As DER penetration continues to increase, new installations will need sufficient interoperability capabilities to maintain power system security. For example, all distributed PV will in time need mandatory feed-in management capability. If DER provides a large proportion of the energy in a region, they will need similar capabilities as scheduled/semi-scheduled generation, as a condition of connection. Without the needed capabilities, the amount of uncontrollable generation will have to be limited in certain conditions and regions, or the power system becomes inoperable. As well, cyber security measures will be needed to avoid unintended new system security risks.

This will require industry collaboration and potentially a new regulatory lever to establish a single interoperability platform.

Technical integration of DER means ensuring operational tools operate effectively in a high-DER world. The key initiatives include:

- **Standards and protocols** – uplift the DER inverter standard AS4777.2 to improve device responses during power quality disturbances[39], implement standards to provide cyber security protocols and interoperability at the device level, improve the compliance framework to ensure devices perform to the agreed standards, and finalise review and implementation of demand response standard AS 4755.2.
- **Visibility** – explore options to get real-time visibility of DER (at a suitable level of aggregation – e.g. zone sub-station or transmission connection point) to support operational decision-making.
- **Operation** – define the technical envelope for secure operations under minimum demand scenarios, implement improved dynamic models for load and DER, improve capability for investigating and understanding DER behaviour during disturbances, amend Emergency Frequency Control Scheme and System Restart arrangements, and prepare for artificial intelligence and other machine learning tools to manage the variable and diverse resources in the system.

Market/regulatory integration is needed to open the market up to various actors, products and system services, and digitalisation.

Key projects that are currently planning that integration include:

[39] https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Technical-Integration/Technical-Integration-of-DER-Report.pdf

- The Open Energy Networks project is providing the blueprint for a two-sided system and marketplace to realise the benefits of DER take-up. This is a collaboration between AEMO and Energy Networks Australia (ENA), expected to be released in December 2019 following extensive stakeholder engagement.
- The ESB and market bodies are examining integration of DER into the electricity market.
- The Australian Energy Market Commission (AEMC) is proposing Wholesale Demand Response rule changes[40] to introduce a new energy market participant that would enable aggregators to bid demand response directly into the wholesale market as a substitute for conventional supply and create bi-directional market arrangements. The AEMC is also considering access and pricing reforms.

These integrations will be needed over the next two to three years, and pilots are already underway: see Section D1 below.

C2 Over 30 GW of new VRE is needed to replace coal-fired generation by 2040

While overall grid demand is being held constant by DER, we will still need generation capacity to meet peak demand and to replace retiring plants. To fill that gap, AEMO forecasts that Australia should invest in a further 30-47 GW of new large-scale VRE – most optimally in REZs – supported by essential storage, GPG, DSP and transmission investments. Some of this additional supply will be needed to make up for the losses that occur during the energy storage cycle.

C2.1 Overall requirements to replace retiring coal

Currently[41] there are already 6 GW of VRE installed, with another 6.5 GW expected to be operational in the next two years. Economics and state RETs are continuing to drive this development. In the Central scenario, a total of 34 GW of VRE is forecast to be needed by 2040 in addition to the already installed or committed VRE.

The optimal split of approximately 56% solar and 44% wind for new VRE in the Central scenario shown in Figure 13 minimises needs for dispatchable storage and generation. In the Step Change scenario, up to 47 GW would be required, with Queensland and New South Wales forecast to add over 15-18 GW and Victoria over 6 GW by 2040.

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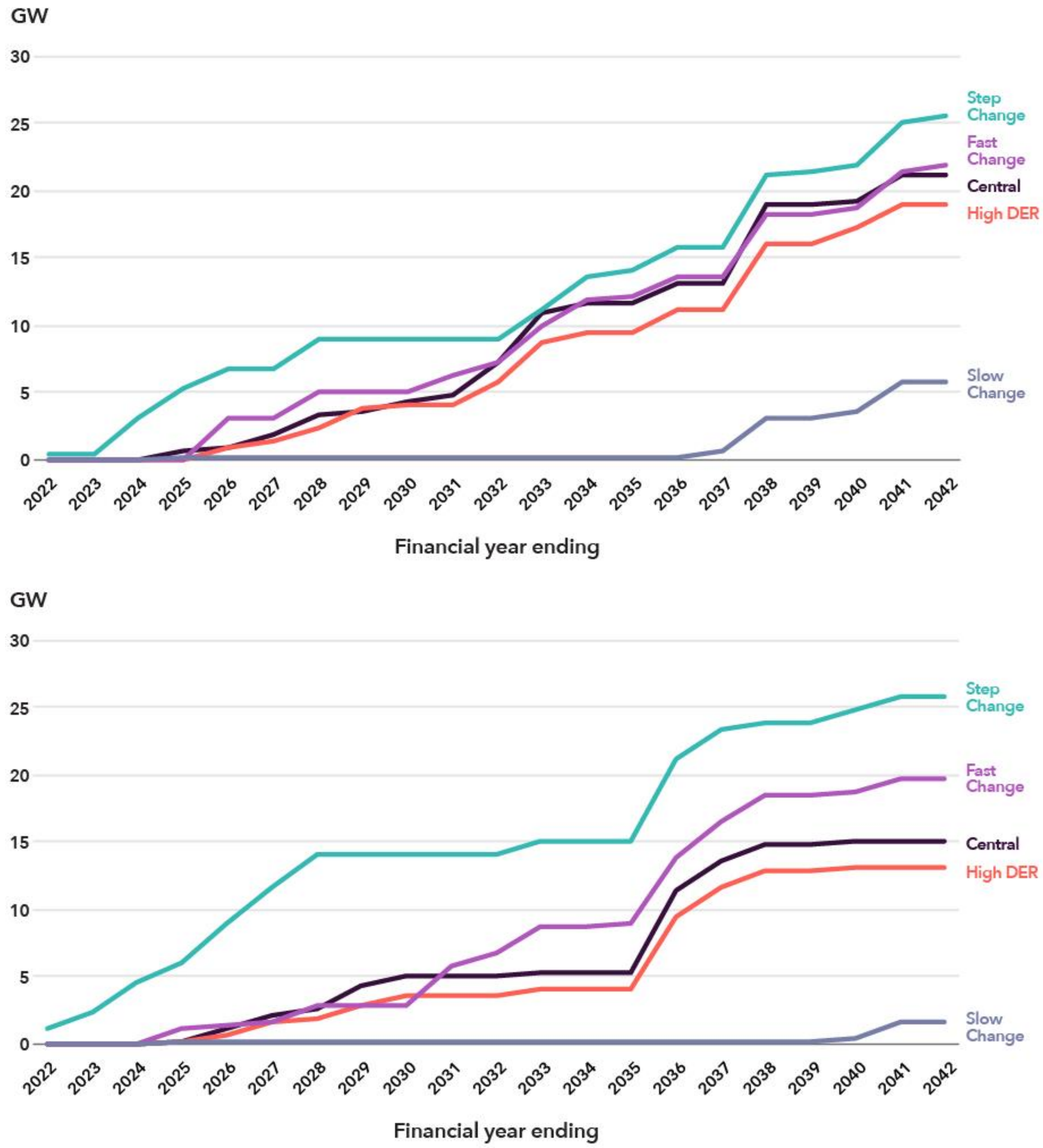
[40] AEMC, 2019, Wholesale Demand Response Mechanism Rule Change

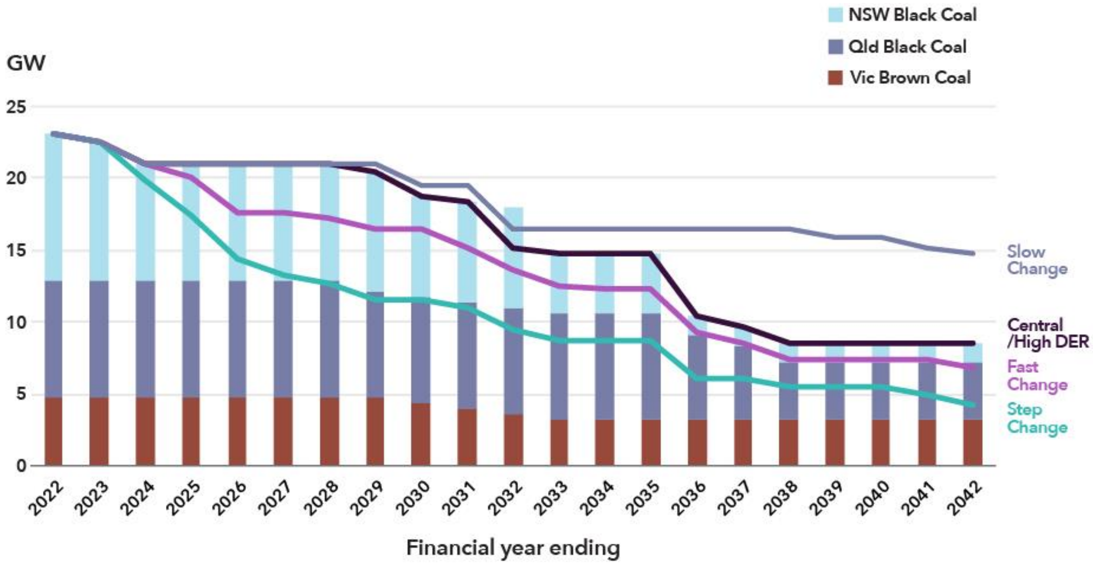
[41] Data is current as at November 2019, AEMO Generation Information Page. At time of ISP modelling, only 5.7 GW of committed capacity was recorded.

Figure 13 New NEM VRE build, solar (top) and wind (bottom)



In all but the Slow Change scenario, existing coal-fired plants are not forecast to continue beyond their planned retirement dates: see Figure 14. In fact, in the Fast and Step Change scenarios, we expect them to exit earlier if competition from renewable generators and carbon budgets reduce their revenue below what is economic for them to continue.

Figure 14 Coal-fired generation capacity to 2042, all scenarios



C2.2 Locating new VRE generation in REZ

In most cases, locating new VRE generation in REZs will both reduce system costs and increase system strength. We have identified potential REZ locations that can connect to the existing transmission network, however not all of these locations would need to be developed to meet the new VRE generation need outlined above. As new regional interconnections are developed, further REZ locations will open up, so that the interconnection routes and REZ locations must be considered together: see Section C4 below.

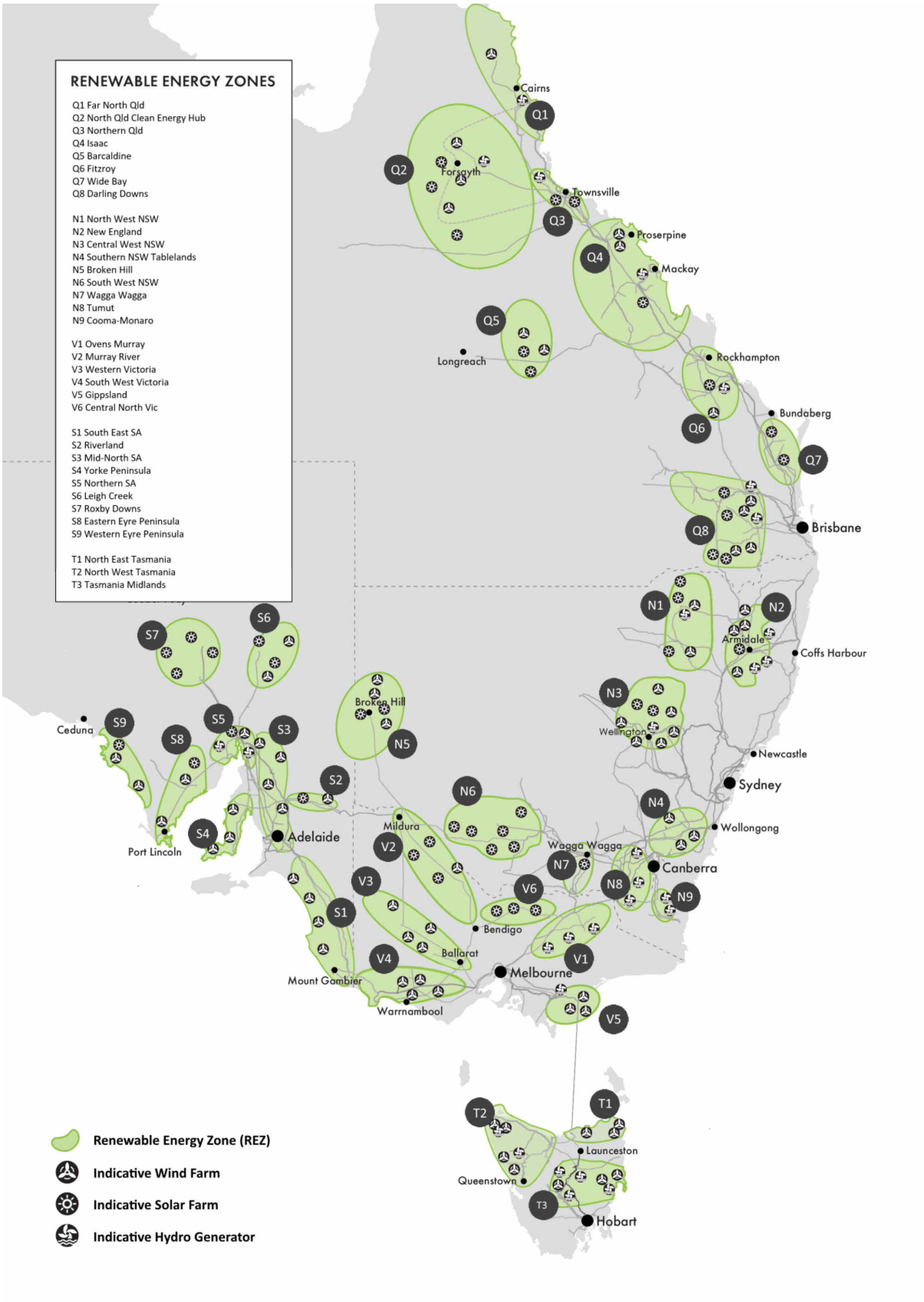
If well located, REZs could materially reduce total system and transition costs. They can:

- reduce the need to build transmission into new areas
- reduce project connection costs and risks
- optimise the mix of generation, storage and transmission investment across multiple connecting parties
- co-locate and optimise the otherwise 'lumpy' investments in network and system support infrastructure[42]
- co-locate and optimise weather observation stations to improve real-time forecasting
- realise benefits of capital scale in all those investments, and
- promote regional expertise and employment at scale.

The Draft ISP considers 35 possible REZ candidates after assessing their resource, technical and economic parameters during the scenario and assumptions consultation process, see Figure 15.

[42] As supply becomes more weather-dependent, AEMO will need excellent temporal and geographic resolution of wind and solar observations to manage REZ generation quantities. Meteorological equipment appropriate to each REZ will augment the BoM's existing observations network, improve now-casting and forecasting, enhance situational awareness and provide invaluable data for market participants.

Figure 15 Identified potential Renewable Energy Zones (REZs) across the NEM



The ideal near-term REZ locations would take advantage of both attractive renewable resources and spare transmission capacity – subject to land availability, regional policies, and consultation with local communities and traditional owners. Where the network is relatively strong, development will be robust to loss factors and system strength. VRE generation in these REZs will be cheaper than building the network infrastructure needed to unlock a new REZ.[43]

While similar REZs would be needed across scenarios, the timeline varies. For example, with VRET and QRET continuing to 2030, most early REZ development occurs in Queensland and Victoria. If those state-based schemes finish early, REZ development in New South Wales, South Australia and Tasmania will be accelerated. The additional 3 GW of VRE now planned for early development in Central West REZ by the New South Wales Government may also influence the location and timing of VRE across the NEM[44]. While long-term stranded asset risk is relatively unlikely, there is a risk of underutilisation if assets are developed and a different scenario unfolds.

The Draft ISP has also made an initial assessment of the highest value REZ development options from an economic efficiency perspective. The REZ developments are co-optimised with other generation and transmission investment decisions within the ISP market modelling. This ensures that economic benefits of co-locating wind, solar and storage resources near existing or new interconnector corridors are captured, and the value of diversity and correlation with demand is recognised. It does not consider the local issues for development however, including community support, land access and approvals and commercial decisions by developers that may impact individual preferences for VRE development.

Further, without strong coordination between new transmission and related system services to enhance system strength, there is a risk of unnecessarily high transmission and connection costs. The lack of system strength has already emerged as a major inhibitor to the grid connection of renewable energy in some areas of the NEM today.

Box 3: Levelised cost of electricity for REZ (LCOE)

The ISP is underpinned by complex integrated modelling that co-optimises generation and transmission build to maximise the value of REZ integration. The downside is, it makes it difficult to unpack the 'black box' to understand why particular development options are preferred. To assist with comprehension, a high-level analysis of the levelized cost of electricity (LCOE) for the various REZs has been prepared for 2040: see figures below. This high-level LCOE assessment, used for reporting purposes only, focuses on the build and operating cost, quality of the local resource, and likely REZ-specific network augmentation costs required to deliver REZ generation to the grid, but does not consider deeper network congestion that may limit the value of this generation to end consumers.

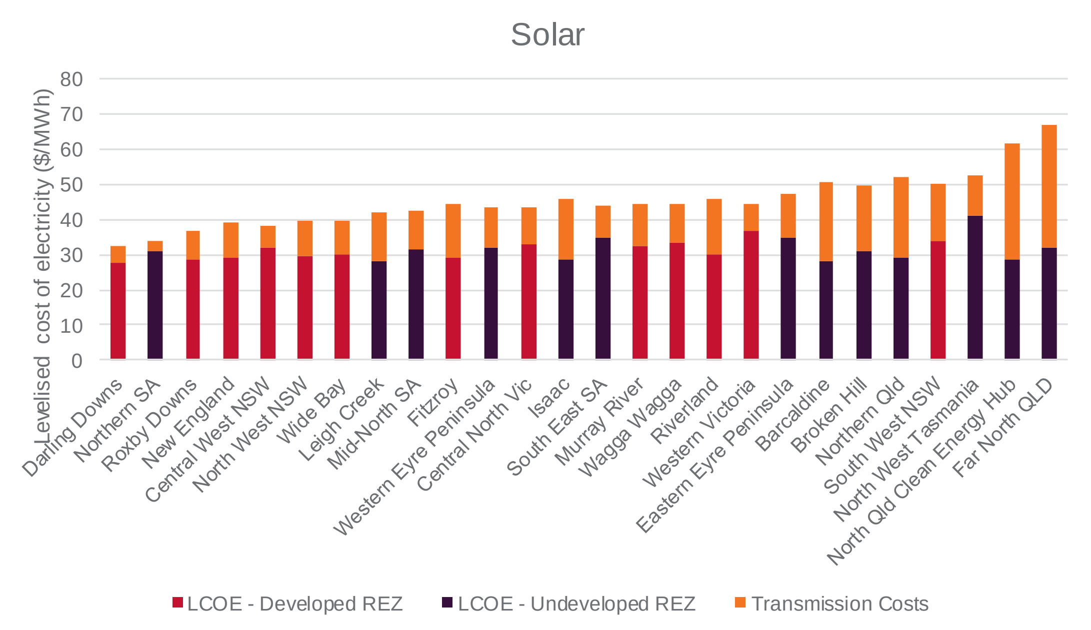
The cost of dedicated network expansion to individual REZ is approximated as a $/MW value. Care should therefore be taken when interpreting these LCOE values.

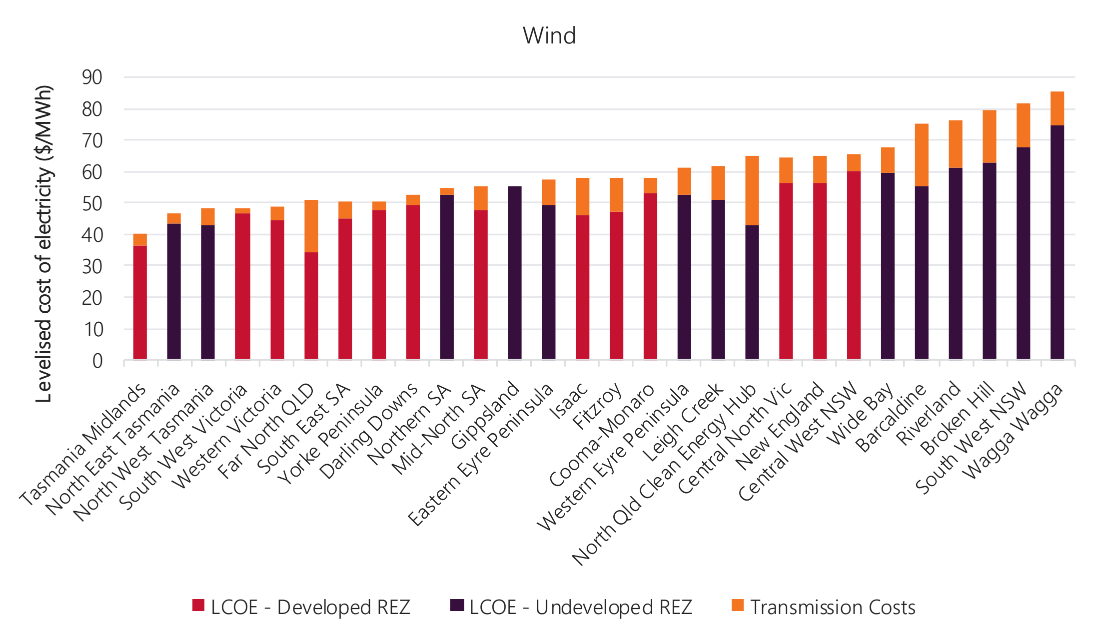
The figures also indicate which of these REZs have been identified in the Draft ISP as potential areas for REZ development (red columns) with potentially high value. Many of the REZs selected are also those with

[43] One exception is where there is an exceptional renewable resource for an otherwise scarce resource within a region (e.g. the wind resource of Far North Queensland), which warrants development of a new REZ and associated network infrastructure: see Appendix 6 of this Draft ISP.

[44] The New South Wales Electricity Strategy published 22 November 2019 has not been explicitly incorporated in this Draft ISP due to the late timing of the announcement.

relatively low LCOEs, although in some cases (e.g. Tasmania), the REZs are low cost but deliver limited market benefits without greater interconnection to load centres.





C3 5-21 GW of new dispatchable resources are needed to back up renewables

Depending on the scenario, we will need 5-21 GW of new flexible, utility-scale dispatchable resources to firm up the inherently variable resources. This will be supported by DSP and innovative power system services: see Section C4 below.

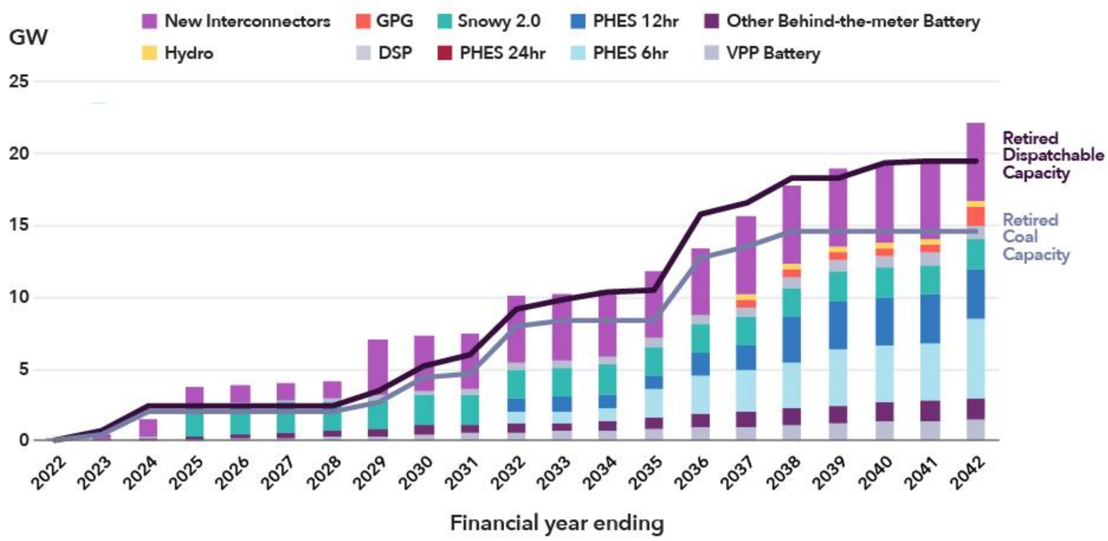
Most initial investment will be in utility-scale pumped hydro or battery storage. New flexible gas generators could play a greater role if gas prices materially reduce. Distributed batteries are assumed to participate in the NEM and operated as a VPP. Ultimately, the NEM will draw on a technologically diverse mix that may diversify further as other technologies, such as hydrogen, mature.

C3.1 Dispatchable storage requirements

Utility-scale energy storage can shift the timing of renewable energy production, reduce the magnitude of new intra-regional transmission, and provide firming support especially during peak loads, or when renewable production is low. The Draft ISP analysis assumes optimal operation of the installed storage with perfect foresight. However, even minor inefficiencies in real world operations lead to the need for more storage or other forms of dispatchable generation, which will be analysed in detail in future ISPs.

The growth in storage is broadly aligned with timing of coal-fired generation retirements, as shown in Figure 16. New interconnectors are also included in this figure as they also help to smooth out local VRE variability by increasing resource diversity across the system. The type and depth of storage required will depend on the mix and location of renewable generation, and the ability of existing generators to themselves smooth out short-term and seasonal renewable variability. Two large-scale storage projects – Snowy 2.0 and Hydro Tasmania's pumped storage scheme called Battery of the Nation (BOTN) – have significantly progressed since the 2018 ISP.

Figure 16 Announced retirements and corresponding builds in Central scenario to help firm VRE

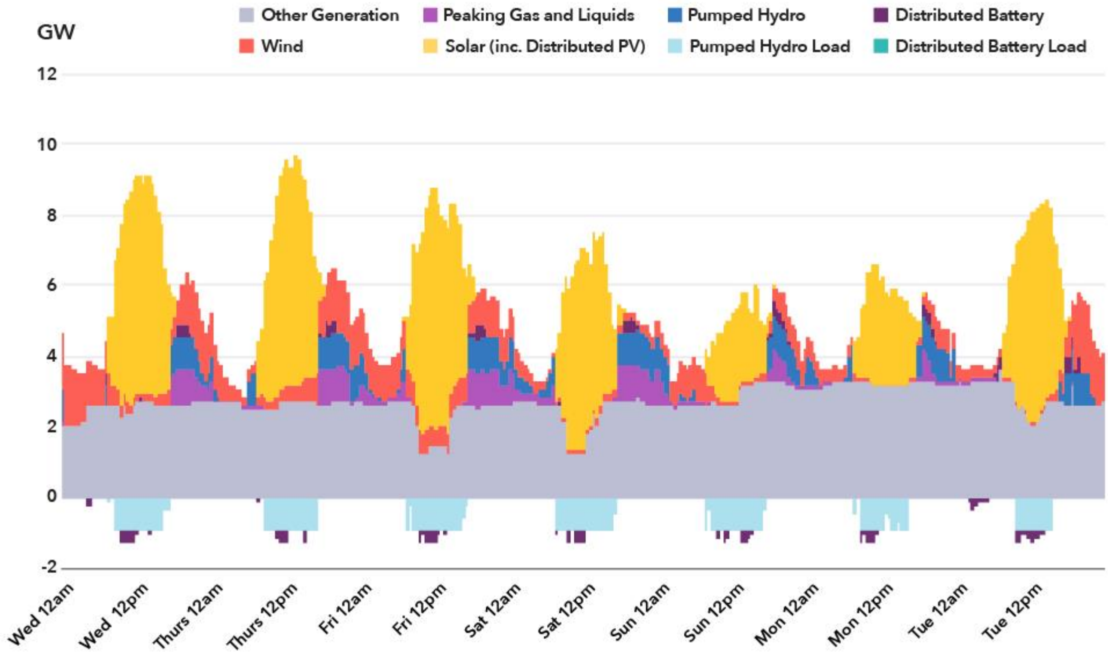


C3.2 Gas-powered generation requirements

Gas-powered generation (GPG) can provide the synchronous generation needed to balance variable renewable supply, and so is a potential complement to storage. The ultimate mix will depend upon the relative cost and availability of different storage technologies compared to future gas prices.

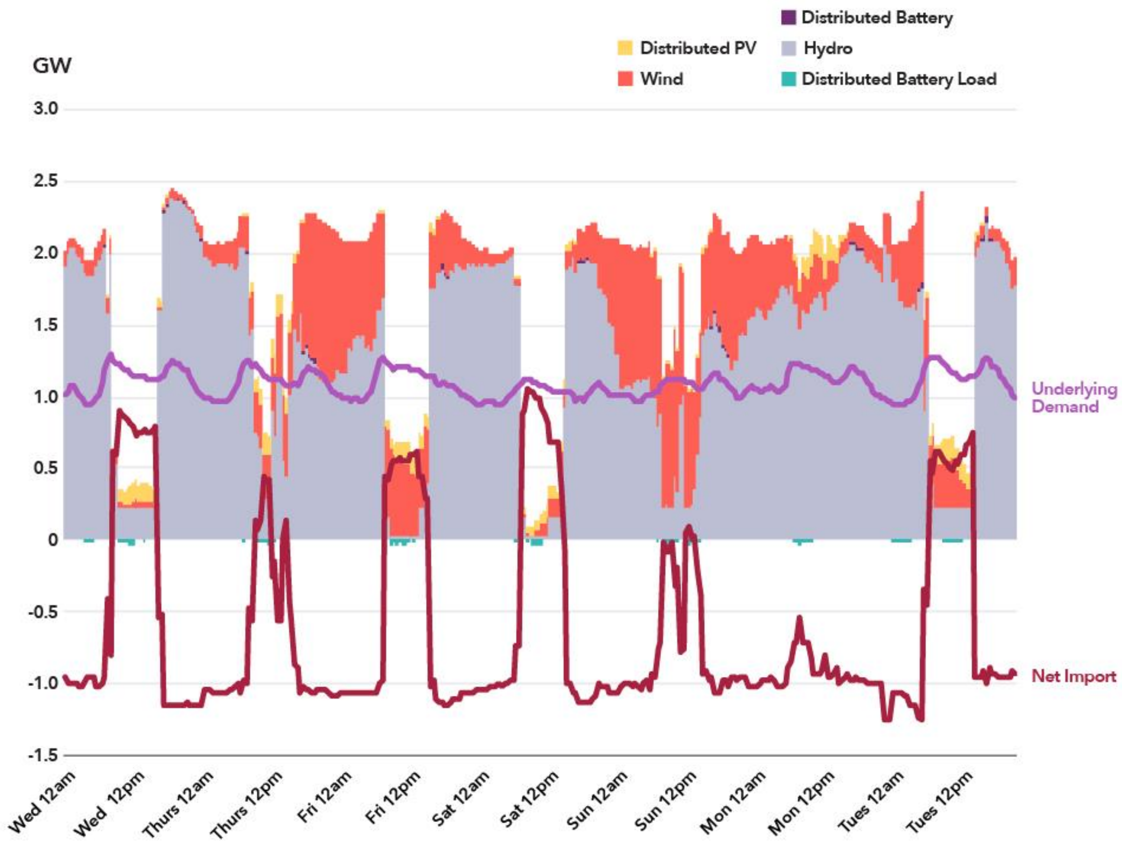
Figure 17 below shows the value of GPG as more renewables are installed, particularly during potential "wind droughts". When there are weeks of relatively still wind conditions, the system relies more on generation from hydro power (including Snowy 2.0), while baseload coal-fired generation continues. They are complemented by smaller batteries (including VPP) that are charged from solar during the day and discharge in the evening peak, while GPG is relied upon overnight.

Figure 17 Resources used in Victoria, low wind week in June 2040, GW



In this example, the utility of Marinus Link and Tasmania's deep hydro storages is also clearly evident, with Tasmania importing and storing surplus solar generation during the day, and then exporting during the night, as shown in Figure 18.

Figure 18 Resources used in Tasmania, same low wind week in June 2040, GW

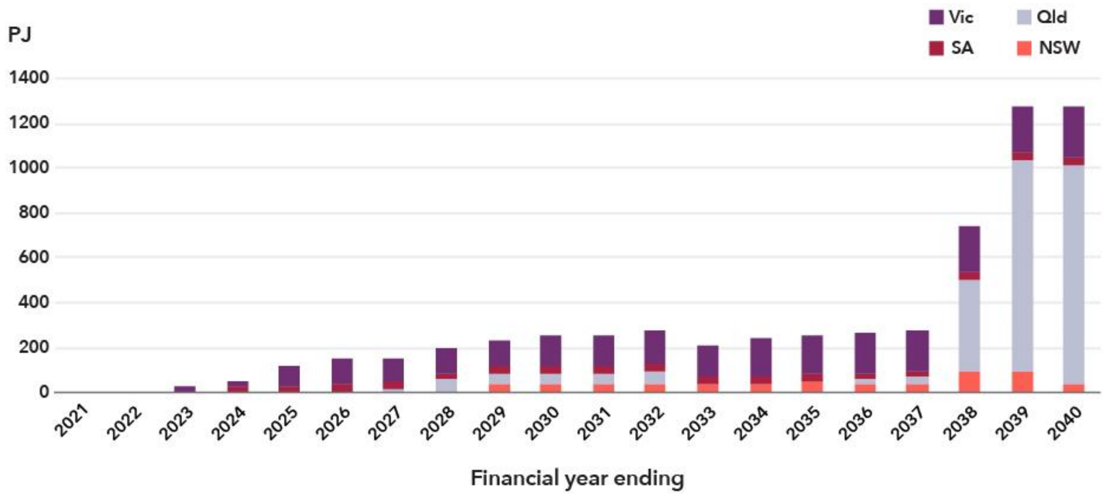


GPG gas consumption can vary significantly from year to year, as it is influenced by weather events such as extreme temperatures or droughts, and prolonged thermal generation outages. Stronger interconnection between NEM regions reduces reliance on GPG, more so during drought conditions, as alternative resources can be shared more effectively to compensate for reductions in hydro generation. By smoothing weather-driven variances in GPG demand, interconnectors help mitigate the risk of gas supply disruptions or shortfalls, and ultimately help keep costs down for consumers.

In our modelling, near-term demand for GPG is projected to decline initially due to the rising cost of gas, then rise again as coal retirements progress. As highlighted in the 2019 GSOO, existing southern gas reserves are in decline, and more development is required in the southern states from 2024 to ensure that all demand is met, whether this is related to a new field development or an LNG import terminal, and associated pipelines to deliver the gas to market.

This Draft ISP modelling forecasts that new gas supplies and associated pipeline infrastructure will need to be discovered and developed, capable of delivering over 200 PJ of additional gas to the domestic market each year each year between 2025 and 2037, to help meet residential, commercial, industrial gas demand, gas for LNG export, and gas supply for GPG. From that point, major Queensland reserves are projected to decline and would then need to be replaced with currently contingent or prospective resources to meet forecast LNG exports through the 2040s. Figure 19 shows the quantities of gas, beyond currently existing and committed projects, that are projected to be needed to meet forecast gas demand out to 2040 in all scenarios, and the likely location of these new gas sources.

Figure 19 New gas discoveries required each year, under all scenarios



C3.3 Demand side participation forecast to double

Demand Side Participation (DSP) is the voluntary reduction or shift of electricity use from the grid by customers, in response to high prices or network reliability events, which can help to moderate prices or ensure available supply can meet demand. The response is typically orchestrated by network companies, retailers or specialist DSP aggregators who trigger load reductions or embedded generation at participating customers.

DSP across the NEM is forecast to double by 2040 in the Central scenario (and almost quadruple in the Step Change scenario). This forecast growth is driven by advances in information and control technology and market reforms. Behind-the-meter battery storage (VPP) and charging of EVs will also add significant extra controllable demand across the NEM. These resources are changing the nature of demand side service offerings – with demand following supply rather than the other way.

Two-sided markets will not only need to be designed for peak shaving services but address other flexibility requirements – minimum demand, load shifting and load shaping to name a few. Demand side resources become an important part of the energy mix because they enable the operator to use aggregated dynamic demand responses to manage the intermittency and rates of VRE ramping.

C4 System services are critical to enabling the transition

Innovative system services that provide the essential system security requirements will be needed to transform a system that has relied on thermal synchronous generation in the past to provide these services. As very large amounts of inverter-based resources (IBR) are projected from the mid-2020s, most new VRE developments utilising current inverter technology are likely to need to be complemented by some form of system strength remediation from the mid-2020s.

There are already examples of this growing need, such as:

- **South Australia** – for which AEMO declared inertia and fault level shortfalls in 2018 and are being addressed currently through operational actions and investment by ElectraNet as recommended in the 2018 ISP, including the installation of major high inertia synchronous condensers by 2020 and 2021. These are needed immediately to supply both system strength and inertia to the region, and remain valuable after the recommended Project EnergyConnect interconnector between South Australia and New South Wales is completed.
- **Tasmania** – AEMO declared inertia and fault-level shortfalls in November 2019, which are currently being addressed through operational actions while TasNetworks develops a long-term solution.
- **Victoria** – for which AEMO expects to declare a fault-level shortfall in north west Victoria in the near future, once assessments are finalised.

With efficiencies of scale applying, the solutions for each of these areas should be considered as a package and optimisation across the areas will lead to much lower costs than if attempted project by project. The system services already provided by new generators entering into the system should be utilised to their full potential. Where necessary, they need to be augmented to ensure there is sufficient system strength, inertia, frequency control, reactive power and voltage control available at each location in the network to operate the power system securely. The Final 2020 ISP will highlight key security needs out to 2030.

C5 Targeted grid augmentation is needed to balance resources and unlock Renewable Energy Zones

The NEM network can provide an interconnected energy highway that is needed to efficiently, reliably and securely support the use of diverse energy resources. Targeted grid investment increases access to lower costs of supply by increasing competition, reducing the cost of resources and increasing resource diversity and trading. This in turn should result in downward pressure on electricity bills. How much of those benefits are passed on to end consumers will depend on the effectiveness of the wholesale and retail markets. Without further grid development, however, consumers will pay more, for less reliable energy.

This section lays out the three types of actions that AEMO recommends:

- grid augmentations currently planned remain valuable and should continue
- major inter-regional interconnectors are needed, with their size dependent on the scenario, and
- future grid expansions should accompany the timely development of REZs.

C5.1 Current planned grid augmentations confirmed as 'no regret' actions

While over 30 GW of new VRE may be required by 2040, the existing network only has an estimated remaining connection capacity for 13 GW in designated REZ.

Reducing that gap are the grid augmentations identified in the 2018 ISP, and currently being progressed by TNSPs:

- **VNI Minor**, a minor augmentation of the existing interconnection that will increase Victorian transfer capacity to New South Wales by 170 MW.
- **QNI Minor,** a minor augmentation of the existing interconnection that will increase Queensland transfer capacity to New South Wales by 190 MW and increase New South Wales transfer capacity to Queensland by 460 MW.
- **Project EnergyConnect,** a new interconnector between South Australia and New South Wales, to increase transfer capacity between South Australia and New South Wales by 750 MW, to achieve fuel cost savings and unlock already stranded renewable investments.
- **HumeLink** from Tumut to Bannaby, including new 500 kV single circuits from Maragle to Bannaby, Bannaby to Wagga Wagga, and Wagga Wagga to Maragle, with associated works at Maragle, Wagga Wagga, and Bannaby, which in combination with Project EnergyConnect will reinforce the New South Wales Southern Shared Network to increase transfer capacity to the state's demand centres.
- **Western Victoria Transmission Network Project**, a committed project that is required to add transmission to unlock renewable energy resources in the western and north-western Victoria REZs, reducing congestion and improving the productivity of existing assets.

These no-regret projects demonstrate value in all scenarios: see Table 4. The major benefits in the Central scenario will be the lower fuel costs of reducing reliance on gas and coal-fired generation ($2 billion) and the deferral of generation capital costs ($1.4 billion). These benefits derive from sharing resources more effectively across the NEM. They would also create competition in the market to put downward pressure on consumer prices, and secure some cost savings in the development of network for REZs ($0.2 billion), voluntary curtailment (DSP) and fixed operating and maintenance costs ($0.2 billion). When we deduct the annualised cost of new transmission over the period ($1.6 billion[45]) it leaves the net market benefits of $2.2 billion.

The NPV in this table represents the present value of annualised net market benefits from 2020 to 2042, determined by comparing total system costs of the no-regret investment decisions against an

[45] Total cost of this suite of transmission projects is estimated to be $3.1 billion. However, as the economic life of the project extends far beyond the ISP planning horizon, the annualised costs to 2041-42 are reduced to $1.6 billion on an NPV basis. Benefits of the no-regret projects are also only considered to 2041-42, but will extend beyond this period.

alternative counter factual without these no-regret investment decisions. Committed projects such as Western Victoria and System Strength are included in all analysis including the counterfactual.

Table 4 Ideal timing and benefit of "no-regret" grid augmentations (NPV, $ billion)*

Scenario	No regret grid augmentation projects				Cost-benefit analysis		
	QNI Minor	VNI Minor	Energy Connect	HumeLink	Total system costs† without projects	Total system costs† with projects	Net market benefits
Central	2022-23#	2022-23	2023-24	2025-26	87.53	85.34	**2.18**
High DER					80.27	78.50	**1.78**
Step Change					92.15	90.98	**1.17**
Slow Change					57.69	56.77	**0.93**
Fast Change					85.74	83.84	**1.90**

† Note that absolute Total System Cost NPV across scenarios should not be compared as they are based on different assumptions, not all of which directly related to the energy sector.
* Represents the present value of annual net market benefits from 2019-20 to 2041-42, determined by comparing total system costs of the no-regret investment decisions against an alternative without these investment decisions.
# Currently on track to be commissioned by December 2021, earlier than originally advised as practical, and assumed in this Draft ISP modelling.

C5.2 Major inter-regional interconnectors needed

Major inter-regional network investments beyond what is currently being studied by TNSPs will also be needed by 2040, to strengthen the NEM and deliver the significant market benefits discussed at the start of Section C4 above.

The following transmission projects have been selected from over 30 credible options and combinations to determine the mix of investments that maximise consumer benefit: see Appendix 6 for full details of options considered. For example, shorter routes to strengthen connection between Victoria and New South Wales were rejected as they did not deliver greater cost savings, or connect diverse REZ and or enable greater VRE development over time under certain scenarios. Alternate options between New South Wales and Queensland may be beneficial if the spatial distribution of new VRE were known – as yet it is not.

The three interconnector options that AEMO has assessed as having the most merit are:

- **VNI West (formerly "Keranglink"[46]), which connects Victoria with New South Wales and Snowy 2.0**, e.g. via Kerang or Shepparton. The modelling clearly demonstrates the needs and benefits of a major new interconnection between New South Wales and Victoria. The timing of VNI West is considered in Part D of this report. The connection with Snowy will give Victoria much needed dispatchable capacity, to maintain reliability when the next major power station (Yallourn) retires. However, the route selection depends on VRE development priorities in local areas. One option would connect North Ballarat and Darlington Point via Kerang, providing network expansion to support developments in the Murray REZ and South West New South Wales REZ. The alternative would be to connect North Ballarat and Wagga Wagga via Shepparton, to support

[46] This project was previously referred to as 'KerangLink', however due to the fact there are a number of potential routes to serve this need, AEMO has decided to give it the more generic VNI West name at this stage.

developments in the Central North Victoria and Wagga Wagga REZs. Each option provides Victoria with access to Snowy Hydro's existing and future generation capacity, and helps alleviate constraints from renewable investment in the north west or central areas of Victoria. As the present modelling indicates that the options deliver near-equivalent net market benefits, the selection may need to consider additional factors, such as REZ prioritisation, community support, and land and environment considerations.

- **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. The timing options for Marinus Link are considered Part D of this report.
- **Queensland – New South Wales Interconnection (Medium or Large QNI)** is beneficial in all scenarios before the closure of the next New South Wales and/or Queensland black coal generators following Liddell. However, the size of the investment varies across scenarios, so flexibility has been built into the roadmap in Part D.

The ideal timing and NPV benefits of these projects under different scenarios are set out in Table 5 below, assuming perfect foresight of the future.

Table 5 Benefit and ideal timing for regional interconnectors (NPV, $ billion)

Scenario	Interconnectors (further to 'no regret' augmentations					Cost-benefit analysis		
	QNI Medium	QNI Large	VNI West	Marinus Link 1st Cable	Marinus Link 2nd Cable	Total system costs without interconnectors	Total system costs with interconnectors	Net market benefits
Central	2028-29	2031-32	2031-32	2036-37		85.34	84.91	**0.43**
High DER	2028-29		2031-32	2036-37		78.50	78.28	**0.21**
Step Change	2026-27		2027-28	2026-27	2031-32	90.98	89.81	**1.16**
Slow Change	2028-29					56.77	56.60	**0.17**
Fast Change	2026-27		2030-31	2036-37		83.84	83.63	**0.21**

Taken together, this set of regional connections have lower benefits (mainly capital deferral, less capital costs), and greater uncertainty than the no-regret set discussed above. The NPV is reduced by the discounted benefits of the later commissioning dates, and the shorter period over which to accrue benefits within the planning horizon. There is also greater uncertainty in benefits that may not be realised until well into the 2030s.

In the Central scenario, the gross market benefits are $1.84 billion, the bulk of which is a $1.1 billion benefit in generation capex savings, as resources can be used more efficiently across the NEM. A further $0.5 billion in REZ network costs will be saved as the strategic routing of interconnectors improves access to high quality REZ. Fixed operating and maintenance cost fall by $0.2 billion, while the benefit in fuel cost savings from the reduced GPG and thermal generation over time is only

$0.1 billion. When we deduct the annualised transmission costs through to 2042 ($1.4 billion), we see the $0.4 billion net market benefit reported in Table 5.

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, and is linked to retirement of black coal in New South Wales and Queensland. Should the NEM begin to track to the Fast Change and Step Change scenarios, with earlier coal retirements and corresponding build of VRE (as indicated in the charts in Figure 11), developing this interconnector as soon as possible (assumed no earlier than 2026-27) would be essential to more efficiently utilize resources between Queensland and New South Wales.

C5.3 Future co-development of grid augmentation and REZs

Further new network development will be needed to accommodate the required VRE in all scenarios other than Slow Change, though the timing and optimal location will depend on which scenario plays out.

The additional connection capacity required in each scenario by 2040 is provided in Table 6. It takes into account both the residual capacity in the existing system and the additional capacity created by the new regional interconnections listed above.

Table 6 Additional connection capacity required by scenario (2040, GW)

Scenario	Total	Vic	Qld	NSW	SA	Tas
Central	15.0	0.3	3.7	8.7	2.3	0
High DER	12.9	0.2	4.2	6.4	2.1	0
Fast Change	20.6	0.3	6.9	11.2	2.3	0
Step Change	29.4	2.0	10.5	13.4	2.3	1.1
Slow Change	0	0	0	0	0	0

The most cost-effective way to provide this extra connection capacity is to develop and link strategically placed REZs that include strong system services and integrated storage options. This will minimise VRE development, connection and transmission costs, and shorten development lead times: see Section C2.2.

Part D
The Draft ISP Optimal Development Path and Roadmap

Part C sets out the energy investments that the NEM will need over the next 20 years to deliver low cost, reliable and secure energy to consumers across a number of scenarios.

It confirms that generation in the NEM will evolve from centralised coal-fired generation to a diverse portfolio dominated by DER and VRE, supported by dispatchable resources, with enhanced grid and power system service capabilities.

This Part D of the Draft ISP identifies the actions that need to happen now, next and in future to enable that energy transition. It covers:

1. The **Draft ISP's Optimal Development Path**, selected from a shortlist of five candidate development paths (noting that each include the Actionable ISP Projects)
2. **Priority, near-term and future projects** to augment the transmission grid
3. **Complementary ISP development opportunities** that increase energy resources as part of the optimal development path
4. The **signposts to look out for** which signal when a change in course is appropriate, and
5. **Complementary policy reforms** for the technical and market integration of distributed energy resources (DER) and for NEM market design, to support efficient and timely investment, potentially with targeted government interventions.[47]

Together, these actions and initiatives form a robust, transparent, dynamic roadmap of least-regret choices, to be acted on at significant decision points during Australia's energy transition.

D1 Selection of the optimal development path

AEMO has shortlisted five candidate ISP development paths, all of which include all of the DER, VRE, dispatchable resources, power system services and grid augmentations described in Part C.

In terms of their transmission projects, all five paths include[48]:

- **Western Victoria Transmission Network Project** in 2025-26, already committed.
- **South Australia system strength remediation** in 2020-21, already committed.
- **Project EnergyConnect** in 2023-24.
- **VNI Minor** in 2022-23.
- **QNI Minor** in 2021-22.

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[47] In particular, there are attributes that become more valuable with higher degrees of inverter-connected generation but are not explicitly priced or valued by the current energy-only market design.

[48] All dates are indicative, and on a financial year basis. For example, 2023-24 represents the financial year ending June 2024.

- **HumeLink** in 2024-25.
- **QNI Medium** which should be delivered by 2028-29, with an option of accelerating delivery to 2026-27 should the Step Change scenario emerge, to increase Queensland transfer capacity to New South Wales by 760 MW.

The candidate paths differ in the timing of investments in the major VNI West and Marinus Link interconnections.

AEMO recommends, using the least-regret approach to cost-benefit analysis and taking into account the asymmetry of risk between delivering a project early versus too late:

- **Accelerating VNI West to be operational in 2026-27** to mitigate the risks of early coal-plant closures. This is likely to be the earliest that this project can be delivered and would require underwriting to cover early works combined with expedited planning and approval processes. This would provide insurance against an early closure of Yallourn which, for the purposes of this analysis, AEMO has assumed may occur as early as 2026-27.
- **Marinus Link 'shovel-ready' works –** 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'. 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.

This combination of credible transmission, generation, storage and DER options will best meet the reliability and security needs of the power system and deliver positive net market benefits, while also providing the necessary flexibility to navigate an ever-changing future at lowest risk for consumers.

D1.1 Five candidate development paths

From the scenario analysis of all Draft ISP credible options, the five potential development paths ("candidates") have been identified, see Table 7, by assessing what decisions would need to be made now, in the absence of better information, to meet the ideal timelines for development identified for each scenario. The five candidate paths are:

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, and
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.

Table 7 Candidate development paths, defined by timing of their common, major interconnection projects

Project	No accelerated action	Accelerated VNI West	Accelerated Marinus Link	Accelerated VNI West and Marinus Link	Accelerated VNI West and shovel-ready Marinus Link
QNI Minor	2022-23				
VNI Minor	2022-23				
Project EnergyConnect	2023-24				
HumeLink	2025-26				
QNI Medium	2026-27 to 2028-29				
QNI Large	2031-32*				
VNI West	2030-31 to 2031-32	2026-27 to 2028-29	2030-31 to 2035-36	2026-27 to 2028-29	2026-27 to 2028-29
Marinus Link (1st cable)	2030-31 to 2036-37	2030-31 to 2036-37	2026-27	2026-27	2026-27# to 2036-37
Marinus Link (2nd cable)	2031-32#				

* in the Central Scenario only, # in the Step Change scenario only.
In the Slow Change scenario, only the first five interconnector options are beneficial.

These candidate development paths have been tested across all scenarios by locking in the decisions that need to be made now (including the no regret decisions and QNI Medium), and then re-optimising subsequent build decisions, assuming that if the decision to build is not made now, the earliest this decision could be revisited is two years from now, in the next ISP cycle. For Marinus Link, it is assumed that if early works do not continue now the current momentum would be lost and result in a four year delay to earliest commencement date.

The regret cost associated with each development path and scenario is calculated by comparing the total system cost of this "adapted" optimal path against the total system costs if decisions made now were in accordance with the scenario's optimal development timing reported in Section C.

Sensitivity outcomes are also included to demonstrate the robustness of the development paths to these possible market events. In the development paths where VNI West is already being prepared for delivery in 2028-29 and brown coal plants retire early, then it is assumed that VNI West could be further expedited to be in service by 2026-27 (which would require arrangements to expedite early investment and approvals).

1. No accelerated action

This candidate development path includes all no-regret transmission projects as well as QNI Medium in either 2026-27 or 2028-29 depending on the scenario, with no accelerated action on VNI West or

Marinus Link. These future projects are timed according to identified need in each scenario, and no further action is required at this time.

This candidate retains little flexibility to respond quickly if coal-fired generators retire earlier than expected, resulting in regret costs of $118 million and $240 million under that sensitivity and the Step Change scenario respectively. If coal-fired generation reduces and neither VNI West nor Marinus Link are ready, Victoria will need new higher-cost local generation and storage to back up the replacement VRE. This results in higher operating fuel and maintenance costs, higher demand side participation costs, higher capital expenditure on local capacity and increased expenditure on intra-regional transmission development to increase local REZ access.

Table 8 Net market benefits of 'No acceleration' development path (NPV, $ billion)

	Total system costs (no new interconnectors)	Total system costs (with candidate development path)	Net market benefits	Total system costs (optimal development timing)	Regret costs
	A	B	A less B	C	B less C
Scenario					
Central	87.53	84.91	2.61	84.91	0.000
High DER	80.27	78.28	1.99	78.28	0.000
Step Change	92.15	90.05	2.10	89.81	-0.240
Slow Change	57.69	56.60	1.10	56.60	0.000
Fast Change	85.74	83.63	2.11	83.63	0.000
Sensitivity					
Early retirement	N/A	85.33	N/A	85.21	-0.118
No QRET	N/A	84.16	N/A	84.16	0.000
Snowy 2.0 delay	N/A	84.83	N/A	84.83	0.000
Central West NSW REZ	N/A	83.10	N/A	83.10	0.000
Early load closure	N/A	82.97	N/A	82.97	0.000

2. Accelerate VNI West for it to be in place if Yallourn retires early

This candidate assumes that VNI West is commenced immediately, allowing seven years to build for delivery in 2028-29. Again, all no-regret transmission projects are included, as well as QNI Medium in either 2026-27 or 2028-29 depending on the scenario.

Earlier delivery by 2026-27 would require arrangements to expedite the approvals and works. While its delivery date ranges from 2027-28 to 2031-32 for all scenarios other than Slow Change, this date is driven by when brown coal-fired generation retires in the next decade, which in reality is uncertain. Delivery too late carries far higher cost and risk than delivery slightly early.

If VNI West is built for 2028-29 but is not needed until 2031-32, the main regret cost is simply the time value of the earlier investment, which is comparatively low under today's low interest rates. We also have the opportunity to start the build, and then re-assess and adapt in two years' time or when new information is available. If the Central Scenario unfolds and brown coal-fired generators retire on their expected closure dates, the worst regret cost is $67 million. However, if we aimed for delivery in 2031-32 and then VNI West was needed before 2028-29, the regret cost would rise to $240 million in missed opportunities and additional costs (see Step Change scenario in Table 8).

Those costs would mount significantly if Yallourn retired earlier than currently anticipated and VNI West was not in place. This would risk both load shedding and scarcity pricing, leading to significant added costs for consumers, as experienced both when Northern Power Station closed in South Australia and when Hazelwood Power Station closed in Victoria. In this Draft ISP, if Yallourn or an equivalent plant in Victoria were to close in 2026-27, and VNI West was not in operation until 2031-32, $118 million regret cost is estimated (see Table 8). For accelerated development to secure the option value that results in the maximum net benefit, the probability of early retirement would need to be greater than 36% in the Central scenario, a relatively small threshold in the current environment, and lower under other scenarios. Details of how this option value has been calculated are provided in Appendix 4.

If Yallourn, or an equivalent plant in Victoria were to close early and VNI West has not been accelerated, the modelling determines that building 300 MW of pumped hydro energy storage would be necessary instead to help firm VRE and avoid load shedding. If this pumped hydro energy storage is not available in the time (which is likely given the conceivably short time to build once early closure is announced) or at the cost assumed in the modelling, the benefits of accelerating VNI West would be even greater.

The greatest regret for this candidate development path is if coal-fired generation retired much faster than currently expected in response to aggressive decarbonisation ambitions. In the Step Change scenario, under this development path, early works on Marinus Link have not progressed and in subsequent ISP assessments, it is no longer possible to get the interconnector in early enough to avoid incurring $139 million in additional costs to consumers.

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 (approximately $125 million) are assumed sunk under this development path.

Table 9 Net market benefits of 'Accelerated VNI West' development path (NPV, $ billion)

	Total system costs (no new interconnectors)	Total system costs (with candidate development path)	Net market benefits	Total system costs (optimal development timing)	Regret costs
	A	B	A less B	C	B less C
Scenario					
Central	87.53	84.98	2.55	84.91	-0.067
High DER	80.27	78.37	1.91	78.28	-0.083
Step Change	92.15	89.95*	2.20	89.81	-0.139
Slow Change	57.69	56.70	0.99	56.60	-0.025
Fast Change	85.74	83.71	2.03	83.63	-0.080
Sensitivity					
Early retirement	N/A	85.21#	N/A	85.21	0.000
No QRET	N/A	84.21	N/A	84.16	-0.049
Snowy 2.0 delay	N/A	84.90	N/A	84.83	-0.066
Central West NSW REZ	N/A	83.18	N/A	83.10	-0.083
Early load closure	N/A	83.01	N/A	82.97	-0.032

* Assuming that VNI West is expedited to be in service by 2027-28, ahead of coal plant closures
# Assuming that VNI West is expedited to be in service by 2026-27, ahead of the coal plant closure

3. Accelerate Marinus Link for it to be in place if more coal-fired generation exits early

This candidate assumes that Marinus Link is commenced immediately and continued through to delivery in 2026-27.[49] Again, all no-regret transmission projects are included, as well as QNI Medium in either 2026-27 or 2028-29 depending on the scenario.

Marinus Link is most beneficial under scenarios with more rapid retirements in coal-fired generation and a more even distribution of VRE across the NEM (Fast Change and Step Change scenario).

The value of early development of Marinus Link is relatively low under the Central and High DER scenarios, where significant volumes of VRE are projected to be built in Victoria in the next decade to meet VRET 50% target by 2030. Consequently, significant regret costs of up to $288 million are estimated under these scenarios and the sensitivities.

There is some benefit in having Marinus Link early in case the next brown coal generator retires earlier than expected. Like VNI West, it would avoid the need to build approximately 300 MW of pumped hydro energy storage (or more costly dispatchable generation alternatives). However, even with Marinus Link in operation, VNI West would still be needed from 2031-32 to support New South Wales following the expected closure of Eraring power station. Total interconnector costs for this candidate are therefore higher than the Accelerated VNI West candidate and outweigh the insurance

[49] Based on earliest start date assumed in AEMO's *Forecasting and Planning Scenarios, Inputs and Assumptions Report*. Latest advice from TasNetworks suggests the earliest in service date may now be 2027-28 unless the delivery timeline is expedited.

value delivered. If VNI West were delayed indefinitely for any reason, or dispatchable generation alternatives in Victoria were more expensive than currently assumed, the merits of accelerating Marinus Link would increase significantly.

Table 10 Net market benefits of 'Accelerated Marinus Link' development path (NPV, $ billion)

	Total system costs (no new interconnectors)	Total system costs (with candidate development path)	Net market benefits	Total system costs (optimal development timing)	Regret costs
	A	B	A less B	C	B less C
Scenario					
Central	87.53	85.20	2.32	84.91	-0.288
High DER	80.27	78.56	1.71	78.28	-0.279
Step Change	92.15	89.81	2.34	89.81	0.000
Slow Change	57.69	56.73	0.97	56.60	-0.130
Fast Change	85.74	83.66	2.08	83.63	-0.025
Sensitivity					
Early retirement	N/A	85.37	N/A	85.21	-0.156
No QRET	N/A	85.17	N/A	84.16	N/A
Snowy 2.0 delay	N/A	85.11	N/A	84.83	-0.281
Central West NSW REZ	N/A	N/A	N/A	N/A	N/A
Early load closure	N/A	N/A	N/A	N/A	N/A

4. Accelerate VNI West and Marinus Link

This development path combines the previous two, with the accelerated development of both VNI West and Marinus Link. All no-regret transmission projects are included as well as QNI Medium in either 2026-27 or 2028-29 depending on the scenario.

Stranded asset risk in the near term is a real possibility under this development path, as the accelerated development of both VNI West and Marinus Link in the next decade is only forecast to be needed under Step Change scenario. The high regret costs associated with this development path reflect this risk.

Table 11 Net market benefits of 'Accelerated VNI West and Marinus Link' development path (NPV, $ billion)

	Total system costs (no new interconnectors)	Total system costs (with candidate development path)	Net market benefits	Total system costs (optimal development timing)	Regret costs
	A	B	A less B	C	B less C
Scenario					
Central	87.53	85.29	2.23	84.91	-0.380
High DER	80.27	78.75	1.52	78.28	-0.470
Step Change	92.15	89.81*	2.35	89.81	0.000
Slow Change	57.69	56.82	0.87	56.60	-0.155
Fast Change	85.74	83.80	1.94	83.63	-0.170
Sensitivity					
Early retirement	N/A	85.52#	N/A	85.21	-0.307
No QRET	N/A	N/A	N/A	N/A	N/A
Snowy 2.0 delay	N/A	85.21	N/A	84.83	-0.372
Central West NSW REZ	N/A	N/A	N/A	N/A	N/A
Early load closure	N/A	N/A	N/A	N/A	N/A

* Assuming that VNI West is expedited to be in service by 2027-28, ahead of coal plant closures
# Assuming that VNI West is expedited to be in service by 2026-27, ahead of the coal plant closure

5. Accelerate VNI West and maintain an early delivery option for Marinus Link

The final candidate is to accelerate VNI West as in (2) above, progress the design and approvals process for Marinus Link to make it 'shovel-ready', and defer a final decision on Marinus Link until 2023-24 when delivery signposts can be assessed more clearly. This would secure a low-cost option for the early delivery of Marinus Link in 2026-27 if needed. Again, all no-regret transmission projects are included as well as QNI Medium in either 2026-27 or 2028-29 depending on the scenario.

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 delayed.

TasNetworks has advised AEMO that approximately an additional $130 million is needed to progress Marinus Link and supporting AC transmission to the point of making a final investment decision and commence construction. AEMO has assumed that, if the project loses its current momentum and is stalled for eight to ten years before then recommencing, the feasibility work already conducted would need to be re-worked, at additional cost to consumers. The total system costs of this accelerated development path therefore reflect a $20 million savings in avoiding that re-work.

The additional $130 million in funding for the 'Design and Approvals' phase will enable completion of land and marine surveys to support approvals and technical designs, plan land use, secure environmental approvals, obtain access to land and easements, complete conceptual technical design and specification, tender for major equipment, and progress financial and commercial arrangements.

This investment would in turn retain the option of delivering Marinus Link by 2027-28[50] if a decision to proceed was made in 2023-24. AEMO believes this would be a prudent investment to consider, as Marinus Link will eventually be required under all scenarios except Slow Change.

Table 12 Net market benefits of 'Accelerated VNI West with Marinus Link shovel-ready' development path (NPV, $ billion)

	Total system costs (no new interconnectors)	Total system costs (with candidate development path)	Net market benefits	Total system costs (optimal development timing)	Regret costs
	A	B	A less B	C	B less C
Scenario					
Central	87.53	85.03	2.51	84.91	-0.112
High DER	80.27	78.41	1.87	78.28	-0.129
Step Change	92.15	89.81	2.34	89.81	0.000
Slow Change	57.69	56.75	0.94	56.60	-0.155
Fast Change	85.74	83.76	1.99	83.63	-0.125
Sensitivity					
Early retirement	N/A	85.25	N/A	85.21	-0.045
No QRET	N/A	84.26	N/A	84.16	-0.094
Snowy 2.0 delay	N/A	84.95	N/A	84.83	-0.112
Central West NSW REZ	N/A	83.22	N/A	83.10	-0.129
Early load closure	N/A	83.05	N/A	82.97	-0.078

In Table 12, the remaining $130 million shovel-ready cost has been included in the total system costs under each scenario, irrespective of whether the project is ultimately needed or not. In all but the Slow Change scenario, Marinus Link is needed eventually, so the shovel-ready cost represents the cost of bringing forward works that would have occurred at a future date, and avoiding the $20M cost of rework.

In effect, this means the early works would cost $130 million if incurred now, and $150 million if incurred ten years from now. Due to the time value of money, the present value difference in cost

[50] Modelling assumed earliest start date of 2026-27 based on AEMO's *Forecasting and Planning Scenarios, Inputs and Assumptions Report*. Latest advice from TasNetworks suggests the earliest in service date may now be 2027-28 unless the delivery timeline is expedited.

associated with accelerating Marinus Link is approximately $41 million (difference in total system costs between Table 9 and Table 12, column B).

D1.2 Accelerated VNI West as the optimal development path, and shovel-ready Marinus Link

VNI West will take seven years to build and be required no later than 2028-29 (or ideally earlier) to mitigate risks of early brown coal closure, meaning that the project needs to commence immediately. AEMO therefore:

- proposes that the second candidate '**Accelerated VNI West**' is the optimal development path for the purposes of the proposed actionable ISP regulatory framework, with arrangements in place to expedite the approvals and works to get the interconnector in service by 2026-27 if needed, and
- additionally, recommends that $130 million be invested to secure the option to deliver the first cable of Marinus Link by 2027-28, with the 'go' decision made by 2023-24. While this investment is not meeting the criteria of an 'actionable ISP project' in the strict sense of its definition, AEMO nevertheless believes this to be a prudent option to take.

The actionable ISP projects and the ISP development opportunities that form part of this optimal development path are listed in Section D3 below and discussed in more detail in the Appendices. The staging of those investments, alongside other actions, are set out in the Roadmap in Section D4.

The rationale for this conclusion is set out in Table 13 and Table 14 below, which summarise the net market benefits and regret costs of the five options across all scenarios.[51] All five development paths deliver positive net market benefits in the Central scenario, as required. "No accelerated action" delivers the maximum net market benefits in this scenario, but also carries significant risk if brown coal retires earlier than expected, or Step Change scenario were to unfold.

The Accelerated VNI West development path has been selected as the optimal development path as it:

- meets power system needs for reliability and security
- achieves positive net market benefits under the Central scenario[52], and
- minimises regrets across all scenarios and sensitivities.[53]

More generally, the timing of VNI West and Marinus Link can have a material impact on net market benefits, and the value to consumers is maximised when these investments are well co-ordinated with the timing of coal-fired generation retirements.

Sufficient development of renewable generation, storage and associated network must be completed before these retirements occur, and in reality these developments will occur incrementally, to manage construction and connection resource constraints. Accelerated development of VNI West will therefore also provide additional benefits by reducing risks of generation curtailment as the replacement generation progressively comes online.

[51] Clause 5.22.6(7) Draft ISP Rules

[52] Clause 5.22.5(e)(3) Draft ISP Rules

[53] Chosen by AEMO as the best method to select the optimal development path clause 5.22.5 (e)(2) Draft ISP Rules

Table 13 Net market benefit of each development path under each scenario (NPV, $ billion)

Scenario	No accelerated action	Accelerated VNI West	Accelerated Marinus Link	Accelerated VNI West and Marinus Link	Accelerated VNI West and shovel-ready Marinus Link
Central	2.61	2.55	2.32	2.23	2.51
High DER	1.99	1.91	1.71	1.52	1.87
Step Change	2.10	2.20	2.34	2.34	2.34
Slow Change	1.10	0.99	0.98	0.87	0.87
Fast Change	2.11	2.03	2.08	1.94	1.99

Table 14 Regret costs of the 'adapted optimal' of each development path under each scenario (NPV, $ million)

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**
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

After looking at the sensitivity results in Table 14, AEMO concludes that:

- Accelerating VNI West mitigates the risk of high costs to consumers if the next brown coal-fired generation retirement in Victoria occurred earlier than announced.
- In the absence of QRET, or large volumes of VRE in New South Wales accelerated by the state's Electricity Strategy, stronger interconnection with Victoria is beneficial earlier, with accelerated VNI West being less regretful under this sensitivity than under Central scenario.

- The benefits of accelerated development of VNI West are also greater if a large industrial load closes in Victoria in the next decade. This is because the project increases the ability for existing brown coal-fired generators to export surplus generation to neighbouring regions, which may lead to the plant being run to the end of technical life.
- If 2 GW of VRE were to be developed early in New South Wales Central West REZ, facilitated by the New South Wales Electricity Strategy, the regret costs associated with accelerated VNI West are similar to in the High DER scenario. In both futures, more solar generation (either behind-the-meter or grid-scale) is built earlier in New South Wales, slightly reducing the value of imports from neighbouring regions[54].
- A delay to Snowy 2.0 would not lead to significant increases in costs to consumers, provided the HumeLink development continues to proceed to plan.

D1.3 Actionable ISP Projects as part of the optimal development plan

While all of the projects discussed in Part C are incorporated in the optimal development path, only some of the transmission-related projects are considered actionable ISP projects under the proposed ISP Rules. These are set out in Table 15, together with the supporting information as indicated in the Draft ISP Rules. The recommended timing of these projects is discussed in Section D2 below.

[54] This initial analysis of the New South Wales Electricity Strategy does not consider the impacts this additional VRE may have on the economic life of aging coal-fired generators.

Table 15 Details of actionable ISP projects

Project	Indicative Timing †	Approval Status	PADR Deadline	Relevant TNSP responsible	Identified need	ISP candidate option††
Minor NSW to QLD upgrade	2021-22	RIT-T in progress	Already published	TransGrid and Powerlink	The identified need for the minor New South Wales to Queensland upgrade 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".	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.
Minor VIC to NSW upgrade	2022	RIT-T in progress	Already published	AEMO and TransGrid	The identified need for Minor Victoria to New South Wales upgrade is "to realise net market benefits by increasing the power transfer capability from Victoria to New South Wales".	VNI Option 1 is a minor upgrade of the existing Victoria-New South Wales interconnector with 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.
Project EnergyConnect	2023-24	RIT-T in progress	RIT-T completed	ElectraNet	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.	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.
HumeLink	2025-26	RIT-T in progress	31 March 2020	TransGrid	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 Sydney, Newcastle and Wollongong load centres. • Reducing the need for new gas fired generation in NSW to meet demand following coal generation retirement. • Facilitating the development of renewable generation resource areas in Wagga Wagga and southern NSW Tablelands REZs.	ISP modelled one transmission line connects Maragle and Bannaby directly and other transmission line connects Maragle and Bannaby via Wagga to provide route diversity. This route option links Wagga Wagga and Southern NSW Tablelands (N4) REZs.

Project	Indicative Timing †	Approval Status	PADR Deadline	Relevant TNSP responsible	Identified need	ISP candidate option††
VNI West	2026-27	RIT-T just starting	30 June 2021	AEMO and TransGrid	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 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.	A new 500 kV double circuit interconnector between Victoria and New South Wales.
Medium QNI upgrade	2026-27	RIT-T not started	10 December 2021	Powerlink and TransGrid	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 aging 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.	A new single 500 kV circuit between New South Wales and Queensland via the western part of the existing interconnection. The proposed route goes through North West NSW and Darling Downs REZs.

† 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. All dates are indicative, and on a financial year basis. For example, 2023-24 represents the financial year ending June 2024.
†† Indicative outline of the recommended option for project delivery

D2 Priority, near-term and future projects to augment the transmission grid

The Draft ISP identifies the required actionable projects and other actions to augment the transmission grid as part of the optimal development path. AEMO has grouped these in three groups to achieve power system needs through a complex, energy sector transition.

To contribute their full value, these projects should be complemented by the ISP development opportunities and policy reforms discussed in Sections D4 and D5 below.

All dates in this part D are indicative, and on a financial year basis. For example, 2023-24 represents the financial year ending June 2024. In most cases, projects are needed to be operational at the beginning of the financial year.

D2.1 Priority grid projects (Group 1)

Priority grid projects required to commence in the near future if not already underway. These projects are critical to address cost, security and reliability issues, and are time-critical, least-regret options that deliver those consumer benefits and/or maintain optionality for future system needs under all or, in the worst case, most scenarios. Not all of these actions represent an actionable ISP project.

Committed priority grid projects

Projects that have become committed since the 2018 ISP:

- **South Australia system strength remediation** – A committed project that is urgently required to supply the necessary system strength required to operate the South Australia power system securely (refer C4).
- **Western Victoria transmission augmentation** – A committed project expected in 2025-26 to add transmission to the western and north-western Victoria REZs, unlocking renewable energy resources, reducing congestion and improving the productivity of existing assets.

Priority grid projects undergoing regulatory approval

These investments are highly likely to provide strong benefits in all, or nearly all scenarios. They require near-term investment to maximise those benefits, and the potential regret costs from over-investment are very low.

- **Project EnergyConnect** (actionable ISP project) – A new interconnector between New South Wales and South Australia, recommended in the 2018 ISP and confirmed as no-regret in this Draft ISP. The RIT-T for this project is complete and, at the time of publication of this Draft ISP, the Australian Energy Regulator's review of the RIT-T process and a decision to amend the revenue determination are still in progress. This project is expected to be delivered in **2023-24**.
- **QNI Minor** (actionable ISP project) – A minor upgrade to the New South Wales – Queensland interconnector recommended as urgent in the 2018 ISP and confirmed as no-regret in this draft ISP. Powerlink and TransGrid are progressing a RIT-T to confirm the optimal solution and gain

regulatory approval.[55] The PADR was published on 30 September 2019. This upgrade is currently expected to be delivered **in 2021-22**.

- **VNI minor** (actionable ISP project) – A minor upgrade to the existing Victoria – New South Wales interconnection recommended as urgent in the 2018 ISP and confirmed as no-regret in this draft ISP. AEMO and TransGrid are progressing a RIT-T to confirm the optimal solution and gain regulatory approval.[56] The PADR was published on 30 August 2019. This upgrade is expected to be delivered **in 2022-23**. The New South Wales component is expected to be delivered in 2021-22 and is expected to provide reliability benefits ahead of the retirement of the Liddell Power Station.
- **HumeLink** (actionable ISP project) – Upgrades to the transmission network between the Snowy Mountains and Sydney were recommended in the 2018 ISP, and for which TransGrid is currently undertaking a RIT-T process to identify a preferred network augmentation and/or non-network option to address the identified need.[57] TransGrid published the Project Specification Consultation Report (PSCR) in June 2019 and is on track to publish a PADR in early 2020. The Draft ISP has considered the options described in the PSCR, which also create network to support development of VRE in the REZs of Wagga Wagga and Southern New South Wales Tablelands. This project is expected to be delivered **in 2024-25**.
- **VNI West** (actionable ISP project) – VNI West, a new interconnector between Victoria and New South Wales that will take seven years to build 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 earliest that this project can be delivered and would require underwriting to cover early works combined with expedited planning and approval processes. This would provide insurance against an early closure of Yallourn which, for the purposes of this analysis, AEMO has assumed may occur as early as 2026-27. AEMO has commenced the RIT-T for VNI West by publishing the PSCR in conjunction with this Draft ISP. After the Final 2020 ISP is published and the actionable ISP rules come into effect, this project is expected to be transitioned to the new rule framework. The optimal routing of this interconnector, e.g. via Kerang or Shepparton, will be assessed during the consultations on the draft ISP and VNI West PSCR.
- **Marinus Link 'shovel-ready' works** (not an actionable ISP project) – 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. While these early works do not fit in the framework of "actionable ISP project"

[55] https://www.transgrid.com.au/what-we-do/projects/current-projects/ExpandingNSWQLDTransmissionTransferCapacity

[56] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Victoria-to-New-South-Wales-Interconnector-Upgrade-Regulatory-Investment-Test-for-Transmission

[57] https://www.transgrid.com.au/what-we-do/projects/current-projects/Reinforcing%20the%20NSW%20Southern%20Shared%20Network/Pages/HumeLink.aspx

as 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.

D2.2 Near-term grid projects (Group 2)

Group 2 transmission investments are near-term grid projects critical to maintain future options or enhance resilience and optionality and for which decisions on commencing the project are required within the next two years. These include:

- **QNI Medium** (Actionable ISP Project) – A medium upgrade to the QNI interconnection (QNI medium) which can later be expanded if needed. While a medium upgrade to the Queensland–New South Wales interconnection is needed for all scenarios, the size and timing of investment needed varies by scenario. The upgrade will require a new transmission interconnector to meet the required minimum expansion in transfer capacity. The project can be staged to best address the future uncertainty, keeping open the options of going ahead with a larger expansion, or to delay or even withdraw that expansion. This analysis demonstrates the value of optionality in interconnector investment, including investments that can be staged to minimise stranded asset risk in future. This project will be required **by 2028-29**. Should the Step Change or Fast Change scenario emerge, an earlier delivery by 2026-27 would be desirable.

D2.3 Future grid augmentation projects (Group 3)

Future grid options proposed to complete the optimal development path, with time in which to investigate further and refine. They may be required to support large amounts of new renewable energy, currently matched in the economic projections to the timing of the bulk of anticipated exits of coal-fired generation from 2030 onwards. Investment in replacement generation and storage projects will be driven by the market incentives and technology costs at the time. These projects should be further explored and progressed as they provide valuable future options for Australia's energy system. The two-year review cycle of the ISP offers time to refine this group of projects.

The supporting transmission grid will require planned, regulated investment if it is to deliver low-cost, reliable, secure supply across the NEM. It must deliver greater volumes of generated and stored energy to meet consumer demand; take advantage of geographic, time, and resource diversity in renewable generation; allow more efficient operation of coal-fired generation and GPG; and improve system reliability and resilience by transmitting energy within and across regions.

In this Draft ISP, we outline what is needed for these developments and the likely signposts or decision points. The timings are indicative only and are influenced by the timing of significant NEM events, such as the exit of coal-fired generation, or the addition of new generation and storage resources, such as Snowy 2.0 and BOTN. AEMO will continue to engage with industry, government, and other stakeholders to refine these longer-term options in future ISPs.

These future actions, grid augmentations and REZ development (see Section D3 below) are inextricably interlinked. The design of transmission routes is critical. Interconnectors that pass through REZs will reduce the cost of or need for intra-regional network extensions, while route diversity may protect against extreme weather events and bushfires. On completion of grid augmentation projects in the ISP roadmap, further REZs can be developed to take advantage of the strengthened grid with reduced system costs. Likewise, future REZ potential is a factor in the optimal development path for transmission assets particularly with sizing and route selection. REZ development potential will be subject to engagement with traditional owners, local community, and completion of required planning and environmental approvals.

The following potential investments should be further assessed and developed in future ISPs:

- **Marinus Link** – Completion of works on a second, and potentially third, HVDC cable connecting Victoria to Tasmania, with associated AC transmission. 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.
- **Queensland grid reinforcements.**
  - **Larger QNI upgrade** – After the development of a Medium QNI upgrade (see Group 2), a larger QNI upgrade could be needed in the 2030's 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 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 2030's 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). 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.
  - **Central to Southern QLD 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 will reduce network congestion and provide value to consumers. These major investments are projected to be required in the 2030s. Alternatives to address current congestion concerns could consider unregulated investment options, and could also explore options for non-network solutions, such as localised storage.
  - **Gladstone Grid reinforcement** – After the closure of Gladstone Power Station (currently expected in 2035), network upgrades are required to supply loads in the Gladstone area

- **New South Wales grid reinforcements.**
  - **Reinforcing Sydney, Newcastle and Wollongong supply –** Sydney and Newcastle will need to be supplied via different network paths once a number of key plants retire, currently anticipated at the end of the next decade (Eraring in 2032, 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: 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 ring needs to be strengthened in New South Wales: a number of additional 330 kV lines between Mt 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** – Development of large amounts of renewables in REZs will be dependent on and influenced by the recommended designs for projects to augment the transmission network. The REZ are likely to require system strength remediation to accommodate the projected future amounts of VRE in the areas, in addition to network upgrades. These are discussed in the next section.

D3 ISP Development Opportunities in Renewable Energy Zones

In some cases the anticipated REZ developments will lead to, and create the need for, concurrent coordinated augmentation of the transmission network. In other cases, network augmentations being undertaken for other reasons will, if suitably designed, enable further development of VRE in specific REZ. Developers of VRE will always decide where and when to invest based on their own commercial criteria. If these investments are not aligned with this ISP development path, then there may not be a sufficiently strong economic case to build transmission necessary to support these VRE developments until much later, such as eventual exit of coal-fired power stations. Simply building VRE does not necessarily create the case for regulated network augmentation. It is very important to consider the overall needs of the power system and take a highly coordinated approach to the development of REZs and augmentations of the power system.

AEMO's Draft 2020 ISP projects such a coordinated and integrated approach, with development of additional VRE in REZs across the NEM to occur in three overlapping development phases. Staging of the identified REZ developments must be coordinated with recommended augmentations of the network and system strength remediation[58]. These opportunities take advantage of additional network capability provided by new interconnectors where possible, however they also require specific transmission projects.

The developmment phases are:

- Phase 1, to help meet regional RETs (such as VRET and QRET) and other policies (such as the New South Wales Electricity Strategy) until those schemes are complete and/or where there is good access to existing network capacity with good system strength within the current power system, good resource potential, and strong alignment with community interests. Note that the New

[58] The limits to renewables, and the requirements to realise these limits, are defined in Part D of this report, and in detailed scorecards in Appendix 8

South Wales Electricity Strategy, which aims to develop 3 GW of VRE in the Central West REZ with associated transmission infrastructure by 2028, may require accelerated development of this REZ. 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.

- Phase 2, to replace energy provided by coal-fired generators that are scheduled to exit, to be ready when coal plant is retired (assumed to occur from the late 2020s) and/or where additional development is supported by the recommended transmission projects in Group 1 and 2 of the optimal development path.
- Phase 3, to accompany group 3 transmission projects that are being developed specifically to support VRE development in these REZs to meet the needs for large-scale replacement of coal when it exits (currently expected from late 2020s to 2040s).

These development opportunities are outlined in Table 16.

Table 16 ISP Development Opportunities – REZs

Phases of REZ Development	REZ
Phase 1 To help meet regional RETs (such as VRET and QRET) and other policy initiatives (such as the NSW Electricity Strategy) until those schemes are complete and/or where there is good access to existing network capacity with good system strength, good resource potential, and alignment with community interests.	**Queensland:** Darling Downs (wind and solar), Fitzroy (wind and solar), and initial development of Far North Queensland (wind) **New South Wales:** Initial medium level development of Central West (wind and solar) **South Australia:** Roxby Downs (solar) **Victoria:** Western Victoria (wind) and South West Victoria (wind), Central North Victoria (wind).
Phase 2 To replace energy provided by retiring coal-fired generators – announced to occur from the late 2020s and/or where additional development is supported by the recommended transmission projects in Group 1 and 2 of the optimal development path.	**Queensland**: Larger development of Darling Downs (wind and solar), supported by QNI medium development **New South Wales**: North West (wind and solar), South West (solar), and Wagga Wagga (solar), supported by expansions including QNI Medium, Project EnergyConnect, HumeLink, VNI West and associated works. **Victoria**: Murray River (solar), supported by VNI West and Project EnergyConnect **South Australia**: Riverland (solar), supported by Project EnergyConnect, **Tasmania**: Midlands (wind), supported by Marinus Link
Phase 3 To accompany recommended group 3 transmission projects that are being developed specifically to support them.	**Queensland**: Larger development of Far North Queensland (wind), Isaac (solar), and larger development of Fitzroy (wind and solar) **New South Wales**: Larger development of Central West (wind and solar), New England (wind and solar), and North West (wind and solar) **South Australia**: Roxby Downs (solar), Mid-North (wind), and South East (wind)

Table 17 lists all REZ development opportunities identified in the Draft ISP and describes the quantity of the opportunity and associated transmission projects if applicable.[59]

[59] Further detail on these development opportunities in REZ, including the transmission augmentation options and opportunities for storage can be found in the Draft ISP Appendices (Appendices 6 and 8).

Table 17 ISP REZ development opportunities and associated network projects, Central scenario

REZ	Amount of additional generation by 2040	Existing Spare Capacity	Hosting capacity increase with new IC	Associated Group 3 REZ development	Amount of additional REZ capacity provided	Year that modelling suggests
Q1 - FNQ	1,700	700	-	Yes	+1,100 MW	2036
Q4 - Isaac	1,000	Q1+Q4+ Q6<2,500		Yes	+900 to Group constraint (Q1+Q4+Q6)	
Q6 - Fitzroy	2,500	Q1+Q4+Q 6< 2,500	-			
Q8 - Darling Downs	5,000	3,000	QNI Medium +1,000 MW QNI Large +2,000 MW	-		
N1 - North West NSW	6,500	100	QNI Medium +1,000 MW QNI Large +2,000 MW	Yes	+8,000 MW N1 and N2 combined	2036
N2 - New England	3,800	300	-			
N3 - Central West †	3,600	700	-	Yes	+2,000 MW	2036 †
N6 - South West NSW	1,500	0	Project EnergyConnect +600 MW HumeLink +1,000 MW	-		
N7 - Wagga Wagga	500	0	HumeLink +500 MW	-		
V2 - Murray	1,100	0	VNI West (Kerang route) +2,000 and Project EnergyConnect +380 MW	-		
V3 - Western Vic	700	450	-	-		
V4 - South West Vic	1,000	750	-	-	-	-
V6 - Central North Vic	800	800	-	-	-	-
S1 - South East SA	800	55	-	Yes	600	2036
S2 – Riverland	1,200	200	Project EnergyConnect +1,000 MW	-	-	
S3 - Mid North	1,200	S3+S7<1,0 00 MW	-	Yes - Mid North group constraint	+1,000 MW S3 and S7 combined	2036
S7 - Roxby Downs	960	960	-			
T3 – Midlands	900		Marinus Link +540 MW	-		

† Timing does not include the New South Wales Electricity Strategy to develop 3 GW of VRE in the Central West REZ with associated transmission infrastructure by 2028, announced just prior to completion of this draft ISP.

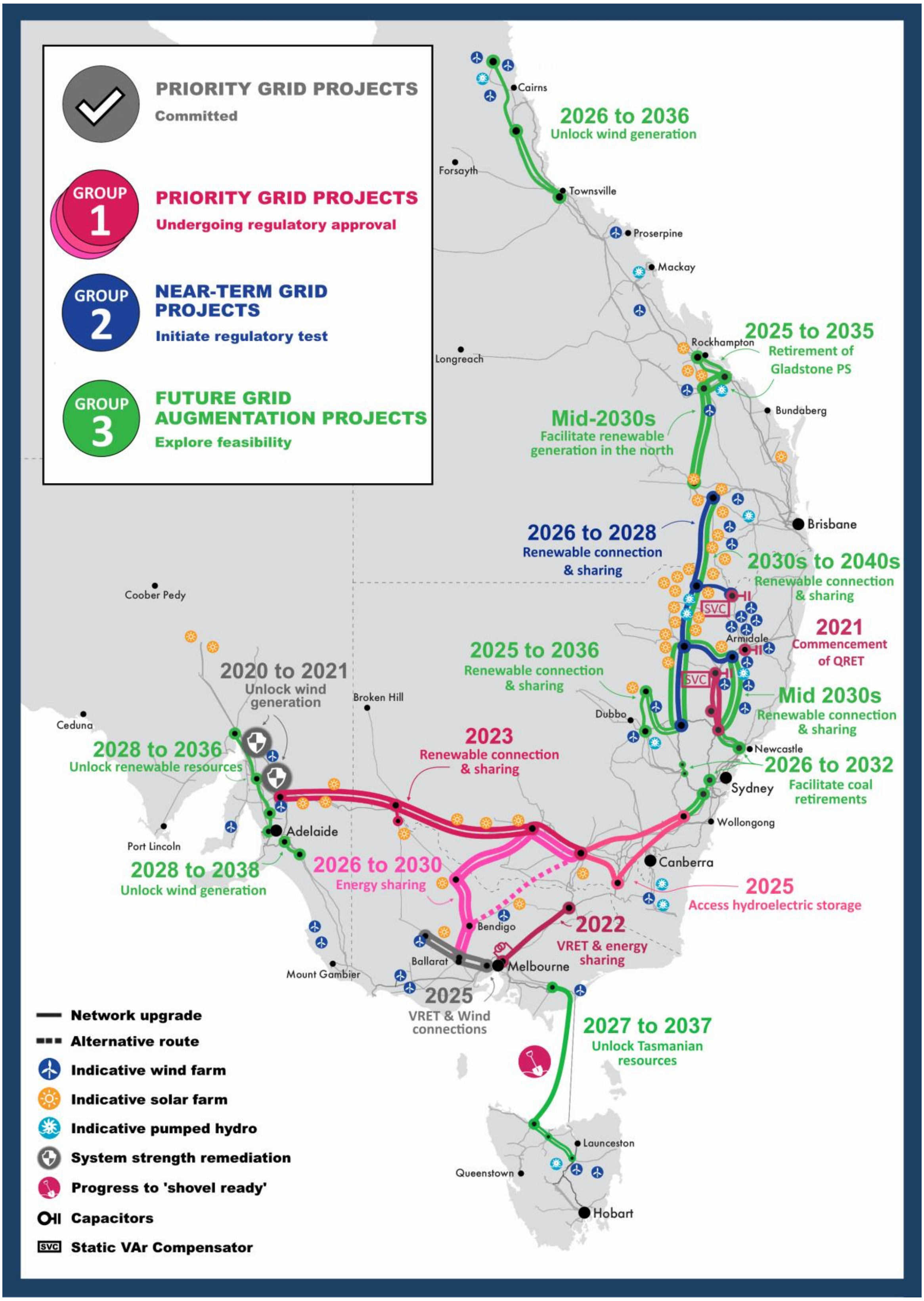
D4 Signposts to inform a dynamic roadmap

The optimal development path consists of all actionable ISP projects and ISP development opportunities. The Draft ISP presents a roadmap on which participants can see the optimal development path, as well as major intersections and signposts at which to reconsider the development path if the scenario changes or other market events occur. This is shown in Figure 21. In subsequent ISPs, or when material new information comes to hand, investment development options can be re-assessed.

Through our comparison of scenario and sensitivity cost-benefit outcomes, AEMO has identified the following signposts to indicate when it may be desirable to adapt from one path to another:

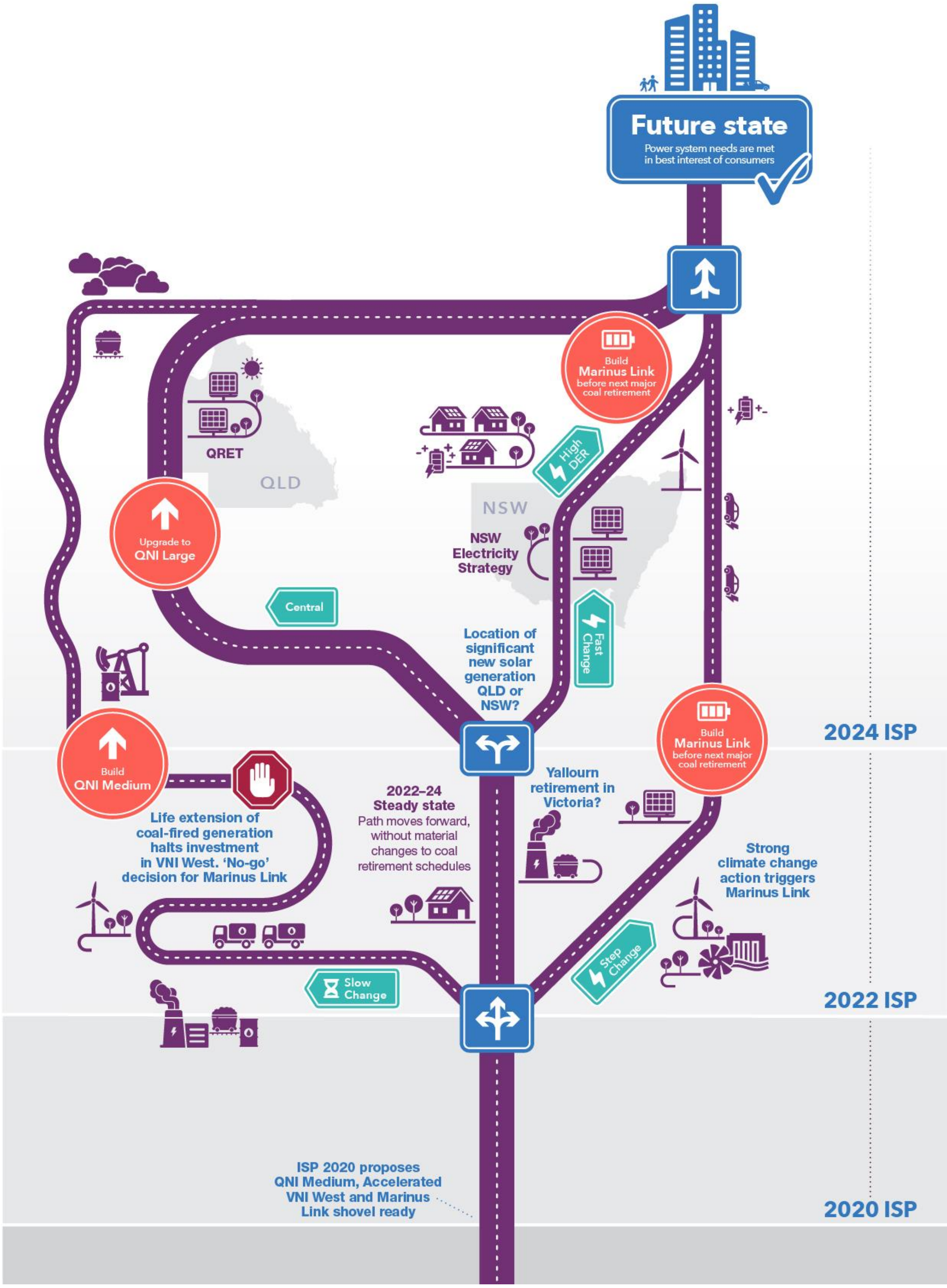
- If we find ourselves in the Slow Change scenario with **slow economic growth, coal-fired generation extensions and load closures**, a "no-go" decision on VNI West and Marinus Link may be made, if the future low economic conditions are recognised prior to construction.
- If **aggressive global decarbonisation and strong infrastructure commitments** are made (Step Change scenario), resulting in more rapid closure of coal-fired generation, then the accelerated development of VNI West, Marinus Link and QNI Medium should be expedited to have these interconnectors in place as soon as possible.
- If **more solar generation than currently projected is installed in New South Wales** (grid-scale or behind-the-meter), the value of a large QNI interconnector diminishes as there is less value in exporting surplus Queensland solar generation to New South Wales. This may occur if QRET is discontinued, if New South Wales attracts more large-scale solar through its Electricity Strategy, or if higher levels of DER akin to the High DER scenario were installed in New South Wales. In this case, the single-circuit QNI Medium option delivers greatest market benefits.
- If **QRET is discontinued**, acceleration of VNI West is more beneficial, confirming action to remain on course.
- Expedited development of QNI Medium, VNI West and/or Marinus Link would be beneficial if **earlier than expected black or brown coal-fired generation closures** are announced in the NEM.

Figure 20 The development paths for the NEM in the Draft ISP[60]



[60] All dates are indicative, and on a financial year basis. For example, 2023-24 represents the financial year ending June 2024.

Figure 21 Dynamic roadmap with choices to be acted on at significant decision points



D5 Complementary policy reforms

D5.1 DER technical and market integration should commence immediately

The technical integration of DER set out in Section C1 needs to be achieved in the next 2-3 years, and to the extent it is not already underway it should commence immediately. This includes:

- uplifting operational tools to operate in a high DER world
- ensuring visibility across the DER ecosystem to support decision-making at the appropriate level of aggregation, and
- uplifting standards, protocols and cyber-security protections to improve performance and capability of DER, across the energy system and in line with international best practice.

DER integration projects in Section C1 already underway are the ENA/AEMO Open Energy Networks project, the ESB's Post 2025 Market Design project, and the AEMC's Wholesale Demand Response rule change.

AEMO is also leading three initiatives to pilot DER capabilities and generate operation and consumer insights, among a range of trials occurring across the industry. The AEMO/Australian Renewable Energy Agency (ARENA) three-year demand response strategic reserve trial is in its third year; AEMO's VPP trial was launched in October 2019; and AEMO is working with parties to design a DER marketplace trial that leverages the Open Energy Networks project.

D5.2 Market reforms currently being reviewed should be pursued

As mentioned in Section B3, the ISP's low-cost low-regret development path can only translate into consumer benefits through market arrangements that encourage the optimal use of existing resources and appropriate signals for further investment.

The current market design needs to be augmented to appropriately recognise and reward not just the provision of energy, but the increasing value of flexibility and dispatchability in complementing and firming intermittent generation, as well as the full range of system security services outlined in Section A2. Market structures are also needed to reduce the risk of disorderly entry and exit of generation, which would result in higher costs to consumers.

For example, an investor in new GPG or pumped hydro could build the new plant with the capability to provide system services such as system strength and inertia, even when it does not need to produce energy. Provide these services with zero megawatts and zero fuel costs is increasingly valuable at very high penetrations of inverter-connected renewable generation.

Operationally, the NEM's real-time market can be complemented by arrangements that give greater visibility of available resources and options. This would ensure resource sufficiency, including day ahead markets, and that the right resources are available at the right time and can be co-optimised to reduce their cost. Managing operations ahead of time can also minimise operational risk for the system operator and revenue uncertainty for market participants. For example, a paper mill may adjust its electricity demand if it has some notice period and pricing can be locked in to reward the adjustment.

The ESB's market reform program is considering many such market and regulatory framework options: their expected benefits and costs and other trade-offs.[61]

D6 Implementing the ISP roadmap

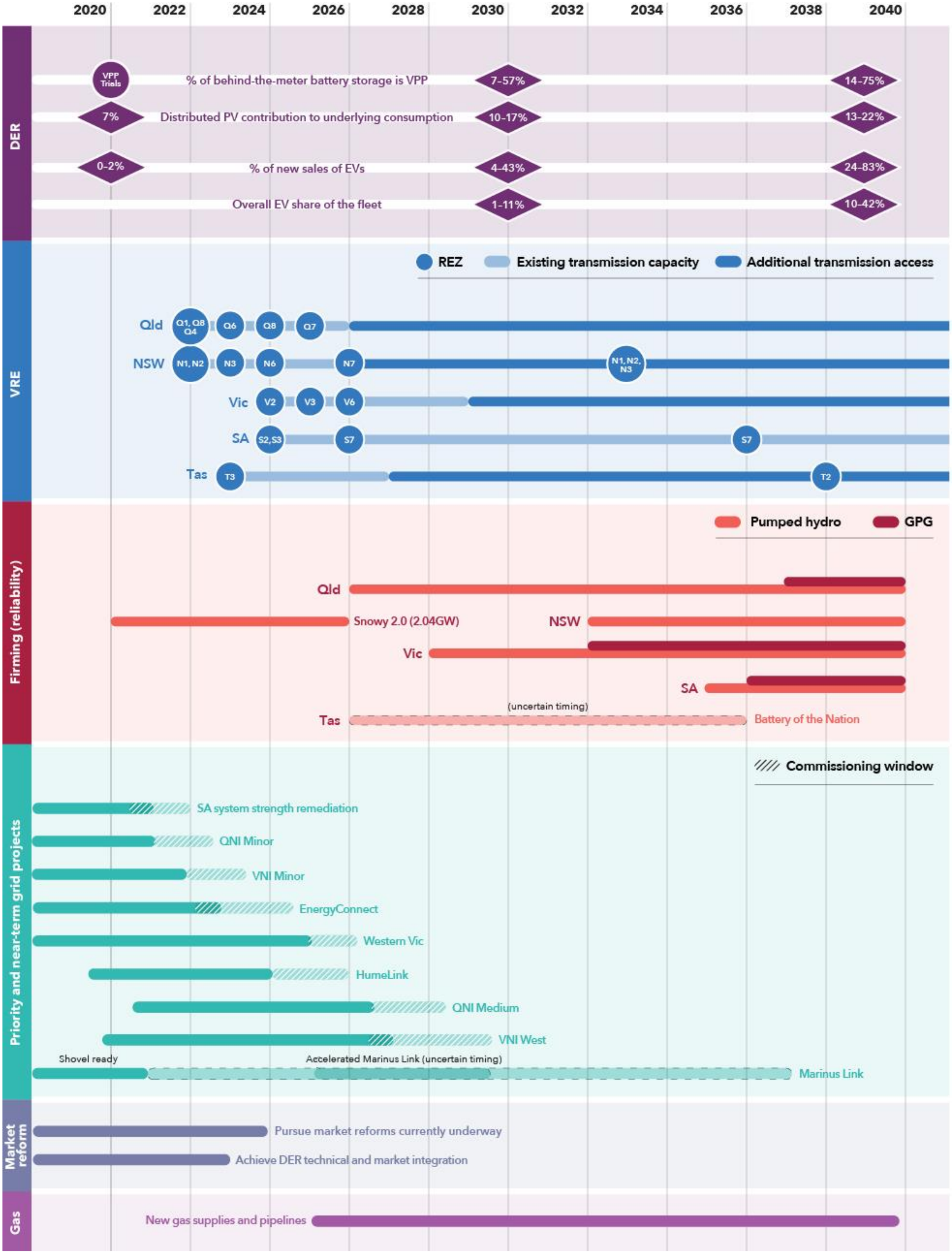
This Draft ISP is a dynamic, whole-of-system plan that includes the optimal development path to assist in planning regulated assets, but also highlights development opportunities and complementary market reform needed to meet future power system needs efficiently and sustainably.

To implement this roadmap, multiple and well-co-ordinated efforts will be needed to progress DER, VRE, firming capability, transmission development, system security, gas development and market reform. And they will need to start now, given the long lead times for major projects, the scale of reform required, and the imminent end-of-life retirement of significant volumes of coal-fired generation.

The indicative timing of these efforts is set out in Figure 22. Given the ISP is a necessarily integrated plan, any lag in in one stream may risk the successful implementation of the roadmap, and lock in a sub-optimal future power system for years to come.

[61] See ESB's information of its post 2025 market design program at http://www.coagenergycouncil.gov.au/market-bodies/energy-security-board

Figure 22 Year-to-year works in the 2020 Draft ISP Roadmap[62]



[62] All dates are indicative, and on a financial year basis. For example, 2023-24 represents the financial year ending June 2024.

Part E

Notice of Consultation on the Draft 2020 ISP

AEMO is developing and consulting on the Draft ISP at the same time as the ESB is consulting on the Draft ISP Rules to make the ISP 'actionable'. The intention is that the 2020 ISP, once finalised will be deemed to have been prepared, consulted and published in accordance with the new ISP Rules on the date when those rules start. In addition, actionable ISP projects will be transitioned to the new regulatory framework, including those that commenced their RIT-T process under the current framework. The concurrent consultations underway are presented in Table 18.

Table 18 Concurrent consultations December 2019 to March 2020

Consultation	Who	Description	Open	Close
Draft ISP Rules	ESB	Converting the ISP into Action - Draft changes to the National Electricity Rules[63] Submissions to: info@esb.org.au	20-Nov-19	17-Jan-20
Draft ISP	AEMO	General comments on the Integrated system plan for the NEM, draft report, including the proposed optimal development path. Call for submissions located within this Draft ISP document, Part E. Submissions to: isp@aemo.com.au	12-Dec-19	21-Feb-20
QNI Medium & VNI West – call for non-network options	AEMO	Submissions relating to non-network options for the QNI Medium and VNI West actionable ISP projects. Call for submissions located in separate notice published on AEMO website[64] Submissions to: isp@aemo.com.au	12-Dec-19	13-Mar-20
VNI West PSCR	AEMO	Project specification consultation report for the Vic-NSW Interconnector West RIT-T[65] Submissions to: VNIWestRITT@aemo.com.au	12-Dec-19	13-Mar-20
Forecasting and planning Inputs and Assumptions	AEMO	Forecasting and Planning inputs and assumptions for 2020[66] Submissions to: forecasting.planning@aemo.com.au	12-Dec-19	7-Feb-20

63 http://www.coagenergycouncil.gov.au/publications/consultation-draft-isp-rules

64 https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan/2019-Integrated-System-Plan

65 https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/VNI-West-RIT-T

66 https://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies

E1. Consultation on the Draft 2020 ISP

Under the Draft ISP Rules, AEMO must publish a Draft ISP and invite written submissions on the content of the draft plan, with the current target publishing date for the Final 2020 ISP being mid 2020. The Draft 2020 ISP includes the Appendices 1-10.

- AEMO invites stakeholders to make written submissions on the Draft ISP. Generally, inputs, scenarios and assumptions should not be re-opened for this consultation for the Draft 2020 ISP (noting that in parallel, AEMO is consulting on inputs and assumptions for use in other 2020 publications).
- Note that VNI West PSCR consultation will occur concurrently with this Draft ISP consultation. AEMO will ensure that comments received for the RIT-T process and the Draft 2020 ISP consultation process will be considered, where relevant, in the other. The intention is to continue the VNI West development under the final ISP rules, once they are in place.

E1.1 Details on making a submission on Draft ISP (before 21 February 2020)

Stakeholders are invited to make a written submission on any matter they consider relevant to the Draft ISP (including the supporting materials). Instructions on how to make a submission are included in the table below. AEMO would particularly welcome submissions on the following matters:

Your views on the development options and actions

1. Has AEMO considered the most appropriate development options for Australia's future energy system? If not, what other credible options should AEMO consider for the 2020 ISP?
2. Has AEMO properly described the identified need for upcoming actionable ISP projects? If not, how can that description be improved?
3. What, if any, additional factors should AEMO consider when identifying which Renewable Energy Zones are best suited to further development?

Your views on the candidate and optimal development paths

4. Has AEMO combined the development options into the most likely candidate development paths? If not, what other combinations should AEMO consider?
5. Are there any other factors that AEMO should take into account when assessing the merits of candidate development paths?
6. What, if any, additional factors should AEMO consider to assess the development and timing of VNI West?

Your views on the ISP document and consultation

7. Are there any aspects of the Draft 2020 ISP that require further or clearer explanation so that results are transparent and can be easily understood?
8. What, if any, modifications should AEMO consider for the proposed 2020 ISP stakeholder engagement plan and timeline?

AEMO notes that the inputs, assumptions and scenarios underpinning the draft ISP have already undergone extensive consultation during the preceding inputs and assumptions consultation.

Table 19 Making a submission on the Draft ISP

Submission close date	21 February 2020. Your input is needed by this time is necessary for AEMO to fully consider it for the final ISP. While AEMO will consider submissions after this date, it may not be possible to include the issues raised in the final ISP.
Form	A document with the title below, emailed to ISP@aemo.com.au
Title of submission document	[Company name] Response to Draft ISP
Confidentiality	Clearly indicate any confidentiality claims by noting "Confidential" in the relevant sections of the submission, and in the body of the email.

E1.2 Public forums on the Draft ISP in early February 2020

AEMO will hold public forums on the Draft ISP on 3, 4, and 5 February 2020 to provide opportunities to raise issues and ask questions on the Draft ISP before close of formal consultation. Information on these sessions is available on our website.[67] Invitations will be sent to our registered mailing list for the ISP. If you are interested in attending, please email AEMO at ISP@aemo.com.au.

E2. Notice requesting submissions on non-network options

The Draft ISP Rules require AEMO to publish a call for non-network options for actionable ISP projects.[68] The purpose of this draft Rule is to ensure that proponents of non-network options have the opportunity to put forward their options for consideration. Submissions on non-network options and other matters are welcome until Friday 13 March 2020.

E2.1 Call for non-network options – QNI Medium actionable ISP project

AEMO has separately published on the AEMO website[69] a call for non-network options in respect of QNI Medium in conjunction with the draft ISP.

E2.2 Call for non-network options – VNI West

The draft ISP also identifies VNI West as an actionable ISP project. Given the need to progress this project quickly, and as the draft ISP Rules are not yet enacted, AEMO has decided to commence the project using the current regulatory framework. To this end, AEMO and TransGrid have published a Project Specification Consultation Report (PSCR) on VNI West in conjunction with the draft ISP 2020. AEMO is also publishing a call for non-network options in respect of VNI West for the purposes of the Draft ISP Rules framework.

AEMO intends to run these consultations in parallel, and coordinate and integrate outcomes. AEMO will ensure submissions to either process will be considered in each, and integrate these into the subsequent modelling and review on a coordinated basis. VNI West may subsequently be transitioned to the new regulatory framework when the draft ISP Rules come into effect (which is proposed to occur on 30 June 2020).

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

[68] Clause 5.22.10 Draft ISP Rules.

[69] https://aemo.com.au/Stakeholder-Consultation/Consultations/Non-Network-Options-Consultation